BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PETITION FOR INCREASE IN RATES BY PROGRESS ENERGY FLORIDA, INC. / DOCKET NO. 090079-EI

PETITION FOR LIMITED PROCEEDING TO INCLUDE BARTOW REPOWERING PROJECT IN BASE RATES, BY PROGRESS ENERGY FLORIDA, INC. / DOCKET NO. 090144-EI

PETITION FOR EXPEDITED APPROVAL OF THE DEFERRAL OF PENSION EXPENSES, AUTHORIZATION TO CHARGE STORM HARDENING EXPENSES TO THE STORM DAMAGE RESERVE, AND VARIANCE FROM OR WAIVER OF RULE 25-6.0143(1)(C), (D), AND (F), F. A. C., BY PROGRESS ENERGY FLORIDA, INC. / DOCKET NO. 090145-EU

VOLUME 11

Pages 1465 through 1687

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN MATTHEW M. CARTER, II
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER KATRINA J. McMURRIAN
COMMISSIONER NANCY ARGENZIANO
COMMISSIONER NATHAN A. SKOP

DATE: Thursday, September 24, 2009

TIME: Commenced at 9:32 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6734

PARTICIPATING: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
41			1619
111	WCS-1	1480	1619
112	WCS-2	1480	1619
113	WCS-3	1480	1619
114	WCS-4	1480	1619
115	WCS-5	1480	1619
116	WCS-6	1480	1619
117	PT-1	1640	
118	PT-2	1640	
119	PT-3	1640	
120	PT-4	1640	
121	PT-5	1640	
122	PT-6	1640	
123	PT-7	1640	
124	PT-8	1640	
125	PT-9	1640	
126	PT-10	1640	
127	PT-11	1640	
128	PT-1 (Bartow)	1640	
129	PT-2 (Bartow)	1640	
130	PT-3 (Bartow)	1640	
131	PT-4 (Bartow)	1640	
132	PT-5 (Bartow)	1640	

EXHIBITS

NUMBER:		ID.	ADMTD.
202	Appendix A (Selecky)	1621	1621
203	JTS-1	1621	1621
204	JTS-2	1621	1621
205	JTS-3	1621	1621
279	Credit Value	1546	1620
280	PSC Typical Bills 1984-2009	1570	1620

PROCEEDINGS

(Transcript follows in sequence from Volume 10.)

CHAIRMAN CARTER: Good morning. I'd like to call the hearing to order. And before we get started, staff, there's some preliminary matters. You're recognized.

MS. FLEMING: Yes, Commissioners and Chairman. It's my understanding that Mr. Wright would like to address the Commission this morning.

CHAIRMAN CARTER: Mr. Wright, good morning. You're recognized, sir.

MR. WRIGHT: Good morning, Mr. Chairman, Commissioners. Thank you.

I think I speak on behalf of all the parties. We are making remarkable progress in this case. By my count we have completed, including through the witnesses who have been stipulated, we have now completed 20 of 43 total testimonies, which, to the best of my recollection, which admittedly is a bit hazy at this moment, puts us about 17 testimonies ahead of where we were in that other case.

Accordingly, we all met last night and, and agreed on a schedule, at least as amongst the parties, that we would submit to you for your approval that would have us take up -- the bottom line is, Commissioners, we're kind of running out of witnesses we're so far ahead.

CHAIRMAN CARTER: Okay.

MR. WRIGHT: And we've got -- the schedule we'd propose to you for today is to take Mr. Slusser, Mr. Toomey and Mr. Schultz, subject to the proviso that Mr. Schultz is not available until after lunchtime. We may or may not finish Mr. Slusser and Mr. Toomey before lunch.

CHAIRMAN CARTER: Okay.

MR. WRIGHT: And then call it a day. And if, if I might pose that in the form of an ore tenus motion for time off for good behavior.

CHAIRMAN CARTER: You know, Mr. Wright, we have to always reinforce good behavior. You know, you guys, I want to say to the attorneys as well as to, both from the company as well as from the Intervenors, you guys have done a yeoman's job of working and all like that, and obviously we'll accept that and that'll be our game plan for today.

I appreciate your hard work, some of you have foregone cross-examination. That was your right to do that, but you, for, for allowing it not to happen for whatever reason, but I appreciate that.

Mr. Wright, you may continue.

MR. WRIGHT: Thank you. And then for tomorrow the way, the way the order of witnesses goes, we would complete the testimony of the Intervenor witnesses who are available tomorrow, and that would be Mr. Pous, Mr. Lawton and Mr. Klepper tomorrow, and then take Professor Vander Weide's rebuttal testimony out of order. And the reason to do that is that he is only available tomorrow and Friday, October 2nd. Then, then we kind of run out of witnesses because the company quite reasonably wants its rebuttal witnesses to follow, follow the witnesses whose testimony they are rebutting.

So our proposal would then be to take those four witnesses, Pous, Lawton, Klepper and Vander Weide, tomorrow and call it a day.

CHAIRMAN CARTER: Do you think we'll get finished by 5:00 tomorrow?

MR. WRIGHT: What I can tell you is that based on the representations of counsel at our sidebar conversation last night, that appears highly likely to me, Mr. Chairman.

CHAIRMAN CARTER: Like I say, obviously I want to reward good behavior. Not that you guys have to do anything that I want you to do or anything like that, but I think that it's been a very professional and collegial process. I mean, obviously it's adversarial and all like that, but we don't have to be mean-spirited about it. And I want to commend the attorneys for what you've done. And if we can do that tomorrow, I think we can do that.

Mr. Rehwinkel.

MR. REHWINKEL: Yes, Mr. Chairman. And I wanted to thank Mr. Wright for his comments, and he's kind of the message bearer. But I would like to state for the record that your staff has been the one that has marshaled the process and coordinated things and they worked behind the scenes to facilitate things and make this process transparent to you and to the public that we're all representing here. So I just wanted to thank, to thank them for that, because that's a big reason why we're here --

CHAIRMAN CARTER: Thank you.

MR. REHWINKEL: -- at this point.

CHAIRMAN CARTER: And thank you to our staff as well. You guys always do a great job.

Ms. Van Dyke.

MS. VAN DYKE: Mr. Chairman, this might be the appropriate time to make a request that the Navy has. We had talked to the other parties and to staff about possibly doing the administrative work for putting in our witness and his exhibits, which have been stipulated to by everyone, when we're done with Mr. Slusser's direct testimony, when all the parties are done with Mr. Slusser today. That would complete what the Navy has to do at this hearing, and we could then save everybody a lot of tax dollars by going back home and not spending your tax dollars on another week of hotels.

CHAIRMAN CARTER: We shall accommodate you.

Is that the agreement of the parties?

MR. WRIGHT: Yes, sir.

MS. KAUFMAN: Yes.

CHAIRMAN CARTER: We, we shall accommodate you.

MS. VAN DYKE: Thank you.

CHAIRMAN CARTER: All right? Any further preliminary matters from the parties?

MR. WRIGHT: Here, here to Mr. Rehwinkel's compliments to the staff.

CHAIRMAN CARTER: Thank you.

Ms. Bradley.

MS. BRADLEY: I wanted to join in that as well. It's made it much easier this time, and they've made sure we had copies of exhibits and things the night before so that we would at least have time to go through them before the next day, and that's been greatly appreciated.

CHAIRMAN CARTER: Thank you.

Ms. Kaufman.

MS. KAUFMAN: Mr. Chairman, I'm concurring with what everyone has said in terms of how far ahead we are and the time off for good behavior, but especially the compliments to the staff, because I think getting the documents and all has been a big part of enabling us to, to move a little quicker and maybe have a little bit less cross-examination. Thank you.

CHAIRMAN CARTER: Mr. Brew, are you doing all right this morning?

MR. BREW: Fine, Chairman.

CHAIRMAN CARTER: Okay. Good deal.

MR. BREW: I don't want to burden the record any more other than saying me too.

CHAIRMAN CARTER: All right. The me too.

MR. MELSON: Me too.

CHAIRMAN CARTER: Okay. Mr. Melson, thank you, sir.

COMMISSIONER EDGAR: Mr. Chairman, just to point out, I think our staff, of course, has done a wonderful job, and I appreciate the collegiality, as you said, in a process that is based often on adversarial positions as part of the process. But I also think it's a great example of lessons learned. You know, the case that we did earlier was the first time that many of us have participated in a case of that magnitude, and the fact that we all saw some things that maybe could be done a little more efficiently and were able to adapt so quickly is a testament to everybody's professionalism.

CHAIRMAN CARTER: Thank you. And also to my colleagues, thank you all for being here and for hanging in there. You kind of alternated the schedule a little for efficiency purposes, and I think it worked to everyone's benefit.

Staff, any further preliminary matters?

MS. FLEMING: Just a couple of comments. Just to be clear for the schedule for today then, it's my understanding we will take up Witness Slusser for direct and then Mr. Selecky for the Navy, then Mr. Toomey for direct and Schultz for direct; is that correct?

CHAIRMAN CARTER: Right. And Mr. Schultz will be available in the afternoon. Is that right, Mr. Wright?

MR. WRIGHT: Yes.

CHAIRMAN CARTER: Mr. Rehwinkel. I'm sorry. Mr. Rehwinkel.

MR. REHWINKEL: Yes, he will.

CHAIRMAN CARTER: Okay. We'll accommodate you.

MR. REHWINKEL: Assuming the airlines are working well today.

CHAIRMAN CARTER: Yeah. Well, we'll work with you on that.

MS. FLEMING: And, Mr. Chairman, if I might, I'd also like to note for the record that as of today it's my understanding that Witnesses Dismukes, Marz and Klepper have been stipulated.

CHAIRMAN CARTER: Is that the agreement of the parties?

MR. WRIGHT: Yes, sir.

MR. MELSON: Yes, sir.

CHAIRMAN CARTER: Okay. So when we get to that, we'll do that. But we will take the Navy witnesses out of order, as we said this morning.

MS. FLEMING: That's correct.

CHAIRMAN CARTER: But the rest of them, we'll take them as we come to them. Okay?

MS. FLEMING: Yes.

CHAIRMAN CARTER: You may proceed.

MS. FLEMING: That's all I have, Chairman.

CHAIRMAN CARTER: Anything further from the parties?

Call your next witness.

MR. MELSON: Progress calls William Slusser.

WILLIAM SLUSSER

was called as a witness on behalf of Progress Energy Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. MELSON:

Q. Mr. Slusser, have you been sworn?

A. Yes, I have.

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, Unit 342, North Reddington Beach, Florida 33708.

Q. And what is your profession or occupation?

A. I'm an electric utility rate consultant.

Q. Did you prefile direct testimony in this docket consisting of 37 pages?

A. Yes, I did.

Q. Do you have any changes or corrections to that testimony?

A. Yes, I do.

Q. Would you give us that, please?

A. The change I have is on Page 20 of my direct testimony, beginning on Line 8, the second sentence there that starts "There are a number of utilities," I wish to strike that sentence, and the sentence that follows that ends in the middle of Line 11.

Q. So that the answer would read, "No, not at all. The Commission also approved the "Equivalent Peaker" methodology," et cetera?

A. Yes.

Q. With that change, if I were to ask you the same questions today that are in your prefiled testimony, would your answers be the same?

A. Yes.

MR. MELSON: Mr. Chairman, I'd ask that Mr. Slusser's prefiled direct testimony be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony of the witness will be inserted into the record as though read.

BY MR. MELSON:

Q. Mr. Slusser, did you have six exhibits to that testimony, WCS-1 to WCS-6, that are identified on the master exhibit list as Numbers 111 through 116?

A. Yes.

Q. And am I correct that your Exhibit WCS-1 lists the MFR schedules that you're sponsoring or cosponsoring?

A. Yes.

Q. Do you have any changes or corrections to your exhibits?

A. No.

(Exhibits 111 through 116 marked for identification.)

DIRECT TESTIMONY OF
WILLIAM C. SLUSSER, JR.

I. Introduction

Q. Please state your name and business address.

A. My name is William C. Slusser, Jr. My business address is 16550 Gulf Boulevard, No. 342, North 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 Progress Energy Florida ("PEF" or the "Company") 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 have been a registered Professional Engineer employed by Florida Power Corporation for over 36 years until January 2001, after which time I became an independent rate consultant. I have devoted most of my career to preparing cost of service studies and performing rate analyses and rate design in the establishment of PEF's electric utility rate structure. I have testified on allocated class cost of service and rate design issues for

PEF for many years and most recently in their prior two base rate proceedings before this Commission in Docket No. 000824-EI and Docket No. 050078-EI.

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 2010 test year period. This study provides the basis for determining the Company's total costs and revenue requirements subject to the jurisdiction of this Commission.

Second, I have prepared and present three retail "Allocated Class Cost of Service and Rate of Return Studies" for the test year, each study differing only as to the weighting of demand and energy responsibilities in the allocator for fixed production capacity costs. The Company is recommending the study being referred to as the "12 CP and 50% AD" method be relied upon in this proceeding for establishing each rate class's allocated cost of service or revenue requirement.

Third, I present the Company's proposed tariff schedules of rates and charges which, when applied to test period billing determinants, produce the Company's class and total retail revenue requirements sought in this proceeding.

Q. Do you have an exhibit to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits which are attached to my direct testimony:

- Exhibit No. ___ (WCS-1), a list of the MFR schedules I sponsor or co-sponsor.
- Exhibit No. ___ (WCS-2), Summary Development of Functional Unit Costs with Proposed Revenue Credits.
- Exhibit No. ___ (WCS-3), Estimate of Alternative Resource Investment Required to Serve Peak Demand Only.
- Exhibit No. ___ (WCS-4), Comparison of Class Allocated Cost of Service Study Results.
- Exhibit No. ___ (WCS-5), Development of Target Revenue Increase by Rate Class.
- Exhibit No. ___ (WCS-6), Summary of Proposed Class Revenues and Class Rates of Return.

These exhibits are true and correct.

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

A. I sponsor all or portions of the MFR schedules listed in my Exhibit ___ (WCS-1). These MFR schedules are true and correct, subject to their being updated in this proceeding.

Q. Are the "Jurisdictional Separation Study", the three "Allocated Class Cost of Service Studies", and PEF's proposed rate schedules provided as a part of the Company's MFRs?

A. Yes, they are provided within the portion of the MFRs designated Section E - Rate Schedules. I should mention that the "Jurisdictional Separation Study" and each of the three "Allocated Class Cost of Service Studies" are provided in separate bound volumes apart from the main volume of Section E because of the voluminous output reports included with these studies.

Q. Would you please provide a summary of your testimony?

A. Certainly. My role in this proceeding has been to develop, and to now support, the tariff rates and charges that produce sufficient revenues to (i) recover the Company's total retail jurisdictional cost of service from its rate classes as a whole and (ii) recover from each rate class, to the extent practicable, the portion of the Company's total retail cost of service properly and fairly allocated to that class. To accomplish this objective, I have prepared and sponsor two types of cost studies.

The first of these cost studies is entitled "Jurisdictional Separation Study." This type of study allocates the various items comprising the Company's total system costs between the Company's two jurisdictional businesses: its retail business and its wholesale business. This separation of costs between the two businesses is based on mathematical factors representing appropriate customer, capacity, or energy related cost responsibilities. The allocation of costs to the retail business that results from the application of these factors is the basis for determining the Company's revenue requirements in this proceeding 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 an extension of allocating the costs initially allocated to the retail jurisdiction to the individual rate classes comprising the retail business. The results of this study form the cost basis for establishing the revenue requirement attributable to each of the retail rate classes.

The most significant and noteworthy cost that must be allocated to rate classes is that of fixed production capacity costs. Production capacity related costs make up about 40% of the Company's base recoverable costs and over 80% of the costs recovered through the Capacity Cost Recovery, Energy Conservation Cost Recovery, and Environmental Cost Recovery clauses. PEF is recommending that production capacity costs be allocated using the method called the "12 CP and 50% AD" method. Simply stated, this method allocates 50 percent of the Company's production capacity costs on class demand responsibility and 50 percent of these costs based on class energy responsibility. As I explain later in my testimony, allocating 50 percent of production capacity costs on the basis of energy usage, instead of only about 8 percent under the "12 CP and 1/13 AD" method, a study method specified to be produced in accordance with the Commission's MFRs, is intended to provide a better matching of the allocation of costs and benefits to customer rate classes.

With respect to rate design, the Company is proposing to maintain its current rate structure and has generally revised its base rate charges to produce each class's revenue requirement and move the classes to parity to the extent practical. However, in keeping with past Commission practice, the Company has proposed to limit the percentage revenue increase for a number of rate classes to 1.5 times the overall percentage increase. In addition, the Company is proposing to complete the transition of its curtailable and interruptible general service customers being served for the last thirteen years under "closed" rate schedules and move these customers under the more up-to-date "open" curtailable and interruptible rate schedules.

III. Jurisdictional Separation Study

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 mostly "joint" costs between those customers served under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and those customers served under the jurisdiction of this Commission, or, in other words, between the Company's retail and wholesale businesses. 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 you used to prepare the Company's "Jurisdictional Separation Study"?

A. The accounting data, particularly the data provided in MFR Schedules B, C, and D, sponsored by Company witness Peter Toomey, provide the basic system cost of service information. This data is organized by primary FERC account and is classified or assigned to functional groupings for allocation purposes. The data represents the fully adjusted data for the test period. The primary allocation factors are those used to allocate the fixed power supply capacity costs and are based on the jurisdictional loads occurring on the production and transmission systems at the time of the Company's projected system monthly peaks. This load data, which is sponsored by Company witness John B. Crisp, is projected for each individual wholesale customer and the total retail class for each month of the test period.

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 this Commission and the FERC?

A. Yes. It is important to utilize procedures and methodologies that are consistent with the regulatory practices of both this Commission and the FERC. 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 develop rate base and rates of return to determine test year revenue requirements. And both commissions have specified the use of the "Average of the 12 Monthly Coincident Peak Demands," or the "12CP" methodology to allocate fixed power supply costs for jurisdictional separation purposes.

The Company is also employing the same computerized cost allocation program for preparing its studies in this proceeding as it has used in its previous rate filings before both the FERC and the FPSC. The computer program called ECOS was developed by the FERC staff and is obtainable from the FERC for a nominal fee. The program is designed to establish the rate groups to be allocated costs and requires the input of functionalized, system cost of service data and appropriate allocation factors. The preparation of the input system data is performed on Excel spread sheet tables described as "Cost Assignments to Allocation Categories." The input allocation factors are also prepared on Excel spread sheet tables and are described as "Development of Input Allocation Factors." These tables are included in the MFR volume containing the "Jurisdictional Separation Study."

Q. Who are the customers that comprise the Company's separated wholesale business?

A. Wholesale customers consist of municipals, rural electric cooperatives, and other electric utilities or entities that have the authority to generate into, or receive power from, PEF's transmission grid. PEF's rates and services to these types of entities are subject to the jurisdiction of the FERC. The Company currently provides wholesale full requirements sales to the Cities of Bartow, Winter Park, Mt. Dora, Quincy, Chattahoochee, and Williston. Wholesale partial requirements sales are provided to the Florida Municipal Power Agency, New Smyrna Beach Utilities Commission, Seminole Electric Cooperative, and the City of Tallahassee. Wholesale stratified production sales, which are sales specifically from a particular type of production resource, such as base, intermediate, or peaking, are made to Seminole Electric Cooperative, Inc., the City of Homestead, Gainesville Regional Utility, Tampa Electric Company, and Reedy Creek Improvement District. In addition to providing power sales to wholesale entities, the Company also provides firm transmission service to a number of other entities including the Cities of Fort Meade, Wauchula, and Tallahassee, the Georgia Power Company, and the co-generator Central Power & Lime.

Q. Have you developed a specific treatment in your "Jurisdictional Separation Study" for assigning production costs to those wholesale customers purchasing stratified production services?

A. Yes. First, it should be understood that production cost responsibilities for most of the Company's sales are based on average, overall production embedded costs. By comparison, the cost responsibilities for stratified wholesale sales are based on average, embedded costs for the particular type or types of production resources used to make these sales.

In order to assign the appropriate costs to stratified sales, it is necessary to present all the various system production costs, i.e. plant-in-service, accumulated depreciation, fuel inventories, operation and maintenance expenses and depreciation expenses, as separately stated stratified costs.

For the assignment of those production costs that are considered fixed, a demand allocator is developed for each stratum that represents the load responsibility of the stratum sales. This is determined by dividing the average 12 CP load of stratified customers by the total average monthly system stratified resource capability adjusted for reserves. Each stratum allocator results in a specific capacity cost responsibility, expressed as a percentage for the type of generation resource required. The remaining cost responsibility for the stratified resources is allocated to the average rate customer classes based on their 12 CP demands. This procedure insures that 100% of the costs have been assigned. This development is contained in the "Development of Input Allocation Factors" section of the separate MFR volume entitled "Jurisdictional Separation Study."

For the assignment of production costs that are considered variable, a stratified resource unit energy cost is calculated and applied to the appropriate stratified customer energy sales. These assignments are contained in the production O&M cost assignments section of the "Jurisdictional Separation Study."

Q. Have you applied any other different costing treatment to the wholesale jurisdiction?

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

Q. Would you summarize the wholesale business's cost responsibilities for the Company's investment in production, transmission, distribution, and general plant that result from the "Jurisdictional Separation Study"?

A. Yes. The wholesale business is responsible for 13.4% of the production, 32.7% of the transmission, 0.2% of the distribution, and 8.7% of the general plant investment of the Company. The wholesale business requires a higher investment in transmission plant due to other wholesale entities delivering power in, on, out, or through the Company's transmission system. The wholesale business requires very little distribution investment since most wholesale points of receipt or delivery are established on the Company's transmission system.

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

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

A. This study is an extension of the "Jurisdictional Separation Study" in which the retail jurisdictional costs are further allocated to the various rate classes comprising the retail jurisdiction. 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 latest load research data. The study provides: (i) class realized rates of return at present and proposed rates, (ii) class revenue surplus or deficiencies from full cost of service, and (iii) functional unit cost information for rate design consideration.

As with the separation study, the FERC computer cost allocation program is utilized to perform the cost allocations to retail rate classes. To obtain the functional cost information required by the Commission's MFRs, additional program runs are made utilizing each class's cost results and allocating this data to functional categories.

Q. How did you establish the customer rate classes or rate groups that were used as costing entities in your "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. The rate schedules for general service non-firm service, i.e. the curtailable and interruptible rate schedules are treated as one rate group since these customers only differ as to Company or customer control of their non-firm load capability. Each rate schedule serving either (i) optional time of use, (ii) load management service, or (iii) standby service, has 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/Interruptible General Service (CS/IS)

(6) Lighting Service (LS), consisting of sub-groups for the costs of

  (a) Lighting Energy

  (b) Lighting Facilities (Fixtures and Poles).

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. The cost of service for each of the Company's rate classes, which ultimately translates into the class's revenue requirement for rate design purposes, is allocated or assigned to the following functional 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) and

(10) Customer Billing, Information, 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, *i.e.*, the number of customer bills, energy sales, or billing demands. This type of information is then used as a consideration in rate design when establishing the level of customer charges, demand charges, energy charges, etc. A summary of the functional cost of service for each rate class and their respective unit costs is provided in my Exhibit No. _____ (WCS-2). The production capacity costs in this exhibit are based on the "12 CP and 50% AD" allocation method. All cost of service amounts shown have been reduced by an allocation of revenue credits from other operating revenues, including the additional revenue credits from proposed increases in service charges.

Q. What costing treatment is utilized in the class cost of service studies for those rate groups that contain non-firm service provisions?

A. PEF's residential service and general service rate groups include optional load management provisions that permit the interruption of certain specified customer equipment, while the interruptible service and curtailable service rate groups require that all, or a significant portion of the customer's load, be subject to interruption or curtailment as a condition for service. However, the development of costs for these rate groups is based on the premise that all of the groups' load requirements are firm. This is because the Company's various forms of non-firm service are elements of its demand side management (DSM) program and, therefore, the value of each rate group's load subject to interruption or curtailment is not a consideration in setting base rates, but instead is recognized separately by the payment of billing credits that are established in and recovered through PEF's *Energy Conservation Cost Recovery* clause.

Q. Mr. Slusser, you indicated that three "Allocated Class Cost of Service and Rate of Return Studies" have been prepared for this proceeding which differ only by the method employed to allocate production capacity costs. Would you describe the three production capacity cost allocation methods that you have employed?

A. Yes. The Commission's MFRs require, at a minimum, a cost of service study be provided that allocates production plant using the average of the twelve monthly coincident peaks and 1/13 weighted average demand (the "12 CP and 1/13th AD" method). This method allocates 12/13, or about 92 percent, of production capacity costs on the basis of class monthly coincident peak demands, thus the term "12 CP"; and 1/13, or about 8 percent, of production capacity costs on the basis of class average hourly demands, thus the term "AD". It should be noted that average demand and annual energy usage are mathematically the same allocation basis since average demand is simply total energy use divided by number of hours of use.

PEF believes that an energy weighted allocation of only 8 percent under this study method gives too little recognition to the role energy is given in generation facility planning. For this reason, the Company has prepared two additional studies that recognize the greater extent that energy considerations bear in the incurrence of production capacity costs.

The Company has prepared and presented studies that weight energy responsibility by 25 percent and 50 percent respectively as being more appropriate weightings. These studies are referred to as the "12 CP and 25% AD" study and the "12 CP and 50% AD" study.

Q. Mr. Slusser, do you know the origin of the Commission MFR's prescribed "12CP and 1/13 AD" study methodology?

A. Yes, this methodology became crystallized by the Commission in a series of rate cases being conducted for each of the four major Florida investor owned electric utilities in the early 1980's. These cases followed the Commission's adoption of a Cost of Service standard stating "Rates charged by any electric utility for each class of customer shall be designed to reflect the costs of providing electric service, to the maximum extent practicable and with due consideration of the other rate making elements specified in Section 366.06(1), Florida Statutes." The adoption of this standard placed a greater emphasis on relying on a specific cost of service study in rate cases thereafter.

At that time the focus was on 12 CP demand responsibility, but there was difficulty in determining the appropriate 12 CP demands to be used in particular for interruptible load. Interruptible customers were, as they are now, significant rate classes for Tampa Electric Company (TECO) and PEF's predecessor company Florida Power Corporation. Since interruptible load is not included in capacity planning, interruptible load would have no cost responsibility under the 12 CP methodology. A consideration of injecting an amount for average demand in the allocator in TECO's rate case, Docket No. 820007-EU, gave rise to the method called "12 CP and 1/13 AD." This was justified on the premise that each class will pay for some portion of the production plant it uses, even if the usage is not coincident with the system peak. It also recognized for TECO, that some of the production plant costs, such as coal handling equipment, varied more with the amount of kWh produced than with the demand placed on the system.

Even with this introduction of average demand into the allocator, there were differences of opinion as to the appropriate mathematical inclusion of average demand in the allocator. At first with TECO, average demand was inserted as a thirteenth number for each class along with the other 12 coincident peak numbers. For a company with a 50% load factor, this resulted in only about 1/26 of production plant costs being allocated on an average demand basis. The "12 CP and 1/13 AD" method was soon thereafter interpreted to mean that 12/13 of production capacity costs be allocated on a 12 CP basis and 1/13 of costs on an average demand basis.

Q. Why does PEF believe now that energy responsibility should be given a much greater weighting for production cost responsibility?

A. Generation investment strategies are different today than that reflected in the Company's generation fleet nearly thirty years ago. The emphasis years ago was to build conventional power plants that met accepted reliability criteria. Today, due to the relatively greater cost of fuel and stricter emissions requirements, the emphasis is on providing clean and efficient generation as well as satisfying reliability criteria. In recent years, PEF has applied state-of-the-art technologies in the construction of more efficient generation including the Hines Energy Complex, the repowering of Bartow power plant, and uprates to the Crystal River nuclear unit. Its future plans to install new, advanced nuclear generation in Florida will provide a clean, low-cost and less volatile fuel source. All of these investment strategies have a higher up-front capital cost. However, the benefits to the customers are primarily related to the costs for fuel which is apportioned on an energy basis. There should be no question that a significant portion of the Company's production capacity costs being incurred should be apportioned in the same manner as the customer realizes the benefits, i.e. on an energy basis.

Q. Have you performed any type of analysis that quantifies how much weighting energy should be given for production capacity cost responsibility?

A. Yes. I had prepared an exhibit in the Company's last base rate proceeding, in Docket No. 050078-EI, which resulted in the determination of an energy weighting of about 50 percent for PEF. I have updated this exhibit for this proceeding with nearly the same results and have included it as Exhibit No. ____ (WCS-3). The exhibit is intended to provide an estimate of the additional investment expended by PEF in production plant for reasons other than meeting peak demand. The theory being employed therein is that if meeting peak demand had been the sole consideration, the Company would have installed less expensive, simple-cycle combustion turbine units. Instead, as can be seen from this exhibit, PEF has invested approximately twice the cost of peaking units in order to incur lower operating costs for those generating units that will need to remain online well beyond peak demand periods.

Q. Is a weighting for energy responsibility of 50% an unusually high weighting by a utility for production capacity cost responsibility?

A. No, not at all. ~~There are a number of utilities of which I am aware that employ a method called the "Average and Excess". This method effectively weights energy responsibility by the utility's load factor which is generally~~ in ~~the 50% to 60% range~~. The Commission also approved the "Equivalent Peaker" method applied inTampa Electric Company's Docket No. 850246-EI, which resulted in an energy weighting of 70%. There are a number of other recognized allocation methods such as "Probability of Dispatch" and "Base-Intermediate-Peaking" that effectively result in a similar weighting of energy responsibility. These latter methods require significant efforts to develop from hourly cost and load data and as a result are not often used. A 50/50 weighting is a good representation of the dual function that generating resources perform: (1) providing the demand capability to meet the Company's system peak loads, and (2) generating the energy needs of its customers throughout all hours of the year.

Q. Why did you prepare the "12 CP and 25 AD%" cost study method for inclusion in this filing?

A. I have included the "12 CP and 25% AD" study in this proceeding because it has been recommended by both PEF and TECO in recent years and is a worthy study method to include in this proceeding. First, this study method was recommended by PEF in each of the Company's prior two base rate proceedings in Docket No. 000824-EI and Docket No. 050078-EI. Second, this is the study method being proposed by TECO in their pending rate case in Docket No. 080317-EI. Although both PEF and TECO have recommended this method, it was viewed as a compromise between that of the Commission prescribed 1/13th energy weighting and that of the "Equivalent Peaker" resultant energy weightings of 50% for PEF and 70% for TECO.

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-4) provides a summary comparison that shows the allocated class cost of service resulting from each study and calculates the difference in base cost responsibility of the two additional studies to that of the Commission MFR's prescribed study method. The base cost of service differences are shown in dollars as well as the base rate effect on a dollars per thousand kWh basis for each rate class.

Q. Would the production capacity cost allocation method that the Commission chooses to rely on in this proceeding for base rate costs also apply to the allocation of capacity costs in any of the Company's cost recovery clauses?

A. Yes. The Commission's practice has been to use the same production capacity cost allocation method approved in a utility's last base rate case as the method to be employed for allocating any demand related costs in a utility's cost recovery clauses. For PEF, the production capacity allocation method is employed for (i) all recoverable costs of the Capacity Cost Recovery (CCR) clause (including Nuclear Cost Recovery), (ii) the demand classified recoverable costs of the Energy Conservation Cost Recovery (ECCR) clause, and (iii) the demand classified recoverable costs of the Environmental Cost Recovery Clause (ECRC). Therefore, any change in production cost allocation methodology resulting from this proceeding would be the method employed in these clause calculations effective on or after the institution of the Company's revised base rates. For purposes of determining the appropriate CCR, ECCR, and ECRC billing adjustments for inclusion in the billing comparisons contained in the MFRs of this filing, the billing adjustment factors for these clauses reflect the "12 CP and 1/13" method for present rate calculations and the "12 CP and 50% AD" method for proposed rate calculations.

V. Billing Determinants

Q. Would you explain the term "Billing Determinants" as it is used in ratemaking?

A. Yes. Billing determinants are those rate parameters or units of measurement of electric service by customers that, by application of the rate charges under the applicable rate schedules, produce the Company's billed revenue. Billing determinants include at a minimum a count of active customers and their kWh usage under each rate schedule. Additional billing determinants may be required in particular rate schedules that include measurements of kW demand, time of use, power factor, metering and delivery voltage, or other unique units of measurement for the services being rendered under the rate schedule.

Q. How did the Company derive the projected billing determinants for the test year that forms the basis for calculating the present revenues and proposed revenues being presented in this proceeding?

A. First, the starting point for deriving the billing determinants in this proceeding is the Company's Customer and MWH Sales Forecast for the 2010 calendar year test period. This forecast is described in the testimony of witness John B. Crisp. The forecast provides numbers of customers and MWH sales by revenue reporting classifications of residential, commercial, industrial, and sales to public authorities. From that forecast, the Company then develops a customer and sales forecast consisting of the Company's major rate schedules RS, GS, GSD, CS, IS, and LS. Next, actual billing determinants based on historic calendar year 2007 are summarized for each rate schedule to identify lines of billing, sales by delivery voltage, kW to kWh ratios, Time of Use rate relationships, and other rate parameters utilized in calculating customer billings. Lastly, these historic billing relationships are applied to the Company's projected 2010 customer and sales forecast by major rate class to derive the projected billing determinants for each rate schedule that correspond with the test year. These resultant calculations are the billing determinants being employed in

MFR Schedule E-13c and applied to present and proposed charges to produce the revenues attributable to each rate class as shown thereon.

VI. Development of Target Class Revenues

Q. Please describe generally the procedure used to determine the portion of the Company's total proposed base rate revenue increase assigned to each rate class.

The focus in determining the portion, or percentage, of the Company's proposed base rate revenue increase to be assigned to each rate class is the class cost of service study. For this purpose, the cost of service study utilizing the "12 CP and 50% AD" production capacity allocation method is relied upon. Ideally, the rates developed in a proceeding such as this will produce revenues from each of the rate classes that equal the costs allocated to that class by the cost of service study.

Therefore, the first step in determining how much each rate class should share in the Company's total revenue increase, *i.e.*, the shortfall between total revenue requirements and total revenues under current rates, is to determine for each rate class the shortfall between the costs allocated to that class and the revenues produced by applying current rates to the class's test year billing determinants. The next step is to determine how much of each class's revenue shortfall will be offset by additional revenues from any increase in other operating revenues, such as the increase in certain service charges proposed by the Company in this proceeding. Once the net revenue deficiency of each rate class has been determined, the final step is to identify whether any ratemaking policy considerations should limit the amount of any rate class's revenue increase. Where an increase limit is imposed on a rate class, the other rate classes must make up the deficiency. This deficiency resulting from limiting class increases is spread to the other rate classes in proportion to each of their deficiencies to the extent that their resultant increase does not exceed an imposed limit.

The completion of this three-step procedure produces what we refer to as the target revenues for each rate class. This is the sum for each class of its present revenues and its apportioned increase. These are the total class revenues the Company will attempt to produce through its design of proposed rate charges and their application to test year billing determinants.

Q. Have you prepared an exhibit that develops the proposed class target revenues from the procedure you have described?

A. Yes. My Exhibit No. _____ (WCS-5) was prepared for this purpose. In this proceeding, three of the rate class's revenue increases were limited as a result of recognizing the Commission's prior practice of limiting any individual class's increase to 150% of the overall percentage increase in the Company's total revenues. Increases for two of the classes, the CS/IS rate class and the Lighting – Energy sub-group rate class, are significantly limited by this practice. The third rate class, GSD, is being limited a very minor amount. In other words, the customers in the Curtailable and Interruptible class and the Lighting- Energy class actually should be bearing a larger percentage of the increase than that being proposed, but because of the practice established by this Commission, the customers in the Residential and General Service non-demand classes must bear a larger percentage of the increase.

VI. Rate Design

Q. Would you summarize the more significant rate design changes or revisions the Company is proposing to make to its Tariff in this proceeding?

A. Yes. The noteworthy proposed changes are as follows:

a. Most all base rate charges contained in the Company's rate schedules have been revised in order to produce the target class and total revenue requirements being sought in this proceeding.

b. The Customer Charge for Residential Service is designed to include the customer's transformer cost in addition to other normally included costs.

c. The Residential Time of Use Rate Schedule, RST-1, is being closed to existing customers.

d. The base rates and billing adjustment charges for general service interruptible service and curtailable service are being set the same.

e. The "closed" IS-1/CS-1 rate schedules are being eliminated and the affected customers transferred to their applicable "open" IS-2/CS-2 rate schedules.

f. The higher voltage delivery credits applicable in the general service demand metered rate schedules reflect the full avoided distribution costs rather than only the avoided transformation cost.

g. The Company is updating its service charges and adding the service charge for "Investigation of Unauthorized Use" to its Tariff.

Q. Why is the Company proposing to include the cost of a customer's transformer in the Residential Service's Customer Charge?

A. The Customer Charge is intended to recover those fixed costs that are independent of the level of a customer's usage. The transformer, like the residential customer's meter and service wire tap, are considered necessary facilities to be installed to make a customer electrically active and should more appropriately be recovered in a Customer Charge than in a usage charge.

Q. Is the Company making any other rate design changes to its Residential Service rate offerings?

A. The only rate design change the Company is seeking for residential service is to close its Residential Time of Use Rate Schedule, RST-1, to new customers. The Company has had little interest in this particular rate schedule and only 38 customers currently take service under this option. The Company plans to introduce in the near future a critical peak pricing rate schedule that is expected to attract more interest and be more effective than the current TOU rate. The Company does not feel it is worthwhile to offer the current TOU rate to any additional customers at this time.

Q. Is the Company making any rate design changes to its General Service Non-Demand Rate Schedules, GS-1 and GST-1?

A. No. As has been the practice since 1982, the base rate energy charges of these schedules are being set equal to that of the effective residential service rate to circumvent any potential administrative problem of residential customers claiming entitlement to the non-residential rate based on commercial activities in a residence.

Q. What changes are proposed for Rate Schedule GS-2, the Company's General Service 100% Load Factor rate?

A. The only change in this rate schedule is the revision of the Customer Charge and Energy and Demand Charge in order to produce the proposed target class revenues.

Q. What changes are proposed for Rate Schedules GSD-1 and GSDT-1, the Company's General Service Demand Rates?

A. As for most all the Company's rate schedules, the Customer Charge and the Energy and Demand Charges are being revised to produce the class's target revenues determined after taking into account (1) the amount of revenues from the proposed Firm Standby Service charges established by the cost of service study, and (2) the effect on revenues from proposed cost of service based changes in delivery voltage credits, power factor credits and charges, and premium distribution charges.

Q. Will the Company's proposed rate changes to its general service rate schedules result in any customers being transferred from one general service rate schedule to another?

A. Yes. Under the Company's proposed rates in this proceeding, it has been determined that approximately 7,500 general service customers, presently taking service under the General Service Demand (GSD) rates, would receive lower billings under the proposed General Service Non-Demand (GS) rates. This is due to the change in the pricing relationship between these rates resulting from different proposed percentage increases being applied. Under current rates and pricing relationships, the GSD rate is more advantageous for customers having average monthly load factors greater than 19%. Under the proposed rates, customers must have average monthly load factors greater than 28% to find the GSD rate to be more economically advantageous. Thus, the Company has recognized that current GSD customers having load factors between 19% and 28% need be transferred to the GS rate as being more economical under the Company's proposed rates.

If further rate revisions to the general service rates are given consideration in this proceeding, a similar analysis must be performed again to determine any change in the pricing relationship between these rates and the resulting change in billing determinants under each rate that would occur as a result of general service customers transferring to the most economic rate.

Q. Why are you treating the curtailable customers and interruptible customers as a combined rate class for establishing cost of service, base rates, and billing adjustments?

A. These customers are simply subsets of customers normally taking service under the Company's general service demand rate schedules. They differ only in that they are willing to subject their load to curtailment or interruption. However, the Commission has had a practice of recognizing these customers as separate rate classes from that of the general service demand rate class. Accepting that, the Company finds no reason to differentiate the curtailable customers from the interruptible customers for ratemaking other than provisions related to their non-firm service. Both groups possess non-firm load capability and only differ as to allowing the Company to control their non-firm load when needed or for the customer to adhere to a Company request to control their non-firm load. For this difference, the curtailable customers are provided a smaller credit than that provided for interruptible customers. In all other respects, the Company has set the base rate charges and billing adjustments the same in the curtailable and interruptible rate schedules and they are treated as one rate class in establishing their cost of service.

Q. Why is the Company proposing to eliminate its "closed" General Service Curtailable and Interruptible rate schedules?

A. The Company is proposing to bring an interim measure to final closure by the elimination of the curtailable and interruptible rate schedules that have been "closed" to new customers since April 1996. The Company will eliminate Rate Schedules CS-1, CST-1, IS-1, and IST-1and transfer the customers served under these rate schedules to the applicable CS-2, CST-2, IS-2, or IST-2 rate schedule. These rate schedules were previously "closed" by the Commission because they were no longer cost-effective. The Commission allowed the customers then served under the rate schedules to be grandfathered to avoid the possibility of hardship from their immediate transfer to comparable, but cost-effective rate schedules.

The customers affected by this elimination will continue to have the same quality of service and be subject to the same base rates and recovery clauses as they would have otherwise, and with some modifications, the same terms and conditions as they would have otherwise. The primary difference is that they will be subject to the application of the curtailable and interruptible demand credits established for the "open" schedule to which each will be transferred.

There are some differences and modifications required to the applicable "open" schedules to accommodate the transferred customers. The first relates to the time period of a required notice provision by a customer who may desire to transfer to a firm rate schedule. The new notice for the customer is actually less restrictive, that being 36 months, than the eliminated rate schedule which requires 60 months. The Company proposes to permit these transferred customers to use the less restrictive provision that is in the open rate schedules.

The second difference relates to the requirement of a minimum billing demand of 500 kW under the applicable rate to which the customer is being transferred. The Company has found that loads of less than 500 kW posed administrative problems and, in many instances, required customized interruptible equipment and metering installations which were not practical or cost effective. The Company is proposing that any transferred customer that has a demand less than the desired minimum be exempt from application of the proposed minimum monthly billing demand. This seems appropriate since the Company has already installed its interruptible equipment and metering for these customers.

A third difference relates to a limitation incorporated in the Applicability Clause of the CS-2, CST-2, IS-2, and IST-2 rate schedules for customer accounts established under any of these schedules after June 3, 2003. The customers establishing service after this date are limited to those premises at which an interruption or curtailment will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. The Company is aware that certain of the customers proposed to be transferred to one of these schedules may not satisfy this limitation and proposes that the limitation not apply to them.

A final difference relates to the closed tariff's exclusion of curtailment or interruption of an affected customer's facility during periods of use as a public shelter. This exclusion is proposed to be added to the open tariffs as it applies only to these transferred customers.

Q. How were the charges for the "open" Curtailable and Interruptible rate schedules modified to produce the target revenue requirements for this class?

A. Similar to the GSD rate design, Customer Charges and Energy and Demand Charges are revised to produce the class's target revenues after taking into account (1) the amount of revenues from the proposed Curtailable and Interruptible Standby Service charges established by the cost of service study and (2) the effect on revenues from proposed cost of service based changes in delivery voltage credits, power factor credits and charges, and premium distribution charges. It was intended to increase Energy Charges and Demand Charges proportionally to provide a uniform percentage increase to customers within the class regardless of load factor. This appears to have been effectively accomplished as evidenced by the resultant similar percentage increases in revenues from Demand Charges as compared to increases in revenues from Energy Charges as shown in MFR E-13c for these rate schedules. However, the proposed Demand Charges as stated for secondary voltage service has the appearance of being increased at a much greater percentage. This development is necessary to recognize the large proportion of service being provided under these schedules at higher voltages. As was previously mentioned and will be discussed further in my testimony, the proposed delivery voltage credits afforded the higher voltage customers are much greater than the present delivery voltage credits. This revenue effect necessitates that the stated charge for secondary service reflect a much larger inclusion of distribution primary and secondary costs in the stated demand charge.

Q. By the elimination of the "closed" curtailable and interruptible rate schedules, all curtailable and interruptible customers are being

transferred to the corresponding "open" rate schedules and are subject to the credits provided for under these schedules. Has the Company reviewed the credits being provided for under the "open" rate schedules?

A. Yes. The credits provided for under the "open" rate schedules differ in two respects from those under the "closed" rate schedules. First, the level of the credit is lower, and second, the application of the credit to the customer's billing demand is different. The Company established both the level and application of the credits provided for in the "open" tariff as being cost effective in Docket No. 000824-EI. Some slight changes have been made to the level of the credits in more recent years when adjustments to the credits were included in base rate adjustments approved by the Commission. The Company believes the level of the credits under these "open" schedules continues to be cost effective, i.e. they do not exceed avoided capacity costs, and therefore are appropriate. The Company also believes that the application of the credits to a load factor adjusted billing demand under the "open" rate schedules more appropriately recognizes the expected demand capability of the customer at peak times than the rate design under the "closed" schedule which applies the credit to a customer's maximum billing demand whenever it occurs.

Q. Is the Company proposing to make any changes in the design and derivation of any of the optional Time of Use rate schedules or its Standby Service rate schedules?

A. No. The Company has designed these rate schedules in the same manner as has been prescribed by the Commission since their inception.

Q. You indicated that the development of delivery voltage credits to customers taking service at higher voltages under demand metered rate schedules is being changed. Would you describe the reason for this change?

A. Yes. This change is being made to provide a consistent treatment in rates with the allocation of costs in the cost of service study. Loads that take delivery at higher voltages, i.e. transmission or distribution primary, are not allocated any cost responsibility in the cost of service study for the lower voltage facilities for which they do not impose their loads on. Since rates are designed for application at the Company's lowest service voltage, i.e. distribution secondary, any customer taking higher voltage service should be credited with the lower voltage costs embodied in the rates for secondary service. This avoidance of lower voltage costs has previously been only partially recognized in the design of delivery credits. The previous design only recognized the avoidance of transformation costs included in the lower voltage costs and was remiss in not recognizing the avoidance of poles, lines, etc. that are also a part of lower voltage costs.

Q. What changes are being made to the Lighting Service Rate Schedule, LS-1?

A. The Company has revised the Customer Charge and the Energy and Demand Charge in order to produce the proposed target revenues for the

Energy sub-group of the Lighting Service rate class. Because the cost of service study shows the revenues from the Facilities sub-group adequately recover its cost of service, no change is being made to any of the fixture, pole, or maintenance charges.

VIII. Other Tariff Revisions

Q. What are the changes being made in the Company's Service Charges that resulted in additional revenue credits to the target class revenue requirements?

A. The Company has updated its service charges, which will produce additional revenues of approximately $4.1 million. PEF has also recognized specifically a service charge for "Investigation of Unauthorized Use" to be described in Rate Schedule SC-1, Service Charges. Revenues from service charges serve as a credit to offset a corresponding revenue requirement that would otherwise increase the Company's base rate charges.

IX. Summary of Class Proposed Rates of Return

Q. Do you have an exhibit that summarizes the Company's proposed class revenues and the class rates of return which would be realized by the Company's proposed rates and charges?

A. Yes. My Exhibit No. _____ (WCS-6) shows this information. The classes are at parity under the proposed rates to the extent the Company was able to accomplish this, considering the limitation recognized by the Company of not increasing any rate class by more than 150% of the total average percentage increase.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. MELSON:

Q. Mr. Slusser, would you please give a brief summary of your testimony?

A. Yes. Good morning, Commissioners.

There are three basic steps involved in developing specific tariff rates and charges in a retail rate case. First, one must determine the costs involved in providing the retail service that is subject to the jurisdiction of this Commission. To accomplish this I prepared a jurisdictional separation study that allocates the company's total system joint costs between its retail business and its wholesale business.

Second, the costs allocated to the retail jurisdiction must in turn be allocated to the individual rate classes that make up the retail business, such as residential service, general service nondemand, general service demand, general service nonfirm service and lighting services.

The most significant costs to be allocated are the fixed costs of production capacity. I am recommending allocating 50 percent of these costs based on each class's 12-month coincident peak demand responsibility, and 50 percent based on each class's annual energy or average demand responsibility. This is called the 12CP and 50 percent AD method.

For Progress Energy Florida this provides a better matching of the costs and benefits to the customer rate classes than either the 12CP and 25 percent AD method approved in the recent TECO rate case or the 12CP and 1/13th AD method that the Commission has employed in the past.

To illustrate the cost differences between these allocation methods I prepared three cost of service studies. My Exhibit WCS-4 is a summary comparison of these allocated costs under the three methodologies.

Finally, one must design rates that recover each class's share of the revenue requirements from the members of that class in a fair and equitable manner. To accomplish this, PEF is generally proposing to maintain its current rate structure. Within the nonresidential classes that pay both demand and energy charges, PEF proposes to increase those rate elements on a proportionate basis.

My testimony also explains several rate design or tariff changes that the company is proposing to better meet the needs of its customers. Many of these proposed changes have been stipulated by the parties.

One significant rate design that remains is the company's proposal to eliminate the IS-1 interruptible service rate schedule and the CS-1 curtailable service rate schedule. These rate schedules have been closed to new customers since April of 1996. PEF proposes to eliminate these schedules and transfer the customers to the open IS-2 and CS-2 rate schedules. Taking this step will ensure that the same cost-effective billing credits that have applied to new interruptible and curtailable customers since 1996 will now apply to the previously grandfathered customers.

That concludes my summary.

MR. MELSON: The witness is available for cross.

CHAIRMAN CARTER: Thank you.

Mr. Rehwinkel.

MR. REHWINKEL: Mr. Chairman, due to conflicts with our office, we do not have any questions for Mr. Slusser in this proceeding. I could probably ask him about his days with Steve Spurrier at the University of Florida, but other than that I have no questions.

CHAIRMAN CARTER: Don't get Commissioner Skop started on the Gators this early in the morning.

Ms. Bradley.

MS. BRADLEY: No questions.

CHAIRMAN CARTER: Ms. Kaufman.

MS. KAUFMAN: Thank you, Mr. Chairman. I do have a few questions for Mr. Slusser.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. Good morning, Mr. Slusser. How are you?

A. Good morning, Ms. Kaufman.

Q. I want to talk for a minute about your experience in the electric industry, and you tell us about that I guess in the very beginning of your testimony on Page 2, going over to the top of Page 3; correct?

A. Yes.

Q. Am I correct that for basically the entirety of your career you worked at Progress Energy Florida or its predecessor company, Florida Power Corporation?

A. Yes.

Q. And you worked there, is it 32 years, 34 years?

A. 36 years.

Q. 36 years. And then as I understand it you retired in 2001 from Progress Energy Florida?

A. Yes.

Q. And I think you said in our, in your summary you became an independent rate consultant; correct?

A. Yes.

Q. Now am I correct that since your retirement in

2001 you have essentially worked on three projects as an independent consultant, not counting the proceeding that we are in now?

A. Yes. Three major projects.

Q. Okay. First you worked on Progress's rate case, 000824; is that right?

A. Yes.

Q. And then -- when was that approximately? Do you know the month and the year that you did that work?

A. 2001 and 2002.

Q. Okay. And am I correct that once you completed that project, then you were lucky enough to take about a year and a half off and you didn't do any work, rate consulting work at that time?

A. That's correct.

Q. Okay. And then Tampa Electric retained you for the rate case that was just completed; correct?

A. Well, there is another case that Progress Energy was involved in in '05.

Q. I was going to get to that.

A. Okay.

Q. But we can talk about that first.

A. That came before Tampa Electric Company.

Q. The '05 case was also a Progress rate case; correct?

A. Yes.

Q. Okay. And then you were retained by Tampa Electric; correct?

A. That's correct.

Q. And am I right that you assisted Mr. Ashburn, who was Tampa Electric's rate design witness?

A. Yes.

Q. And you helped him with his testimony in that case?

A. Yes.

Q. Okay. And then you, you've been retained for the third Progress rate case; correct?

A. Yes.

Q. Okay. So I guess it's fair to say that all of the work that you have done, including your professional career and the four projects since your retirement, have been for Progress Energy with the exception of the one Tampa Electric rate case?

A. Yes.

Q. And you haven't done any work for any other utilities and you haven't done any work for any nonutility intervenors, have you?

A. That's correct.

Q. Let's talk about the cost of service methodology that you mentioned in your summary. And would you agree with me that once the Commission determines what Progress's revenue requirements are, that it has to select a methodology to allocate that revenue among rate classes?

A. Yes.

Q. And that's the, one of the primary jobs of a cost of service study; correct?

A. Yes.

Q. Okay. And would you also agree with me that the primary basis that the Commission ought to use to determine which cost of service study to select is to try to properly match the costs that you're trying to allocate with the classes that have caused the costs?

A. Yes.

Q. Okay. So what you want to do in an appropriate cost of service study is to be sure that the customers that are causing the costs are the ones that bear the cost?

A. Yes.

Q. Okay. Now I think you would agree with me, wouldn't you, that there's a pretty strong disagreement among the company and other Intervenors in this case in regard to what the right cost of service methodology is?

A. Yes.

Q. Okay. Now you have suggested, as you said in your opening, a 12 coincident peak and 50 percent average demand; correct?

A. Yes.

Q. And would I be correct that obviously FIPUG, the Navy, AFFIRM and PCS don't think that that's the correct methodology?

A. Yes.

Q. Now you filed your direct testimony in this case on March 20th, 2009?

A. Yes.

Q. How much time do you think that you spent working on your testimony, drafting it, reviewing it, looking at whatever materials you needed to be sure it was accurate?

A. Well, the testimony per se was after a lot of study work was done.

Q. Well, I'm really interested in the total amount of time that you spent on this, including the preparation of the testimony, just an estimate.

A. Yes. Progress began its efforts to develop the overall costs that I can allocate between wholesale and retail business and the classes. That information was gathered late in '08.

Q. Okay.

A. Or it may be even a little earlier, September, October of '08. And then we filed, as you said, in March of '09.

Q. What I'm, what I'm trying to find out is how much time you spent reviewing whatever materials you needed to review and drafting and preparing your testimony for this case.

A. I, I spent a substantial amount of time beginning in September of '08 through the filing of the case.

Q. Do you have any -- do you bill Progress on an hourly basis or on a flat fee basis?

A. I have a billing schedule that's on a monthly, weekly or hourly basis. It's a declining schedule.

Q. A declining block rate.

A. Yes.

(Laughter.)

Q. Do you, do you have an estimate of how many hours you spent working on this project, not including your testimony preparation, but what you reviewed in your drafting of your testimony?

A. Let me count the months.

Q. I'm just asking for an estimate. It doesn't have to be precise.

A. About five months, six months.

Q. Well, did you spend 40 hours a week for five months working on it?

A. No. I found it very helpful to work right along with the staff, the regulatory staff at Progress Energy on a full-time basis.

Q. Okay. So for those five months you were pretty much working on it full time, give or take?

A. Yes.

Q. Okay. Do you believe that when your direct testimony was filed that you did a thorough job and that it was complete?

A. Yes.

Q. I want to talk to you for a minute about the correction that you made at the beginning of your testimony, your summary on Page 20. And you told us, or I guess Mr. Melson asked if you had any corrections or changes. And essentially what you did was to strike the testimony at Page 20, Lines 8 through 13, where you discussed, discuss the average and excess method; correct?

A. Yes.

Q. Now when you filed your testimony on March 20th, am I correct that you thought the information there was accurate and complete?

A. Yes.

Q. Okay. And am I also correct that now you have stricken it because you didn't do your homework on that issue?

A. I was not as familiar with that method as I expected to be by the name that was given the method. The method is called average and excess demand. The method is described in the NARUC Cost Allocation Manual. I did find a number of utilities in the country that use the method, and I made a presumption that it was a method that heavily weighted average demand. Upon further review after I filed this testimony I found otherwise. I think the method is a misnomer and does not weight energy responsibility the way the company is, is wanting to weight it.

Q. Did you review the method before you included it in your accurate and complete direct testimony?

A. I didn't go through any mathematics. I just read the verbiage regarding it.

Q. Did you look at the NARUC cost allocation manual?

A. Yes.

Q. And let me ask you this question again. Is part of the reason that you're now withdrawing that testimony is because you didn't do your homework on it?

A. If you wish to characterize it that way.

Q. Is that the way you characterized it in your deposition?

A. Again, upon review, I was, I made the wrong assumption that that method did heavily weight average demand.

Q. Do you have your deposition with you?

A. Yes.

Q. Okay. I just, I just want to turn quickly to our little discussion about that. If you take a look at Page 82, I believe the staff was asking you some questions about this. And if you look at Line 8, you tell us there that you didn't do your homework on this method; correct?

A. That is correct.

Q. Okay. Are there any other parts of your direct testimony where you didn't do your homework?

A. Nothing comes to my mind.

Q. Now the methodology that you're recommending, the 12CP and 50 percent AD, would you agree with me is a method that has never been utilized by this Commission?

A. Specifically, no.

Q. And I think you also, you said in response to another question that you are aware that there are a number of utilities in the country that use the average and excess demand method; correct?

A. Yes. That's my understanding.

Q. And that the NARUC manual recognizes it as a cost allocation methodology.

A. Yes. Yes.

Q. Okay. You're familiar with the equivalent peaker methodology, are you not?

A. Yes.

Q. Okay. It's your view, is it not, that the methodology that you recommend, the 12CP and 50 percent AD, is essentially the same as the equivalent peaker methodology?

A. That's, that's difficult to answer.

Q. I'm sorry?

A. It's difficult to answer with a yes or no.

Q. Give it, give it your best.

A. Give it my best? The method, I like to describe it as a peak and average demand method. It weights peak 50 percent and average demand 50 percent. There are a number of ways of supporting that weighting, and I will admit to some degree it's very judgmental.

The equivalent peaker method also attempts to come up with a weighting of how much is peak responsibility and how much is energy responsibility. When I've attempted to calculate that for Progress Energy, it does come up with the 50 percent support figure. So it is kind of a test for the methodology.

Q. Do you have your -- I guess you have your deposition with you. If you'd turn to Page 144. We talked about this in your deposition, I think.

A. I have it.

Q. Okay. If you take a look at Line 12, I asked you, "And is the equivalent peaker method the same as the 12CP and 50 percent AD that Progress is proposing in this case?"

And your answer was, "Mathematically I would say that it is. For all practical purposes, yes, it is."

Is that your answer?

A. Yes. But I wish to say it's because my, the test that I gave was a calculation of the equivalent peaker method, and it's my Exhibit WCS-3, and that method did, or that calculation did come up with a 50 percent weighting, which is the same weighting that I think average demand deserves.

Q. And if I --

A. So for Progress Energy at this point they are one and the same.

Q. Okay. That was what, where I was going for. For Progress Energy the methodology you're recommending is essentially the same as the equivalent peaker methodology.

A. The equivalent peaker will support 50 percent.

Q. Are you familiar with the Gulf Power rate case from -- I guess the Commission's decision was in 1990. It's Docket 891345.

A. I probably read it at one time.

MS. KAUFMAN: Okay. Commissioners, I'm going to distribute an excerpt from the order just for everyone to look at.

CHAIRMAN CARTER: Okay.

MS. KAUFMAN: I don't need a number.

CHAIRMAN CARTER: Mr. Rehwinkel will help you.

MS. KAUFMAN: Thank you, Mr. Rehwinkel.

Just for the record while Mr. Rehwinkel is doing that, it's Docket 891345, and it's Order Number 23573. This is just an excerpt of a much longer order. There's only one section I want to ask Mr. Slusser about.

BY MS. KAUFMAN:

Q. Mr. Slusser, while it's being distributed, if you could turn to -- up in the corner it says Page 33. What I've given you is the cover sheet -- I mean, the first page so we could see the order number and all, and then Pages 33 through 34. And actually there's two Page 33s in my copy. It's such a good page.

And I'm going to focus your attention,

Mr. Slusser, on Page 33, the right-hand column, A, Cost of Service Methodology. And if you'd take just a minute to review the first, there's a single line and then that first paragraph that begins with "Gulf Power."

A. Yes, I read it.

Q. Now in that case am I correct that Gulf Power proposed the 12CP and 1/13th methodology?

A. Yes.

Q. And you've reviewed Mr. Pollock's testimony in this case, have you not?

A. Yes.

Q. And you'd agree that that's the method that he advocates for this case?

A. Yes.

Q. Okay. Other parties in the Gulf case, particularly Public Counsel, advocated the equivalent peak, peaker methodology; correct?

A. Yes.

Q. Okay. Would you read the sentence that begins, it's in the middle of the paragraph? It starts, "The equivalent peaker methodology."

A. It states, "The equivalent peaker methodology implies a refined knowledge of costs which is misleading, particularly as to the allocation of plant costs to hours past the break-even point."

Q. And am I correct that the Commission in the Gulf case rejected the suggestion that they should utilize the equivalent peaker method?

A. They may have. But I know there's a unique situation with Gulf Power and their relationship of being able to obtain power from the Southern Company based on their loads at the time of the monthly peaks. That was a major factor in supporting the 12 monthly coincident peak method or some small variant of that with Gulf Power.

I might just also add this was in 1990. I think a lot has changed since 1990. Our whole thinking of the types of generation that utilities are building has changed the cost perspective of, of who is responsible for the cost of generation plant.

Q. You would agree with me that this method was rejected for the reasons that are stated in the sentence that you said.

A. Well, it appears, it appears in the order that it was, yes.

Q. Are you familiar with the Florida Power & Light pending rate case?

A. I followed it somewhat.

Q. I thought you might have. Are you aware that in that case Florida Power & Light is suggesting that the Commission adopt the 12CP and 1/13th methodology?

A. Yes, I'm aware of that.

Q. Turn to your direct testimony, if you will. Page 21 at the bottom is where the question begins on Line 22. But I want to actually talk to you about the answer that is on Page 22, Lines 1 to 17.

A. Yes.

Q. Now I think we've established that you have proposed the 12CP and 50 percent average demand methodology to the Commission; correct?

A. Yes.

Q. And if the Commission were to adopt that methodology, that would apply not only to the base rate increase that we're here about, but you have also suggested on Lines 9 through 12 that the same methodology would apply to the cost recovery clauses; correct?

A. Yes. It's a production cost allocation methodology and should apply to all production resource costs.

Q. Okay. Now on your WCS-5 you -- let me let you get there.

A. Okay.

Q. You have shown us the, the, the rate impact essentially of your proposed cost of service allocation on the requested revenues, the revenues the company has requested?

A. I don't believe it's WCS-5. I believe it's WCS-4.

Q. And that WCS-4 doesn't show us the impact of applying the methodology you suggest to the cost recovery clauses, does it?

A. No. It just shows the effect on the base rate charges. I shouldn't say charges. The base rate revenue requirements.

Q. Do you have the stack of documents that I think the staff is going to introduce with you? It -- I don't -- maybe someone will bring that to you. I'm just going to -- I thought you might have it, but I'm just going to pull one out. Yes. Mr. Rehwinkel will then, will help me again. Thank you. I'm fortunate.

In that stack, Mr. Slusser, kind of, about a quarter of the way through, look at the Bate stamp number all the way down at the bottom. It's four zeroes and then 1552. Let me know when you get there. I'll just hold -- it looks like this. It's a bunch of columns.

A. At the bottom it says "1552." Is that what you're referring to?

Q. Right.

A. Yes, I'm there.

Q. And this was a response to staff's seventh interrogatory question 116.

Okay. Now you're familiar with this exhibit, are you not?

A. Yes.

Q. Okay. And what this exhibit shows is the impact of closing or moving the IS-1 and CS-1 customers to the IS-2 and CS-2 rates; correct?

A. Yes.

Q. Okay. And would you agree with me that there -- and let me back up. And this does include the impact on the cost recovery clauses as well as the base rates; correct?

A. It's a total billing.

Q. So it includes everything.

A. Total billing comparison.

Q. Okay. So would you agree with me that many of these customers are going to see a substantial increase if your proposed allocation methodology is adopted?

A. I don't know what you mean by substantial.

Q. Well, let's, we'll just look at a couple of them, if you don't mind. Take a look at -- let me be sure I get you on the right line here. Take a look at, for example, Customer Number 17.

MS. KAUFMAN: And, Commissioners, the customers aren't identified to protect their confidentiality, and I don't think we need to know who they are.

BY MS. KAUFMAN:

Q. But Customer 17 is going to see over an 85 percent increase; correct?

A. Yes. And I can explain why that customer is so much greater than many of the other customers.

Q. Well, let's -- and that is one of the highest, and I did pick that out. But let's look, for example, at Customer Number 20. That customer is going to see a 45 percent increase; correct? I know it's hard to line up the lines.

A. I think it's Customer 21.

Q. Right. Customer 21. So Customer 21 is going to see a 45 percent increase; correct?

A. Again, I can probably explain why that customer is more than others.

Q. Take a look at Customer Number 50. That customer is going to see almost a 40 percent increase; correct?

A. You probably mean 51. We're off a line.

Q. Okay. 51. I'm not going to take you through, I think the Commissioners can look down this list and --

A. Right. Right. Yeah.

Q. -- see that there are many customers that are going to receive what might be characterized as a very large increase. Would you agree with that?

A. Yes.

Q. Okay. Now I want to talk to you a little bit about your proposal that the IS-1 and IS, CS-1 rates be closed and that those customers be moved to the current IS-2 and CS-2 rates.

Those customers that are currently on the IS-1 and CS-1 rates have been on those rates for some time; is that correct?

A. Yes. The rate was grandfathered in 1996.

Q. And if your proposal is adopted, those customers -- well, let me back up. We should probably start with a little background. We're talking about interruptible and curtailable customers; correct?

A. Yes.

Q. Okay. And would you agree with me that an interruptible customer is one who can have his supply interrupted at any time, with notice or no notice, if the company needs the capacity to serve its, its firm customers?

A. That's what the tariff provides for.

Q. And they can also be interrupted with no notice at any time if the company needs to call -- if another utility calls on Progress to help them out with a contingency situation in another service territory?

A. To serve firm load in another service area, yes.

Q. Okay. So they can be interrupted to serve Progress's firm load or another utility's firm load in an emergency situation?

A. Yes.

Q. Okay. And in exchange for that lower quality of service, they receive a credit; correct?

A. That's correct.

Q. Now -- so that's the interruptible. The curtailable customers, do they receive notice before interruption?

A. Yes. The company generally provides as much notice as they can, but no less than 15 minutes, 30 minutes, something like that.

Q. And do they have the option to decline interruption?

A. If they do not curtail to a level that they have agreed upon, they will be penalized rate wise.

Q. So just to make a slight distinction, the interruptible customers have no choice. If you need them, you shut them off. The curtailable customers, we can call it a choice if they're willing to pay a penalty for it.

A. Well, they're -- it's not as simple as that.

Q. I am trying to make it simple.

A. There are other options that the company undertakes to try and mitigate the interruptions to customers. As you probably know, there's a buy-through provision. If the company is able to buy power from another source, it will purchase that power, and the customers pay for that power in lieu of being interrupted.

Q. And --

A. Also the customers are, are at the lowest level of interruptions of the company's curtailable interruptible programs. The company tries to, to minimize disruptions on customers and will -- if needing, if it needs resources, it will first start with the type of load management or interruptible type of load that provides for the, the least impact on customers, which would be like residential water heating, for example.

So there is a hierarchy of, of interruptions, and very oftentimes we don't need as much capacity to interrupt to get to the interruptible customer.

Q. Well, let me ask you two questions about that.

Number one, on the buy-through that you mentioned --

A. Uh-huh.

Q. -- you said that you can go off system and sometimes buy through power for these customers. And that's generally more expensive than Progress's cost; correct? Otherwise you would be doing that for your firm customers.

A. Well, you're at the market for power, yes.

Q. Yeah. So, I mean, we might -- would it be fair to say that that's at premium prices?

A. Yes. The customers can make a decision. However, if they're unwilling to pay the purchased power costs, they can curtail on their own.

Q. And as far as the hierarchy that you mentioned, how much, do you know how much interruptible load that you have on your system?

A. Yes. Around 300 megawatts.

Q. Okay. And do you know how much residential load management you have?

A. It will vary by season. I think we have as much as a thousand megawatts in the wintertime and possibly four or five hundred megawatts in the summertime.

Q. Would you agree with me that -- I think you mentioned the water heater, and there's probably pool pumps that are residential load management; correct?

A. Yes.

Q. Those are very, very small increments, are they not, of the load?

A. Well, in accumulation they're not. We have a large number of our residential customers that have selected that service.

Q. Do they have an option as to whether or not they want to curtail their load, their residential?

A. Not once they agree to the load management program.

Q. So then in that instance you can automatically shut off a pool pump without any notice or permission?

A. Yes. During -- there is one caveat there. During normally designated critical peak hours. However, if the company is in a very emergency stage, it can ignore those hours.

Q. And there's no such limitation on the interruptible customers; right? They can be interrupted regardless of peak, nonpeak, if you need the capacity.

A. If, if the resources are needed to satisfy its firm load requirements.

Q. Okay. I just wanted -- sorry for that little digression. I want to get back to what I started talking to you about, which is your proposal to move the

IS-1 and CS-1 customers to the IS-2 and CS-2 rates. And you talk about that I think on Page 34 of your direct testimony. Do you see that?

A. I am there.

Q. And there's essentially -- there will be two changes basically if your proposal is adopted. And the first thing that will change for these customers that you want to move is that the credit that they receive for the value of being interrupted is going to be lowered; correct?

A. Yes. Because the reason they were grandfathered in 1996 was the credit was not cost-effective. And, and the company opened a new schedule, IS-2 and CS-2, that was considered cost-effective, and that's what we're trying to move these customers to.

Q. What is the current credit, do you know, under the IS-2?

A. I just want to be sure. I believe it's $3.31 per load factor adjusted billing demand. Let me check that.

Yes. $3.31 per kilowatt of load factor adjusted demand.

Q. And that's the, that's the second change is that the credit will be load factor adjusted; correct?

A. Yes. When the open schedule was developed, much study went into the method of applying the credit. And the belief was that by applying it to the load factor adjusted demand was a better measurement of the amount of curtailable or interruptible load that was available.

Q. So that for most customers the credit will actually be less than $3.31, correct, once you make your adjustment?

A. It'll be $3.31 times their billing demand, which can be a maximum demand any time during the month, times the load factor, which is a proxy for the customer's coincidence factor with the company's peak.

Q. So is my statement -- let me just rephrase. Maybe we can agree that certainly some of those customers are going to see a lower, lower than the $3.31 once the load adjustment factor is applied. Is that right?

A. Well, the trouble I'm having is they're getting the $3.31 for what we are estimating as his coincident demand. And his coincident demand is being estimated by applying the load factor to his billing demand.

Q. What's the load factor that you apply?

A. His monthly load factor.

Q. Now would you agree that the value of the credit is, the interruptible credit is based on the avoidance of, of the avoidance of -- let me state that again -- the company's next avoided unit, the deferral of that unit?

A. I didn't hear your latter sentence.

Q. I garbled that, so let me, let me ask that again.

Would you agree that the value that is assigned to the interruptible credit is related to the capacity value of the company's next avoided unit?

A. I think the capacity value is the maximum credit that should be provided.

Q. And that -- but all I'm saying is by being able to not plan for these customers' demand, drop them off the system, you're trying to give them credit, if you will, for avoiding the necessity of y'all having to build the next unit. Is that accurate in layman's terms?

A. Yes. There is an avoided cost.

Q. And right now in the IS-2 and CS-2, that's $3.31 load factor adjusted; correct?

A. $3.31 per coincident demand.

MS. KAUFMAN: Okay. I've got another exhibit that I'm going to ask my assistant --

CHAIRMAN CARTER: Do you need a number?

MS. KAUFMAN: Yes, Commissioner, please. I would like a number.

CHAIRMAN CARTER: 279, Commissioners, Number 279.

Short title?

MS. KAUFMAN: Credit Value.

CHAIRMAN CARTER: Excellent.

(Exhibit 279 marked for identification.)

MS. KAUFMAN: I've been working on those.

CHAIRMAN CARTER: Outstanding. You may proceed.

BY MS. KAUFMAN:

Q. Mr. Slusser, we talked about this document a little bit in your deposition. And as you can see by the Bates stamp identification in the bottom right-hand corner of the second page, this was provided in response to a FIPUG production request, Number 39. And we asked in this request that the company provide us with their latest rate impact test. And can you flip over to the, it's the second page after the cover, take a look at that?

A. Yes.

Q. And do you see up in the right-hand corner in a yellow box that it appears that under the current rate impact test the value of the credit is $10.49?

A. First, I did not prepare this.

Q. Understood. Let me ask you this, if I might, before you explain.

Would you accept, subject to check, that this was provided to us in discovery from the company?

A. Yes.

Q. And would you all -- do you have any reason to doubt that it is accurate as the company provided it to us?

A. I have no doubt at the time it was prepared.

Q. Okay. Thank you. If you had something further to add, please go ahead.

A. I would like to. Yes. I believe this was prepared maybe as long as two years ago, so things have changed in the last two years, if one was to redo the study.

Secondly, the, what you want me to read up in the right corner has the word "maximum" in it. It represents a maximum incentive per kW, and it should say coincident kW that can be supported.

Q. And you said that this study looked as though it was two years old, or you thought it was two years old?

A. I think it is.

Q. Is there any reason the company wouldn't have provided the most current study when we asked for it in this case?

A. I don't think they've done any further studies. I'm not sure that any further studies have been provided in the conservation docket, which is where these type of studies are presented.

Q. So as far as you know, when we made this request this is the most current study and the company gave it to us?

A. That's my understanding.

Q. And you don't have any reason -- I apologize if I asked you this. You don't have any reason to doubt the accuracy of the document as it was provided?

A. Well, again, I did not prepare it. I'm assuming the personnel that are familiar with the RIM test calculations have made the calculations accurately.

Q. If you'd turn to Page 32 of your direct testimony, Mr. Slusser.

A. I have it.

Q. Actually I was looking for -- I don't think I've given you the right reference, but you discuss in your testimony the, or you present the proposed energy and demand charges; correct? I don't think it's on Page 32, but that is part of your testimony; correct?

A. I didn't hear your whole question.

Q. I'm sorry. In your direct testimony you present the proposed energy and demand charges; correct?

A. I prepared the proposed demand and energy charges for all the rate schedules. Yes.

Q. Okay. And I think we already discussed the fact that you have reviewed Mr. Pollock's testimony. Did you review his testimony on this issue?

A. Yes.

Q. Okay. And we talked about this in your deposition. And while you may disagree with his position, you do not disagree that he correctly calculated those numbers; correct?

A. Yes. I think he did correctly determine what are called the capacity costs and the energy costs from the cost of service study.

MS. KAUFMAN: Mr. Chairman, if I could have a moment.

CHAIRMAN CARTER: Yes, ma'am.

(Pause.)

MS. KAUFMAN: I think I'm done. Thank you very much, Mr. Slusser.

THE WITNESS: Thank you, Ms. Kaufman.

CHAIRMAN CARTER: Thank you, Ms. Kaufman.

Mr. Brew.

MR. BREW: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. BREW:

Q. Good morning, Mr. Slusser.

A. Yes. Good morning, Mr. Brew.

Q. Let's see. To avoid not going over stuff, let me just skip along quickly.

Your testimony beginning on Page 26 gets into rate design, does it not?

A. Yes.

Q. And by that, that includes not just the rates, but terms and conditions that are included in those tariffs too?

A. Yes.

Q. Okay. And you talked a minute ago about the company doing some, what you described as much study into developing the credit on the IS-1, IS-2?

A. I'm sorry. Would you repeat that?

Q. You talked about the study the company did into developing the credits.

A. Well, I was presented a study that was done prior to my being retained by the company. I'm familiar with the looks of it, because this is what's called a rate impact measure test, a RIM test, that is used to develop support for programs in the company's conservation forum.

Q. Okay. I understand. I'm actually going in a slightly different direction.

A. Okay.

Q. And in terms of preparing your testimony here, one element which you've already discussed is eliminating the grandfathered IS and CS rates and transferring existing customers on those tariffs to the comparable IS and CS-2s; is that right?

A. That's correct.

Q. Okay. And in making that determination did you talk to any of the customers on those existing rates?

A. I did not personally, but the personnel that I work with have discussed with the representatives of the company the types of customers that you have, or your customer. So we are getting feedback in the regulatory area.

Q. But so, for example, there were, I think, 71 IST-1 customers currently, is that right, according to Response 115?

A. I'll agree.

Q. Okay. Did you personally talk to any of those customers?

A. No.

Q. Okay. And you, you discussed a moment ago with Ms. Kaufman that there are substantive changes in the rates between the grandfathered IST and the IS -- IST-1 and IST-2; is that right?

A. The substantive change is the method that the credit is being applied.

Q. Okay. But there are substantive changes between the grandfathered tariff and the IS-2 tariff?

A. I would, wouldn't say there are other substantive changes. Mostly it's the credit and the credit application to the load factor adjusted demand. We tried to make all the other terms and conditions inclusive of, of what is in the IS-1 and CS-1 rate schedules.

Q. Okay. But my question was not whether others, but are there, are there substantive differences between the two?

A. As the company has proposed its IS-2 and CS-2 schedules?

Q. Right. From, from the terms that exist for customers that are under IS-1.

A. Again, we've tried to modify IS-2 and CS-2 to accommodate those customers.

Q. The question is real simple. Is the IS-2 tariff the same as the IST-1 tariff?

A. No.

Q. Okay. So there are differences?

A. Yes.

Q. Could those differences make a difference to those existing customers?

A. It's my belief it's only the credit that's the big difference, is the only difference.

Q. No. We've established there's a difference. My question is would that difference make a difference to the customers that are under the existing rates?

A. Yes.

Q. Okay. So it could make a difference to some of those customers?

A. The amount of the credit would make a difference. Yes.

Q. Okay. On Page 31 of your testimony you talk about some of the other changes, and one of those was beginning on Lines, Line 18, that the, the notice to terminate, meaning to get off the rate, under the IS-2 rate is 36 months as opposed to the IST-1 rate, which is 60 months. Do you see that?

A. Yes.

Q. Okay. Is there any existing tariff that has a 60-month notice to get off besides the IST rate?

A. I don't believe so.

Q. Okay. And so that, that long a notice serves the purpose of allowing the company to count on that resource; is that right?

A. Well, I disagree.

Q. So then you wouldn't, you wouldn't be opposed to shortening the notice to terminate to a year, would you?

A. I wouldn't be opposed to shortening it to 36 months, because that's what the company believes its planning horizon is.

Q. Did the company have a reason for wanting a 60-month notice in the first place?

A. At one time that was a planning horizon.

Q. Because the company counts on that interruptible load for reliability purposes when it needs it; right?

A. It is planned for, yes.

Q. Okay. All right. How do you know that any of the existing 71 IST customers would care to take service under IST-2?

A. Again, other than the billing that they would receive, all other terms and conditions would be the same or better in the case of the notice provision.

Q. That wasn't my question. My question is how do you know the customers would want service under the

IST-2?

A. Well, that's why it was grandfathered initially.

Q. My question is not why did you have the IST-1 grandfathered. My question is why would you expect in January 2010 that any of those 71 customers would want service under IST-2?

A. Because the customers have been given a transition period to determine whether they have other options, and ultimately they knew they were going to be transferred to the IS-2 rate.

Q. Under the new IS-2 rate that you would transfer those loads to, they have to give you three years' notice; right?

A. I'm not following you. We're missing something here.

Q. I'm an IST-1 customer.

A. Yes.

Q. January 1st I become an IS-2 customer.

A. Yes.

Q. I don't want the rate. I have to give you 36 months' notice to get off; right?

A. No, sir. We're transferring you to the IS-2 rate. The IS-1 rate will be terminated and all customers transferred to the IS-2 rate.

Q. Right. But if I don't want that rate, since you've automatically transferred me, I have to give you notice to get off, and that takes three years; right?

A. I see your point. Let me think about it a second.

(Pause.)

That's the provision we have right now, yes.

Q. So wouldn't it make more sense, since you're eliminating the grandfathered rate and imposing new conditions and tariffs on those customers, that they be given an upfront choice as to which tariff they want to take service under?

A. I think the company would give that some consideration.

Q. Would it be reasonable to force the customer to move on to new terms and conditions without giving them that choice?

A. Well, again, the company doesn't believe the customer is being subject to any change in terms and conditions, other than the economic effect of lesser credits. They'll get the same service. Nothing else has changed other than --

Q. Nothing else has changed?

A. Other than the credits.

Q. Okay. So for a -- just to back up. With the credit on the IST-2 rate, the load factor adjusted rate, am I not correct that no customer would receive the 3.31 per kW credit unless they operated at 100 percent load factor?

A. That's right.

Q. Okay. So that means that -- do you have any -- are any of the existing 71 customers that are on the IST-2, IST-1 rate operating at 100 percent load factor?

A. I have a document that shows the load factors by each customer. There are few, if any, that would be at 100 percent load factor.

Q. To be at 100 percent load factor I'd have to have everything on 8,760 hours a year.

A. Yes.

Q. And nobody, nobody operates like that.

A. Well, we do have some loads like traffic signals and amplifier stations that operate continuous loads. But it's not likely that an industrial customer would operate at 100 percent load factor.

Q. It's not likely that anybody, any of the 71 customers on the IST-1 rate would operate at 100 percent load factor.

A. I can check the list of the customers and find out.

Q. Okay.

A. Can you give me a moment?

Q. Yeah, sure.

(Pause.)

A. I did find my list.

Q. Are you finding any 100 percent load factor customers?

A. I see an 89 percent. I see a 90 percent.

Q. Do you see any 20 percents?

A. Oh, yes. Those are the highest I see, 90 percent.

Q. Okay. So then am I correct that there are no IST-1 customers that would qualify for the $3.31 credit, because all of them would receive a lower load factor adjusted credit?

A. They would get the 3.31 adjusted by the load factor.

Q. Okay. And assuming that that economic difference was significant to that customer, you would transfer them automatically, nonetheless, without giving them a choice as to what tariff they would want to take service under.

A. Well, again, they were grandfathered to a generous credit and have had a long transition period of, of deciding whether they're going to continue as interruptible customers or have other options.

Q. Well, that wasn't my question. My question was whether you would transfer them without giving them a choice. Isn't that right?

A. I'm not following your definition of choice. Choice between firm service or interruptible service?

Q. Anything other than the IST-2. Well, let me back up.

Earlier in your testimony you indicate that the company is canceling the RST tariff; is that right?

A. Yes.

Q. And the reason was because customers didn't show any interest in it; right?

A. Yes.

Q. Okay. Let's assume that none of the IST-1 customers are interested in the IST-2 tariff. I have to give 36 months' notice to get out from under that; right?

A. Okay. Yeah. We covered that. Yes.

Q. Okay. All right. I thought I heard earlier that you said that you thought the maximum value of the credit should be based on avoided generation capacity costs?

A. That's the way the RIM test is calculated.

Q. Okay. So if the avoided unit is a combustion turbine, there would be the fixed capital cost of the turbine property; right?

A. Yes.

Q. Taxes?

A. Yes.

Q. O&M?

A. Yes.

Q. Fuel?

A. Yes.

Q. Emissions?

A. Well, the fuel may be negative. It, it depends on the avoided resource. Yes.

Q. Okay. And emissions?

A. Yes.

Q. Okay. If the company has CTs that can't start up in ten minutes but it can interrupt a 50-megawatt load on no notice, isn't there also a reliability benefit of that interruptible load that the CT can't serve?

MR. MELSON: Objection. This is beyond the scope of Mr. Slusser's direct.

MR. BREW: If he knows.

CHAIRMAN CARTER: You may proceed.

BY MR. BREW:

Q. If you know.

A. I don't know the operation of our CTs.

MR. BREW: Okay. Thank you. That's all I have.

CHAIRMAN CARTER: Thank you, Mr. Brew.

Ms. Evans.

MS. EVANS: Yes, Mr. Chairman.

CROSS EXAMINATION

BY MS. EVANS:

Q. Good morning, Mr. Slusser. We met briefly yesterday, I believe. Ellen Evans here for the Navy.

A. Yes, Ms. Evans.

Q. Is it correct that you were proposing the Commission adopt a methodology for the retail class cost of service study that weights 50 percent of the production fixed costs on a coincident peak basis and 50 percent on an energy basis?

A. Yes.

Q. Okay. Do I refer to that as a 12CP 50AD methodology, or as a 50CP 50AD methodology?

A. Well, the 50 percent on the 12CP is implied, so it's, it is weighting the 12CP demands by 50 percent response -- responsibility is weighted 50 percent, and 50 percent of the costs are being weighted by average demand responsibility.

Q. Okay.

A. Excuse me. Basically trying to separate the cost into two pots. One pot is going to be out half -- the pots are equal. Half the pot is going to be allocated on demand responsibility, the other half on energy responsibility.

Q. Okay. So it would not be incorrect to refer to it as a 50CP 50AD methodology; is that correct?

A. No, it wouldn't be incorrect.

Q. Okay. Is it correct that the current cost of service methodology utilized is referred to as the 12CP and 1/13 AD method?

A. Well, it's a methodology that's been used in the past.

Q. Well, that is the current methodology, is it not?

A. It has been a method that the company has been using, yes.

Q. Okay. And under the current method, 12/13 (phonetic) of the production capacity costs are allocated based on a 12 coincident peak, and 1/13th of the costs are allocated on an average demand or energy basis; is that correct?

A. That's the methodology, yes.

Q. Okay. And do you agree that average demand and energy are the same?

A. Yes.

Q. Okay. The method you're proposing, the 50CP 50AD method, is it correct that you're proposing this method because you believe that for baseload production or generating units additional capacity costs are incurred to produce lower fuel costs?

A. Yes.

Q. Do the higher capital costs associated with baseload units produce higher fixed production costs, such as return of investment and return on investment and associated income taxes, than the peaking units methodology -- excuse me, than the peaking units do?

A. Yes.

Q. Under your proposed methodology, a high load factor customer will be allocated more fixed production costs than under the method currently utilized by the Commission; isn't that so?

A. Yes. And he obtains more beneficial energy savings.

Q. Okay. Well, just to clarify, let's assume that Progress Energy has a rate class that consists of a high load, of high load factor customers. Can you presume that for a minute? For this rate class would it be correct that under your proposed methodology the high load class customers would be allocated more fixed production costs than under the method currently utilized by the Commission?

A. Yes.

Q. Is it also true that under your proposed methodology customers who exhibit significant offpeak usage will be allocated more production costs than under the method currently utilized by the Commission?

A. I'm going to have to ask you to repeat that one.

Q. Is it true that under your proposed methodology, the 50CP 50AD, customers who exhibit significant offpeak usage will be allocated more production costs than under the method currently utilized?

A. It's difficult to answer yes or no. Presumably the offpeak energy uses improve the customer's load factor, and therefore he, he would be contributing more to the fixed cost.

Q. Are you saying you can't answer yes or no? If you can, I'd like you to. Would you like me to repeat the question?

A. Please repeat the question.

Q. Is it true that under your proposed methodology, the 50CP 50AD, customers who exhibit significant offpeak usage will be allocated more production costs than under the method currently utilized by the Commission?

A. I can't answer that yes or no.

Q. Can you answer it if we just simply say under your method would customers who exhibit offpeak usage at all be allocated more production costs than under the method utilized currently?

A. Again, I'm struggling that that can be answered yes or no. Any additional energy use will take on capacity responsibility, whether it's peak or offpeak. All additional energy use will bear additional cost responsibility under the average demand methodology.

Q. Okay. Well, let's assume that Progress Florida has a rate class and rate design that encourages offpeak usage, and that this rate class is identified in the cost of service study as a separate rate class. For that scenario, is it true under your proposed methodology customers who have a significant offpeak usage will be allocated more production costs than under the method currently utilized?

A. I'll answer it yes, but they will be getting the benefits of, of lower fuel costs.

Q. Okay. Thank you. And assuming that the increase in capital costs of a baseload unit produces lower fuel costs, this lower fuel cost is primarily the result of having high load factor customers or customers who have offpeak usage; correct?

A. I'm sorry. I'm going to have to ask you to repeat that.

Q. Sure. No problem. Assuming that the increase in capital costs of a baseload unit produces lower fuel costs, this lower fuel cost is primarily a result of having high load factor customers or customers who have offpeak usage; correct?

A. Well, the lower fuel costs are a result that the company found the, the baseload unit to be more cost-effective to meet the, the total energy requirements of the system. So, so any additional energy use beyond the peak period will contribute to supporting a, a more efficient generating unit because that generating unit is capable of being more efficient and producing lower fuel costs, and therefore we can justify putting more capital costs into the unit.

Q. So that's a yes?

A. If, if you think my answer complies with your question.

Q. That's a yes? Do you think your answer complies with my question?

A. Well, I'm still struggling with your question.

Can you try me one more time?

Q. Sure. If we assume that the increase in capital costs of a baseload unit produces lower fuel costs, that lower fuel cost is a result of having high load factor customers or customers who have offpeak usage; correct?

A. It's a result of more energy use. I don't know about it being a result of high load factor customers. That's where I'm having a little trouble. It is an economic determination based on how much energy is expected to be supplied. In general I think I agree with the concept, especially the first part of your, your question. Where you're throwing me is the addition of, of high load factor customers. It doesn't have to be -- it's, it's any additional energy use beyond what is required just to meet reliability.

Q. Well, and the high load factor customers and the customers having offpeak usage contribute to that, do they not?

A. Yes, they would. I'd buy that.

Q. Okay. For allocating fuel costs in this case you relied on each class's energy consumption adjusted for losses to allocate the fuel cost; is that correct?

A. Well, this is a base rate case. But in the fuel adjustment clause customers would be allocated fuel costs based on their adjusted, their energy use adjusted for losses.

I'll add one caveat to that. Customers that are under time-of-use rates will also get a lower fuel cost for their usage during offpeak periods and a little bit higher cost during on-peak periods.

Q. Okay. So customers with a high load factor get allocated the same fuel costs on a per unit basis as low load factor customers who are served at the same voltage level; correct?

A. With the exception I just mentioned of time-of-use customers.

Q. Customers who use a significant energy offpeak are allocated energy costs on an average system basis. That is they get allocated the same cost on a cents-per-kilowatt basis for energy-related costs, such as fuel, as customers who use most of their energy on peak; is that correct?

A. Yes. Fuel costs are based on average, they're averaged. As you might expect, fuel costs can vary every hour. They can vary seasonally. The, the Commission has determined fuel costs for Progress Energy on an annual basis and it's averaged.

MS. EVANS: Thank you. Nothing further.

CHAIRMAN CARTER: Thank you.

Before I go to Mr. Wright, Linda is going to be with us all morning, going all the way to our lunch break, so I'm going to give the court reporter a break. Let's take ten, everybody.

(Recess taken.)

We are back on the record. We had just taken a break for our court reporter, and before we took our break we were about to recognize Mr. Wright for cross-examination.

Good morning, Mr. Wright. You're recognized.

MR. WRIGHT: Good morning, Mr. Chairman. Thank you very much. I just have a few questions for Mr. Slusser.

CROSS EXAMINATION

BY MR. WRIGHT:

Q. Good morning, Mr. Slusser.

A. Yes. Good morning, Mr. Wright.

Q. It is always a pleasure to see you.

A. Thank you.

Q. One question was deferred to you from Mr. Dolan, and that question is approximately what percentage of the company's total revenues from sales is, is represented by cost recovery, amounts that are recovered through the cost recovery clauses?

A. Mr. Wright, these numbers I have in front of me are ones that I jotted down probably the beginning of the year, so it will, it will change based on your point in time. And it represents our base rates as of probably 2008, our base revenues. But including the clauses and our base revenues, I have a total of $4,905,000,000, of which the clauses represent $2,000,961,000, or 60.4 percent.

That is 60.4 percent of our total revenues, which are our base revenues, and our billing adjustment revenues are represented by the clause revenues.

Q. Thank you. And, and taxes are, taxes are -- let me rephrase.

What taxes are recovered through the base rates and what are recovered through additional line item charges?

A. Taxes such as gross receipts taxes and franchise fees would be in addition to those numbers.

Q. Thank you.

CHAIRMAN CARTER: Do you need a number, Mr. Wright?

MR. WRIGHT: I do, Mr. Chairman. 280.

CHAIRMAN CARTER: 280. You're right.

(Exhibit 280 marked for identification.)

Short title? Give it a shot. Just give it a shot.

MR. WRIGHT: There's a typo on the cover sheet, Mr. Chairman, that I just recognized. It should say -- no, there's not either. PSC Typical Bills, 1984-2009.

CHAIRMAN CARTER: You almost had me, then you added something on the end.

MR. WRIGHT: I added the dates. PSC Typical Bills.

CHAIRMAN CARTER: PSC Typical Bills?

MR. WRIGHT: Yes, sir.

CHAIRMAN CARTER: And you added the dates?

MR. WRIGHT: 1984-2009.

CHAIRMAN CARTER: Okay. 1984-2009. And that is Number 280, Exhibit Number 280.

MR. WRIGHT: And, Mr. Chairman, I previously had given Mr. Slusser a copy of the document. I will aver to you that these are copies of the reports that you regularly see and that are available on the PSC's website and that I obtained these from Ms. Kummer some time ago. So with that understanding, they are public records of the type normally kept, and I think they're admissible as such.

BY MR. WRIGHT:

Q. But, Mr. Slusser, I'd like to ask you to, if you would, I think you had a chance to look at them during the break a little bit, but if you'd look at the bill for 1984, the typical residential bill, and also the typical residential bill for two thousand -- for today. You'd agree, I think, that the typical residential thousand kWh bill in 1984 was around $76?

A. That's what this report shows.

Q. Have you seen these reports before?

A. Not in this format. Of course over time I've seen many typical bill calculations and comparisons. I would say that's a reasonable amount for that point in time.

Q. All right. And of that amount approximately $31 is fuel; correct?

A. That's what it shows. Yes.

Q. And today the total bottom line bill for 1,000 kWh residential is just under $123; correct?

A. Is that in this report?

Q. It's the last page, Mr. Slusser.

A. That's what it shows. Yes.

Q. And today fuel is about $56; correct?

A. Yes.

Q. Now doing some simple arithmetic I calculate a difference of $25 between the fuel charge in 1984 and 2009.

A. Yes. Just about double.

Q. And about $47 difference in the total bottom line bill.

A. Yes.

Q. Okay. So would you agree that most of the difference is in additional recoveries through the capacity clause and the environmental clause?

A. Yes.

Q. Do you consider costs recovered through the capacity clause or the environmental clause to be volatile?

A. Well, the capacity cost recovery clause is predominantly a number of contracts with QFs, and they, they do escalate. But I don't know about being extremely volatile. I don't remember what your adjective was. But they do escalate. And what was the other clause?

Q. Environmental.

A. Environmental? Understandably recently a lot of environmental additions to the company have been made through this clause, and that has been volatile.

Q. But once made, those are predictable, are they not? For example, scrubbers or electrostatic precipitators?

A. Yeah. But they keep being, excuse me, they keep being required.

Q. I'm going to ask you one more question. It's actually two more questions. Are you familiar with the PURPA ratemaking standards?

A. Yes.

Q. Would you agree that your declining block rate structure that you charge the company for your services would violate the declining block rate structure in the PURPA standards?

A. It doesn't make it wrong. It's efficient.

(Laughter.)

Q. Thank you. Thank you, Mr. Slusser.

MR. WRIGHT: And thank you, Mr. Chairman.

CHAIRMAN CARTER: Thank you, Mr. Wright.

Staff.

MR. SAYLOR: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. SAYLOR:

Q. Good after -- good morning, Mr. Slusser. How are you today?

A. Good morning, Mr. Saylor.

MR. SAYLOR: As a quick preliminary matter I wanted to let the Chairman know that the parties last night agreed to stipulate the responses that Mr. Slusser provided, which, I apologize, was provided a little bit late at the beginning of his testimony. It's identified in the staff's composite exhibit as Exhibit Number 41. And it was that stack of papers. There was a question regarding interrogatory Number 116, and it was in that stack of papers.

I just wanted to make you aware that the parties had stipulated to that last night, and at the appropriate time that we will ask to have that moved into the record.

CHAIRMAN CARTER: Okay.

MR. SAYLOR: All right.

CHAIRMAN CARTER: You may proceed.

MR. SAYLOR: Thank you.

BY MR. SAYLOR:

Q. Good morning, Mr. Slusser. My name is Erik Saylor. I'm an attorney with the Commission legal staff.

Do you recall your deposition September 10th?

A. Yes.

Q. All right. And if we were to ask you those same questions, they would be substantially the same; right?

A. Hopefully shorter.

(Laughter.)

Q. All right. And some of these early questions are going to cover a little bit of ground that have been covered already this morning.

It is my understanding that Progress Energy is proposing the 12 month CP and 50 percent average demand; is that correct?

A. Yes.

Q. All right. What specific -- what's the reasoning behind Progress's proposal to go to that, that 12CP 50 percent average demand?

A. Well, I think it's obvious what the company is endeavoring to do when, especially this decade here that fuel costs have almost tripled since the company's rate case at the beginning of the 2000. The, all the projects that our president Vinny Dolan described are very capital-intensive, designed to improve generation efficiency and/or use the most highly technical facilities available to generate cheaper, cleaner electricity in the future. And all that to me is obviously additional costs that are being borne for the benefits of energy, and energy therefore should deserve as much weighting as, as capacity in the allocation of production costs.

Q. All right. Thank you. And you're aware of the Commission's decision in the recent Tampa Electric rate case where the Commission approved a 12CP and 25 percent average demand cost allocation methodology for them.

A. Yes.

Q. All right. Do you happen to have a copy of Progress Energy's minimum filing requirements Section E for the rate schedules?

A. Yes.

MR. SAYLOR: All right. Commissioners, if, for your reference, it is part of the MFRs. It's PSC Document Number 02440, if you would like to look at it. I just have a couple of questions on that.

BY MR. SAYLOR:

Q. Mr. Slusser, if you'll refer to Page 36 of your direct testimony, and then we'll go to the Schedule E.

On Page 36 of your direct testimony you state that the company has updated its service charges, which will produce additional revenues of approximately $4.1 million; is that correct?

A. Yes.

Q. All right. And if you will turn to your MFR, MFR Schedule E7, which is -- I will ask you to turn to Page 19 of that. It should be Schedule E7, Page 1 of 7.

MR. MELSON: Mr. Saylor, there's a Bate stamp number at the bottom of the pages, on this side of the page. Would that be an easier reference?

MR. SAYLOR: Yes. Page 19 at the very bottom.

MR. MELSON: I'm sorry. Thank you.

BY MR. SAYLOR:

Q. Page 19 at the bottom of that schedule. That's E-7, Page 1 of 7. So Page 19. We'll just go with that.

A. I have it.

Q. All right. And on that page it shows the calculation of the initial establishment of a service charge; is that correct?

A. Yes.

Q. And that establishment of a service charge is the cost to hook a customer up to a service; is that correct?

A. The very first installation.

Q. All right. And if you'll look down at the bottom right-hand corner of that page, Line 10, it's my understanding that this MFR shows that the total cost for providing initial establishment of this service is actually $179.23; is that correct?

A. Yes.

Q. All right. Now if you will flip to Page 72 of that same MFR schedule for me. At the top right-hand corner it's the, Progress's proposed revised tariff sheet 6.110, but it's on Page 70 in the notebook. Are you there, Mr. Slusser?

A. Yes.

Q. All right. That tariff sheet shows the service charges. And is it correct that Progress is proposing to increase the initial establishment of the service charge from $61 to $75; is that correct?

A. Yes.

Q. All right. Then why is Progress proposing an initial establishment charge that is actually lower than the cost Progress, the cost -- excuse me. Let me rephrase the question.

Why is Progress proposing an initial establishment charge of $75, which is lower than their actual cost, which is about $197?

A. Well, as you said, the current charge is $61. And the company was trying to be reasonable in increasing this charge, and believes that $75 is a fair, appropriate charge to, to charge an initial customer that is beginning service with the company. We just felt going to full cost of service is, is just an unreasonable assessment in getting a customer started at a new location.

Q. All right. So it's fair to say that was done to mitigate the impact of, on the customers; is that correct?

A. Yes.

Q. All right. And would it also be correct to say that the, the delta difference between the actual cost and the cost that you're charging the ratepayers will be recovered through base rates for all ratepayers; is that correct?

A. Well, it would. Yes.

Q. All right. For my next question, if you'll turn to Page 153 of the same MFR schedule. And this is the company's proposed revised tariff sheet 6.330. Are you there, sir?

A. Excuse me. You said Page 153?

Q. 153. Yes, sir.

A. That's tariff sheet 6.330.

Q. Okay. Correct. Sorry. My apologies.

A. Okay.

Q. All right. And that is the rate schedule for TS-1 for temporary service; is that correct?

A. Yes.

Q. And temporary service is provided for when a customer needs temporary service, for like a construction site or something like that.

A. Exactly.

Q. All right. And if you'll look down to the bottom of the page where it says special provisions, provision number three, that temporary service charge, Progress is proposing to change that from $227 to $250; is that correct?

A. Yes.

Q. Now if you will flip back forward in the MFR schedule to Page Number 24 of Schedule E7, 6 of 7, and I believe that's where it shows Progress's actual cost for providing that temporary service charge; is that correct?

A. Yes.

Q. All right. And at the bottom of that page it shows the, Progress's cost of providing that service as being $302.07; is that correct?

A. Yes.

Q. All right. And would it also be correct to say that the difference between PEF's, Progress's actual cost and the costs that they're proposing to charge will also be recovered in base rates?

A. Yes, it would.

Q. All right. Would you refer to your direct testimony, your Exhibit WCS-5?

A. I have it.

Q. All right. And this exhibit, if I'm, as I recall, addresses the proposed revenue increase by class; is that correct?

A. Yes.

Q. All right. And can you explain how that revenue increase was applied?

A. Yes. And I'll try and be very brief here because there's a lot of numbers on here.

Q. All right. Thank you.

A. But basically we're relying on the results of the cost of service study as the target, you might say, of what we'd like to have each rate class produce, and if they did, they would be at parity. We credit the cost of service with any additional revenues from what you were describing as service charge revenues to get the amount of revenues that are required from base rates.

And the company's proposed -- the difference between the cost of service or revenue requirements and the company's present revenues by rate schedule is what each class's deficiency is from cost of service. And using that deficiency as the basis for the revenue, the target revenue requirements, an increase is calculated. It appears in Column E of this exhibit. And in Column F of this exhibit it, it will show a percentage resulting increase to bring each class to parity.

The remainder of the exhibit is an attempt to employ mitigation principles that the Commission has applied in the past, in particular the one where a rate class should not be increased more than one and a half times the system average increase or the overall average increase. So some classes that would have resulted in a greater percentage deficiency than one and a half times the system average has been fixed at one and a half times the system average.

The remaining rate classes would have to make up the difference in proportion to their revenue deficiency. And we arrive at the last column, which is the desired target revenues that we're going to design proposed rate charges to produce.

Q. All right. Thank you. And some of those classes a customer, which is I guess the first column on the left side, the rate class, that would be affected by that one, one point, one and a half times would be the lighting and also the curtailable interruptible customers; is that correct?

A. That's correct.

Q. All right. Still looking at that same column, Lines 19 and 20, where it says Section 5, curtailable/interruptible general service (CS/IS), do you see that?

A. Yes.

Q. All right. Could you walk us through why those two classes are not shown separately?

A. Yes. Both of these classes do have their own unique rate schedules because there are different terms and conditions, as I was discussing with Ms. Kaufman today, regarding interruptible is at the control of the company to be interrupted, and curtailable is one where we, we give notice and the customer must reduce his demand to a certain level. Both, both types of customers are subsets of our general service demand customers.

When we looked at the load characteristics in the past, the curtailable and interruptible, the load characteristics -- and by load characteristics, I mean their load at the time of the peak compared to their energy use, something we call coincident load factor, has been similar but different, but has been favoring one class over the other each time we do a new load research study. One load research study will show curtailable having a slight advantage in their load characteristics. The next time we did a study the interruptible had a favorable.

We've come to the conclusion that it would be best just to treat the two as one combined class for establishing their cost of service, which means their base rate charges and their billing adjustment charges.

We think the characteristics of the two classes, two rate schedule requirements are so close that they can be combined as one rate class.

Q. All right. Thank you. If you will refer to Page 27 of your direct testimony, please. And we'll be looking at Lines 6 through 11.

A. Yes.

Q. And this is where you discuss Progress's proposal to include the cost of a transformer in their residential service charge; is that correct?

A. Yes.

Q. How is Progress currently recovering the cost of this transformer?

A. Currently, assuming the company's rates have been established based on a cost of service study at some point, the transformer is usually included in the energy, demand and energy charge, or the charge per kilowatt hour.

Q. All right. And if the, and if the Commission does not approval Progress's proposal to include the cost of the transformer in the customer charge, Progress will still be able to recover that transformer through the energy charge; correct?

A. Yes.

Q. We're crossing off questions.

If you'll turn to Page 22 of your direct testimony. Excuse me. Strike that. Strike that.

It's my understanding that for this customer charge for residential class that Progress is proposing a $13.21 charge; is that correct?

A. Yes.

Q. All right. And by including, by excluding the cost of the transformer, the charge would be $8.97; is that correct?

A. That's right.

Q. And the higher the customer charge -- excuse me. A higher customer charge has a larger impact on the total bill for a low usage customer than a higher usage customer; is that correct?

A. Yes. I actually calculated a break-even point. It's 1,118 kilowatt hours. So usage less than 1,118 kilowatt hours would incur a higher bill, and usage above 1,118 would incur a lower bill if we put the transformer cost in the customer charge.

Q. All right. Thank you. Earlier we discussed the proposed elimination of the IS and CS rate schedules; is that correct?

A. I discussed it with the Intervenor lawyers.

Q. All right. And it is my understanding that all those customers were grandfathered in in 1986; is that correct?

A. 1996.

Q. Excuse me. 1996. And that would be, subject to check, that was in Docket 950645-EI, and that was done by Commission Order PSC-96-0589-S-EI. And that was issued May 6th, 1996; is that correct?

A. That sounds correct.

Q. All right. Thank you. And previously you answered that the reason why Progress or Florida Power Corp. was proposing to eliminate the CS-1 and the IS-1 was because it was no longer cost-effective; is that correct?

A. Yes. That was actually found by the Commission in, in that time frame earlier than '96, '95, and brought it to the company's attention that, that IS-1 and CS-1 rates were not, the credits were not cost-effective. And we were asked to consider actually eliminating those tariffs, and we came to an agreement to grandfather the tariffs and open up cost-effective tariffs.

Q. And is this the first time that Progress is now proposing to eliminate those class of customers?

A. No. We attempted to do that in the last two rate proceedings.

Q. And why were those customers not eliminated then?

A. The company entered into rate stimulations -- rate stimulations -- rate stipulations that maintain those rate schedules.

Q. All right. Thank you. Would you please refer to staff's composite exhibit that we provided to you earlier?

MR. SAYLOR: And, Commissioners, for your reference, it's Bate stamp pages 1551 through 1554. And this will be in response to staff's, Progress's response to staff's interrogatories Number 116. And it was the charges that, or the schedules that Ms. Kaufman and Mr. Brew went over with, with the witness.

BY MR. SAYLOR:

Q. Are you there?

A. I have it.

Q. All right. And it is my understanding that Progress is proposing to move the IS-1 and the CS-2, which is a closed rate schedule, to the open rate schedule of IS-2 and CS-2; is that correct?

A. Yes.

Q. All right. And it is my understanding that customers with a load -- a low load factor will experience a larger increase than compared to customers who have a high load factor; is that correct?

A. That's correct.

Q. All right. And could you explain why customers with a low load factor will experience that larger increase than compared to those customers who have a high load factor?

A. Yes. The basis for the credit under the IS-1 and CS-1 is the billing demand. A billing demand can occur at any time during the billing period. A low load factor customer -- let's just take an example of a 10 percent load factor customer, very low load factor customer, based on load research experience, there's a good probability that he will have little of his load on at a critical time when the company really needs to interrupt him. So giving him a credit, giving a 10 percent load factor customer a credit based on his billing demand is not really supportable.

The IS-2 rate has remedied that by recognizing that a 10 percent load factor customer, it's assumed that he's going to have only a 10 percent probability of his demand being available for interruption, and therefore he should get 10 percent of the credit, the credit being based on load at the time of the system peak.

So it's a rate structure that is -- the IS-2 is an improved rate structure that tries to remedy the,

the flaws in providing a credit simply based on billing demand.

Q. All right. Thank you. And do you recall questioning from Mr. Brew when he asked you about the IS-1 and the IST-1 and the CS-1 and the CS-2, or CS-1 customers; is that correct?

A. Which question? I recall questions.

Q. Sorry. Just in general reference, if you'll refer to your interrogatory response, question 116. The spreadsheet at the top of the page says, "Customers taking service under the IS-1, IST-1, CS-1 and CST-1 as of June 2009." Do you see that on your response?

A. Are you -- can you give me a number at the bottom?

Q. Sure. If you'll look at the Commission Bates stamp number 1554. It's the --

A. Okay.

Q. Okay. And it appears that there are four class of customers that take use or, that take service under these rate schedules; is that correct?

A. Did you say 133?

Q. I mean, that's the total number that your chart shows, 133 customers. I was just trying to clarify that these are the customers that are in fact currently grandfathered under the order that was issued by this Commission in 1996; is that correct?

A. Yes. Yes.

Q. And in my reading of the chart, there doesn't appear to be any customers in the CS-1 class; is that correct?

A. Oh, correct. We don't have any CS-1 customers.

Q. All right. And, and Mr. Brew earlier asked you about the notice provision, the difference between the IS-1 or the grandfathered class versus the IS-2 or the class that you're proposing to move these customers to; is that correct?

A. Yes.

Q. And the, under the grandfathered class it is currently 60 months; is that right?

A. Yes.

Q. And if they get moved to the new class, it would be 36 months; is that correct?

A. Yes.

Q. Can you please explain to me why there is a notice provision at all in the tariff, you know, a 60 or a 36-month notice?

A. Well, the purpose of the notice provision is for the company to, to change its planning horizon to recognize load that, that has been interruptible if they choose to go firm. There needs to be a lead time to adjust its generation facility plans.

Fortunately, if it's, if it's interruptible load, typically the company can obtain a peaking resource rateability (phonetic) peaking resource to make up for the interruptible customer becoming firm. Because, remember I said earlier in the planning process, for an interruptible customer, we don't plan to serve his capacity but we do plan to serve his energy. So the company just needs a lead time to, to find the capacity. And three years is, is considered an ample lead time to, to reschedule its planning facilities for a peaking type of requirement.

Q. All right. Thank you. Could there be a potential harm to the firm customers if all the grandfathered IS-1 and CS-1 customers just started taking service, excuse me, took firm service as of January 1st, 2010? If they, instead of being -- let me rephrase my question.

If the grandfathered customers, instead of going to the CS-2 schedule or the IS-2 schedule, if they just started taking firm service, could there be a potential harm to the other firm customers?

A. Well, there could be. Again, the company had not planned for that load being firm. So it depends on its resource situation at that point in time. Again, if it planned not to serve it and all of the sudden it finds it needs capacity to serve it, it may, it may be a difficult costly remedy to serve that load.

Q. Okay. So if all 133 customers who are now interruptible or curtailable suddenly were no longer that, would that potentially cause Progress firm customers some issues?

A. It could, but it depends at the point in time of what the company's generation, available generation resources were.

Q. All right. Thank you. Now for those customers who are currently grandfathered, what other rate schedules would be available to them other than IS-2 or CS-2?

A. It would typically be GSD and GSDT.

Q. Okay. And would these other rate schedules result in higher bills or potentially lower bills for those grandfathered customers?

A. It would be higher bills.

Q. All right. And, excuse me, and would it be higher compared to the IS and CS-2 rate schedule?

A. Yes.

Q. All right. During your deposition do you recall a few questions about the Leave Service Active

Agreement that the tariff has in its proposal?

A. Yes.

Q. All right. And -- one moment.

(Pause.)

Thank you for your indulgence. If you will, in that same E rate schedule, if you'll turn to Page 72.

A. I have it.

Q. Okay. Okay. And it is Line 3 where you discuss, or where it mentions the Leave Service Active Agreement; is that correct?

A. Yes.

Q. And, excuse me, and in your deposition you mentioned how landlords with only one or two rental units which may not be continuous, excuse me, contiguous -- excuse me. Strike that.

Could you walk through why Progress is wanting to change their Leave Service Active Tariff and add some of those provisions at the, in the Number 3 where it says you're changing it to add for a multifamily rental housing facility on a continuous, contiguous property with a minimum of ten rental properties and one owner account?

A. Yes. Progress is adding this language to be consistent with how the company is applying the Leave Service Active Agreement with customers.

Q. Okay. And this is to address the potential problem of one owner who owns multiple rental houses scattered throughout Progress's service territory wanting to take under the Leave Service Active Tariff; is that correct?

A. Yes.

Q. All right. And the reasoning for that, if I understand correctly from your deposition, was that these landlords would not be able to provide as close a supervision of their properties as, say, a rental apartment complex; is that correct?

A. Yes.

Q. Okay. But let me ask you this, isn't it the point of this LSA agreement to make the manager or the entity requesting the LSA responsible for the usage, or for electrical usage between two different tenants?

A. Well, the point of the LSA was an offering that was requested by a group of Pinellas apartment owners' association that were in the business of having large rental projects. And, as you were saying, under those type situations there is supervision of the tenants coming and going and they know when power is, is truly being transferred to their name and they know the customer, the departing customer has left.

In recent years there have been a lot of, lot more investor-owned individuals that have been buying one and two or three homes or apartments or whatever that aren't in the full-time business of monitoring their, their tenants. And the company, the company is frankly uncomfortable with dealing with those customers when it comes to transferring the responsibility of usage at those rental locations. They want -- they have administered this in a way that it was created. It was created for large apartment complexes, and that's how they want to restrict the language here to, to apply to.

Q. Okay. And why does Progress believe that a ten-unit minimum is necessary for the LSA?

A. I can't say how we pick ten. We just thought that was an ample number of units to, to comply with our requirements.

Q. Okay. So if an owner of a four-plex or an eight-plex, they wouldn't be eligible for this LSA; is that correct?

A. That's my understanding of how the company is applying it.

Q. All right. Now under, under the current LSA, if the landlord is responsible for all the usage that, for electrical usage at that particular property, wouldn't the landlord be responsible for any usage that occurred inbetween two tenants?

A. Yes.

Q. Even under the current one?

A. Yes.

Q. So the question I'm struggling with is as long as someone is responsible for the bill, such as the landlord, why is that potentially an issue for Progress?

A. I'm not sure I have a good answer for you other than this is the way the company wishes to apply the agreement.

Q. Fair enough. Are you aware of whether Progress has had a large number of defaults under its current LSA program?

A. Well, it's my understanding they have not been allowing the example that you gave to take, to execute these agreements.

Q. Okay.

A. So I'm not aware of any problems or complaints of refusing to, to provide this to, to small landlords.

Q. Fair enough. With regards to the, getting back to that ten-unit minimum, because you're also adding the language "contiguous property and one owner account," why not just make that the requirement as opposed to having that ten-unit minimum, and then a four-plex or an eight-plex would qualify?

A. Because our customer service people do not want to deal with small landlords.

Q. Fair enough. We'll move on. Mr. Slusser, if you'll turn to Page 15 of your direct testimony.

A. I have it.

Q. All right. And this is where you discuss the development costs for interruptible and curtailable load; is that correct? Lines 14 through the end of that page to the top of Page 16.

A. Yes.

Q. All right. And are you -- and you may have touched on it earlier today. Are you familiar with any of Progress's demand-side management programs?

A. I didn't quite hear you.

Q. Excuse me. Are you familiar with any of Progress Energy's demand-side management programs?

A. Yes.

Q. And are you familiar with their interruptible service program?

A. That's what our IS and CS rate schedules are.

Q. All right. And these customers who are on the interruptible service program, it is correct to say that they are offered a credit to their electrical bill for participating in the program?

A. Yes.

Q. And all expenses for this program, including the credit offer to the customers, is recovered by Progress through the energy conservation cost recovery clause.

A. Yes.

Q. All right. And what is the process for changing that credit offered to the customer who participates in that program? Is that done at a rate base proceeding or somewhere else?

MS. KAUFMAN: Excuse me, Mr. Chairman. I think we're going beyond the scope of Mr. Slusser's direct testimony, so we would object.

CHAIRMAN CARTER: Thank you.

Mr. Saylor, to the objection.

MR. SAYLOR: It is my understanding that on Page 15 he discusses his demand-side energy programs. And if you look on Page 16, he starts talking about the allocated cost of services and rate of return studies. So -- and also at the top of Page 16 he's talking about the, Progress's conservation cost and recovery clause.

MR. BREW: Mr. Chairman, if I may be heard.

CHAIRMAN CARTER: Mr. Brew, you're recognized.

MR. BREW: I recall that there was an objection to my questions when I asked about the underpinnings for some of the things on the basis of his direct.

CHAIRMAN CARTER: Okay.

MR. BREW: So if it's not, if it's not good for the goose, it's not good for the gander.

CHAIRMAN CARTER: Objection sustained. Move on.

MR. SAYLOR: Okay. That is it for staff's direct questions.

CHAIRMAN CARTER: Wait, wait for the exhibits. We'll get with that in a minute.

Commissioner McMurrian, you're recognized.

COMMISSIONER McMURRIAN: Thank you, Mr. Chairman.

I wanted to follow up, Mr. Slusser, with a couple of the questions that Mr. Saylor was asking you about the service charges, the initial establishment of service, which was on Page 19 of those E schedules, and then also the service charge for temporary service.

CHAIRMAN CARTER: Chris, give her some more volume.

COMMISSIONER McMURRIAN: I'm sorry. I'll try to get closer.

Could you hear me, Mr. Slusser?

THE WITNESS: Yes, Commissioner.

COMMISSIONER McMURRIAN: And also the service charge for temporary service, which is on Page 24 of those E schedules. And I guess -- I think I'm understanding correctly that you all are increasing the tariff charges from how they exist now, but you're not increasing them to the full cost of service for both of those charges; is that correct?

THE WITNESS: That's correct.

COMMISSIONER McMURRIAN: And is there some -- I guess let me back up and say, it seems like I can understand perhaps why the company may be looking at not increasing those charges to the full cost of service. For instance, with the initial establishment of service perhaps it's aimed at trying to help people move to Florida, move to the service area and have lower cost of establishing service.

THE WITNESS: Yes.

COMMISSIONER McMURRIAN: At the same time, not charging for the full cost of service, from the questions Mr. Saylor was asking, I think shows that the general body of ratepayers may be absorbing that impact.

Is there something, and my question is is there something that shows the impact to the general body of ratepayers, particularly the RS-1 rate, of not having the full cost of service charged to those specific service charges? Does that make sense?

THE WITNESS: Yes. I could simply make the calculation of how much revenues we're forgoing. That would probably answer your question.

COMMISSIONER McMURRIAN: Is there something that shows that in --

THE WITNESS: Yes, ma'am. E, in our E schedules.

COMMISSIONER McMURRIAN: Okay.

THE WITNESS: On Page 36 we show how many transactions we expect in the test period. And that's 20 -- I don't know if you're looking at it.

COMMISSIONER McMURRIAN: I am.

THE WITNESS: But it's showing 25,819 transactions are expected. If we don't go to full cost of service -- let's see. I can't, I can't remember the full cost. It was a hundred and --

COMMISSIONER McMURRIAN: It was 179.23.

THE WITNESS: 139?

COMMISSIONER McMURRIAN: 179.23.

THE WITNESS: 179? So let's just round that to forgoing $100. So $100 times 25,819 is $2,582,000. And if we want to put that on a per-megawatt-hour basis, the residential is 19,535,853 megawatt hours. Let me do the math.

COMMISSIONER McMURRIAN: Thank you.

THE WITNESS: It's, it's costing the

residential ratepayers 13 cents per thousand kilowatt hours.

COMMISSIONER McMURRIAN: Okay.

THE WITNESS: By not charging an additional $100.

COMMISSIONER McMURRIAN: Okay. And the same kind of calculation could be done for the, the temporary service charge as well; right?

THE WITNESS: It could. But as you can imagine, we don't have too many temporary services at this time with the economy. So it would be very, very de minimis.

COMMISSIONER McMURRIAN: And the difference in the cost of service, which I think is 30207, and then the --

THE WITNESS: Yeah. So we're talking, say, $50 more.

COMMISSIONER McMURRIAN: $50.

THE WITNESS: Times 5,164. That's only one cent per thousand kilowatt hours.

COMMISSIONER McMURRIAN: Okay. Thank you. That helped a great deal.

THE WITNESS: Yes, ma'am.

COMMISSIONER McMURRIAN: Thank you.

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman. Good morning, Mr. Slusser.

THE WITNESS: Who's talking? Oh, I'm sorry. Commissioner Skop.

(Laughter.)

COMMISSIONER SKOP: Good morning, Mr. Slusser.

THE WITNESS: Good morning.

COMMISSIONER SKOP: If I could please refer you to Page 16 of your prefiled testimony.

THE WITNESS: I have it.

COMMISSIONER SKOP: Okay. And generally Lines 5 through 20 on that page.

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. And specifically on Lines 13 through 15 you discuss the 12CP portion of that methodology; is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. With respect to the 12CP, what rate class typically drives the coincident peak demand?

THE WITNESS: Well, our predominant load is residential of course.

COMMISSIONER SKOP: Okay. And would you agree that peak demand drives the need to build additional generation to maintain adequate reserve margin?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. So essentially, based on your two prior responses, residential load basically drives the need for new power plants; is that correct?

THE WITNESS: Generally speaking, yes.

COMMISSIONER SKOP: Okay. Now with respect to the one 1/13 AD method, and, again, I had -- it may be semantics, but I'm trying to gain a better appreciation as to the traditional method versus some of the alternate methods that you stated, and I'll get to that on a previous page of your testimony.

But with respect to the 1/13 AD method, which is generally discussed on Lines 15 through 20 on that page -- do you see that?

THE WITNESS: Yes.

COMMISSIONER SKOP: Do commercial and industrial customers represent the largest users with respect to average hourly demand?

THE WITNESS: No. Percentage-wise residential is still the greatest class energy use.

COMMISSIONER SKOP: Okay. If I could turn your attention now back to Page 6 of your prefiled testimony.

THE WITNESS: I have it.

COMMISSIONER SKOP: Okay. And like I say, this often gives me -- I'm trying to understand -- I know the semantics here on Page 6, Lines 12 through 16, I guess caused me some pause, and it prompted a question from one of the Intervenors, but typically we talk about capacity and energy and such like that. But with respect to what's proposed on Line 13, which is identified as the 12CP 50 percent AD method, do you see that?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: In response to a question from one of the Intervenors, I believe it was the Navy, that that method could equally be known as the 50CP 50AD, 50 percent AD method; is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. And that's because on Lines 14 through 16 it seeks to allocate those production capacity costs on class demand responsibility, 50 percent on those and 50 percent on the cost based on energy class responsibility; is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. I guess what I'm trying to understand -- and if now I can turn your attention to your Exhibit WCS-4, please.

THE WITNESS: I have it.

COMMISSIONER SKOP: Okay. And I guess what I'm trying to rationalize is the, the ramifications that might result from adopting the proposed 12CP 50 percent AD request. And on this sheet, which is Page 1 of 1 of Exhibit WCS-4, do you see Columns D through I?

THE WITNESS: Yes.

COMMISSIONER SKOP: Excuse me for a sec. I need to take my glasses off. I think I'm going to have to get bifocals soon.

But does that generally, do those columns generally reflect the difference that might occur as a result of adoption of the traditional test versus the, I mean, excuse me, adoption of the traditional method versus the adoption of the method proposed by Progress?

THE WITNESS: Well, it does both the method proposed by Progress as well as the 25 percent AD method.

COMMISSIONER SKOP: Okay. And looking at the left-hand side of that exhibit under the column Rate Class, do you see that?

THE WITNESS: Yes.

COMMISSIONER SKOP: And it articulates the various rate classes that are subject to the cost allocation study?

THE WITNESS: That's correct.

COMMISSIONER SKOP: Okay. So generally speaking, looking at Line 1, which is the residential rate class, and then referencing that to Column I, which is the difference of 50 percent to 1/13th AD and the effect or base rate effect in dollars per megawatt hour -- do you see at that?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. So am I correct to understand that that would result, the proposed adoption of the methodology would result in a base rate reduction in terms of dollar per megawatt hour to residential classes as shown in that column?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. Now for the other remaining classes in that same column, which appear to be general service and some of the curtailable interruptible, adoption of that methodology would essentially increase the base rate effect in dollars per megawatt hour for those particular classes of service; is that correct?

THE WITNESS: That's correct.

COMMISSIONER SKOP: Okay. So would it be correct to understand that the proposal seeks to credit the residential customer but equally passes additional costs on to what would otherwise be your commercial industrial customers?

THE WITNESS: It has that result, but it's, but it's because I believe that that's a fair and appropriate methodology.

COMMISSIONER SKOP: Okay. Fair enough. I just wanted to get some clarification on that. There's been quite a bit of discussion, and I think I was concerned by some of the semantics on Page 6, which got clarified by in lieu of it really being a 20 -- hold on real quick -- a 20, and I apologize, a 20CP 50 percent AD. It's really a 50CP 50 percent AD type of methodology. Okay.

THE WITNESS: That's correct.

COMMISSIONER SKOP: Thank you for that. And just a few remaining questions. If I could next turn your attention to Pages 35 and 36 of your prefiled testimony.

THE WITNESS: I have it.

COMMISSIONER SKOP: Okay. And on those pages, basically at Line, beginning on Lines 22 of Page 35 and ending at Line 4 on Page 36, it discusses the proposed changes to the lighting service rate class; is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. And would it be correct to understand that the, Progress has proposed revising the customer charge and the energy charge for lighting service, but is not changing the charges that would be made to rental fixtures or pole maintenance and such?

THE WITNESS: That's correct.

COMMISSIONER SKOP: Okay. If I could briefly ask you to turn back to that same exhibit, WCS-4.

THE WITNESS: I have it.

COMMISSIONER SKOP: Okay. And on Line 19 of that exhibit, which is the energy charge under lighting -- do you see that?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. And if I could ask you to look at Column I again, which would be the difference for adoption of the 50 percent AD test versus the 1/13th AD -- do you see that?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. So the net effect of the proposed change under the methodology proposed by Progress would be to substantially increase the energy charge related to lighting in terms of the base rate effect on a dollar-per-megawatt-hour basis; is that correct?

THE WITNESS: It does.

COMMISSIONER SKOP: Okay. Who might be affected by that increased energy charge in terms of lighting services? Would that be municipalities, homeowners' associations, cities?

THE WITNESS: Yes. Yes, they would. Keep in mind, lighting has become very efficient when it comes to energy use. Most of the cost of lighting service is in the fixtures, the facilities. When you look at how much revenue is from the facilities, they're like $60 million, but the energy, base energy charges for lighting is about a tenth of that, $6 million.

Under the, the, I'll call it traditional 12CP and 1/13th method, energy use did not get but an 8 percent allocation. And now the reason they're getting such an effective larger increase is because their energy now is being weighted by 50 percent rather than 8 percent. They really don't get any demand responsibility because lighting is very seldom on at the time of the peaks. So any effect on energy for cost responsibility will impact the lighting energy charge very significantly.

COMMISSIONER SKOP: Okay. And one additional question on this page. If you could look at Lines, in the aggregate Lines 1 through 15 -- do you see that?

THE WITNESS: Are we on WCS-4?

COMMISSIONER SKOP: Yes, sir.

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. And then moving over to, again, Columns D through I, which illustrate respectfully the comparison of the difference of 25 percent AD to 1/13th AD, and also the difference between 50 percent AD to 1/13th AD -- do you see that?

THE WITNESS: Yes.

COMMISSIONER SKOP: In light of your responses to some of the Intervenors' questions and some of my questions, noting that the residential class drives peak demand, in looking at the equality of adopting either one of those respective methodologies over their traditional test, which is the 1/13th AD -- do you see that?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. Which in your opinion is more equitable in terms of those two tests in terms of the overall shift of benefit to the residential class versus the increase in cost of service to the other classes?

THE WITNESS: Can I just say you made a statement that the residential drives the peak?

COMMISSIONER SKOP: Yes, sir.

THE WITNESS: It may drive the peak, but it's not driving the cost that the company incurs to build that capacity. That's an economic decision. Because if all they wanted to do was serve the peak, they don't need to build a nuclear unit or a coal unit or a combined cycle unit. They can just invest in a low cost combustion turbine. So substantial additional dollars are being spent, capital dollars are being spent in order to achieve the lowest cost by virtue of lower fuel costs to serve the energy. So that's why the company is proposing a greater energy responsibility.

COMMISSIONER SKOP: Okay.

THE WITNESS: And so -- I don't know if I answered your question. I firmly believe that the 50 percent method for Progress Energy does recognize the extent of the projects that the company is involved in that really are providing energy benefits.

COMMISSIONER SKOP: And I appreciate that clarification. And that's a point that I know that's discussed extensively through your prefiled testimony, a point which I need to further consider the merits of.

I guess what I was trying to do is, you know, yesterday in terms of depreciation studies there was discussions into granularity, and today we're discussing the nuts and bolts at a very fine detail level. And what I'm trying to do is try and facilitate a more accurate understanding of cause and effect on a, on a macroscopic level instead of getting into the kind of minutia.

So perhaps some of the gross, I don't want to say assumptions, but, you know, I'm trying to look at things at a high level, and perhaps those require some refinement. So I do appreciate the clarifying comment.

But with respect to driving peak demand, again, if the residential growth is causing, whether it be combustion turbines or new baseload generation or peaking generation or even power purchase agreements to be entered into, isn't that predominantly driven by residential growth and peak consumption rather than influx of new industry and business?

THE WITNESS: Again, it's the capacity requirement. But you can spend different amounts for that capacity.

COMMISSIONER SKOP: Okay. And --

THE WITNESS: That's, that's my point.

COMMISSIONER SKOP: Right. And I've got a good appreciation on that in terms of what the various capacity costs would be for various forms of power generation. But I guess the point I'm coming back to is that peak demand in reserve margin requirements drive the need to add additional generation generally speaking; would you agree with that?

THE WITNESS: Generally speaking. There have been exceptions where, where the justification for power plants has been for, just for fuel savings.

COMMISSIONER SKOP: Okay. So if, if I understand the point you made, to try and clarify my thinking, was that in lieu of the residential class traditionally driving peak demand, which drives the need for new power generation, a more appropriate way to perhaps view this in terms of the equality of cost of service allocations would be that investments in new, more fuel-efficient plants benefit others such as the industrial and commercial customers equally as well as they do the residential, so therefore the cost of that incremental new capacity should be borne by both. Is that generally what you're trying to suggest?

THE WITNESS: Actually they may benefit more because they claim their higher load factor, so they're even realizing more fuel benefits.

COMMISSIONER SKOP: Okay. All right. Just one final question, and I appreciate the clarification. Again, this is something that I guess has been hotly discussed this morning. So, again, I wanted to make sure I clearly understood the respective positions of the parties.

If I could turn your attention to Page 34 of your prefiled testimony, please.

THE WITNESS: I have it.

COMMISSIONER SKOP: Okay. And with respect to Lines 23 through 25, do you see that?

THE WITNESS: Yes.

COMMISSIONER SKOP: All right. The optional time-of-use rate schedule. On the following page, Page 35 of your prefiled testimony, Lines 1 through 2, you indicate that the company is not considering any changes to the time-of-use rate schedule; correct?

THE WITNESS: In the overall design, that's correct.

COMMISSIONER SKOP: Okay. Has -- do you know or have you specifically benchmarked on what other companies may be doing in terms of time-of-use type tariffs?

THE WITNESS: I'm only familiar with the Florida requirements. I do think we're in an area though with, with more smart meters and electronic metering and better two-way communication with the customer, that the future is going to hold better ratemaking for time of use and zero in more on the critical hours. I appreciate some of the criticism of the companies, not only Florida Power's, but all the Florida utilities' rating periods as being too broad and -- but they have to be to cover the potential of when peaks occur. But I think in the future you're going to see, because of what I just said, technology, we might be able to improve on time-of-use pricing, but we're not there yet.

COMMISSIONER SKOP: Okay. And I guess my concern in that would be, you know, the adoption of what appears to be the standard in Florida, which is a four-tier pricing structure versus a three-tier that perhaps Pacific Gas & Electric might use.

But would it be correct to understand that time-of-use and any related tariffs and changes really aren't the sole focus of the cost allocation study that you performed?

THE WITNESS: That's correct.

COMMISSIONER SKOP: All right. Thank you so much. Appreciate it.

CHAIRMAN CARTER: Redirect?

MR. BREW: Excuse me, Mr. Chairman.

CHAIRMAN CARTER: Mr. Brew.

MR. BREW: Earlier staff counsel crossed over my cross.

CHAIRMAN CARTER: Yes, sir.

MR. BREW: In a way that I, that I think muddled what had otherwise been a pretty clear point, and I was wondering if I might be permitted to ask some clarifying questions of the witness so that the record doesn't stay muddied on it.

CHAIRMAN CARTER: Ever, ever so briefly, Mr. Brew, ever so briefly. Because I did sustain the objection, as you remember.

MR. BREW: This is on a different point that Mr. Saylor raised.

CHAIRMAN CARTER: Ever so briefly.

MR. BREW: Thank you. I appreciate it.

FURTHER CROSS EXAMINATION

BY MR. BREW:

Q. Mr. Slusser.

A. Yes.

Q. Do you recall the question from Mr. Saylor about whether if the existing IST, IS customers switched all at once to the firm rate, whether that would harm other customers?

A. Yes.

Q. Were you here yesterday?

A. Yes.

Q. While Mr. Crisp was being cross-examined?

A. Yes.

Q. Did you hear him say that the company has adequate capacity to absorb the interruptible load without impacting the system?

A. Yes.

Q. Okay. Thank you.

CHAIRMAN CARTER: Thank you. Redirect?

MR. MELSON: No redirect.

CHAIRMAN CARTER: Exhibits?

MR. MELSON: Progress moves Exhibits 111 through 116.

CHAIRMAN CARTER: Are there any objections? Without objection, show it done.

(Exhibits 111 through 116 admitted into the record.)

Staff?

MR. SAYLOR: Staff would move Exhibit 41.

CHAIRMAN CARTER: Are there any objections? Without objection, show it done.

(Exhibit 41 admitted into the record.)

Let me do this before we go further. Is there -- oh, hang on a second. Do we have any on the back page? I think we had some on the back pages, too.

MS. KAUFMAN: Yes, Mr. Chairman.

CHAIRMAN CARTER: Ms. Kaufman, you're recognized.

MS. KAUFMAN: I think I'm next in the order. We would move --

CHAIRMAN CARTER: 279?

MS. KAUFMAN: Yes, sir.

CHAIRMAN CARTER: Credit Value? Are there any objections? Without objection, show it done.

(Exhibit 279 admitted into the record.)

Mr. Wright, 280?

MR. WRIGHT: Move 280, Mr. Chairman.

CHAIRMAN CARTER: Any objections? Without objection, show it done.

(Exhibit 280 admitted into the record.)

Anything further for this witness on direct?

Thank you so kindly. You may be excused.

THE WITNESS: Thank you, Mr. Chairman.

CHAIRMAN CARTER: Where do I hear that voice from?

Okay. Look, here's the plan, boys and girls.

You heard it too, didn't you, Mr. Wright?

MR. WRIGHT: I did.

CHAIRMAN CARTER: That can't be God because he calls me by my first name.

(Laughter.)

Let me do this, Ms. Evans and Ms. Van Dyke. I know that we talked to you this morning about

Mr. Selecky. Now do you have cross for the next witness? If so, we can go ahead on and take care of your witness now.

MS. VAN DYKE: No, we don't.

CHAIRMAN CARTER: Okay. Is that all right with everyone? Since they don't have any cross on the next witness, and they've been most kind and generous and everyone has pretty much stipulated to their witness and the exhibits to that, so let's kind of take care of that now.

So at this time, Ms. Evans will move the prefiled testimony of Witness James Selecky into the, into evidence, and the prefiled testimony of the witness will be inserted into the record as though read.

Ms. Van Dyke would move Exhibits Number 202 through 205.

MS. VAN DYKE: Correct.

CHAIRMAN CARTER: Okay. Are there any objections? Without objection, show it done.

(Exhibits 202 through 205 marked for identification and admitted into the record.)

Thank you so kindly.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Rate Increase by Progress Energy Florida, Inc.	**Docket No. 090079-EI**

Direct Testimony of James T. Selecky

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. 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 a managing 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 presenting testimony on behalf of the Department of the Navy (DoN). DoN purchases electricity from Progress Energy Florida, Inc. (PEF or the Company).

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address PEF's "Allocated Class Cost of Service and Rate Return Study" (CCOSS). Specifically, I will discuss PEF's proposed allocation of production capacity costs. The fact that an issue is not addressed in my testimony should not be construed as an endorsement of PEF's position.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A The summary of my conclusions and recommendations is listed below:

1. The retail class cost of service study methodology proposed by PEF is inappropriate because it allocates 50% of the production fixed cost on an energy basis.

2. Allocating 50% of the fixed production cost on an energy basis has the effect of skewing allocation of generation capacity costs toward high-load factor customers without providing a proper share of the lower cost of fuel from the base load resources.

3. If the Commission is going to allocate a significant portion of the fixed production costs on energy basis, it should also allocate the energy symmetrically. That is high load factor customers who receive an above average allocation of base load production costs should receive the benefit of lower fuel costs produced by this generation resource.

4. PEF's system winter and summer peak demands are the most prominent and therefore the most important in determining PEF's capacity needs. Therefore, summer/winter coincident peaks should be used to allocate fixed production costs.

5. If the Commission elects not to utilize a summer/winter peak coincident peak allocation, I recommend using the 12 coincident peak study with a 1/13 weighting to energy as contained in the Minimum Filing Requirements.

Q ARE YOU FAMILIAR WITH THE METHODOLOGY WHICH PEF HAS PROPOSED TO USE FOR DETERMINING THE COST OF SERVING ITS VARIOUS RATE CLASSES?

A Yes, I am. The cost of service studies are sponsored by PEF witness William Slusser.

Q HAS PEF FILED MULTIPLE CCOSS IN THIS CASE?

A Yes. As indicated in the direct testimony of PEF witness William Slusser, PEF has filed three CCOSS(s). The first CCOSS is required under the Commission's Minimum Filing Requirements (MFR). This CCOSS allocates production fixed costs using the average of the 12 monthly coincident peaks and 1/13 weighted average demand (12CP and 1/13 AD method). This method allocates 12/13 or approximately 92% of a production capacity cost on the basis of class multi-coincident peaks and 1/13 or approximately 8% of the production capacity on the basis of class average hourly demands or energy.

In addition, PEF has prepared and presented the results of two additional CCOSS(s). These CCOSS(s) weight energy responsibility by 25% and 50% respectively. These studies are referred to the 12CP and 25% AD study and 12CP and 50% AD study.

Q WHAT IS PEF'S POSITION IN THIS PROCEEDING REGARDING THE ALLOCATION OF FIXED PRODUCTION COSTS.

A PEF is supporting the allocation of fixed production costs on a basis of 50% demand and 50% energy. To develop its proposed revenue increases by rate class, PEF utilized the results of the CCOSS 12CP and 50% AD method.

Q WHAT ARGUMENT DOES PEF ADVANCE TO SUPPORT ITS PROPOSED ENERGY WEIGHTING?

A In the testimony of PEF witness Slusser, he states that a significant energy weighting in the allocation of production plant capital costs is needed because the higher up-front capital costs are incurred to achieve lower energy or fuel costs. The lower cost of fuel is allocated to the rate classes on an energy basis. Therefore, Mr. Slusser argues that a significant portion of its production capacity costs should be apportioned in the same manner as customers realized the benefits i.e., on an energy basis.[1]

Q HOW DID PEF DETERMINE HOW MUCH OF THE FIXED PRODUCTION COST SHOULD BE ALLOCATED ON AN ENERGY BASIS?

A To determine the percentage of base load generation that is energy related, Mr. Slusser estimates what PEF's generation fleet would have cost if the investment were entirely in peakers. Dividing the hypothetical peaker investment by the actual production generation investment produces a factor of 50.9%. As a result of this analysis, 50% of the fixed production cost was allocated on an energy basis.

Q DO YOU AGREE WITH MR. SLUSSER'S APPROACH?

A No. The fact that different technologies have different capital costs and different fuel costs does not provide justification for Mr. Slusser's energy weighting.

Q PLEASE EXPLAIN.

A Utilities generally select the mix of generation facilities that they expect will be able to serve the total load at the lowest overall cost, taking into account the combination of fixed costs and variable costs. Having made that decision, the amount of fixed costs on the system is set, and does not vary with kilowatthour output or the number of hours that a facility is operated. These are truly fixed costs, which traditional allocation methods treat as demand related costs and allocate to customer classes

[1] PEF's witness Slusser testimony, page 19.

based on a method such as average and excess demands or coincident peak demands, using one or more peaks.

The type of fuel is determined by the specific type of generation, but the total fuel cost varies as a function of total kilowatthour output – and thus is treated as a variable cost. Generally, the variable costs are allocated on the basis of the total annual kilowatthours required by the various customer classes.

Q **DO UTILITY PLANNERS CONSTRUCT MORE CAPITAL-INTENSIVE CAPACITY FOR THE SOLE PURPOSE OF REDUCING FUEL COSTS?**

A No. This belief is based on an oversimplification of the planning process. In reality, planners are faced with the decision of providing reliable service and minimizing total costs.

Cost minimization is a requirement so that the utility provides services at the lowest overall cost. The utility strives to install a mix of generating capacity that, along with its existing generation, yields the lowest total cost. In other words, the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs.

The utility's investment decisions are affected by many factors, among them; the existing generation mix, the availability of a suitable site for the plant, environmental restrictions, and fuel diversification.

Q **WHAT FACTORS INFLUENCE THE UTILITY'S CHOICE OF GENERATING TECHNOLOGY?**

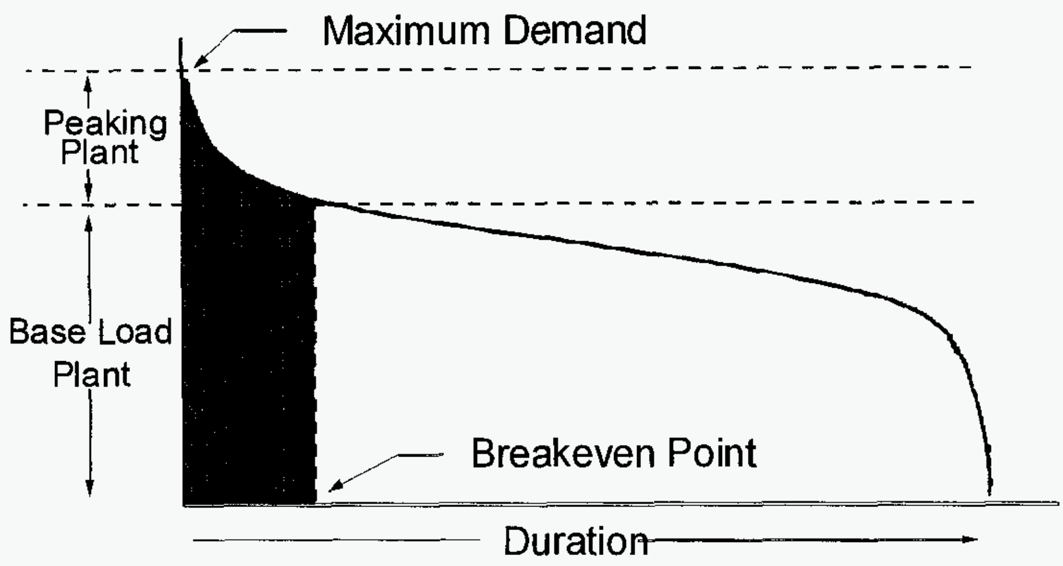
A The planning decision is dictated by engineering and economics. The utility seeks to minimize its total costs. Once a utility decides to install additional capacity, it must examine the economics of the situation. If the new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaking unit. On the other hand, if it were projected that the unit will run for a sufficient number of hours, then a baseload unit would be the more economical choice.

Q **DOES THIS MEAN THAT THE UTILITY SPENDS MORE ON CAPITAL IN ORDER TO SAVE FUEL?**

A No. In practice, the utility seeks to minimize its total costs – capital plus fuel. Thus, one could say that the utility spends more on fuel by using a peaker in order to save capital. In truth, such a statement does not give the complete picture.

Q **COULD YOU PLEASE ILLUSTRATE THE DECISION-MAKING PROCESS?**

A The basic idea is that utilities spend additional capital to save fuel costs–but only if the fuel savings are expected to outweigh the additional capital cost. If the baseload unit runs enough hours, the additional capital cost will be more than offset by the lower fuel cost. The point at which the fuel savings of the baseload plant just begin to offset the additional capital cost commonly is referred to as the "break-even" point. Of course, baseload plants normally run well beyond their break-even points. Hence, if things work out as planned, the total cost of baseload generation, per kWh, generally is much less than the total cost of peaking generation.



Q HAVE UTILITY REGULATORS RECOGNIZED THE RELEVANCE OF THE BREAK EVEN POINT?

A Yes. The NARUC Cost Allocation Manual alludes to this fundamental concept:

> The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit (Page 53).

Q DID PEF REFLECT THE CONCEPT OF BREAK-EVEN ANALYSIS IN ITS ALLOCATION METHODS USED IN ITS CCOSS?

A No. The Company's CCOSS ignores this concept. In other words, if the break-even point between a baseload plant and a peaking plant is, for example, 1,500 hours, PEF's method erroneously presumes that energy consumed beyond the 1,500-hour mark contributes to the choice of the baseload plant when in fact it does not. Once the baseload plant is expected to run beyond the 1,500 hour mark, any additional usage is irrelevant to the choice of the baseload plant and thus plays no role whatsoever in the incurrence of fixed costs.

Q DOES PEF'S PROPOSED FIXED PRODUCTION COST ALLOCATION METHODOLOGY APPROPRIATELY REFLECT ANY CAPITAL COSTS/FUEL COST TRADEOFFS?

A No. PEF's proposed allocation method only addresses the capital side of the equation, and completely ignores the fuel side. PEF's proposed production cost allocation is not symmetrical regarding the allocation of fixed and variable cost.

Q HOW DOES THE PEF METHOD FAIL TO PROVIDE A SYMMETRICAL ALLOCATION OF BOTH CAPITAL AND OPERATING COSTS?

A The method proposed by PEF focuses on the allocation of fixed production costs. This result is claimed to be fair because high load factor customers require more base load capacity and because the capital cost of base load units tends to be higher than peaking plants. However, PEF's proposed allocation method makes no attempt to recognize the other side of the capital cost/operating cost trade-off. Base load plants may have above average capital costs, but they also have below average operating costs relative to peaking units. To ignore the fuel cost differential creates a mismatch between the theory and application. If system planning principles are to be applied in determining the allocation of production plant, then it is also logical and consistent to apply the same principles to the allocation of fuel expense.

Q IN WHAT WAY IS THE COMPANY'S COST OF SERVICE STUDY DEFICIENT IN THE ALLOCATION OF FIXED PRODUCTION COSTS?

A The Company's cost of service study understates the consequences of peaking behavior. The Company must build and design its system to accommodate its peak demand. Moreover, because generating units are dispatched in merit order, with the more expensive units coming on last, classes contributing to the peak loads are also responsible for higher fuel costs. PEF's proposed method masks or dilutes the consequences of peaking behavior.

Q IF A SYMMETRICAL APPROACH WERE TO BE FOLLOWED, HOW WOULD IT BE USED TO ALLOCATE THE ACTUAL COSTS THAT A UTILITY HAS INCURRED?

A Different types of generating plants have different combinations of fixed and variable costs. Therefore, any analysis that attempts to more precisely articulate costs by customer class requires a determination of the different types of generating plant that would be installed if a utility served each customer class independently, at its lowest cost. The result would be that for high load factor customer classes relatively more base load plants and less peaking plants would be installed. The converse would be true for lower load factor classes.

High load factor classes have more fixed costs, but they also have lower fuel costs; while the low load factor classes have less capital costs but more fuel costs. This type of analysis is necessary in order to reflect both sides of the capital costs/fuel cost tradeoff. The simplistic approach taken by PEF does not recognize the fuel cost side of the equation, and as a result overcharges high load factor customer classes.

If this type of analysis were done for each class on a stand-alone basis, then the results would have to be analyzed to determine how to apply them to the actual fixed and variable costs, which the utility has incurred in pursuit of its goal of selecting that combination of technologies which serves its total load at the lowest total (fixed plus variable) cost.

Q HAVE YOU PERFORMED THIS TYPE OF ANALYSIS?

A No and neither has Mr. Slusser. This type of analysis would be needed if fixed production costs were allocated on an energy basis, as recommended by Mr. Slusser to demonstrate the impacts of the issues he has raised.

Q HOW DO TRADITIONAL COST OF SERVICE STUDIES GENERALLY RECOGNIZE THIS MIX OF VARIOUS TYPES OF GENERATING STUDY?

A Traditional cost of service studies recognize that the mix or combination of generating plants is built to serve the overall or combined load characteristics of all customer classes – not the load characteristics of any particular customer class. Therefore, energy costs are allocated across all customer classes on an equal cents per kilowatthour basis, and fixed costs are allocated across all customer classes on an equal dollars per kilowatt of demand basis. This approach is reasonable, and avoids a lot of complexity and assumptions that would be required if one were to attempt to more precisely identify the specific mix of plants and the resulting separately determined capital and fuel costs.

Q CAN YOU ILLUSTRATE?

A Yes. Assume Technology A has a capital cost of $500 per kilowatt, a heat rate of 7,000 Btu per kilowatthour, O&M expense of 0.3¢ per kilowatthour, and that it is fired with natural gas at a delivered cost of $7.00 per MMBtu. The total of fuel and O&M expenses would be 5.2¢ per kilowatthour ((7,000 Btu/kWh x $7/MMBtu) + 0.3¢/kWh)).

Assume that a second technology has a capital cost of $300 per kilowatt, a heat rate of 12,000 Btu per kilowatthour and O&M expenses of 0.3¢ per kilowatthour. With the same fuel price, the total variable cost of this unit would be 8.7¢ per kilowatthour.

The difference in variable cost is, therefore, 3.5¢ per kilowatthour (8.7¢ 5.2¢). Assuming a carrying charge rate of 15%, the difference in capital cost is $30 per kW (the $200 per kW ($500 per kW - $300 per kW) difference in capital cost times 15%). The break even point (the hours of operation required for the lower fuel cost to outweigh the higher capital cost) is 860 hours ($30 ÷ $0.035).

This illustrates that only about 10% of the hours in the year (860 out of 8,760) are arguably important in the technology choice question. Since the additional hours are not relevant in this decision – it is wrong to include loads in those additional hours in the cost allocation process – because those loads had nothing to do with the incurrence of the capital cost. The cost allocation methodology used by Mr. Slusser suffers heavily from this problem because he allocates a significant proportion of capital costs on energy.

Q HOW MUCH CAPITAL COST PER KW DID MR. SLUSSER ASSIGN TO EACH CUSTOMER CLASS IN HIS 12CP WITH 50% ENERGY WEIGHTING COST OF SERVICE STUDY?

A This is shown on Exhibit No. JTS-1 ( ). The values are obtained by dividing the net plant investment allocated to each customer class by the average of the 12 monthly coincident peak demands used in the cost allocation. As expected, classes with an above average load factor are allocated an above average capital cost per kW of demand.

Q DO THE DIFFERENT TECHNOLOGY TYPES HAVE THE SAME FUEL COST?

A No. As noted above, fuel costs vary quite significantly among base load, intermediate and peaking facilities.

Q DOES MR. SLUSSER RECOGNIZE THIS IN HIS ALLOCATION?

A No. As noted above, he allocates the same base rate energy-related cost per kWh to all classes. Furthermore, fuel cost is recovered through the separate fuel adjustment clause, and that also is on an average basis with no distinction made with respect to class load pattern, load factor, or how much base load plant and production plant investment Mr. Slusser assigns in his cost of service study.

Q ARE THERE SIGNIFICANT VARIATIONS?

A Yes. Exhibit No. JTS-2 ( ) shows the costs by resource group. PEF has classified its generation investments as base, intermediate and peaking. This data was taken from the 2008 FERC Form 1 for data. The fuel costs range from $45.92 per MWh for base load facilities to $151.72 per kWh for peaking facilities. If an energy weighting is included in the allocation of capacity costs, then there must be some symmetrical consideration given to the assignment of fuel and variable purchase power costs. The variations in fuel and purchased power costs are quite significant, and it is inconsistent to reflect differential costs on the capital side, as Mr. Slusser has done, and not reflect similar considerations that offset these differences on the energy side.

Q IN PERFORMING THE COST ALLOCATIONS TO THE "STRATIFIED" CUSTOMER GROUP IN THE WHOLESALE JURISDICTION, DOES MR. SLUSSER RECOGNIZE THE RELATIONSHIP BETWEEN THE ENERGY COSTS AND THE CAPITAL COSTS ASSIGNED TO THESE CUSTOMERS?

A Yes, he does. Since he obviously recognizes both sides of the equation in his wholesale allocation, it is not clear why he has not done so in his retail allocation.

Q HAVE YOU REVIEWED PEF'S ANNUAL DEMAND LOAD PATTERN?

A Yes, I have. Exhibit No. JTS-3 ( ) presents PEF's load characteristics for the historical period 1999 through 2008.

Q WHAT DOES PAGE 1 OF EXHIBIT NO. JTS-3 ( ) SHOW?

A In addition to the system peak, it shows the ratio of the peak demand in the maximum month to the peak demand in the minimum month for each year (column 3) and the ratio of the maximum demand to the annual average of the monthly peaks (column 4).

Column 3 indicates the extent of spread between the highest annual peak demand and the highest demand in the month which had the lowest maximum demand. The larger this number, the more seasonal the utility system. As can be seen, the PEF load pattern remains very seasonal.

Column 4 is a measure of the extent of spread between the maximum annual demand and the average of the maximum demands in the other months of the year. Again, the larger the number, the more seasonal the load pattern. Column 4 also indicates a highly seasonal load pattern.

Q **WHAT IS SHOWN ON PAGE 2 OF EXHIBIT NO. JTS-3 ( )?**

A Page 2 shows, for each year, the monthly peak demands. The last column shows the average demands for the 10 year period from 1999 through 2008 and the percentage of each month's average demand to the peak.

Q **BASED ON THIS INFORMATION, WHAT METHODOLOGY DO YOU RECOMMEND FOR ALLOCATING FIXED PRODUCTION COSTS TO CUSTOMER CLASSES?**

A This analysis indicates that PEF's load is seasonal, with a strong winter and summer peaks.

In order to provide reliable service, PEF must build capacity or acquire resources under contract to meet its anticipated firm annual system peak demand, plus a reserve margin. Since it is these peaks that drive the capacity additions, it is reasonable to use the average of the winter and summer peak demands for purposes of allocating costs to customer classes.

However, if the Commission prefers to allocate a portion of the fixed production cost on an energy basis, the results of the 12 CP and 1/13 AD CCOSS contained in the MFD should be used to allocate any increase.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

CHAIRMAN CARTER: And is there anything further for the Navy?

MS. EVANS: No.

MS. VAN DYKE: I believe Ms. Evans does plan to stay a little longer. I'm going to head out.

CHAIRMAN CARTER: Okay, then. Thank you so kindly.

MS. VAN DYKE: Thank you, Your Honor. Thank you, Mr. Chairman.

CHAIRMAN CARTER: All righty. I wanted to take care of that.

Anything, any further preliminary matters, Commissioners, staff, before we go to our next witness? Nothing further?

Call your next witness.

MR. BURNETT: Thank you, sir. We call Peter Toomey.

CHAIRMAN CARTER: Mr. Burnett, was Mr. Toomey sworn in this morning, or has he been sworn?

MR. BURNETT: I am not sure, Mr. Chairman.

CHAIRMAN CARTER: Okey-dokey. Let's do this then.

Mr. Toomey, would you please stand and raise your right hand?

Any of the other witnesses in here that will be testifying: Mr. Schultz or Mr. Pous or Mr. Lawton? Okay. Would you please stand and raise your right hand.

(Witnesses collectively sworn.)

Thank you. Please be seated. You may proceed.

MR. BURNETT: Thank you, sir. Apparently Mr. Toomey brought a small apartment with him, so I --

CHAIRMAN CARTER: Give him a moment to get settled in.

We will just -- FYI, everyone, we will be on our regular break, so we're going to break at 1:00 for our lunch and come back. And the reason I'm trying to keep us on that schedule is because it works for our court reporters, and it kind of works for the rest of us too. Okay?

You said a small apartment. I think it's more like a duplex.

(Pause.)

MR. BURNETT: All set, Mr. Toomey?

THE WITNESS: I am.

PETER TOOMEY

was called as a witness on behalf of Progress Energy Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BURNETT:

Q. Mr. Toomey, will you please introduce yourself to the Commission and provide your business address?

A. Yes. Good afternoon. I'm Peter Toomey. My business address is 299 First Avenue North, St. Petersburg, Florida.

Q. And I saw you were just sworn, so will you state who you work for and what your position is?

A. Certainly. I'm the Vice President of Finance for Progress Energy Florida.

Q. And you have filed direct testimony and exhibits in this proceeding; correct, sir?

A. I have.

Q. Do you have any changes to make to your prefiled direct testimony or exhibits?

A. I do not.

Q. If I asked you the same questions in your prefiled direct testimony today, would you give the same answers that are in that testimony?

A. I would.

MR. BURNETT: Mr. Chairman, Mr. Toomey's exhibits have been premarked as 117 through 132, and we would request that the prefiled direct testimony be entered into the record as if it were read here today.

CHAIRMAN CARTER: The prefiled testimony of the witness will be inserted into the record as though read.

(Exhibits 117 through 132 marked for identification.)

In re: Petition for rate increase by Progress Energy Florida, Inc.
Docket No. 090079-EI

DIRECT TESTIMONY OF PETER TOOMEY

I. **INTRODUCTION AND PURPOSE.**

Q. Please state your name and business address.

A. My name is Peter Toomey. My business address is 299 First Avenue North, St. Petersburg, Florida, (33701).

Q. What is your position with Progress Energy Florida?

A. I am the Vice President of Finance of Progress Energy Florida, Inc. ("PEF" or the "Company").

Q. What are the duties and responsibilities of your position with the Company?

A. My duties and responsibilities with the Company include strategic planning, financial planning and forecasting, business planning, budgeting, cost management, management accounting, and key performance management.

Q. Please describe your educational background and professional experience?

A. I received a Bachelor of Science degree in Economics from Florida State University and an MBA from the University of South Florida; I also completed the Advanced Management Program at the Fuqua School of Business at Duke University. I joined PEF in my current capacity at the end of 2007. Prior to that, I was employed by Allegheny Power, a utility with operations in four Mid-Atlantic States, since September 2003. I was named the Executive Director of Customer Service in January 2007; I was previously the Director of Rates from March 2005; and prior to that I was the Director of Finance for the regulated utilities. My areas of responsibility included Rates, the Customer Service Center, Customer Relations, and Electric Supply. My other utility industry experience was from 1984 to 2000, when I was employed by PEF or one of its affiliates. During that time I held the titles of Vice President of Corporate Development from 1997 to 2000, Director of Strategic Planning and Business Improvement from 1995 to 1997, Director of Strategic Analysis from 1992 to 1995, and Assistant Treasurer of an unregulated subsidiary from 1989 to 1991. I have provided testimony to the Public Service Commissions of West Virginia, Ohio, and Maryland.

Q. What is the purpose of your testimony?

A. I will describe the base rate increase that the Company is requesting in this proceeding and generally explain why the Company needs this increase at this time. I will further explain the Company's efforts to mitigate this increase by reducing or maintaining our cost levels while at the same time continuing to provide our customers with safe, reliable electric service. Importantly, as I explain too, this requested base rate increase follows a period of almost a decade where PEF reduced its base rates and absorbed the cost of an entire additional generation plant, subject only to upward adjustments to pay for two additional generation plants, despite steadily increasing inflation and the resulting upward pressure on our cost of providing electric service.

I will describe PEF's Budget & Financial Forecast Process to explain how the Company determined that this base rate increase was necessary to continue to provide customers safe, reliable electric service. This Process was used to develop the Company's detailed "per books" income statement and balance sheet information for 2009 and the 2010 test year. I will present the key assumptions for, and the key components of, the Company's 2009 and 2010 budgets, income statements, and balance sheets.

I will also describe the procedures the Company uses to monitor and control its Operation and Maintenance ("O&M") and Construction budgets. I will explain how the Company's 2009 and 2010 budgets and resulting financial data were used to develop the Company's Minimum Filing Requirements ("MFRs"). I will explain why 2010 is the appropriate test year and I will describe the Company's rate-making adjustments to per books net operating income ("NOI") and rate base. In this process, I will explain how the NOI, rate base, and capital structure were developed. I will also discuss taxes other than income and income taxes.

I will further introduce and generally explain the reports the Company prepared that are being filing in this rate proceeding. These include the Company's Depreciation Study, Fossil Dismantlement Study, Nuclear

Decommissioning Study, and Storm Damage Reserve Study. Mr. Earl Robinson with AUS Consultants prepared the Company's Depreciation Study and is filing testimony in this proceeding to support that Study. Similarly, Mr. Steven P. Harris with ABS Consulting was retained to prepare a Storm Damage Reserve Study and is filing testimony in support of that Study. The 2008 Fossil Dismantlement Study and Nuclear Decommissioning Study were prepared by Mr. Jeff Kopp with Burns and McDonnell and Mr. William A. Cloutier, Jr. with TLG Services, Inc., respectively. Mr. David Sorrick is co-sponsoring the Fossil Dismantlement Study, specifically section 7, and Mr. Dale Young is co-sponsoring the Nuclear Decommissioning Study. I am a co-sponsor of these Studies. Specifically, with respect to the Fossil Dismantlement Study, I am sponsoring sections 1 through 6.

Finally, I will explain the Florida Public Service Commission's (the "Commission" or the "PSC") benchmarking policy for O&M expenses and the resulting Commission O&M benchmarking test. I will generally explain how the Company fares under the O&M benchmarking test and whether that test is in fact appropriate to use in this proceeding.

Q. Do you have any exhibits to your testimony?

A. Yes, I prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (PT-1), a list of the MFRs I sponsor or co-sponsor in this rate proceeding;

- Exhibit No.___(PT-2), a summary table of the Company's 2010 test year results;
- Exhibit No. ____(PT-3), a summary of the revenue requirements associated with the Bartow Repowering project;
- Exhibit No. ___ (PT-4), a summary of the revenue requirements associated with the Steam Generator replacement project at the Crystal River nuclear facility;
- Exhibit No. ___ (PT-5), the calculation of the revenue requirements for Interim Rate Relief;
- Exhibit No. ___ (PT-6), PEF's key assumptions for its 2009 and 2010 Budget & Financial Process;
- Exhibit No. ___ (PT–7), PEF's O&M and construction budgets by functional area;
- Exhibit No. ___ (PT-8), an analysis of O&M expenses compared to the Commission's O&M benchmark test;
- Exhibit No. ___ (PT-9), a detailed calculation of the impact of the change in depreciation rates;
- Exhibit No. ___ (PT-10), the 2008 Fossil Dismantlement Study; and
- Exhibit No. ___ (PT-11), a reconciliation of the capital structure to rate base.

These exhibits are true and accurate.

Q. Do you sponsor any schedules in the Company's MFRs?

A. Yes. I will sponsor or co-sponsor the MFR schedules listed in Exhibit No. __ (PT-1). These schedules are true and accurate, subject to their being adjusted in this proceeding.

Q. What are the time periods covered by the MFRs that you will address in your testimony?

A. The MFR schedules provide financial data and other information for three annual periods: The "test year" is the forecasted calendar year 2010 and is based on the results of PEF's 2010 budget process; the "prior year" is a calendar year 2009 and is based on the results of PEF's 2009 budget process; and the "historic year" is calendar year 2008 and is based on actual data from the Company's books and records. Certain MFR schedules also encompass additional periods such as, for example, 25 years of historic weather data to support "normal" weather figures used in the test year.

II. OVERVIEW OF THE COMPANY'S BASE RATE NEEDS.

Q. What are the Company's test year revenue requirements?

A. The Company's 2010 test year produces net operating income for the retail jurisdiction of $268.5 million and a retail rate base of $6,238.6 million. The return requirement using a weighted average cost of capital of 9.2 percent, which includes a rate of return on common equity of 12.54 percent, is $574.6 million. This produces a net operating income deficiency of $306 million which results in a revenue deficiency of $499.9 million as reflected on MFR Schedule

A-1. This is the base rate increase PEF requests in this proceeding. A summary of the 2010 test year results is contained in Exhibit No. ___ (PT-2) to my testimony.

Q. What are the primary drivers of this revenue deficiency?

A. The primary drivers of the revenue deficiency are $130 million for the Bartow Repowering Project, $48 million for the CR3 Steam Generator replacement project, $170 million for the impact of the economy on sales, $34 million for increased Pension Expense, and $41 million for increases in depreciation, in addition to our on-going capital and O&M expenditures to meet federal and state reliability initiatives and continue to provide our customers with the reliable, efficient electric service they demand. Detailed calculations of the revenue requirements for the Bartow Repowering project and the CR3 Steam Generator replacement project are provided in Exhibits Nos. ___ (PT-3) and ___ (PT-4) to my testimony.

In sum, our 2010 test year revenue requirements are reasonable and necessary to provide our customers with reliable power to meet their energy needs consistent with federal and state energy policies. The Bartow Repowering project satisfies our obligation to meet customers' needs for power while fulfilling state energy efficiency policies. Similarly, the CR3 Steam Generator replacement project will enable the Company to continue to provide customers energy from the lowest cost fuel source available to the Company while ensuring the Company maintains a diverse fuel mix consistent with state energy goals. Other capital and O&M expenditures will ensure we continue to reliably provide power to our customers by meeting federal regulatory reliability requirements and state legislative and regulatory storm hardening initiatives. These expenditures, the need for them, and their related benefits are explained in more detail by the Company's other witnesses in this proceeding.

The necessity of these capital and O&M investments in the Company's system for our customers' benefit is not diminished by the economic circumstances the Company and its customers face. Simply put, we are serving more customers today and they place more demands on our system than they did four years ago, but sales are not keeping up with the cost to meet their demands, and the financial crises that led to volatile, constrained capital markets directly impact our ability to cost-effectively meet their demands for reliable power. The economic circumstances, therefore, enhance the need for this rate increase to ensure that the Company recovers its required investment and remains financially sound to provide the reliable power our customers demand throughout our capital expenditure program to bring new nuclear generation, improved transmission and distribution reliability, and enhanced electric service to our customers. The Company needs the base rate increase it requests to fulfill our obligation to reliably and efficiently serve our customers and achieve the energy policy goals that have been set before us.

Q. Is the Company also seeking interim rate relief?

A. Yes. PEF requests interim relief of $13.1 million as shown on Exhibit No. ___ (PT-5) to my testimony, based upon the historic twelve-month period ending December 31, 2008, which upon Commission approval will become effective with the first billing cycle for July 2009 and result in a percent increase of 1.70 of the monthly billed base rate revenues. This amount was calculated in accordance with Section 366.071(5), Florida Statutes, and represents the additional revenues required to achieve a 10 percent return on equity for calendar year 2008. The 10 percent return on equity was established as the earnings floor in the Stipulation and Settlement approved by the Commission in Order No. PSC-05-0945-S-EI in Docket No. 050078-EI. I sponsor the Company's MFR schedules supporting its request for interim rate relief contained in the MFR volume entitled Section G – Interim Schedules.

The Company is projecting its 2009 return on equity to be below 7 percent. Accordingly, PEF needs this interim relief, and PEF further needs the limited base rate relief in 2009 requested in its limited proceeding petition, and the accounting and cost adjustments requested in its petition for approval of the deferral of pension expenses and the ability to charge storm hardening initiative expenses to the storm damage reserve, in order to move closer to the 10 percent return on equity floor for 2009 set forth in the Stipulation and Settlement approved by the Commission. Also, the interim tariff sheets are the same tariff sheets for PEF's requested limited proceeding base rate relief because, if the limited proceeding petition is granted by the Commission, the adjustments to rates to include the limited proceeding and interim relief revenue requirements can be accomplished at the same time, thus, eliminating the need for separate base rate adjustments to customer bills.

Q. Please explain why 2010 is the appropriate test year for this base rate proceeding.

A. The 2010 test year represents the financial and business operations of the Company during the period when new rates will be in effect. The Bartow Repowering project will go into service in June 2009 and the CR3 Steam Generator replacement project will go into service in December 2009, thus, 2010 represents the first full year both projects will be in-service. The revenue requirements for these projects, as I explained previously, are among the primary reasons for the 2010 revenue deficiency. Additionally, transmission and distribution expansion and/or reliability projects enter service in 2010. With these capital investments, and our on-going O&M requirements to provide customers reliable, efficient electric service, the Company's 2010 test year rate base, net operating income, and capital structure more reasonably reflect than any other year the Company's expected operations during the period the approved rates will be in effect. Further, the Company's use of the projected 2010 test year to set rates is consistent with the Commission's long-standing practice to approve projected test years.

Q. Was a base rate increase at this time avoidable?

A. No, it was not. First, the Company has not had a general base rate increase since 1993. Instead, PEF lowered its base rates beginning in 2002, and kept them at that level through 2007 when they were adjusted only for the addition of two combined cycle generation plants, as a result of the settlement of the Company's last two base rate proceedings. During that period, PEF absorbed the cost of another combined cycle generation plant that was needed to meet customer demand, as well as the on-going escalations in labor, material, equipment, health care, and insurance costs, among others, over the past two decades since our last general base rate increase.

This extended period of relatively flat base rates demonstrates the Company's long history of effectively managing its costs and living within its means while continuing to meet the growing need for power of an increasing level of customers. In fact, we have managed to maintain our base rates at essentially the same levels they were twenty-five years ago but our cost management efforts and customers growth can no longer keep pace with our necessary capital and O&M requirements to deliver reliable electric service to customers consistent with federal and state reliability requirements and energy policy goals.

Second, the Company continues to focus on effectively managing its costs. For example, the Company has employed in each functional area sustainable cost management or reductions and/or efficiency gains without sacrificing safety, operational excellence, and customer satisfaction. These cost management and reduction efforts, and the Company's efficiency gains, are explained by the Company's witnesses, Mr. Young, Mr. Sorrick, Mr. Oliver, Mr. Joyner, Ms. Morman, Mr. DesChamps, and Ms. Wyckoff. We also strive to keep staffing levels aligned with the work load as evidenced by the work force reductions that we have announced in our Energy Delivery business unit. However, our continuing need for capital and O&M investment in our system to reliably deliver power to our customers makes it impossible for the Company to continue to earn a reasonable return on its investment without a base rate increase.

These capital investments include, among others, the Bartow Repowering project and the CR3 Steam Generator replacement project, both of which must be added to satisfy our obligation to meet our customers' need for power while also providing our customers with fuel efficiency and environmental benefits. The Company understands the tough realities of the current economic situation and the Company is doing what it can to manage costs and remain financially strong through this period and beyond. But the Company is already in the largest capital expansion program in its history to meet customer needs for reliable, cost-effective power produced by cleaner, more efficient resources, and transmitted and distributed across a safe, reliable, and hardened system consistent with federal and state energy policy requirements and goals. It is imperative that the Company remain financially healthy and earn reasonable returns to raise the capital it will need to meet its obligation to serve customers consistent with these energy policy goals.

III. PEF's BUDGET & FINANCIAL FORECAST PROCESS.

Q. Will you please explain the Company's Corporate Planning and Budgeting Process?

A. Certainly. Normally, we plan and budget on a two year basis – planning in 2008, for example, for the business years 2009 and 2010. We conduct this process throughout the course of the year in several stages. We begin by engaging in a review of strategic and corporate objectives for the coming year. Then we set financial targets for business units, taking into account the resource needs of each of the Company's business units and the corporate objectives we have established for the coming year. Next, the business units develop business plans and budgets calculated to achieve these targets. Once these are complete, we integrate them into an overall corporate plan and budget. Finally, this is reviewed, modified as may be appropriate, and approved by senior management and the Board.

The development of the budget and corporate plan is a dynamic process that involves the interplay of strategic planning, ongoing re-examination and adjustment of historical spending levels, energy and sales forecast updating, rigorous review of resource needs and operational constraints, and target setting designed to drive performance and control costs and to ensure that any additional outlays for capital projects and O&M expenditures are necessary and cost-effective.

Q. How is the Company's operating budget developed?

A. The corporate operating budget includes necessary revenue and cost components, such as revenues, fuel and non-fuel expenses, O&M, and taxes, among other components. This is distinguished from the business unit O&M budget, which addresses the Company's period costs by functional areas, i.e. power production, operations (transmission, distribution, and customer services), and Administrative and General expenses. The corporate operating budget includes the business unit O&M and construction budgets. The corporate operating budget process begins in July with the conclusion of the financial target setting process. Business unit O&M and construction budgets are developed over a two month process running concurrently with the corporate operating budgeting process.

Q. What are the key assumptions for PEF's 2009 and 2010 budgets?

A. The key assumptions underlying the 2009 and 2010 budgets are listed in Exhibit No. ___ (PT-6) to my testimony and in MFR Schedule F-8.

Q. What are the significant components of the Company's 2009 and 2010 operating budgets?

A. The revenues budget is based on the most recent customer, load, and energy sales forecast and it is integrated into the Company's corporate financial model (the "Model"). The Model is a computer simulation application used to forecast monthly and annual financial data through the use of a number of integrated calculation modules. The Model is updated on a timely basis to include the most current rate data as well as the approved corporate customer, sales, and demand forecast. The Model then calculates base revenues. Other revenue components, such as fuel, energy conservation, environmental cost recovery, capacity, and franchise fees are then computed to develop the total operating revenue projection.

The O&M budget development is exclusive of fuel costs recoverable through the fuel adjustment clause. Managers develop a detailed operating plan for the budget year. From this operating plan, a preliminary budget is developed on a project, FERC, and resource basis. This budget represents the base line for which the manager is held accountable during the upcoming year. The budget reflects the manager's goals and objectives to be justified to successive levels of management. The individual budgets are consolidated at various levels within each business unit to create a preliminary corporate budget. At the conclusion of the preliminary review and analysis, each department's detailed budget is input into the corporate budget system. Each department inputs its direct expenditures, and then a series of burdens and allocations are run. These include benefit and tax burdens on payroll, inventory burdens, sales and use tax burdens on materials, and the allocation of Service Company costs to business units. Other adjustments are made to the budget for certain corporate level expenses and accruals, such as the nuclear outage, pension costs, and nuclear joint-owner credits.

Q. How are the Company's planned construction programs developed in the Company's operating budgets?

A. The foundation of the construction program and, in turn, the construction budget, is the need for the physical facilities required to provide electrical energy to our customers. Examples of these physical facilities are generating units, transmission lines and substations, and distribution substations and structures. The need for these facilities is driven by a number of factors, either individually or in combination, such as customer growth projections, age of existing facilities, technological obsolescence of existing plant, availability of alternative energy sources such as purchased power and qualified facilities, demand-side management programs, system reliability, and qualitative considerations. Various alternatives are evaluated based on reliability, cost, and fuel type and a specific plan for construction of generating facilities of specific size, at specified points in time, including related transmission and distribution facilities is developed. The essential construction requirements data included in this plan are then transmitted to various construction management groups who develop the detailed Construction Budgets.

Q. How does the Company monitor and control the Company's operating budgets after they have been put into effect?

A. The primary means to monitor and control the O&M and construction budgets is through the monthly Cost Management Reports ("CMR"). These reports reflect monthly and year-to-date variances by business unit and are distributed to senior management as part of the Company's monthly corporate financial report. Cost management reports also include current year projections of O&M and capital spending compared to annual budgets. These projections are the basis for updated corporate income and cash flow projections, which are presented to senior management monthly and to the Board of Directors quarterly.

Q. What are the 2009 and 2010 operating budgets for PEF's Production, Transmission, Distribution, Customer Service, and Administrative and General (A&G) functional areas?

A. The breakdown of the Company's 2009 and 2010 O&M and construction budgets for the five functional areas is attached as Exhibit No. ___ (PT-7) to my testimony. PEF's witnesses for these functional areas will address and support the specific components of the O&M and construction budgets for their respective areas.

IV. DEVELOPMENT OF THE COMPANY'S MFRs.

Q. Please explain how the Company's MFRs were developed.

A. The starting point in the development of the MFRs was PEF's budget process for 2009 and 2010. The budget data from these periods coupled with the actual data from 2008 provide the foundation for the MFRs. The budget data for 2009 and 2010 was prepared in accordance with the reasonable procedures and processes used by the Company to prepare its budgets for normal business purposes. These budget numbers reasonably represent the actual expected financial results from the operation of the business for 2009 and 2010.

Q. In developing the MFRs, did the Company make any adjustments to the per books financial information derived from the Company's budget process?

A. Yes, a number of adjustments were made to the "per books" actual and budget data for retail ratemaking purposes.

Q. Did the Company comply with Commission-approved practice and policy when it developed its MFRs?

A. Yes. The Company completed the MFRs in accordance with Commission approved practices and policies.

Q. Please explain how the Company determined its net operating income for the 2010 test year.

A. The test year per books net operating income ("NOI") was derived from the PEF Corporate budget for 2010. The following is a description of the key inputs into this process:

- System revenues from sales of electric energy were developed within the Corporate Model. Other Operating Revenues were developed by the Strategic and Financial Planning Department and the Financial Planning organizations within the Business Units. These revenues were determined through an analysis of historic trends adjusted for the current economic conditions and associated anticipated future events.

- Fuel and purchased power expenses were developed through PROMOD cost simulations and the Corporate Model.
- Non-fuel O&M expenses were developed through a rigorous top-down, bottom-up budget process.
- Depreciation Expense was calculated using the rates developed in the most recent Depreciation Study included in the testimony of Mr. Earl Robinson in this proceeding and applied to the projected electric plant in-service balances.
- Decommissioning Expense was determined based on the projected accrual resulting from the updated Decommissioning Study prepared by Mr. Bill Cloutier and included as an exhibit to the testimony of Mr. Dale Young in this proceeding.
- Fossil Dismantlement Expense was based on the accrual to the reserve based on the updated Fossil Dismantlement Study prepared by Mr. Jeff Kopp, included in section 7 of my Exhibit No. __ (PT-10), and sponsored by Mr. David Sorrick.
- Amortization expense was derived from amortizing investment in electric plant dedicated to Commission-approved energy conservation programs and other intangible plant.

- The details of the development of Taxes Other than Income, including the type, amount, and rate of each tax is provided in MFR Schedule C-20.
- Income taxes were calculated based on application of the federal and state statutory tax rates applied to projected taxable income.
- The Allowance for Funds Used During Construction ("AFUDC") was calculated using the Company's Commission-approved annual rate of 8.848 percent in Order No. PSC-05-0945-S-EI in Docket No. 050078.

Q. Please explain how the Company determined what O&M costs were necessary for the 2010 test year in the MFRs.

A. The O&M costs were developed based on a top-down, bottom-up budgeting process. The business units each developed O&M budgets based on their business plans. The business plans are designed to achieve certain levels of performance and provide certain levels of service. The budgets are reviewed by several levels of management to ensure that they provide the dollars necessary to achieve the business unit goals and objectives and to ensure that they are in line with the overall corporate financial and operational objectives. The budgets are entered into the Corporate budgeting system and then rolled up to the FERC account level.

V. COMMISSION O&M BENCHMARK TEST.

Q. What is the Commission's O&M benchmark test?

A. The O&M benchmark test consists of two distinct but related parts. The first part is a comparison of PEF's test year O&M expenses, broken down into six functional areas, against the O&M benchmark for each functional area. The O&M benchmark for each functional area was developed by escalating the actual O&M expenses for 2006, which was the test year for the Company's last base rate case, by the CPI and, except for power plant O&M, the customer growth rate. This part of the test shows what the level of O&M expenses would be within each functional area assuming that these expenses experienced only increases due to inflation, measured by the CPI, and, except for power plant O&M, the rate of customer growth since the Company's last base rate proceeding. No presumption that the benchmark O&M expenses should be the Company's test year O&M expenses is created under the Commission test. Rather, the Commission recognizes that its benchmark test is merely an analytical tool to help the Commission focus attention on those O&M expense areas that experienced proportionally higher O&M increases than other areas compared to inflation and customer growth.

The second part of the Commission test is the justification provided by the Company for increases in O&M expenses that are not explained by inflation and customer growth. These reasons can include the need to perform new activities or increases in the scope of existing activities to provide safe, reliable electric service compared to the last base rate proceeding, additional expenses due to expansion of the generating fleet, or inflation rates for certain costs that are greater than the benchmark escalator (CPI), among others.

Q. What are the results of applying the Commission O&M benchmark test to PEF's O&M costs in the 2010 test year?

A. The O&M benchmarking test shows that the Company's test year O&M exceeds the O&M benchmark by approximately $143 million. An analysis of the Company's O&M expenses compared to the Commission's O&M benchmark test is contained in Exhibit No. ___ (PT-8) to my testimony. The Company's justification for this variance is provided on MFR Schedule C-41 and explained by the individual Company witnesses for each functional area in which the O&M benchmark test is applied.

VI. NOI AND RATE BASE.

Q. Please describe the ratemaking adjustments you made to PEF's per books NOI in the Company's MFRs.

A. These adjustments are reflected on MFR Schedule C-3. Certain of these adjustments are explained further below:

Recoverable Clause Expenses. Expenses recoverable by PEF through its adjustment clauses (fuel and capacity cost recovery, energy conservation cost recovery ("ECCR"), environmental cost recovery ("ECRC"), and nuclear cost recovery ("NCR")) have been removed from the test year NOI.

Franchise fee & gross receipts tax revenue and expense. The revenues and expenses have been eliminated from the income statement for ratemaking purposes consistent with Commission policies and orders. (See Order No. 11307 issued November 10, 1982 in Docket No. 820007-EU).

Economic development expenses. An adjustment based on Commission Rule 25-6.0426, F.A.C., has been made for these expenses.

Industry Association Dues. Consistent with Commission practice, the Company has removed $22,000 for industry association dues.

Rate case expenses. Based on long-standing Commission practice, the Company has amortized rate case expenses over a two-year period. MFR Schedule C-10 itemizes and details these expenses.

Corporate aircraft expenses. Consistent with Company and Commission practice, the Company has removed the impact of these costs from NOI.

Interest on income tax deficiency. An adjustment has been made consistent with Commission authorization in Order No. PSC-92-1197-FOF-EI in Docket No. 910890-EI.

Interest synchronization. Consistent with Commission practice the Company has made an adjustment to NOI to reflect the income tax impact of interest expense inherent in the Company's capital structure.

Q. How did the Company determine the appropriate accrual to the Storm Damage Reserve?

A. Based on the results of an updated Storm Loss and Reserve Solvency Study, PEF has increased the annual accrual to its Storm Damage Reserve to $16 million on a system basis, or $10 million more than the $6 million accrual approved by the Commission in Order No. PSC-94-0852-FOF-EI, in Docket No. 94621-EI. The updated Study was commissioned by PEF to analyze the Company's risk of various storm events and the resulting damage from those events. The proposed $16 million accrual is equivalent to the expected, average recoverable annual storm loss based on the study. This accrual level produces an expected reserve balance in five years of $152.5 million with a 10 percent probability of a negative balance during that period. PEF believes that an annual accrual to the Storm Damage Reserve set at the expected average annual storm loss is reasonable and appropriate. The updated Storm Loss and Reserve Solvency Study is included as an exhibit to the testimony of Mr. Harris.

Q. Does the Company plan to continue to accrue interest on the storm damage reserve?

A. No, the Company proposes to include the storm damage reserve in rate base and to discontinue the practice of accruing interest on the reserve balance. In accordance with the provisions of the Settlement Agreement in Docket No. 041272-EI, the Company is accruing interest on the storm reserve. The terms of that agreement provide that this interest treatment is only in effect until such time as new permanent base rates are set and the parties to that agreement are free to advocate any position regarding interest on the storm reserve in any future proceeding. PEF advocates discontinuing the accrual of interest on the storm reserve balance and including the storm reserve in the calculation of PEF's rate base, which results in a reduction of rate base and, therefore, lowers the revenue requirements on rate base.

Q. How was the Company's test year rate base in the MFRs developed?

A. The rate base MFRs begin with the per books data derived from the 2009 and 2010 budget process, in combination with the actual rate base investment through 2008. Since the per books data represents information developed by the Company for its business purposes, certain adjustments to this data are required to develop test year data suitable for ratemaking purposes.

Q. What adjustments were made to PEF's per books rate base?

A. These adjustments are listed and explained in MFR Schedule B-2. Certain of the Company's per books rate base adjustments that I generally describe below are simply the corresponding entries to account for the rate base effect of adjustments to per books NOI that I previously described.

<u>Recoverable adjustment clause costs</u>. These adjustments correspond to the NOI adjustments made to remove from the test year all costs that are recoverable through the adjustment clauses for fuel and capacity cost recovery, ECCR, Storm Cost Recovery Surcharge ("SCRS"), ECRC, and the NCR.

<u>AFUDC bearing Construction Work in Progress ("CWIP")</u>. Consistent with Commission policy any construction project that qualifies under Commission Rule 25-6.0141, F.A.C. to receive AFUDC has been removed from rate base.

Q. How did the Company determine the appropriate depreciation rates and expense for the test year?

A. The Company commissioned a depreciation study to determine the appropriate level of depreciation expense. That depreciation study was prepared by Earl Robinson with AUS Consultants and is included as an exhibit to Mr. Robinson's testimony in this proceeding. The depreciation rates produced in this study result in an increase in depreciation expense for the test year of $61 million (system) and $56 million (retail). A detailed calculation of this adjustment is included in Exhibit No.___ (PT-9) to my testimony.

Q. Did the Company prepare a Fossil Dismantlement Study?

A. Yes. The Company's Fossil Dismantlement Study was prepared by Mr. Jeff Kopp with Burns and McDonnell. This Study provided the Company a review of the Company's fossil fuel, power generation facilities and a recommendation regarding the total cost to dismantle the facilities at the end of their useful lives. Based on that study, the fossil dismantlement accrual for the 2010 test year is $3.8 million (system). A detailed calculation of the accrual included in the test year, along with the other information required by the Commission's fossil dismantlement rule, is provided in Exhibit No. __(PT-10) to my testimony.

Q. Did the Company prepare a Nuclear Decommissioning Report?

A. Yes. The Company's Nuclear Decommissioning Report was prepared by Mr. William A. Cloutier, Jr. with TLG Services, Inc. The Report presents estimates future cost of decommissioning including life extension and, therefore, there is no need for a going-forward annual accrual to the reserve.

Q. How did the Company develop its capital structure for the 2010 test year in its MFRs?

A. Similar to the NOI and rate base adjustments, several adjustments to PEF's per books capital structure for the test year are necessary to comply with the Commission's ratemaking policies. These adjustments are identified and explained in MFR Schedule D-1b.

Q. Was an adjustment made to the Company's capital structure to recognize the rating agencies' treatment of PEF's obligations under its long-term PPAs?

A. Yes. PEF made an adjustment to the equity component of its capital structure to recognize the practice of rating agencies to impute debt to a utility's capital structure to account for the utility's off-balance sheet obligations under long-term purchased power agreements ('PPAs"). Mr. Sullivan explains in his testimony this rating agency practice, in particular the practice by Standard & Poors, of treating payments under long-term PPAs as debt-like obligations that result in additional, imputed debt to the utility's capital structure for credit analysis. As Mr. Sullivan explains, PEF must account for this imputed debt with sufficient additional equity in its capital structure to maintain its target credit rating and, ultimately, preserve its access to the capital markets for capital at a result in additional, imputed debt to the utility's capital structure for credit analysis. As Mr. Sullivan explains, PEF must account for this imputed debt with sufficient additional equity in its capital structure to maintain its target credit rating and, ultimately, preserve its access to the capital markets for capital at a reasonable cost. The consequences for failing to make this adjustment can include a lower rating or credit outlook and a higher cost of debt for the utility and its customers.

Q. Please describe the capital structure adjustment regarding the source of funds supporting PEF's unrecovered fuel cost balance.

A. PEF accounts for these costs through a direct assignment of commercial paper as the source of capital for these costs, rather than through a pro rata assignment of all sources of capital. This adjustment is prudent because commercial paper is uniquely used to finance unrecovered fuel costs.

Q. Why didn't you make a similar adjustment for the unrecovered balance resulting from PEF's other clauses?

A. The nature of the expenses recovered through the ECCR and ECRC, which includes such recoverable costs as depreciation, return on investment, taxes, and O&M, just to name a few, is different from the recoverable fuel costs and, therefore, it is not appropriate to direct assign the unrecovered balances from these other cost recovery clauses to commercial paper. The expenses recovered in these other clauses are the types of costs that are more typically funded from all sources of capital.

Q. Please describe the other clause related source of funds adjustment made to the capital structure.

A. Given the unique nature of the Nuclear Cost Recovery mechanism, it is prudent to recognize the impact that recovery of these costs has on deferred taxes through a specific adjustment to the accumulated deferred income tax balance included in the capital structure, thus allowing the remaining rate base (excluding nuclear cost recovery) to be synchronized to the capital structure through a pro rata assignment of all sources of capital. This adjustment is prudent because of the unique creation of accumulated deferred income taxes which result from this clause related cost.

Q. Please describe the capital structure adjustment for non-utility investment.

A. Consistent with past Commission practice, PEF's non-utility investment was removed entirely from the equity component of PEF's capital structure, rather than pro rata from all sources of capital.

Q. Are there any other Commission ratemaking policies that the Company must apply to its test year capital structure?

A. Yes. Commission ratemaking practice requires the reconciliation of the test year capital structure with the utility's rate base. This reconciliation is summarized in Exhibit No. ___ (PT-11) to my testimony.

Q. Please explain the Taxes Other than Income in the 2010 test year in the Company's MFRs.

A. The total Taxes Other than Income included in the 2010 test year are $390.4 million. Of this amount, $239.6 million are revenue related taxes which are basically passed through to customers on their bills. The remaining Taxes Other than Income represent property taxes and payroll taxes. Property taxes are projected to be $125.1 million and they are calculated by applying the projected tax rates to the projected plant balances. Payroll taxes are projected to be $25.7 million, and they are calculated by applying projected payroll tax rates to the 2010 budgeted payroll expense.

Q. How were income taxes accounted for in the Company's MFRs?

A. Income taxes were calculated by first adjusting the pre-tax net operating income for any tax exempt items and then by multiplying the adjusted pre-tax net operating income by both the state and federal statutory tax rates. The income taxes were split into current and deferred taxes by adjusting book taxable income by any timing differences for revenues and expenses.

VIII. CONCLUSION.

Q. What are the test year revenue requirements that the Company needs?

A. Based on the fully adjusted NOI, rate base, and capital structure set forth in the Company's MFRs, PEF requires retail revenues of $2,017.8 million in order to cover operating expenses and produce a return of $574.6 million on retail rate base of $6,238.6 million at a weighted average cost of capital of 9.21 percent, including a rate of return on common equity of 12.54 percent. Mr. Slusser's testimony presents proposed rates and charges that will produce these revenue requirements from PEF's rate classes in proportion to the Company's costs to serve each of the revenue classes.

Q. How do these revenue requirements compare with the test year revenues that would be produced under the Company's current rates?

A. Using the test year billing determinants provided in Mr. Slusser's testimony, PEF's current base rates would produce revenues of $1,517.9 million. When compared to the Company's test year revenue requirements, current rates would result in a revenue deficiency of $499.9 million. This is the base rate increase that PEF reasonably requests in its petition for rate relief and the rate increase that is supported by the Company's MFRs and witnesses.

Q. Does this conclude your testimony?

A. Yes.

In re: Petition of Progress Energy Florida for Limited Proceeding to Include the Bartow Repowering Project in Base Rates
Docket No. ________-EI

DIRECT TESTIMONY OF PETER TOOMEY

I. INTRODUCTION, PURPOSE, AND SUMMARY.

Q. Please state your name and business address.

A. My name is Peter Toomey. My business address is 299 First Avenue North, St. Petersburg, Florida, (33701).

Q. What is your position with Progress Energy Florida?

A. I am the Vice President of Finance of Progress Energy Florida, Inc. ("PEF" or the "Company").

Q. What are the duties and responsibilities of your position with the Company?

A. My duties and responsibilities with the Company include strategic planning, financial planning and forecasting, business planning, budgeting, cost management, management accounting, and key performance management.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Economics from Florida State University and an MBA from the University of South Florida; I also completed the Advanced Management Program at the Fuqua School of Business at Duke University. I joined

PEF in my current capacity at the end of 2007. Prior to that, I was employed by Allegheny Power, a utility with operations in four Mid-Atlantic States, since September 2003. I was named the Executive Director of Customer Service in January 2007; I was previously the Director of Rates from March 2005; and prior to that I was the Director of Finance for the regulated utilities. My areas of responsibility included Rates, the Customer Service Center, Customer Relations, and Electric Supply. My other utility industry experience was from 1984 to 2000, when I was employed by PEF or one of its affiliates. During that time I held the titles of Vice President of Corporate Development from 1997 to 2000, Director of Strategic Planning and Business Improvement from 1995 to 1997, Director of Strategic Analysis from 1992 to 1995, and Assistant Treasurer of an unregulated subsidiary from 1989 to 1991. I have provided testimony to the Public Service Commissions of West Virginia, Ohio, and Maryland.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the calculation and recovery of the revenue requirements that PEF proposes to recover in base rates in 2009 for the Company's Bartow Repowering Project, consistent with the Company's 10 percent return on equity ("ROE") floor in its Stipulation and Settlement Agreement ("Stipulation") in its last base rate proceeding that was approved by the Commission in Order No. PSC-05-0945-S-EI in Docket No. 050078-EI.

Q. Do you have any exhibits to your testimony?

A. Yes, I prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (PT-1), contains the revenue requirements for the Bartow Repowering Project that PEF proposes to recover in base rates commencing with the commercial in-service date for the Bartow units to be effective the first billing cycle for July, 2009;
- Exhibit No. __ (PT-2), contains the Stipulation and Order No. PSC-0945-S-EI that approved the Stipulation and resolved the Company's petition to increase base rates in Docket No. 050078-EI;
- Exhibit No. __ (PT-3), illustrates the impact to retail rates due to base rate recovery of the Bartow Repowering project revenue requirements for 2009;
- Exhibit No. __ (PT-4), contains the revised tariff sheets for each rate schedule (legislative format); and
- Exhibit No. ___ (PT-5), contains the revised tariff sheets for each rate schedule (clean copy format).

These exhibits are true and accurate.

Q. When is the Bartow Repowering Project expected to begin commercial operations?

A. PEF expects the Bartow Repowering Project combined cycle units to begin commercial operation on June 1, 2009.

Q. What are the total Bartow Repowering Project revenue requirements?

A. The total project cost of $800.2 million (including AFUDC) equates to approximately $126 million in annual revenue requirements. PEF proposes to recover approximately $63 million through base rates for the period July through December 2009. This calculation is based on a 10 percent ROE for purposes of this limited proceeding. See Exhibit No. __ (PT-1), to my testimony for the revenue requirements calculation.

Q. Why have you calculated the Bartow Repowering Project revenue requirements using a 10 percent ROE?

A. The 10 percent ROE is the ROE floor established in the Stipulation approved by the Commission in Order No. PSC-05-0945-S-EI, in Docket No. 050078-EI. See Exhibit No. __ (PT-2) to my testimony. Pursuant to the terms of that Stipulation, if PEF's retail base rate earnings fall below a 10 percent ROE, PEF may petition the Commission to amend its base rates as a limited proceeding under Section 366.071, Florida Statutes. The floor or minimum, for purposes of calculating the revenue requirements, is therefore 10 percent for purposes of this limited proceeding.

Q. Will the Company fall below the minimum allowed 10 percent ROE absent the relief requested in this limited proceeding?

A. Yes. PEF's revenues from sales under current economic conditions are not covering PEF's required expenditures to provide customers reliable electric service, such as the addition of the Bartow Repowering Project to PEF's system, which is required to meet customer need for reliable power. As explained by Mr. Murray, the Bartow Repowering Project is necessary for PEF to meet its obligations to satisfy its customers' capacity needs in 2009 with cost-effective, environmentally responsible sources of large-scale power generation consistent with the goals of Florida's Energy and Climate Change Action Plan. As a result, these expenditures will drive PEF's equity return even further below the 10 percent ROE floor as reported on the Commission adjusted or pro-forma basis on PEF's monthly earning surveillance reports filed with the Commission. Accordingly, PEF has met the condition that it may petition for base rate relief in a limited proceeding under the Stipulation approved by the Commission if the Company's retail base rate earnings fell below a 10 percent ROE as reported on a Commission adjusted or pro-forma basis on a PEF monthly surveillance report during the term of the Stipulation.

Q. Will the requested Bartow Repowering Project revenue requirements cause the Company to exceed a 10 percent ROE in 2009?

A. No. If the Bartow Repowering Project revenue requirements are included in PEF's base rates the Company will approach but will not exceed a 10 percent ROE on its retail base rate earnings.

Q. When will PEF adjust its 2009 base rates to account for recovery of the Bartow Repowering Project revenue requirements?

A. PEF's base rates will be adjusted the first billing cycle for July 2009.

Q. What is the impact to retail base rates due to base rate recovery of the Bartow Repowering Project revenue requirements?

A. As shown in Exhibit No. ___ (PT-3) to my testimony, retail base rates will increase by a factor of 9.12 percent. This percentage increase will be uniformly applied to PEF's base rate billings. This rate adjustment factor will not apply to service charges, interruptible demand credits, curtailable demand credits, stand-by generation credits, or load management credits. This rate adjustment factor is reflected in the tariff sheets in Exhibit No. __ (PT-4) and Exhibit No. ___ (PT-5) to my testimony. These tariff sheets are also the same tariff sheets for PEF's requested interim relief in its pending base rate proceeding because, if this Petition is granted by the Commission, the adjustments to rates to include the 2009 Bartow Repowering project revenue requirements and interim revenue requirements can be accomplished at the same time, eliminating the need for separate base rate adjustments to customer bills.

Q. Does this conclude your direct testimony?

A. Yes.

BY MR. BURNETT:

Q. Mr. Toomey, do you have a summary of your prefiled direct testimony?

A. I do.

Q. Thank you, sir. Keeping in mind the five-minute limitation and the lights in front of you, will you please summarize your testimony?

A. I will.

Good after -- good afternoon.

I, I'm the Vice President of Finance for Progress Energy Florida. You already heard that. In this role, my duties and responsibilities include strategic and financial planning, budgeting, cost management, management reporting and key performance management.

The purpose of my testimony is to support the calculation and recovery of the revenue requirements that PEF is proposing to recover in base rates in 2010. We are requesting a base rate increase of 499.9 million, as reflected in MFR Schedule A-1.

The 499.9 million revenue deficiency is comprised of the following: 130 million for the Bartow repowering project; 48 million for the Crystal River 3 steam generator replacement project; 170 million for the impact of the economy on sales; 34 million for increased pension expense; 56 million for increases in depreciation; and, finally, the ongoing capital and O&M expenditures to meet federal and state reliability initiatives and to continue to provide our customers with the reliable and efficient electric service they demand.

Our 2010 test year requirements are reasonable and necessary. The Bartow repowering project satisfies our obligation to meet customers' needs for power while fulfilling state energy efficiency policies. Also, the CR-3 steam generator replacement project will allow us to continue to provide customers energy from our lowest cost fuel source while ensuring that we maintain a diverse fuel mix.

The need for these capital and O&M investments in our system is not diminished by the economic circumstances the company and our customers face. We are serving more customers today and they place more demands on our system than they did four years ago, but sales are not keeping up with the cost to meet their demands.

The financial crisis that led to volatile constrained capital markets directly impact our ability to cost effectively meet their needs for reliable power. The economic circumstances therefore enhance the need for this rate increase to ensure that the company recovers its required investment and remains financially sound to provide reliable power our customers demand.

The company needs the base rate increase it requests to fulfill our obligation to reliably and efficiently serve our customers and to achieve the energy policy goals that have been set before us.

This concludes my summary, and I'm now prepared to answer any questions you may have.

MR. BURNETT: Mr. Chair, one brief procedural matter before I tender Mr. Toomey. I've been presented two red envelopes. One I understand contains compensation information. I'm not allowed to see that. So if there are any questions yielding from this envelope, I'm going to switch chairs with Mr. Glenn to field those. I just didn't want to do that without your permission.

CHAIRMAN CARTER: Okay. That'll be fine. That'll be fine.

MR. BURNETT: Thank you, sir. And we tender Mr. Toomey.

CHAIRMAN CARTER: Okay. Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. -- excuse me. Thank you, Mr. Chairman. It happens to me every time these days.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q. Good morning, Mr. Toomey. Or I guess it's afternoon.

A. Good afternoon.

Q. My name is Charles Rehwinkel with the Office of Public Counsel.

Before I ask you any questions about, in cross-examination, I just would like to understand, on June 5th you filed corrected Page 27 and a corrected exhibit to your testimony; is that correct?

A. That's correct.

Q. Okay. And so when you, just for the record, when you said you had no changes, you were assuming those were already incorporated into the filing?

A. Yes. Those are filed and incorporated into the record. That was my understanding.

Q. Okay. And I'm not raising an issue about that. I just want to understand the difference between what was, what was filed on March 20th and then what was filed on June 5th.

Do you -- can you tell me what was different in -- I think you changed Page 27, and then you changed, or filed an Exhibit PT-9 that had ten pages instead of 11. Can you help me understand what the differences were?

A. I can. I can. First starting with my testimony and the correction to the testimony, the change basically stems from the exhibit and where the numbers roll up into the testimony, and it has to do with the change in the depreciation expense that we were capturing in that exhibit.

So if you're on the testimony on Page 27, on Lines 7 and 8 I have dollar amounts shown there on the amended page. I'll read those to you. Depreciation expense for the test year of 61 million system and 56 million retail. In my original testimony those were different and lower amounts.

Q. Were they 46 and 41 respectively?

A. I can tell you in a second.

Q. Okay.

A. Yes, they were. 46 million system and 41 million retail. And you'll see just below that it refers to the Exhibit PT-9, which is a detail exhibit that basically comes down to a total that those numbers themselves refer to. And so also in that update on June 5th the exhibit itself was changed, and so the testimony changed to reflect in sync with the amendment to the exhibit.

Q. Okay. Now was there a math error on the original PT-9?

A. No, I don't believe that there was. I believe that the original PT-9, because the exhibit is trying to capture what is the change in depreciation caused by the change in rates, and I believe that incorrect rates were used on the first exhibit.

Q. When you say incorrect rates, do you mean depreciation rates?

A. Yes.

Q. Do you have both documents with you, the originally filed PT-9 and the revised PT-9?

A. I do.

Q. Okay. Can you direct me to what changed on that document, on the original filed document?

A. Yes. I'll have a look and see.

Q. Okay.

(Pause.)

A. I was just trying to flip back and forth to compare the pages that have changed, and the, one of the first items, I'll just make certain here, is in the original. I don't believe that the changes to the dismantlement rates had been incorporated. And in the revised on the dismantlements, that's one of the first things that I see. So the dismantlement rates, which were also were, are included in this exhibit, I believe you'll, I see that as one of the differences.

Q. And where, where on the exhibit is that? What page?

A. For example, dismantlement of fossil steam, on the original exhibit it was showing 2,994,747 of both new rates and old rates with no variance. And on the corrected page, showing 2,994,000, under the old rates non, and so it's showing that amount as a variance.

MS. KAUFMAN: Mr. Chairman, I don't want to interrupt, but if the witness could direct us to a page.

THE WITNESS: I'm sorry.

CHAIRMAN CARTER: Can you guys hear?

MS. KAUFMAN: I could hear, but --

CHAIRMAN CARTER: Staff, can you hear?

THE WITNESS: Okay. If --

MS. KAUFMAN: -- I just didn't know where he was.

THE WITNESS: I can speak louder too.

CHAIRMAN CARTER: We can give you some more volume.

Chris, would you raise the volume on his microphones, please?

COMMISSIONER ARGENZIANO: Thank you, Mr. Chairman. That would be beneficial.

THE WITNESS: Okay. Okay. On the new amended

Exhibit 9 it would be Page 2 of 10. If you'll look at Lines, say, 9 to 19, total dismantlement, and it's dismantlement of fossil steam that we're picking up there. Under the new rates you can see there's a subtotal on Line 19 of 2,994,747. Under the old rates it's zero, and so it's showing a variance or a change of 2 994,000.

In the original, the exhibit that was amended to kind of try to highlight some of the differences, the new rates showed the 2,994,747, but the old rates, in fact, showed a zero, and so it highlighted that as the difference. It showed no difference, I'm sorry, in the old schedule.

So, Mr. Rehwinkel, back to your point, I was trying to quickly compare subtotals between the schedules to see what had changed, and the dismantlement was the first thing that stuck out to me. But I was kind of flipping quickly there. I'm just trying to go group by group to see.

BY MR. REHWINKEL:

Q. And while you're doing that, can I ask you, this page, this exhibit, this exhibit is, is intended to present the results of the depreciation study; is that correct?

A. Yes. I think this is intended to present what is the change in effect being caused and requested in base rates as a result of that.

(Pause.)

CHAIRMAN CARTER: Mr. Rehwinkel?

MR. REHWINKEL: Yes, sir.

CHAIRMAN CARTER: We've got -- I don't want to lose another lightbulb, particularly while I'm sitting here, but we've got a little problem here. I'm going to have to have Chris check it out. Why don't we do this, if we can break a little early. The witness can get you those comments and then when we come back on he can give them to all of us. And in the meantime we can get this little, get this little technical problem taken care of before we come back in.

We're on break for lunch, guys.

COMMISSIONER ARGENZIANO: Mr. Chair?

CHAIRMAN CARTER: 2:15.

COMMISSIONER ARGENZIANO: Okay. Thank you.

CHAIRMAN CARTER: All right.

(Recess taken.)

(Transcript continues in sequence with Volume 12.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 29th day of September, 2009.

Linda Boles
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