BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Increase in Rates by Florida Power & Light Company	)))))	**Docket No. 120015-EI**

Direct Testimony and Exhibit of

Robert R. Stephens

On behalf of

Federal Executive Agencies

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July 2, 2012

BRUBAKER & ASSOCIATES, INC.

Project 9608

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Direct Testimony of Robert R. Stephens

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I will address certain cost of service and rate design issues.

Q PLEASE SUMMARIZE YOUR DIRECT TESTIMONY IN THIS CASE.

A My direct testimony can be summarized as follows:

1. I provide an overview of the basic steps needed for establishment of fair and reasonable rates, including the development and use of embedded cost of service studies.
2. I have found three shortcomings in FPL's embedded cost of service study, all related to distribution costs.
   a. It does not appear that FPL has properly separated primary voltage and secondary voltage distribution costs.
   b. FPL should include single-phase primary voltage facilities as functioning only to serve secondary voltage customers and, thus, allocating the cost only to secondary voltage customers.
   c. FPL's cost study ignores the customer-related component of the distribution system associated with the minimum distribution system.
3. I recommend that each of the shortcomings identified above be corrected in this case (in the case of the first item) and in the next rate case for the second and third items.
4. With respect to rate design, I recommend that the rate moderation approach used in revenue allocation be modified from FPL's proposal. Specifically, a 1.5x (times) system average increase criterion should be applied to the base rate charges, rather than total revenues including adjustment clauses.

COST OF SERVICE

Q HAVE YOU REVIEWED THE DIRECT TESTIMONY OF FLORIDA POWER & LIGHT COMPANY ("FPL" OR "COMPANY") AS IT RELATES TO CLASS COST OF SERVICE?

A Yes, I have. This subject is addressed in the testimony and exhibits of Company witness Joseph A. Ender. My focus is on the retail cost of service study and its results, which Mr. Ender addresses beginning at page 20 of his testimony.

Q CAN YOU PLEASE PROVIDE AN OVERVIEW OF THE PURPOSE OF UTILITY COST OF SERVICE STUDIES AND HOW THEY FIT INTO THE RATEMAKING PROCESS?

A Yes.

Overview

Q PLEASE EXPLAIN THE BASIC STEPS FOR ESTABLISHMENT OF FAIR AND REASONABLE RATES?

A The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and whether an increase or decrease in revenues is necessary. Second, we must determine how any increase or decrease in revenues is to be distributed among the various customer classes, i.e., the class revenue allocation. A determination of how many dollars of revenue should be produced by each class is essential of obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues from each class of service and to send efficient price signals to customers.

The standard tool for determining whether a class requires a rate increase or decrease is an embedded class cost of service ("ECOS") study, which shows the rate of return for each class of service. Ideally, rate levels should be modified so that each customer class provides approximately the same rate of return. Finally, in designing individual tariffs, the goal is to base the rate design on the cost of service so that each customer's rate tracks, to the extent practicable, the utility's cost of providing that service to the customers on the tariff.

Q HOW ARE LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS AFFECTED BY THE PRICE OF ENERGY?

A For many large commercial and industrial customers, energy is a primary component of their costs. For some, it may be the most critical component. As such, rate stability and overall cost of electricity prices are vital to the economic health of large commercial and industrial customers in Florida, and to the economic health of Florida itself. Furthermore, any cost of service study or rate design that misallocates costs to large customers will also result in unjust and unreasonable rates.

Q WHAT IS THE BASIC PURPOSE OF AN ECOS STUDY?

A The basic purpose of a class cost of service study is an empirical determination of the cost of serving classes of customers. After determining the overall cost of service or revenue requirement, an ECOS study is used to ascertain the cost of service among customer classes; i.e., a cost of service study shows how each customer class contributes to the total system cost. For example, when a class produces the same rate of return as the total system, it is returning to the utility revenues just sufficient to cover the costs incurred in serving it (including a reasonable authorized return on investment). If a class produces a below-average rate of return, it may be concluded that the revenues are insufficient to cover all relevant costs. On the other hand, if a class produces a rate of return above the average, it is paying revenues sufficient to cover the cost attributable to it and, in addition, is paying part of the cost attributable to other classes who produce a below-average rate of return. The class cost of service study is important because it shows the class revenue requirement, as well as the rate of return under current and any proposed rates.

Q **PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A COST OF SERVICE STUDY.**

A In all cost of service studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the functionalization of costs, as well as the classification of the nature of these costs as to whether they vary with the quantity of energy consumed, the demand placed upon the system or the number of customers being served. Stated another way, functionalization is the classification and arrangement of costs according to major functions, such as production, transmission, and distribution.

Fixed costs are those costs which tend to remain constant over the short run irrespective of changes in output and are generally considered to be demand-related. Fixed costs include those costs which are a function of the size of the investment in utility facilities, and those costs necessary to keep the facilities "on-line." Variable costs, on the other hand, are basically those costs which tend to vary with output and are generally considered to be commodity-related. Customer-related costs are those which are closely related to the number of customers served, rather than the quantity of energy consumed or the peak demands placed upon the system. An understanding of these concepts is essential to cost of service studies, as well as appropriate rate design.

FPL's ECOS Study

Q HAVE YOU REVIEWED THE ECOS STUDY PROVIDED BY FPL?

A Yes.

Q PLEASE DESCRIBE WHAT YOU DETERMINED FROM YOUR REVIEW.

A The ECOS study presented in FPL witness Joseph Ender's direct testimony uses the 12 MCP & 1/13th kilowatthour ("kWh") allocation for generation and transmission costs, with the exception that the cost of transmission "pulloffs," which are essentially the "service drops" for transmission voltage customers, are allocated only to transmission customers. Distribution costs that FPL deems to be demand-related are allocated on non-coincident peak ("NCP") demand allocation factors for primary and secondary distribution costs.

Q DOES FPL's ECOS STUDY ADEQUATELY MEASURE CLASS COSTS?

A FPL witness Mr. Ender states:

> "FPL's cost of service study results for the projected 2013 Test Year are accurately determined and fairly present each rate class's cost responsibility, Rate of Return ("ROR"), and parity position relative to FPL's projected retail jurisdictional ROR.

> These results reflect the forecast of base revenues for each rate class, and an equitable allocation of rate base, other operating revenues, and expenses. The methodologies used to allocate rate base, other operating revenues, and expenses were appropriately applied and are consistent with those previously approved by this Commission." (Direct Testimony of Joseph A. Ender, page 5, lines 5-12).

Unfortunately, FPL's cost of service study fails to measure up to Mr. Ender's claims regarding it. Specifically, FPL's ECOS study fails in three significant ways: First, it fails to clearly segregate the cost of distribution equipment into primary voltage and secondary voltage components, and therefore appears to inappropriately allocate the costs of secondary voltage equipment to primary voltage customers. Second, it fails to recognize that primary voltage lines that are operated in single-phase and dual-phase configurations are rarely constructed to serve primary voltage loads and function primarily to serve secondary customers, and therefore should be allocated to primary voltage customers using only the levels of demand, if any, that are served by those facilities. Finally, FPL's ECOS study fails to recognize that a significant portion of distribution costs - other than the cost of services and meters, are incurred on a per customer basis (i.e., they are incurred whenever service is provided to additional customers, and are incurred regardless of customer demand.)

Separation of Primary and Secondary Distribution Costs

Q DOES MR. ENDER CLAIM TO SEGREGATE PRIMARY AND SECONDARY COSTS IN HIS ECOS STUDY?

A Yes, he does. However, it is unclear from my review whether the FPL ECOS study actually does what Mr. Ender claims. In his direct testimony, Mr. Ender states:

> "... Substations and primary voltage lines are allocated on the basis of the GNCP of customers served from the distribution system. Secondary voltage lines are allocated on the basis of the GNCP of customers served at secondary voltage levels. Transformers are allocated on the basis of the NCP of customers served at secondary voltage levels." (Direct Testimony of Joseph A. Ender, page 22, lines 19-23).

However, upon review of Mr. Ender's workpapers and the minimum filing requirement ("MFR") schedules, I see no evidence that primary and secondary costs are actually segregated. Rather, it appears that FPL only adjusts the loads it used to develop the demand allocation factors so that they reflect the portions of load received at primary and secondary voltages.

Q PLEASE EXPLAIN WHAT YOU MEAN?

A Mr. Ender identifies MFR schedules E-1 through E-6 as those pertaining to the cost of service. Specifically, Mr. Ender sponsors Exhibit JAE-1 which is titled "MFRs and Schedules Sponsored or Co-Sponsored by Joseph A. Ender." Upon review of Exhibit JAE-1 and the MFR schedules referenced by it, I have been unable to find any exhibit that shows how distribution facility costs are segregated into primary facilities and secondary facilities. I have also been unable to identify any schedule that shows the costs associated with primary and secondary facilities being separately allocated.

Q IS IT YOUR BELIEF THAT THESE COSTS ARE NOT BEING ALLOCATED AS MR. ENDER HAS CLAIMED?

A No; I am only saying that if these costs are separated into primary and secondary voltage components, this step is not shown in any of the exhibits or schedules I have reviewed. Neither the MFR schedules sponsored by Mr. Ender, nor the exhibits attached to his testimony show the segregation and allocation of secondary facilities costs separate and distinct from the allocation of primary voltage facility costs.

Q WHY IS THIS AN IMPORTANT ISSUE?

A The separation of distribution costs into primary and secondary portions is important because it ensures that customers served at primary voltages, and which do not receive any benefit whatsoever from the secondary distribution system, will not be allocated costs associated with that secondary distribution system. In contrast, customers who take service at secondary voltage utilize both the secondary system and, in part, the "upstream" primary voltage system.

Q WHAT DO YOU RECOMMEND ON THIS ISSUE?

A I recommend that in his rebuttal testimony, Mr. Ender make more clear and provide explicit evidence that FPL has, in fact, segregated primary and secondary voltage facilities. Alternatively, if FPL has not done so, as suggested by my review of the ECOS study, then it should modify its ECOS study in order to properly take these considerations into account.

Recognizing Single-Phase Primary Voltage Facilities as Functioning Only to Serve Secondary Voltage Customers

Q DO YOU HAVE CONCERNS ABOUT ANY OTHER ASPECTS OF THE COMPANY'S ECOS STUDY?

A Yes. I believe the allocation of certain distribution system plant costs should be more refined.

Q WHY IS A REFINEMENT TO THE DISTRIBUTION PLANT ALLOCATION NEEDED?

A The Company has made no attempt to separate the cost of its single-phase primary distribution system from its three-phase primary distribution system. As a result, the Company's ECOS study allocates costs related to single-phase primary distribution circuits to both primary voltage customers and secondary voltage customers[1] and, therefore, is unreasonable. This allocation is not reasonable because single-phase distribution equipment generally is not used in any significant way to serve primary customers. Therefore, the Company's ECOS study does not properly allocate these distribution costs to the customers for which they are incurred. The ECOS study should be refined to ensure that

[1]Primary voltage customers are metered at 600 volts or higher and will be referred to as "primary customers." Similarly, secondary voltage customers are metered at voltages below 600 volts, and will be referred to as "secondary customers."

customer classes pay for primary voltage facilities only to the extent that those facilities are used to serve them.

Q PLEASE DEFINE THE TERM "PHASE," AS IT IS USED TO DESCRIBE SINGLE- DUAL- OR THREE-PHASE, PRIMARY DISTRIBUTION CIRCUITS?

A When power is generated, it leaves the generating plant in three separate phases, and is transmitted via separate conductors for each phase. Single-phase primary distribution circuits are composed of a single conductor that is energized to a primary voltage level, and a ground conductor. Dual-phase primary distribution circuits consist of two energized conductors and a ground conductor and three-phase primary distribution circuits consist of three energized conductors and a ground conductor. All household appliances, for example, operate on single-phase service, while some industrial applications, such as large motors, operate on three-phase service.

The costs of single- and three-phase distribution facilities are recorded in FERC Accounts 364 – Poles and Towers, 365 – Overhead Conductors and Devices, 366 – Conduit and 367 – Underground Cables and Devices.

Q WITH RESPECT TO ELECTRICAL DISTRIBUTION SYSTEMS, HOW DO THE NUMBER OF PHASES COMPARE TO THE VOLTAGE LEVEL?

A Theoretically, the number of phases and the voltage level are separate and independent parameters of a distribution system. Therefore, a single-phase circuit *could* operate on one of any number of primary or secondary voltages. Likewise, a primary voltage customer could receive single-phase, dual-phase or three-phase service. In practice, however, certain phase/voltage combinations (such as when a single-phase primary circuit is used to serve the heavy load of a primary voltage customer), can lead to instabilities on the electric system and are only used when no other alternative is available. For this reason, costs associated with single-phase primary distribution circuits are predominantly incurred to serve secondary voltage customers. They are seldom used to serve primary voltage customers.

Q HOW SHOULD DISTRIBUTION SYSTEM COSTS BE ALLOCATED IN THE ECOS STUDY?

A Other than those that are directly assigned, distribution system costs should be sorted into three separate sub-functions: (1) three-phase primary costs; (2) single- and dual-phase primary costs; and (3) secondary costs. Three-phase primary costs should be allocated to all customer classes on the basis of peak demand, since these costs are incurred to serve both primary and secondary voltage customers. However, single- and dual-phase primary circuits are not often, if at all, used to serve primary customers. Therefore, single- and dual-phase primary circuit costs should be allocated to the rate classes based only on the load served via such circuits. Secondary costs, of course, should be allocated only to secondary customers.

Q HAS THE COMPANY SORTED THE DISTRIBUTION CIRCUIT COSTS INTO THE SUB-FUNCTIONS AS YOU HAVE DESCRIBED?

A No. As I stated earlier, the Company claims to separate distribution costs into primary and secondary sub-functions, but has not provided any exhibits or schedules showing this separation. Rather, FPL's ECOS study appears to combine distribution costs by FERC Account, and does not differentiate facility costs by voltage level or phase configurations. As such, FPL's ECOS study method is imprecise. By allocating distribution costs as it does, the Company significantly overstates the cost of serving primary customers, nearly all of which tend to utilize three-phase service.

Q HAVE YOU REFINED THE COMPANY'S ECOS STUDY TO CORRECT ITS MIS-ALLOCATION OF COSTS ASSOCIATED WITH SINGLE- AND DUAL-PHASE PRIMARY DISTRIBUTION FACILITIES?

A No, I have not. It would be relatively difficult and time consuming for a non-utility party to have adequate access to records to perform the necessary separations of cost. I have not attempted to do so in the context of this case.

Q IS IT REASONABLE TO EXPECT FPL TO BE ABLE TO SEPARATE COSTS BY SUB-FUNCTIONS AS YOU HAVE DESCRIBED?

A Yes, it is. To begin, single-phase circuits operate at different voltages than three-phase circuits. The common reference to 12 kV, 34.5 kV or 69 kV circuits actually refers to the voltage difference between one energized phase wire and another, that is, the phase-to-phase voltage. Single-phase circuits, however, are typically "split off" from three-phase circuits and are designated by their phase-to-ground voltage, which is generally about 58% of phase-to-phase voltage of the three-phase circuit they originate from. Thus, a single three-phase circuit operating at 12 kV (phase-to-phase) can be split into three single-phase circuits that operate at 7.2 kV (phase-to-ground) each. To ensure the safe and reliable operation of its system, utilities like FPL generally will have operational systems in place such as automated mapping/facility management (AM/FM), supervisory control and data acquisition (SCADA) and geographic information systems (GIS) that should make the identification of single-, dual- and three-phase circuits a relatively simple task.

Q **WHAT IS YOUR RECOMMENDATION IN THIS REGARD?**

A The Company should be required to alter its ECOS study so that the costs of primary distribution facilities are allocated to the customer classes in a manner that reflects cost-causation. Specifically, three-phase primary system costs should be allocated to primary and secondary customers, but the costs associated with single- and dual-phase, primary distribution should be allocated only to rate classes in proportion to the amount of class load served by those facilities. If this cannot reasonably be accomplished in this case, it should happen at the next opportunity, e.g., the next rate case.

Finding the Customer-Related Component of the Distribution System

Q **DOES FPL USE COST OF SERVICE METHODS TO IDENTIFY A PORTION OF PRIMARY AND SECONDARY DISTRIBUTION COSTS AS CUSTOMER-RELATED?**

A No. In its allocation of distribution system costs, FPL identifies only the costs of services[2] and meters as customer-related costs. FPL fails to recognize that there is a customer-related component in the costs recorded in FERC Account 634 – Poles and Towers, Account 365 – Overhead Conductors and Devices, Account 366 – Conduit, Account 367 – Underground Cables and Devices and Account

[2] Transmission and Primary voltage "pull-offs," which are similar to services, are allocated to transmission and primary customers, respectively, on the basis of customer numbers.

368 – Line Transformers, because there is a minimum cost the Company must incur simply to provide service to its customers. This minimum distribution system ("MDS") cost must be incurred whenever a new customer is added to the system, and regardless of the customer's level of demand.

Q IS RECOGNITION OF MINIMUM COSTS A NEW COST OF SERVICE CONCEPT?

A No. Such costs are often recognized in the concept known as the MDS, which represents a collection of costs that must be incurred to extend distribution service to the customers. The MDS has been accepted as valid by numerous state public utility commissions for decades. It has also been presented in the NARUC Manual.[3]

The central idea behind the MDS concept is that there is a cost incurred by a utility when it extends its primary and secondary distribution system, or replaces a component on those systems, that is caused by the utility's obligation to connect customers to its distribution system. This extension of the distribution system is how the utility was built up over decades. By definition, the MDS represents a portion of the cost of every distribution component necessary to provide service, (i.e., meters, services, secondary and primary wires, poles, substations, etc.). The cost included in the MDS, however, is only that portion of the total distribution cost that the utility must incur to provide service to customers; it does not include costs specifically incurred to meet the peak demand requirements of the customers.

[3]National Association of Regulatory Utility Commissioners "Electric Utility Cost Allocation Manual" ("NARUC Manual"), 1992. See Chapter 6, Section II, pages 90-96 of the NARUC Manual.

It is noteworthy that, historically, some opponents to the MDS have incorrectly described it as a method that is based on a set of distribution facilities designed to serve zero or minimum load requirements of customers. This is a faulty description and leads to faulty conclusions. Therefore, it is worth repeating that the MDS method attempts to account for only that portion of the total distribution cost that the utility must incur to provide service to customers; it does not try to measure a specific capacity (i.e., zero or minimum load) of the system.

Q WHAT ARE THE COST-CAUSATIVE FACTORS OF UTILITY DISTRIBUTION SYSTEM INVESTMENT?

A Although it is widely agreed that distribution systems are installed in anticipation of a projected level of peak load, this load is not the only cost-causative factor affecting the cost of the distribution system. Safety and reliability standards, as mandated in the Florida Administrative Code ("F.A.C."), also have a cost-causative impact on the installation of FPL's distribution system. Furthermore, these cost-causative factors have a clearly identifiable "minimum" requirement that is directly related to the number of customers on the system. For example, F.A.C. Rule 25-6.034 – Standard of Construction, states:

> "Each utility shall, <u>at a minimum,</u> comply with the National Electrical Safety Code [ANSI C-2] [NESC], incorporated by reference in Rule 25-6.0345, F.A.C. [4]" (F.A.C. Rule 25-6.034, subpart (2), emphasis added).

This rule, in and of itself, clearly shows that the requirements of the National Electrical Safety Code ("NESC") serve as the basis of the smallest distribution system that every Florida utility must construct.

However, other F.A.C. rules mandate that certain facilities be constructed to NESC standards that are significantly higher than the minimum NESC requirements. For example, F.A.C. Rule 25-6.0342 – Electric Infrastructure Storm Hardening states:

> "...This rule is intended to ensure the provision of safe, adequate, and reliable electric transmission and distribution service for operational as well as emergency purposes; require the cost-effective strengthening of critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions; and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions. This rule applies to all investor-owned electric utilities." (F.A.C. Rule 25-6.0342, subpart (1), emphasis added).

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[4] F.A.C Rule 25-6.0345 – Safety Standards for Construction of New Transmission and Distribution Facilities states:

> "(1) The Commission adopts and incorporates by reference the 2002 edition of the National Electrical Safety Code (ANSI C-2) [NESC], as the applicable safety standards for transmission and distribution facilities subject to the Commission's safety jurisdiction. For electrical facilities constructed on or after February 1, 2007, the 2007 NESC shall apply..."

This rule mandates that the storm hardening plans adopt the extreme wind loading standards specified in the 2007 version of the NESC, for new construction, major planned expansions, rebuilds, or relocations of existing facilities, and critical infrastructure facilities. Such F.A.C. rules cause Florida's electric utilities to incur costs in a manner that is, in no way whatsoever, related to the peak load of the customers, but is directly related to the existence of customers on the system and the facilities required to provide any level of service at all.

Q WHAT EVIDENCE EXISTS THAT SUGGESTS THESE DISTRIBUTION COSTS ARE DIRECTLY RELATED TO THE NUMBER OF CUSTOMERS ON THE SYSTEM?

A As I have already stated, F.A.C. Rule 25-6.0342 requires that planned expansions, upgrades, or relocations of facilities be constructed to "extreme weather conditions." F.A.C. Rule 25-6.064 describes how financial contributions from customers (i.e., Contributions-in-Aid-of-Construction or "CIAC"), that are collected to pay for a portion of the costs of these new or upgraded facilities, should be treated. This rule states:

> "All CIAC calculations under this rule shall be based on estimated work order job costs. In addition, each utility shall use its best judgment in estimating the total amount of annual revenues which the new or upgraded facilities are expected to produce.
>
> (a) ...
>
> (b) In cases where more customers than the initial applicant are expected to be served by the new or upgraded

> facilities, **<u>the utility shall prorate the total CIAC over the number of end-use customers</u>** expected to be served by the new or upgraded facilities within a period not to exceed 3 years, commencing with the in-service date of the new or upgraded facilities." (F.A.C. Rule 25-6.064, subpart (6), emphasis added).

The language in this F.A.C. rule provides support for the idea that the costs associated with providing service to customers, which is what the CIAC is intended to offset, is directly proportional to the number of customers being served. It is a small step to recognize that the costs that are not offset by CIAC payments, i.e., costs that are recorded in FERC Accounts 364 through 368, are also incurred in direct proportion to the number of customers.

Commission's Acceptance of MDS for <u>Choctawhatchee Electric Cooperative, Inc. ("CHELCO")</u>

Q HAS THE COMMISSION RULED ON THE USE OF MDS IN ALLOCATING DISTRIBUTION COSTS IN THE PAST?

A Yes, it has. Unfortunately, the Commission has generally failed to recognize this very real cost driver in allocating costs in several instances. However, this does not mean that the Commission has never recognized MDS in cost studies or that it never will be persuaded that recognition of MDS is proper.

Q HAS THE COMMISSION EVER ADOPTED AN ECOS STUDY THAT INCLUDED THE USE OF AN MDS METHOD BY ANY FLORIDA UTILITY?

A Yes. In Order No. PSC-02-1169-TRF-EC, issued in Docket No. 020537-EC on August 26, 2002, the Commission approved rates for CHELCO that were based on an ECOS study which used the "zero-intercept" method to estimate the MDS costs, and allocated them based on the number of customers.

In addition, I am aware of a rate settlement in the recent Gulf Power Company rate case, Docket No. 110138-EI, which was based on cost of service results that recognized the MDS and allocated associated costs on a customer basis.

Q WHY DID THE COMMISSION APPROVE THE USE OF AN MDS METHOD FOR CHELCO WHEN IT GENERALLY HAD NOT ALLOWED SUCH USE FOR IOUS?

A In its Order No. PSC-02-1169-TRF-EC, the Commission stated:

> "In the past 20 years, we have consistently rejected the use of the MDS classification methodology by investor-owned utilities. In this case, however, we find that CHELCO has four unique characteristics that justify the use of the MDS classification methodology in its cost of service study." (Choctawhatchee Electric Cooperative, Inc., Order No. PSC-02-1169-TRF-EC, issued August 26, 2002 in Docket No. 020537-EC, page 3).

The first unique characteristic identified by the Commission was that "CHELCO has a density of ten customers per mile, while most investor-owned utilities have a density of fifty-five customers per mile or greater." (*Id.*). The Commission's Order also states:

> "In a high-density service territory, several customers may be served by a single transformer, while in a sparsely populated rural area there is usually one transformer for each residential account. Thus, the significant costs of constructing and maintaining a mile of line in a rural service territory are spread to a significantly fewer number of customers." (*Id.* page 4).

Q DO YOU WISH TO COMMENT ON THE COMMISSION'S STATED RATIONALE?

A Yes. There are a couple of problems with using relatively low customer densities as a basis for approving an MDS. First, it is counterintuitive. The customer densities of the IOUs suggest that, on average, "most" IOUs have incurred the cost of connecting an additional customer five and a half times more frequently than CHELCO. This implies that the customer-related costs incurred to connect customers to the system will be much higher for the IOUs than for CHELCO. In other words, most IOUs will incur the costs of transformers and secondary voltage circuits five times as often as CHELCO does. It is unclear, therefore, why CHELCO's relatively low customer density justifies its use of MDS methods, but the much more frequent incurrence of customer-related costs of "most" IOUs does not.

More importantly, I am unaware of any other instances where a Commission has based adoption of the MDS method on the customer density of one utility relative to another. Indeed, the Commission's allowance of the MDS method in the case of CHELCO demonstrates, at the very least, that the Commission is aware that some portion of the primary and secondary distribution system costs, other than those related to services and meters is customer-related. Furthermore, the Commission's acceptance of CHELCO's zero-intercept analysis shows that it also recognizes the usefulness of such analyses to estimate this customer-related portion.

Q WHAT IS THE SECOND UNIQUE CHARACTERISTIC OF CHELCO THAT THE COMMISSION IDENTIFIED?

A The second unique characteristic identified by the Commission was that "CHELCO's rural service territory is quite different from an urban investor-owned utility." The Commission explains in its order:

> "Urban areas are normally occupied throughout the year, and customers usually consume a large amount of electricity that varies seasonally with their heating and cooling load. By contrast, CHELCO provides service to a significant number of barns, stock tanks, electric fences, hunting cabins, and vacation homes. These types of customers consume small amounts of electricity during the course of the year, and their usage is sporadic. A rate design with a relatively low customer charge and a high energy charge for these customers may not recover the costs of investment necessary to serve their load." (*Id.*).

This explanation is surprising in that it begins by describing how perceived differences between rural and urban service territories pertain to the MDS method, yet then draw a conclusion about measuring cost, an empirical determination, on a decision about rate design. Nothing is said to address how urban/rural territory differences negate the importance of the MDS in one case, or increase the importance of the MDS in the other. Furthermore, the comments regarding rate design appear out of place since the MDS is specific to the ECOS study and therefore precedes, but is otherwise unrelated to the rate design process.

Reasons for Past Commission Failure to Adopt of MDS

Q GIVEN THAT THE COMMISSION HAS APPROVED THE USE OF MDS METHODS FOR AN ELECTRIC COOPERATIVE, WHAT REASONS HAS THE COMMISSION GIVEN IN REJECTING THE USE OF MDS METHODS FOR IOUS IN PAST CASES?

A The Commission's objections to the MDS have been numerous and varied. In its June 10, 2002 order (Order No. PSC-02-0787-FOF-E1) issued in regard to FPL's 2002 rate case (Docket No. 010949-E1), the Commission rejected the use of the MDS after providing the following explanations:

1. Although utility and intervenor witnesses relied on the NARUC Manual to support the use of MDS, the NARUC Manual's stated purpose shows it was designed to educate regarding various cost allocation methods, not mandate any particular method.

2. FPL provided no evidence on the specific circumstances that made it choose the MDS methodology over the method approved by the Commission in FPL's previous rate case.
3. The MDS methodology requires construction of a hypothetical system consisting of equipment that is designed to carry zero load. Therefore, no real equipment equates to the costs identified by the zero-intercept methodology. The Commission has rejected MDS in the past for this very reason.
4. Prior orders by the Commission show that it was the MDS's theoretical construct with which the Commission disagreed, not the end result of ECOS studies that use MDS methods.
5. The MDS is internally inconsistent in that it separates out distribution facilities for different treatment than transmission lines.

These are just a subset of the arguments against the MDS that the Commission has accepted over the last 30 years. Indeed, the Commission has not only rejected MDS proposals from FPL, but has also rejected MDS proposals from the Commission Staff, Florida Industrial Power Users Group, South Florida Hospital and Healthcare Association, Tampa Electric Company, and Florida Power Corporation.[5] Unfortunately, there are logical or inapplicable problems with each of the reasons previously relied on by the Commission.

[5]It is noteworthy that the Commission did not raise these objections in approving the rate settlement in the previously mentioned Gulf Power Company case.

Q **DOES THE MDS METHODOLOGY REQUIRE CONSTRUCTION OF A HYPOTHETICAL SYSTEM CONSISTING OF EQUIPMENT THAT IS DESIGNED TO CARRY ZERO LOAD?**

A No. The notion that the MDS is designed to carry no load is an over-simplification, and is also something of a straw-man argument. A better description of the MDS is that it reflects the smallest, lowest cost distribution system that *must be installed for the utility to meet its obligation to provide service to its customers*, but does not contain costs incurred to meet the customer's peak load. Therefore, the MDS methodology only requires the analyst to identify the electric system components that must be installed to meet whatever construction, safety and/or reliability standards are enforced by the governing authorities at the time the line is installed. Costs for meeting system demand above these minimum levels are properly allocated on demand, as FPL has done.

The most realistic and accurate concept of the MDS is that it consists of the network of electric lines that conform to the NESC requirements described in the F.A.C.

Q **IS THE MDS INTERNALLY INCONSISTENT IN THAT IT SEPARATES OUT DISTRIBUTION FACILITIES FOR DIFFERENT TREATMENT THAN TRANSMISSION LINES?**

A No. It is universally understood that any electric system that carries electricity from the generator to the customer must contain transmission, sub-transmission, and distribution components. However, it is also widely recognized that the customer-related portion of costs steadily decreases as one moves away from the end-use customer toward the generator. At the transmission level, the customer-related portion of costs is generally low.

For example, at the meter, the customer-related portion of costs is 100%. Likewise, the customer-related portion of service costs is also 100%. However, the customer portion of costs drops significantly at the level of primary distribution lines. Although the MDS approach could be applied to transmission lines as well, the impact of any reallocation likely would be minor and would not justify the complexity of the additional analysis.

Q PLEASE DESCRIBE THE NESC STANDARDS THAT THE COMMISSION ADOPTED IN THE F.A.C.

A F.A.C. Rule 25-6.0345 – Safety Standards for Construction of New Transmission and Distribution Facilities states:

> "The Commission adopts and incorporates by reference the 2002 edition of the National Electrical Safety Code (ANSI C-2) [NESC], as the applicable safety standards for transmission and distribution facilities subject to the Commission's safety jurisdiction. For electrical facilities constructed on or after February 1, 2007, the 2007 NESC shall apply. Electrical facilities constructed prior to February 1, 2007, shall be governed by the edition of the NESC specified by subsections 013.B.1, 013.B.2, and 013.B.3 of the 2007 NESC. <u>Each investor-owned electric utility, rural electric cooperative and municipal electric system shall, at a minimum, comply with the standards in these</u>

provisions." (F.A.C. Rule 25-6.0345, subpart (1), emphasis added).

Q WHAT IS THE PURPOSE OF THE NESC?

A Section 1, Part 010, of the NESC states:

"The purpose of these rules is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and their associated equipment. They contain minimum provisions considered necessary for the safety of employees and the public. They are not intended as a design specification or an instruction manual." (Emphasis added).

Q DOES THE NESC ALSO ESTABLISH STANDARDS FOR THE ELECTRICAL DEMAND EACH COMPONENT MUST BE CAPABLE OF CARRYING?

A Not directly. To my knowledge, the only situation where the NESC covers something like this is in the case of grounding wires where the NESC sets the "short time ampacity adequate for a fault current."[6] Yet even here, the purpose of the grounding wire is to provide safety or enhance reliability rather than to serve electrical load.

[6]Section 9, Subsection 93.C., Ampacity and Strength.

Q ARE MDS METHODS USED FOR ALLOCATING DISTRIBUTION COSTS IN OTHER STATES?

A Yes, it is not uncommon outside of Florida. Our firm's research indicates that MDS methods are currently, or have been approved by at least 17 state commissions.

Q WHAT DO YOU RECOMMEND?

A The Commission should require FPL to use the zero-intercept method to estimate the customer-related costs associated with the Company's primary and secondary distribution system in its next rate case. By recognizing the MDS in its ECOS study, FPL will obtain a reasonable, yet understated, estimate of costs associated with the MDS. Based on MDS studies by other utilities and in other jurisdictions, it is reasonable to expect that FPL would find that the customer-related component of the distribution system to be in the neighborhood of 35% to 40%, with the remainder being demand-related. Failure to recognize the MDS at all implicitly assumes zero percent, which is arbitrary and unreasonable as an estimate.

RATE DESIGN

Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE DESIGN AND THE ASSOCIATED TESTIMONY?

A Yes. This topic is addressed by FPL witness Renae B. Deaton.

Q DO YOU TAKE ISSUE WITH ANY OF THE PROPOSED BASE RATE DESIGN IN THIS PROCEEDING?

A Yes. The Company's class impact moderation method should be applied differently.

Q HOW DO YOU PROPOSE TO APPLY THE RATE MODERATION APPROACH DIFFERENTLY?

A I propose to alter the rate increase moderation methodology employed by the Company and described in Ms. Deaton's testimony. The Company calculates the 1.5x system average increase cap based on the total increase to each class, including adjustment clauses. Yet, this case involves increases in base rates only, and the adjustment clauses are not affected by decisions in this case. Allowing for the inclusion of adjustment clause revenue impedes somewhat the goal of efficiently and equitably bringing classes closer to parity because it distorts the view of which classes deserve the greatest rate increases according to the Company's cost of service study. It also dilutes the rate moderating effect of the mitigation criterion.

Q PLEASE EXPLAIN WHY INCLUDING ADJUSTMENT CLAUSE REVENUE IN THE RATE MODERATION PROCESS IMPEDES SOMEWHAT THE GOAL OF EFFICIENTLY AND EQUITABLY BRINGING CLASSES CLOSER TO PARITY.

A As alluded to early in this testimony, one of the purposes of a class cost of service study is to be used as a basis for rate design to ensure that the total revenue increase requested by the Company is properly allocated to those classes that are currently being subsidized by other classes. In this rate proceeding, only the base rate revenue is being investigated, and only the base rate revenue was included in the cost of service studies performed. The results of these studies tell us which classes are most deserving of a rate increase. If, then, the resulting revenue increases are adjusted and re-allocated based on a metric that includes non-base rate revenue, the view of which classes are most deserving of a rate increase gets distorted.

Q PLEASE EXPLAIN WHY INCLUDING ADJUSTMENT CLAUSE REVENUE IN THE RATE MITIGATION PROCESS DILUTES THE RATE MITIGATING EFFECT OF THE MODERATION CRITERION.

A Two of the basic tenets of sound rate design are to promote gradualism and the avoidance of rate shock. The 1.5x system average increase cap clearly is a step toward this goal. Since the adjustment clause revenues are not at issue in this case, the only rates that need to be increased gradually, in order to avoid rate shock are the base rates. Other costs, such as the adjustment charges, or even other costs that might be faced by a customer (e.g., natural gas) are not as relevant. Therefore, rate moderation criteria are most effective if applied to only those charges that are subject to change in this case, i.e., base rate charges.

Q WHAT IS YOUR SUGGESTED ALTERNATIVE TO THE COMPANY'S RATE MITIGATION PROCESS?

A As opposed to calculating the maximum revenue increase allowed, and redistributing the revenue shortfall to classes based on the total proposed increase including adjustment clause revenue, I propose to follow the Company's process, except to utilize the proposed base-rate-only increase. Exhibit RRS-1 shows the effects of this adjustment on all rate classes.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Robert R. Stephens

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Southern Illinois University at Carbondale in 1984 with a Bachelor of Science degree in Engineering. During college, I was employed by Central Illinois Public Service Company in the Gas Department. Upon graduation, I accepted a position as a Mechanical Engineer at the Illinois Department of Energy and Natural Resources. In the summer of 1986, I accepted a position as Energy Planner with City Water, Light and Power, a municipal electric and water utility in Springfield, Illinois. My duties centered on integrated resource planning and the design and administration of load management programs.

From July 1989 to June 1994, I was employed as a Senior Economic Analyst in the Planning and Operations Department of the Staff of the Illinois Commerce Commission. In this position, I reviewed utility filings and prepared various reports and testimony for use by the Commission. From June 1994 to August 1997, I worked directly with a Commissioner as an Executive Assistant. In this role, I provided technical and policy analyses on a broad spectrum of issues related to the electric, gas, telecommunications and water utility industries.

In May 1996, I graduated from the University of Illinois at Springfield with a Master of Business Administration degree.

In August 1997, I joined Brubaker & Associates, Inc. as a Consultant. Since that time, I have participated in the analysis of various utility rate and restructuring matters in several states and the evaluation of power supply proposals for clients. I am currently a Principal in the firm.

The firm of Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients, including large industrial and institutional customers, some utilities, and on occasion, state regulatory agencies. More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate, feasibility, economic and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services; and provide technical support to legislative activities.

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

Florida Power & Light Company

Adjustment of Proposed Rate Cap

Line	Rate Schedule	Present Revenue ($000) (1)	FPL Proposed Increase ($000) (2)	Percent Increase (3)	Capped Increase (4)	Reallocated Revenue Increase ($000) (5)	Corrected Proposed Increase ($000) (6)	Corrected Percent Increase (7)	Capped Increase (8)	Reallocated Revenue Increase ($000) (9)	Final Proposed Increase ($000) (10)	Final Percent Increase (11)
1	CILC-1D	$ 74,615	$ 13,033	17.5%	17.5%	$ 287	$ 13,320	17.9%	17.6%	$ (203)	$ 13,117	17.58%
2	CILC-1G	$ 5,563	$ 337	6.1%	6.1%	$ 19	$ 356	6.4%	6.4%	$ 0	$ 357	6.41%
3	CILC-1T	$ 23,669	$ 5,679	24.0%	17.6%	$ (1,518)	$ 4,161	17.6%	17.6%		$ 4,161	17.58%
4	GST-1	$ 313,434	$ 3,471	1.1%	1.1%	$ 989	$ 4,460	1.4%	1.4%	$ 15	$ 4,475	1.43%
5	GSCU-1	$ 1,690	$ 39	2.3%	2.3%	$ 6	$ 45	2.6%	2.6%	$ 0	$ 45	2.65%
6	GSDT-1	$ 880,590	$ 97,178	11.0%	11.0%	$ 3,161	$ 100,339	11.4%	11.4%	$ 47	$ 100,386	11.40%
7	GSLDT-1	$ 319,253	$ 66,065	20.7%	17.6%	$ (9,941)	$ 56,124	17.6%	17.6%		$ 56,124	17.58%
8	GSLDT-2	$ 58,716	$ 13,055	22.2%	17.6%	$ (2,733)	$ 10,322	17.6%	17.6%		$ 10,322	17.58%
9	GSLDT-3	$ 4,086	$ 594	14.5%	14.5%	$ 15	$ 609	14.9%	14.9%	$ 0	$ 610	14.92%
10	MET	$ 2,947	$ 553	18.8%	17.6%	$ (35)	$ 518	17.6%	17.6%		$ 518	17.58%
11	OL-1	$ 11,684	$ 1,303	11.2%	11.2%	$ 43	$ 1,346	11.5%	11.5%	$ 1	$ 1,347	11.53%
12	OS-2	$ 890	$ 123	13.8%	13.8%	$ 4	$ 127	14.2%	14.2%	$ 0	$ 127	14.25%
13	RST-1	$ 2,632,543	$ 306,519	11.6%	11.6%	$ 9,419	$ 315,938	12.0%	12.0%	$ 140	$ 316,078	12.01%
14	SL-1	$ 71,559	$ 7,990	11.2%	11.2%	$ 271	$ 8,261	11.5%	11.5%	$ 4	$ 8,265	11.55%
15	SL-2	$ 1,335	$ (226)	-16.9%	-16.9%	$ 3	$ (223)	-16.7%	-16.7%	$ 0	$ (223)	-16.70%
16	SST-DST	$ 380	$ 58	15.3%	15.3%	$ 1	$ 59	15.6%	15.6%	$ 0	$ 59	15.61%
17	SST-TST	$ 4,297	$ 750	17.5%	17.5%	$ 9	$ 759	17.7%	17.6%	$ (3)	$ 755	17.58%
18	Total	$ 4,407,251	$ 516,521	11.7%	11.7%	$ 0	$ 516,521	11.7%	11.7%	$ 0	$ 516,521	11.7%
19			1.5x system increase	17.6%								

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Rate Increase Mitigation
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