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 23
Pages 3132 through 3324

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THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

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: Tuesday, September 29, 2009

TIME: Commenced at 2:15 p.m.
Concluded at 5:00 p.m.

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

REPORTED BY: CLARA C. ROTRUCK
Court Reporter
(850) 222-5491

PARTICIPATING: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
186 through 201			3156
307			3153
308	Pollock Errata	3154	3154
309	Response to OPC POD 31	3271	3271

P R O C E E D I N G S

(Transcript follows in sequence from Volume 22.)

CHAIRMAN CARTER: We're back on the record and when we last left we were in cross-examination. Mr. LaVia, you're recognized.

MR. LaVIA: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. LaVIA:

Q Good afternoon, Mr. Joyner. I believe you have Exhibit 293 in front of you. I think your counsel provided it to you.

A I do.

Q I'm going to ask you some questions on that to sort of follow up to some of the questions Mr. Moyle asked you.

Were you here when Mr. Dolan was talking about this exhibit yesterday?

A Yes, sir.

Q So you heard the general discussion. Could you please turn to Bates page 000024, which is entitled, O&M Cost Management? It's at -- in the bottom right are the Bates stamped numbers.

A I was going by the page number, sorry about that. 24?

Q Yes, 24. Tell me when you have it.
A O&M Cost Management is the title on the page?
Q That is it.
A All right.
Q And you see there are three categories. The bottom category is Expense Reductions, do you see that?
A Yes, sir, I do.
Q And then the first line states, "significant belt-tightening efforts, correct?
A Yes, sir, it does.
Q Those are Progress Energy's words, not mine, correct?
A Yes, sir.
Q Now, you answered some questions from Mr. Moyle about this exhibit. He even turned you to this page and you talked about workforce reductions and how that was some belt-tightening and minimizing O&M that you guys were undertaking, is that accurate?
A I don't know that I would consider, no, sir, in that regards. I would consider that under the second bullet called, "Workforce Reductions," the first sub-bullet there that you see that eliminated 150 employees. That would be my reference. The belt-tightening would have been other means.
Q And thanks for getting to that. That's going

to be where I focus, on the belt-tightening.

A Okay.

Q Has management given you any specific belt-tightening directives or goals for 2009?

A No, sir, just an expectation that we should be doing that at all times.

Q And the same question for 2010, any specific goals from management with regard to belt-tightening?

A No, sir, just the expectations again.

Q Could you give me an example of how, within your jurisdiction of O&M issues, how you would tighten your belt other than workforce reductions?

A Yes. Well, when you say belt-tightening, that typically means, you know, at some point in time there is what I call sustainable versus belt-tightening may be something you elect to do short term versus long term. That's how I differentiate it.

But significant belt-tightening efforts in my case would be more long-term, and that would be meals, travel, training, those things would be what I would refer to as belt-tightening exercises.

Q And you have no, to reiterate, you have no goals that have been provided to you with regard to those type of belt-tightening efforts from your management?

A No specific goals, sir, other than the fact that we're expected to ensure that we're doing a good job in those areas I just mentioned, and that's reviewed on a monthly basis on whether we're meeting, you know, that obligation or not.

Q Have you heard that term, *belt-tightening efforts*, before?

A I have, yes, sir.

Q You have. Outside of this hearing, have you heard that term?

A Yes, sir, I have.

Q I would like you to turn to Bates-stamped page 8, which also happens to be page 8.

A Okay, that will help me, then.

I'm with you, sir.

Q I'm asking questions about the three to five percent productivity gain that's referenced there, the financial performance, right-hand side.

A I'm sorry, my page 8 was Dolan No. 19, I'm sorry. So you said number 8?

Q Yes, sorry.

A I'm with you now, thank you.

Q Were you given any specific targeted productivity gains by management for 2009?

A No, sir.

Q How about for 2010?

A No, sir.

Q Have you developed any metrics for measuring productivity gains within your jurisdiction of O&M costs?

A In regards to our execution responsibility there has been productivity measurements in place in general for how well we restore, how well we construct. Those have been in operations for, you know, several years, because we go in and we measure our own means of productivity and efficiency. Specific to something that would tie back directly to this, have I been given direction, no, sir.

Q So are you developing any new metrics right now or any new ways of measuring productivity gains?

A We're continually trying to, that's part of our culture, to continue to look for ways, new metrics, things of those natures, of that manner.

In this case specifically going into 2010, are we going to change the way that we track productivity, no, sir, not that I'm aware of.

Q One last very short line of questioning. Could you please turn to page 10 of your rebuttal testimony?

A I'm there, sir.

Q Mr. Moyle asked you several questions about the first, lines 4 and 5, the first two lines of the response. He focused more on the fuel rates. My question for you focuses more on the labor rates.

I believe your testimony is that between 2006 and 2010, the labor rates have -- you've seen a double digit increase in labor rates, is that accurate?

A From that time frame, yes, sir, during that time frame.

Q What has happened to labor rates, say, for the first nine months of this year?

A Going into 2010, we're in the process now of going out for bids for 2010, but all indications are we will not see double-digit going from into from '09 to '10, but its early indications, sir, I don't know exactly what those are yet.

Q Let's say from 2008 to 2009, were you still seeing an increase in labor rates given what was happening to the economy during that time period?

A Yes, sir, we did.

Q And can you explain that increase? Do you know what was driving it?

A It's just a lot of times it's the overhead that your vendors -- with any contractor, typically to go in you will see some means of escalation, whether it be for their fleet, their labor or whatever, but you will see some means of escalation when you do contract negotiation.

Q Can you quantify for me, say, from 2008 to 2009, what those increases were?

A I cannot, sir.

Q But still double-digit?

A I cannot commit to whether they are double-digit or not. I just do know that there was an increase.

Q Do you know what was happening generally to labor rates in this country during that time period?

A No, sir, I do not.

Q Would you have any reason to expect the labor rates in your jurisdictional areas, these vegetation management rates, to differ from what was happening in the general economy?

A I can't speculate either way, sir, in that regards.

MR. LaVIA: That's all I have, thank you.

CHAIRMAN CARTER: Thank you, Mr. LaVia.

Staff?

MS. FLEMING: We have no questions.

CHAIRMAN CARTER: Commissioner Skop?

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Good afternoon, Mr. Joyner.

THE WITNESS: Good afternoon, sir.

COMMISSIONER SKOP: Just some brief follow-up questions to the questions that you've been asked.

On page 5 of your rebuttal testimony you indicate that for 2010, the vegetation management budget is approximately $13.9 million, is that correct?

THE WITNESS: Yes, sir, in respect to the benchmark, yes, sir.

COMMISSIONER SKOP: Thank you. And if I could just turn your attention to page 6 of your rebuttal testimony, lines 23 through 24, continuing onto page 7, lines 1 through 4.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: And basically that provides the question and answer as to why the vegetation management costs are projected to be higher in 2010, is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: And then for, is that just for distribution- or transmission-related vegetation management costs? I think it's alluded to by Mr. Oliver in addition to that.

THE WITNESS: Right. Sir, this specifically represents distribution only.

COMMISSIONER SKOP: Great.

And with respect to page 7, lines 1 through 4, I guess that you spoke to the need to keep pace with the three-year backbone cycle and complete the fifth year of a five-year lateral cycle, is that correct?

THE WITNESS: Yes, sir. And if I may, that's a good distinction, because when we say fifth year lateral, already we're two years into the keep pace for the third year feeder. So I appreciate your bringing that up.

COMMISSIONER SKOP: With respect to that clause or the phrase, *keep pace on the three-year backbone*, does that imply that they're not keeping pace or they're behind schedule?

THE WITNESS: No, sir. When you say three- and five-year, the intent there was, everybody, myself included, may want to go and just look at the fifth year 2010 as the expectation when you have laterals trimmed.

What you will also see again in 2008, was when we had to have our feeder, feeders trimmed. What we're actually saying is '09, '10 and '11 is a three-year period, so in 2011, we will be expected to have our feeder backbones trimmed.

So when it says "keep pace 2010," the miles trimmed will not be just for the laterals to make the fifth year commitment, it will also consist of keeping pace to ensure we meet the 2011 lever feeder commitment.

COMMISSIONER SKOP: On the end of the bottom of page 7 of your rebuttal testimony, lines 21 through 23, do you see that?

THE WITNESS: Yes, sir, I do.

COMMISSIONER SKOP: Is it correct to understand that the storm-hardening rule adopted by the Commission, I believe in 2006, requires an increased scope of work, but the recovery of those funds are not included within the -- or provided for within the 2005 settlement agreement, is that correct?

THE WITNESS: Yes, sir. Yes, sir.

COMMISSIONER SKOP: So Progress is alleging that to do what the Commission had requested it to do through its storm-hardening initiatives, that additional funding is required that was not already included previously?

THE WITNESS: My understanding is during those discussions during the rate settlement, storm-hardening initiatives were not part of that dialogue. Now there is an increased scope of work that was not taken into consideration when that settlement was done.

COMMISSIONER SKOP: Thank you.

Just two final questions. On page 8 of your rebuttal testimony, lines 12 through 19 --

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: -- you were previously asked a question I believe by Mr. Moyle as to whether the vegetation management costs and the requirements may decline after 2010, and to the extent that if you put something or request to put something in base rates and if you don't spend at that level, then essentially the customers are being asked to pay for something that has not occurred yet.

But do you feel with relation to your testimony on page 8, 12 through 19, that those costs are legitimate and are not heavily loaded or padded, as suggested by Mr. Schultz and Mr. Marz, that's being discussed on page 2?

THE WITNESS: I'm sorry, I'm trying to think.

Yes, sir, I feel very -- ask your question again. I just want to make sure I answer it specifically. I wanted to say yes.

COMMISSIONER SKOP: My problem is I'm trying to do this on the fly and I haven't had a couple of months like the Intervenors to prepare my questions.

But listening as we go, I think the discussion centered on, you know, are the costs legitimate in terms of vegetation management costs and those are being built into rates, and I think the concerns are threefold: one, are those costs heavily padded for heavily loaded for 2010, as suggested by Intervenor testimony Schultz and Marz, and I think you addressed that on page 2 of your rebuttal testimony.

THE WITNESS: Right, right.

COMMISSIONER SKOP: I think the second part of that is assuming the costs are required and put in rates, how -- to Mr. Moyle's question -- how is it ensured that those amount of funds will actually be expended, so I think if you could just briefly comment on both of those in relation to the Intervenors' assertion that basically it looks like a lot of costs were loaded in 2010, and there may be good reason for why Progress did that and I think that your rebuttal testimony tries to explain that, but I'm just trying to get clarification on my point.

THE WITNESS: Thank you for going through that clarification for me.

On point one you mentioned, yes, absolutely these costs reflect the need for 2010 spending for our vegetation management program in regards to meeting our three/five-year storm-hardening rule. There's no question about that.

The second part to your question, sir, with the O&M expenses, again, as we discussed in 2011, we will see validation on whether we did utilize, whether we did meet our five-year lateral commitment.

COMMISSIONER SKOP: And if by fact that does not occur, what will be the contingency plan for either keeping parity with the vegetation management schedule or addressing the issue that Mr. Moyle raised about your recovering that money in rate but not spending to that level? Is there any way to provide a remedy if that spend level does not reach what's projected to be necessary?

THE WITNESS: At this point we have not discussed what that remedy would be, only because right now our expectation is to meet our commitment in 2010.

In the event something changes, again, as we have discussed, there's always the balance of reliability and other issues with a proactive maintenance program, so there would be a specific explanation as to the why that we would need to meet and for you to gain that understanding.

COMMISSIONER SKOP: So I guess just in a nutshell the key point is that you would, I guess, basically disagree with the assertions raised by Mr. Schultz and Mr. Marz from the Intervenors that the 2010 is heavily loaded by these vegetation management expenses?

THE WITNESS: I absolutely disagree with that, sir.

COMMISSIONER SKOP: All right, thank you.

CHAIRMAN CARTER: Anything further from the bench?

Redirect?

MR. BURNETT: Yes, sir.

REDIRECT EXAMINATION

BY MR. BURNETT:

Q Mr. Joyner, will you please open Mr. Schultz's testimony that I believe you have there to page 37?

A I'm there.

Q And do you remember Mr. Rehwinkel had some questions that he was asking you that suggested that you may have misunderstood Mr. Schultz's testimony with regard to this page, do you recall that?

A I do remember that discussion.

Q Will you please open your testimony to page 3, and keep Mr. Schultz's open if you wouldn't mind?

A I've got it, thank you.

Q Now, I want to look at page 37, line 22, of Mr. Schultz's testimony, and can you tell what the dollar figure there is on page 37, line 22?

A The dollar figure is 7.7 million.

Q Now, look at your testimony on page 3, line 2. What is the dollar figure there?

A 7.7 million.

Q Flip your page over to page 4, if you would.

A And if -- I mean on this one, the 7.7, the confusion may have been, I want to make sure that the 7.7 was, we explained that variance, I just want to make sure. There may have been a different means on how someone understood how to get there, Mr. Schultz, but the 7.7 we did explain to your point.

Q Thanks. Will you go ahead and flip over to your page 4?

A I'm there.

Q Now, if you look on page 37, line 16, of Mr. Schultz's testimony, what MFR is he referring to there?

A I'm sorry, what page on Mr. Schultz?

Q Page 37, line 16. What MFR schedule is Mr. Schultz referring to?

A MFR Schedule C-41.

Q Page 4, line 7, of your testimony, what MFR schedule are you referring to?

A MFR C-31.

Q And jump down to line 17 on page 37 of Mr. Schultz's testimony. Again, what MFR schedule is he referring to?

A C-41.

Q Page 4, line 8, of your testimony, which one are you referring to?

A C-41.

Q Flip your page over to page 5 of your rebuttal, please.

A I'm there.

Q On page 37 of Mr. Schultz's testimony, line 12, what organization's O&M expenses is he talking about there at the end of line 12?

A Distribution.

Q And on page 5, your Table 1, line 2, what organization's O&M expenses are you talking about there?

A Distribution.

Q With respect to the year on page 5, line 2, of your testimony, what year are you referring to there?

A 2010.

Q And page 37, line 13, of Mr. Schultz's testimony, what year is he referring to?

A 2010.

Q And then finally, if you would refer to, bear with me one second, if you would refer to line 37, I'm sorry, page 37, line 12, of Mr. Schultz's testimony, what is the dollar figure he's referring to there?

A $145 million.

Q And if you go to page 5, line 3, of your testimony, what's the dollar figure you're referring to there?

A 144,900.

Q And is 144.9 about the same as 145?

A Yes, it is.

Q Okay, thank you.

MR. BURNETT: Nothing further.

CHAIRMAN CARTER: You said 144,000. Is that what you meant to say?

MR. BURNETT: No, sir, I think we were talking millions.

THE WITNESS: I said million that time, didn't I, sir?

CHAIRMAN CARTER: No, you said thousand.

THE WITNESS: Thank you for that clarification.

CHAIRMAN CARTER: Yes, I think Mr. Rehwinkel would be glad to stipulate to it if it was 144,000.

THE WITNESS: I bet he would.

CHAIRMAN CARTER: Let's do exhibits.

Mr. Rehwinkel moves Exhibit 307. Are there any objections?

MR. BURNETT: No, sir.

CHAIRMAN CARTER: Without objection, show it done.

(Exhibit No. 307 admitted into the record.)

CHAIRMAN CARTER: This would have been direct and rebuttal for this witness, right?

MR. BURNETT: Yes, sir.

CHAIRMAN CARTER: You may be excused, and thank you and have a nice day.

Ms. Kaufman, good afternoon.

MS. KAUFMAN: Good afternoon, Mr. Chairman.

FIPUG would like to call Jeffry Pollock, and we would like to thank the Commissioners and the parties for working with us on Mr. Pollock's schedule.

CHAIRMAN CARTER: Absolutely.

MS. KAUFMAN: And Mr. Pollock has not been sworn. He just flew in this morning. While he's getting settled, I wanted to pass out his errata sheet if that will be all right.

CHAIRMAN CARTER: All right, you may do that. I'll let him get settled in before I swear him in.

Staff, we did -- we had an errata sheet with Dr. Woolridge and we entered it in just for the sake of clarity. Do we need to do this in this case, too?

MS. CIBULA: I would suggest that we do as well.

CHAIRMAN CARTER: Okay.

Ms. Kaufman, we're going to number this Exhibit No. 308.

MS. KAUFMAN: Thank you, Mr. Chairman.

CHAIRMAN CARTER: And here's the way I'd like to do it. After we do the introduction of the prefiled testimony to the record and before he does his summary, then I'll ask if there is an opposition from the other side, then we'll go ahead and enter it in and that way we won't have to worry about it at the end of his testimony.

MS. KAUFMAN: That will be fine.

CHAIRMAN CARTER: Mr. Melson, is that okay with you?

So this will be Exhibit 308, and --

MS. KAUFMAN: Pollock Errata.

CHAIRMAN CARTER: Excellent, excellent.

MS. KAUFMAN: And this has previously been provided to the parties.

(Exhibit No. 308 marked for identification.)

CHAIRMAN CARTER: Does everyone have one?

Would you please stand and raise your right hand? In this matter before the Florida Public Service Commission, do you swear or affirm to tell the truth?

MR. POLLOCK: I do.

CHAIRMAN CARTER: Thank you. Please be

seated.

Ms. Kaufman?

MS. KAUFMAN: Thank you, Mr. Chairman.

Whereupon,

JEFFRY POLLOCK

was called as a witness on behalf of Florida Industrial Power Users Group and, having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. KAUFMAN:

Q Mr. Pollock, would you state your name and business address for the record?

A Jeffry Pollock; business address is 12655 Olive Boulevard, St. Louis, Missouri, 63141.

Q And on whose behalf are you appearing in this case?

A I'm appearing on behalf of the Florida Industrial Power Users Group, or FIPUG.

Q Did you cause to be filed in this case 60 pages of testimony? Actually, it's more than that, sorry.

A 60 pages of testimony plus two appendices.

Q And with the errata that we have distributed, if I ask you the same questions that are contained in your testimony, would your answers be the same?

A Yes, with one minor correction.

Q Go ahead and let us know what that is.

A On the errata -- and this is really embarrassing, so I apologize.

Q We have an errata to the errata.

A An errata to the errata.

On Exhibit JP-6 under Progress Energy Florida, the word *production* should be stricken and replaced with the word *transmission* so that it matches the title on the header of the schedule.

CHAIRMAN CARTER: *Transmission* should be changed to *production*?

THE WITNESS: No, *production* should be changed to *transmission.*

CHAIRMAN CARTER: You may proceed.

BY MS. KAUFMAN:

Q And, Mr. Pollock, did you also cause to be filed in this case Appendix A and Appendix B and Exhibits JP-1 through JP-14?

MS. KAUFMAN: And, Mr. Chairman, those are Exhibits 188 through 201 on the master list.

CHAIRMAN CARTER: Thank you. And for the record, that begins on page 40, Commissioners, of the comprehensive exhibit list.

/ / / / /

BY MS. KAUFMAN:

Q With your errata sheet, are those exhibits true and correct to the best of your knowledge?

A Yes.

MS. KAUFMAN: Now, I should move the errata sheet?

CHAIRMAN CARTER: Let's do this. With the revisions and the errata and the errata, the prefiled testimony of the witness will be inserted into the record as though read.

1. INTRODUCTION, QUALIFICATIONS, AND PURPOSE

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock; 12655 Olive Blvd., Suite 335, St. Louis, MO 63141.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am an energy advisor and President of J. Pollock, Incorporated.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. I have participated in regulatory matters before this Commission since 1976. More details are provided in Appendix A to this testimony.

Q **ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). Participating FIPUG companies take power from Progress Energy Company (PEF). These customers require a reliable low-cost supply of electricity to power their operations. Therefore, participating FIPUG companies have a direct and significant interest in the outcome of this proceeding.

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A I will address the following issues:

- Class cost-of-service study;
- Class revenue allocation;
- Rate design, including the design of the interruptible credit;
- Depreciation-related matters (*e.g.,* the estimated life spans of PEF's coal and combined cycle units and further ratemaking adjustments to reduce the $789 million surplus depreciation reserve); and
- The appropriate common equity ratio for determining PEF's cost of capital.

Q ARE OTHER WITNESSES PROVIDING TESTIMONY ON FIPUG'S BEHALF?

A Yes. Mr. Martin Marz will address the storm reserve, incentive compensation and other test year issues.

Q ARE YOU FILING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A Yes. I am filing **Exhibits JP-1** through **JP-14**. These exhibits were prepared by me or under my direction and supervision.

Q IN SOME OF THESE EXHIBITS, YOU HAVE USED PEF'S CLAIMED REVENUE REQUIREMENTS. DOES THIS CONSTITUTE AN ENDORSEMENT OF THE COMPANY'S PROPOSALS?

A No. My use of PEF's claimed revenue requirements is strictly for illustrative purposes and should not be interpreted as an endorsement of the proposed base revenue increases.

Summary

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A PEF has failed to justify changing the method of allocating production plant-related costs from the Twelve Coincident Peak (12CP) and 1/13th Average Demand (AD) method to the 12CP-50% AD. The 12CP-50% AD method does not reflect cost causation because:

1. PEF has strong summer and winter peaks and experiences its tightest margins during the summer/winter peak months. Therefore, greater emphasis should be placed on the demands during the summer/winter peak months than is provided in the 12CP-50% AD Method.
2. The 12CP-50% AD method is designed to match production plant costs relative to the benefits received. However, PEF fails to apply the same "costs follow the benefits standard" to recognize that some variable costs provide reliability benefits;
3. The higher costs of base load and intermediate capacity are not caused by average demand;
4. Capacity is severely under-valued; and
5. Coincident demand is double-counted.

If the Commission decides to replace 12CP-1/13th AD, it should adopt the Average and Excess (A&E) method because A&E appropriately recognizes the dual functionality of generating plants (*i.e.*, that such plants serve both base and cycling loads) without double-counting peak demand. The Summer/Winter Coincident Peak (SWCP) method should be used to allocate Transmission plant costs.

Second, the Commission should use the results of a proper class cost-of-service study to determine the class revenue allocation. In addition, the following principles, which the Commission has traditionally endorsed, should be applied:

- No rate should receive an increase higher than 150% of the system average base rate increase; and
- No rate should receive a decrease.

Third, PEF's proposed rate design should be revised to:

- Assign no increase to non-fuel energy charges to more closely align the demand and energy charges to reflect the corresponding demand and non-fuel energy-related costs; and
- Increase the Interruptible Demand Credit to at least $10.49 per kW-Month to reflect the costs PEF avoids by providing this service.

Further, the Interruptible Demand Credit should not be load factor adjusted because load factor is not a reasonable proxy for the amount of capacity that a customer curtails, and because curtailments can occur at any time, not just during the hour that PEF's monthly coincident peak occurs. In lieu of measuring the amount of load curtailed, the Credit should not be less than $7.13 per kW-Month of billing demand, which recognizes that the interruptible class has an average 68% (12CP-to-Billing demand) coincidence factor.

Finally, with respect to revenue requirements, I recommend:

- Reductions in depreciation expense based on longer life spans for PEF's coal (at least 55 years) and combined cycle (at least 35 years) units. Further, PEF should reduce the depreciation reserve by $100 million per year to correct the very large ($789 million) surplus in the depreciation reserve to restore generational equity; that is, current ratepayers should be charged only for the assets that are consumed to provide electric service.
- Rejection of PEF's proposal to impute debt associated with purchased power agreements. This would change the common equity portion of PEF's capital structure to 50% on an adjusted basis. A 50% equity ratio is in line with the equity ratios of other comparably-rated electric utilities.

2. CLASS COST-OF-SERVICE STUDY

Background

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A cost-of-service study is an analysis used to determine each class' responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class' cost-of-service. A class cost-of-service study separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures used in a cost-of-service study are described in greater detail in **Appendix B.**

Q HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY PROGRESS ENERGY FLORIDA FILED IN THIS PROCEEDING?

A Yes.

Q DOES PEF'S CLASS COST-OF-SERVICE STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?

A Yes. With three exceptions, PEF's class cost-of-service study recognizes the different types of costs as well as the different ways electricity is used by various customers. The three exceptions are:

1. The failure to classify any distribution network costs as customer related.
2. Using 12CP-50% AD to allocate production plant-related costs.

3. Using 12CP to allocate transmission plant-related costs.

The problem with PEF's distribution plant classification is discussed in **Appendix B.** However, at this time, I am only addressing the production/transmission plant allocation issues.

Q WHAT CHANGES ARE YOU RECOMMENDING?

A As explained below, PEF has failed to demonstrate that any change in production/transmission plant allocation is warranted. Thus, the Commission should retain the 12CP-1/13th AD method. However, if the Commission decides to change to a method that places more emphasis on average demand, it should adopt the A&E method for production plant. Transmission plant should be allocated using the Summer/Winter Coincident Peak (SWCP) method.

<u>**Allocation of Production and Transmission Plant Costs**</u>

Q HOW SHOULD THE COMMISSION DETERMINE WHICH METHODOLOGY SHOULD BE USED TO ALLOCATE PRODUCTION AND TRANSMISSION PLANT COSTS?

A The Commission should use the methodology that most accurately reflects cost-causation for PEF.

Q WHAT IS COST CAUSATION?

A Cost causation means allocating production and transmission plant costs to customer classes in a manner that reflects how each class causes PEF to incur them.

Q HOW IS COST-CAUSATION RELEVANT IN DETERMINING THE PROPER METHOD OF ALLOCATING PRODUCTION AND TRANSMISSION PLANT?

A In order to provide reliable service, PEF must size production and transmission plant to meet the maximum expected demands imposed on it. Once installed, this capacity is available to meet customer demands throughout the year. This point is illustrated in **Exhibit JP-1**, which depicts a utility that serves two customer classes (A and B).

Each class uses 2,400 kWh of energy over a 24-hour period. Thus, both classes have an average demand of 100 kWh (2,400 kWh ÷ 24 hours). However, Class A has a cyclical load shape while Class B has a flat load shape. Because of its cyclical load shape, Class A's maximum demand is 200 kW. Class B's maximum demand is 100 kW. In order to serve both classes, the utility would require 300 kW (ignoring reserves). Had the utility provided only 200 kW (which is the combined average load of the two classes), it could not have provided reliable service.

In summary, cost-causation is primarily a function of peak demand. Thus, a proper allocation method for production and transmission plant costs should emphasize the demands imposed during PEF's peak periods.

Q WHAT METHODOLOGY DOES PEF PROPOSE TO ALLOCATE PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS?

A PEF proposes to use the 12CP-50% AD method to allocate production plant costs and the 12CP method to allocate transmission plant-related costs.

Q WHAT IS THE 12CP-50% AD METHOD?

A The 12CP-50% AD method allocates costs partially on a 12CP demand basis and partially on an average demand, or energy, basis. Thus, 12CP-50% AD assumes that production plant-related costs are caused by year-round coincident peaks and average demand. This method is sometimes referred to as the Peak and Average method.

Q WHAT IS THE 12CP METHOD?

A The 12CP method allocates costs relative to each customer class' demand that occurs coincident with PEF's monthly peaks in all twelve months of the test year. Thus, this method improperly assumes that transmission plant-related costs are caused by year-round coincident peaks. This is clearly not the case for PEF as explained below.

Q DOES EITHER THE 12CP-50% AD OR THE 12CP METHOD TRULY REFLECT COST-CAUSATION?

A No. PEF experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit JP-2, page 1**, which is an analysis of PEF's monthly peak demands as a percent of the annual system peak for the years 2004 through 2008 and the 2010 Test Year. The peak demands in the other months are typically well below PEF's summer and winter peak demands. These characteristics are further summarized in **Exhibit JP-2, page 2:**

- PEF's minimum monthly peak is 65% of the annual system peak.
- PEF's average monthly peak demands are only 84% of the annual system peak.

- PEF's average peak month demands are 21% higher than the average non-peak month demands.
- PEF's annual load factor is only 54%.

These ratios confirm that PEF has clear seasonal load characteristics. Thus, electricity demands in the spring and fall months are not relevant in determining the amount of capacity PEF needs to provide reliable service.

Q **ARE THE MONTHLY PEAKS IN THE SPRING/FALL MONTHS IMPORTANT BECAUSE PEF HAS TO REMOVE GENERATION FOR SCHEDULED MAINTENANCE?**

A No. Although PEF does schedule most planned outages during the spring and fall months, this does not make these months important from a cost-causation perspective. Specifically, despite planned outages, PEF generally has higher reserve margins during the non-peak months than during the peak months. This is shown in **Exhibit JP-3**. The reserve margins were calculated as the margin (available capacity less scheduled outages less peak demand) divided by peak demand. PEF's peak month reserve margins, adjusted for scheduled outages, range from 27% to 47% of the corresponding non-peak month reserve margins.

Q **WHAT DO THE PEAK DEMAND AND RESERVE MARGIN ANALYSES DEMONSTRATE?**

A The analyses demonstrate that the summer and winter peak demands determine PEF's capacity requirements and make the other months irrelevant. Thus, the 12CP method does not reflect cost-causation in light of PEF's load and supply characteristics. The SWCP method best reflects PEF's load and supply characteristics and is consistent with cost-causation.

PEF's Proposed 12CP-50% AD Method

Q ARE PEF'S REASONS FOR PROPOSING THE 12CP-50% AD METHOD RELATED TO COST-CAUSATION?

A No. PEF witness Slusser argues that:

> 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*. (*Direct Testimony of William C. Slusser* at 19; emphasis added)

This point was further amplified in discovery:

> *For clarification*, Mr. Slusser stated that the proposed allocation method, i.e. the 12CP and 50%AD, **is a better matching of a class's fixed allocation with that of a class's realized fuel benefits** from such additional fixed costs. (*PEF's Response to FIPUG's Interrogatory No. 46*; emphasis added)

Q IS 12CP-50% AD A REASONABLE METHOD?

A No. Mr. Slusser is proposing to replace cost-causation with a "costs follow the benefits" standard in judging the reasonableness of the 12CP-50% AD method. As previously discussed, cost-causation is the standard by which a reasonable methodology should be judged. Further, as explained below, Mr. Slusser has failed to fully apply his "costs follow the benefits" standard. 12CP-50% AD is also flawed because:

- The higher costs of base load and intermediate capacity are not caused by average demand;
- Capacity is severely under-valued; and
- Coincident demand is double-counted.

Q HAS MR. SLUSSER APPLIED THE SAME "COSTS FOLLOW THE BENEFITS" STANDARD THROUGHOUT THE CLASS COST-OF-SERVICE STUDY?

A No. Mr. Slusser has applied this standard only to the allocation of production plant costs. He fails to apply the same standard to the allocation of variable costs (of which fuel is the primary component). For example, he is not proposing to change how customers are charged for fuel, which is currently on an equal cents per kWh basis (adjusted for losses). If certain customer classes benefit more from the lower fuel costs of base load and intermediate plants, it follows that they should also pay below-average fuel costs, and vice versa. By failing to apply his theory consistently to both plant and operating costs, his class cost-of-service study is fundamentally flawed and discriminatory.

Q HOW ELSE HAS MR. SLUSSER FAILED TO APPLY HIS "COSTS FOLLOW THE BENEFITS STANDARD" TO ITS LOGICAL CONCLUSION?

A Mr. Slusser has assumed that all variable costs are energy-related. This assumption is flawed because it overlooks the fact that the Company also incurs higher fuel costs:

1. To save plant costs; and
2. To maintain system reliability.

If it is proper to classify 50% of plant-related costs to energy because certain customer classes may realize greater cost benefits than others, it is equally proper to classify some operating costs to demand because they provide reliability benefits. Stated differently, if reducing fuel costs makes some base load plant costs energy related, (*i.e.*, capital substitution) it is equally valid that a portion of the higher variable costs a utility incurs are demand-related because the utility chooses to spend less capital (*i.e.*, fuel substitution).

Q **CAN YOU PROVIDE SOME EXAMPLES OF WHEN A UTILITY SUBSTITUTES FUEL COSTS FOR PLANT COSTS?**

A Yes. PEF is required to provide ancillary services to maintain system reliability. In providing certain ancillary services, PEF will incur additional fuel costs without generating additional kWh.

Q **WHAT ARE ANCILLARY SERVICES?**

A Ancillary services are those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission grid. Examples of capacity-related ancillary services are regulation and contingency reserves.

Q **WHAT IS REGULATION?**

A Regulation is provided by resources to follow the minute-to-minute differences between resources and demand.

Q **WHAT ARE CONTINGENCY RESERVES?**

A Contingency reserves are required to restore resource and demand balance after a contingency event, such as the loss of a major generating unit or transmission line. The latter consists of spinning reserves and supplemental reserves. Spinning reserves are provided by resources that are synchronized to the system and fully available within 15 minutes. Supplemental reserves are provided by resources that are capable of being synchronized to the system and fully available within 15 minutes.

Q ARE FUEL COSTS INCURRED TO PROVIDE CONTINGENCY RESERVES?

A Yes. Providing contingency reserves requires a utility to either maintain additional generation capacity on-line at all hours or to commit additional capacity not actually needed to provide service. Units designated to supply spinning reserves will run at less than full load. This will require the utility to dispatch more expensive generation to meet load. Similarly, providing spinning reserves during low-load periods will require the utility operating certain units at minimum load because it is impractical to cycle the unit completely off. During these periods, the unit is consuming fuel even though it is not generating kWh. Committing additional capacity means starting-up a unit that was otherwise scheduled to be off-line. Start-up requires the utility to burn fuel, again without generating kWh. Thus, absent the need to provide contingency reserves, PEF's fuel costs would be lower.

Q ARE REGULATION AND CONTINGENCY RESERVES ESSENTIAL TO MAINTAINING SYSTEM RELIABILITY?

A Yes. They are required for the continued reliable operation of the system. Thus, they are capacity-related services.

Q **DOES PEF'S COST STUDY RECOGNIZE THESE RELIABILITY-RELATED FUEL COSTS?**

A No. PEF makes no adjustments for these costs and fails to apply its "benefits" theory symmetrically.

Q **ARE THERE OTHER REASONS THAT THE 12CP-50% AD METHOD IS FLAWED?**

A Yes, there are several additional flaws. For example, Mr. Slusser asserts that PEF has spent twice as much capital on base load and intermediate capacity than it would have otherwise spent if it had built only combustion turbine (CT) peaking units. This assertion is based on Exhibit WCS-3, which quantifies the hypothetical cost of capacity had PEF built only CTs instead of a mix of base, intermediate and peaking capacity.

Q **IS THIS ANALYSIS ACCURATE?**

A No, this analysis is flawed because it places a value on capacity of only $209 per kW ($2,249,078 ÷ 10,772 MW). However, the current cost of capacity is at least $329 per kW (*PEF's Response to FIPUG's Production of Documents Request No. 4*). **Exhibit JP-4** demonstrates that by restating the capacity value from $209 to $329 per kW, PEF is spending less than 20% of capital for reasons other than maintaining system reliability.

Q DOES THIS MEAN THAT 20% OF PEF'S PRODUCTION PLANT SHOULD BE ALLOCATED ON AVERAGE DEMAND?

A No. Allocating the extra plant investment of those generating units that have lower fuel costs (*e.g.,* base load and intermediate capacity) on energy usage is at odds with the utility planning process. This is because <u>all</u> production from a specific plant (*i.e.*, kWh sales) is not the critical factor in deciding what type of plant to install. It is only the energy up to the economic breakeven point between base/intermediate and peaking capacity that is relevant to the decision.

Q WHAT DO YOU MEAN BY THE "BREAK-EVEN POINT?"

A The break-even point is the number of operating hours in which the total cost of base/intermediate and peaking capacity is the same.

Q WHAT IS THE SIGNIFICANCE OF THE BREAK-EVEN POINT?

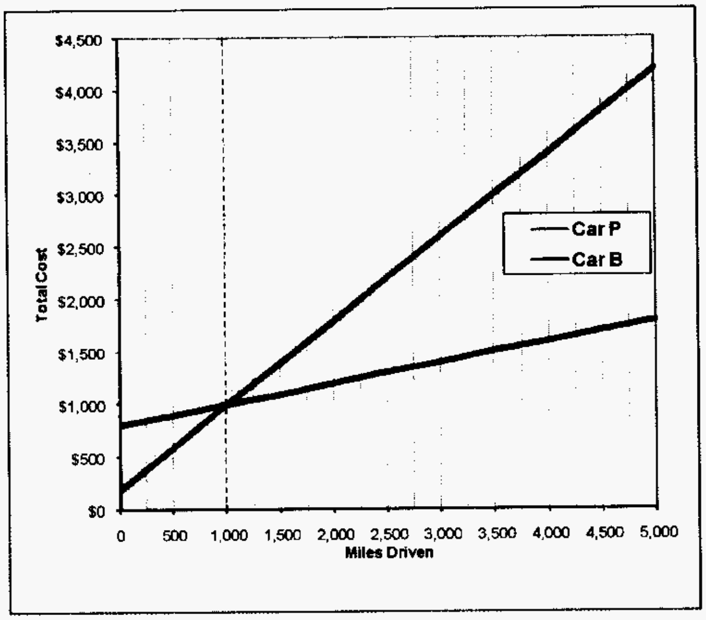
A Once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, then the intermediate or base load unit will be more economical.

Therefore, annual energy usage does not cause plant investment. However, load duration up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity.

To provide an analogy, suppose two different customers are required to rent cars from a fleet that contains only two types of cars, "Car P" and "Car B":

	[redacted]	Car B
Fixed Charge	$200	$800
Mileage Charge	80¢	20¢

Car B has a high fixed charge and gets high mileage (like a base load plant), while the Car P has a low fixed charge but gets poor mileage (like a peaking unit). The graph below shows total cost of both cars over a range of miles driven.



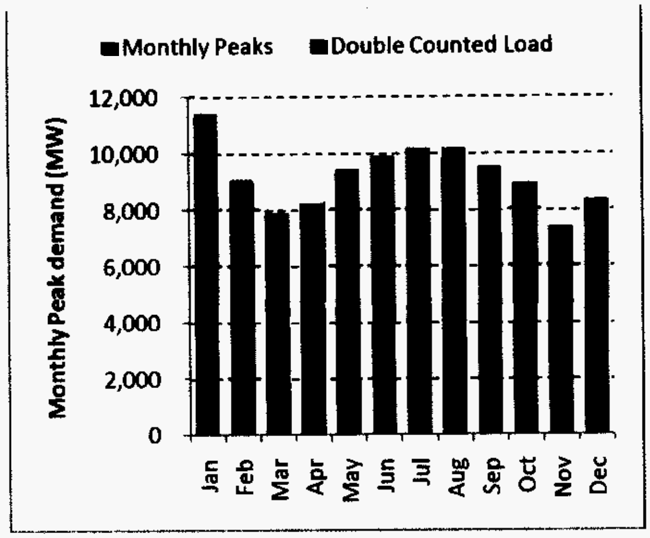
The total cost is also calculated in the following table.

Miles Driven	Total Cost			Best Choice
			Car B	
0	$200		$800	
500	$600		$900	
1,000	$1,000		$1,000	P or B
1,500	$1,400		$1,100	B
2,000	$1,800		$1,200	B
2,500	$2,200		$1,300	P
3,000	$2,600		$1,400	B
3,500	$3,000		$1,500	B
4,000	$3,400		$1,600	B
4,500	$3,800		$1,700	B
5,000	$4,200		$1,800	B

As can be seen, the break-even point between *Car P* and *Car* B is 1,000 miles. That *is, the higher mileage* Car B has *a* lower total cost per mile than Car P if it operated more than 1,000 miles. If one customer needed to drive 1,500 miles and a second customer needed to drive a car 4,500 miles, both customers would choose the same car, Type B. The 12CP-50% AD, however, would charge the second customer 60% more than actual cost solely because that customer needed to drive three times as many miles. This result is arbitrary and inequitable because the Type B car was the more economical choice for both drivers.

Q WHAT OTHER FLAWS DOES THE 12CP-50% AD METHOD HAVE?

A The 12CP-50% AD method also suffers from a double-counting problem. This is because the method allocates production plant costs partially on average demand and partially on coincident peak demand. Double-counting occurs because average demand (which is the equivalent of year-round energy consumption divided by 8,760 hours) is also a component of the coincident peak demand. This is illustrated in the following chart.



The portion of plant allocated on average demand is the black shaded area of the chart. Coincident demand is represented by the bars. As can be seen, double-counting occurs because the portion of plant allocated on average demand already includes a portion of the coincident peak demands.

By allocating some plant costs relative to average demand and some relative to coincident peak demand, energy is counted twice: once by itself and a second time as a subset of the coincident peak demand. If year-round energy is analogous to base load units, which supply capacity on a continuing basis throughout the year, then it follows that the only time intermediate and peaking units would be needed is to meet system demands when they are in excess of the average year-round demand. Energy allocation advocates improperly allocate the cost of this additional capacity relative to *total* coincident demand, rather than the *excess* demand.

Q **HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLAW IN ENERGY-BASED ALLOCATION METHODOLOGIES?**

A Yes. The Public Utility Commission of Texas (PUCT) has recognized the double-counting problem in numerous cases. For example, the PUCT has said:

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50% of the intermediate demand, includes with it an energy component. Dr. Johnson has elected to use a 4CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and this "double-dipping" is taking place. (El Paso Electric Company, *Examiner's Report*, Docket No. 7460, at 193)

Q **SHOULD 12CP-50% AD BE ADOPTED?**

A No. This method would improperly replace the long-standing "cost-causation" standard with a "costs follow the benefits" standard that focuses solely on allocating production plant costs and, thus, is not consistently applied. As such, it fails to recognize the substitution of fuel costs for capital costs in providing certain ancillary services necessary to maintain reliability. Further, capacity is significantly undervalued, the amount of investment spent to save fuel costs is significantly over-stated, and the method double-counts CP demand. For all of the above reasons, 12CP-50% AD should be rejected.

<u>**Average and Excess Method**</u>

Q **IF THE COMMISSION DETERMINES THAT MORE WEIGHT SHOULD BE PLACED ON AVERAGE DEMAND, IS THERE A MORE APPROPRIATE METHODOLOGY (OTHER THAN 12CP-50% AD) FOR DOING SO?**

A Yes. Although I disagree with the premise, if more emphasis is to be placed on average demand, my recommendation would be to adopt the A&E method. Under A&E, a portion of production/transmission plant costs equal to the utility's annual system load factor (or 53% as projected by PEF during the 2010 test year) would be allocated on average demand. The remaining costs would be allocated on the difference between a class' maximum demand and its average demand, which is the "Excess Demand" (ED) component of the A&E formula.

Q **DOES MR. SLUSSER RECOGNIZE THE AVERAGE AND EXCESS METHOD AS VALID?**

A Yes. Mr. Slusser acknowledges that:

> 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 (*Testimony of William C. Slusser* at 20).

Q **HAVE YOU DEVELOPED ALLOCATION FACTORS USING THE A&E METHOD?**

A Yes. The derivation of the A&E allocation factors is presented in **Exhibit JP-5**. The primary inputs are the group coincident peak (GCP) and the AD, which are shown in columns 1 and 2, respectively. The A&E allocation factors are derived as follows:

$$A\&E = AD\,x\,LF + ED\,x\,(1 - LF)$$

Where: AD=Average Demand
LF=Annual System Load Factor
ED=Excess Demand

Q DOES THE A&E METHOD RECOGNIZE WHAT MR. SLUSSER CHARACTERIZES AS "THE DUAL PROCESSES THAT GENERATING RESOURCES PERFORM?"

A Yes. A&E recognizes dual cost-causers. First, some plant is required for year-round operation (*i.e.,* Average Demand). High load factor customers that use electricity throughout the year would receive a larger share of the Average Demand. Second, the remaining plant is required for cycling (*i.e.,* Excess Demand). That is, generators must also be capable of load following from the minimum loads that occur at night to the peak loads that occur on hot summer afternoons. Low load factor customers have variable demands, which require more cycling capacity than do high load factor customers. This is reflected in apportioning more Excess Demand to the lower load factor classes.

Q IS AVERAGE AND EXCESS A RECOGNIZED METHOD?

A Yes. A&E is recognized in the NARUC *Electric Utility Cost Allocation Manual.* Specifically, A&E is listed under the category of "Energy-Weighting" methods. That is, it gives substantial weight to average demand or energy in determining cost causation.

Q IS A&E SUPERIOR TO OTHER ENERGY WEIGHTING METHODS?

A Yes. Unlike other energy weighting methods, such as 12CP-50% AD, A&E does not double-count peak demand.

Summer/Winter Coincident Peak Method

Q WHAT IS THE SUMMER/WINTER COINCIDENT PEAK METHOD?

A The SWCP method allocates costs relative to each class's coincident demands during the summer and winter peak months.

Q SHOULD THE SWCP METHOD BE USED TO ALLOCATE TRANSMISSION PLANT COSTS?

A Yes. As previously stated, the PEF system is highly seasonal, with peak demands occurring in both the summer and winter months. Thus, the SWCP method appropriately reflects cost-causation.

Q HAVE YOU DEVELOPED ALLOCATION FACTORS FOR THE SWCP METHOD?

A Yes. The retail class allocation factors under the SWCP method are shown in **Exhibit JP-6**. They were developed using the demand data in MFR Schedule E-9.

Revised Class Cost-of-Service Study

Q HAVE YOU REVISED PEF'S CLASS COST-OF-SERVICE STUDY USING THE A&E METHOD?

A Yes. A revised class cost study at present rates is summarized in **Exhibit JP-7, page 1**. In this study, the A&E method was applied to production plant costs, while the SWCP method was applied to transmission plant costs. I conducted a second revised cost study using 12CP-1/13th AD for production plant and SWCP for transmission plant. This is shown in **Exhibit JP-7, page 2**. In both studies, the results are measured in three ways: (1) rate of return, (2) relative rate of return, and (3) interclass subsidies.

Rate of return (line 7) is the ratio of net operating income (revenues less allocated operating expenses as shown in line 6) to the allocated rate base (line 1). Net operating income is the difference between operating revenues at current rates (line 3) and allocated operating expenses (line 4). If a class is presently providing revenues sufficient to recover its cost-of-service (at the current system rate of return), it will have a rate of return equal to or greater than the total system return of 4.31%.

Relative rate of return (RROR), which is shown on line 8, is the ratio of each class' rate of return to the Florida retail average rate of return. A relative rate of return above 100 means that a class is providing a rate of return higher than the system average, while a relative rate of return below 100 indicates that a class is providing a below-system average rate of return.

Subsidy (line 9) measures the difference between the revenues required from each class to achieve the system rate of return and the revenues actually being recovered. A negative amount indicates that a class is being subsidized each year (*i.e.*, revenues are below cost at the system rate of return), while a positive amount indicates that a class is providing a subsidy each year (*i.e.*, revenues are above cost).

Q WHAT DO THE RESULTS OF YOUR REVISED CLASS COST-OF-SERVICE STUDIES SHOW?

A The A&E cost-of-service study **(Exhibit JP-7, page 1)** demonstrates that the Residential and General Service Demand (GSD) classes are close to cost, the Curtailable/Interruptible and Lighting Energy classes are below cost, and all other classes are above cost. The 12CP-1/13th AD study **(Exhibit JP-7, page 2)** shows that the Residential, General Service Non-Demand, and Lighting Facilities classes are above cost, while all other classes are below cost.

3. CLASS REVENUE ALLOCATION

Q **WHAT IS CLASS REVENUE ALLOCATION?**

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be apportioned to each customer class the utility serves.

Q **HOW SHOULD A CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET, IF ANY, BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES PEF SERVES?**

A Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism and rate administration.

Q **PLEASE EXPLAIN THE PRINCIPLE OF GRADUALISM.**

A Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase. That is, the movement to cost-of-service should be made gradually rather than all at once because an abrupt change would result in rate shock to the affected customers.

Q **SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?**

A Yes. Cost-based rates will send the proper price signals to customers. This will allow customers to make rational consumption decisions.

Q ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?

A Yes. The other reasons to adhere to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

Q WHY ARE COST-BASED RATES EQUITABLE?

A Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually costs the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?

A With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q HOW CAN COST-BASED RATES PROVIDE STABILITY?

A When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses.

Q HOW DO COST-BASED RATES ENCOURAGE CONSERVATION?

A By providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just less use). If rates are not based on a class cost-of-service study, then consumption choices are distorted.

Q DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal. The Commission reiterated this principle in the recent Tampa Electric Company (TECO) rate case:

> It has been our long-standing practice in rate cases that the appropriate allocation of any change in revenue requirements, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study, and move the classes as close to parity as practicable. The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease. (Docket No. 080317–EI, *Order No. PSC-09-0283-FOF-EI,* Issued: April 30, 2009 at 86-87, footnote omitted).

Therefore, gradual movement of PEF's rates closer to cost would be consistent with Commission policy.

Q HOW IS PEF PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?

A PEF's proposed base revenue increase is shown in **Exhibit JP-8**. As can be seen in **Exhibit JP-8**, PEF is proposing a 34.2% base rate increase. The increases by class would range from 0% for Lighting Facilities service to 55.15% for the Interruptible (IS-1, IS-2) rate class.

Q IS PEF'S PROPOSED CLASS REVENUE ALLOCATION CONSISTENT WITH THIS COMMISSION'S PRACTICES?

A No. As shown in **Exhibit JP-8**, the proposed relative increases for the GSD-1, IS-1/IS-2, and SS-3 rates would exceed 150% of the system average increase which is the standard the Commission applies. PEF's proposal is clearly contrary to this Commission's practice and precedents and should be rejected. PEF apparently tries to mask this fact by showing that its proposed class revenue allocation would result in no cost-of-service class receiving a <u>relative increase</u> higher than 150% of the FPSC retail average increase (column 4). However, the appropriate standard is to examine the impact on individual rates.

Q HOW SHOULD ANY RATE INCREASE OR DECREASE RESULTING FROM THIS CASE BE ALLOCATED AMONG CUSTOMER CLASSES?

A Consistent with Commission policy and precedent, rates for each class should be set at a level that will recover the cost of serving that class, subject to the policy that no rate should receive an increase greater than 150% of the retail average base rate increase. This is reflected in **Exhibit JP-9** using PEF's proposed 2010 revenue requirement. However, as I noted earlier, this illustration is not an endorsement of the revenue requirement requested. **Page 1** is based on the A&E method, while **page 2** is based on the 12CP-1/13th AD method.

The relative increases to Interruptible and Lighting Energy classes were limited to 150%, while no class received a decrease.

Q **WOULD YOUR RECOMMENDED REVENUE ALLOCATION MOVE ALL CLASSES CLOSER TO COST?**

A Yes. This is shown in **Exhibit JP-10**, which shows the cost-of-service study results under my recommended class revenue allocation. **Page 1** is based on the A&E method, while **page 2** is based on the 12CP-1/13th AD method. All but one class (due to the 150% constraint) would be moved closer to cost. The remaining classes would produce the same rates of return.

4. RATE DESIGN

Q WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A In this section, I will discuss the appropriate design of the firm and non-firm rates. Specifically, I will discuss:

- Demand and Non-Fuel Energy charges; and
- The Interruptible Demand Credits.

Demand and Non-Fuel Energy Charges

Q DESCRIBE THE DEMAND AND NON-FUEL ENERGY CHARGES.

A These charges are designed to recover base rate (non-fuel) costs. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the non-fuel energy charges are billed on the kWh purchased.

Q DO YOU AGREE WITH HOW PEF HAS PROPOSED TO DEVELOP THE DEMAND AND NON-FUEL ENERGY CHARGES?

A No. Consistent with cost-causation, PEF's demand-related costs should be recovered through the demand charge and energy-related base rate costs should be collected through the energy charge. However, PEF's proposed rate design does not follow this practice. Specifically, PEF has underpriced the demand charges and overpriced the energy charges in Schedules GSD, CS, and IS. The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in the class cost-of-service study.

Q **WHAT ARE THE UNIT DEMAND AND ENERGY COSTS DERIVED FROM PEF'S CLASS COST-OF-SERVICE STUDY?**

A PEF's proposed 2010 unit costs and proposed rates for service provided at transmission delivery for the GSD and Interruptible classes are as follows:

Component	GSD		Interruptible	
	Unit Cost	Proposed Rate	Unit Cost	Proposed Rate
Demand Unit Cost ($ per kW-Month)	$10.88	$2.14	$10.30	$5.20
Non-Fuel Energy Unit Cost (¢ per kWh)	0.508¢	2.274¢	0.499¢	1.070¢

Q **HAS PEF EXPLAINED WHY THE NON-FUEL ENERGY CHARGES ARE MUCH HIGHER THAN ACTUAL ENERGY COSTS? THAT IS, HAS PEF EXPLAINED, FOR EXAMPLE, WHY THE PROPOSED GSD NON-FUEL ENERGY CHARGE IS TWO TO FOUR TIMES HIGHER THAN THE ACTUAL COST?**

A No and I find it difficult to postulate a scenario where such extreme differentials would be appropriate.

Q **HOW DO YOU RECOMMEND THAT THESE EXTREME DIFFERENTIALS BE REMEDIED?**

A The current non-fuel energy charges in Schedules GSD, CS, and IS already exceed non-fuel energy unit costs at PEF's proposed rates. Thus, any increase allocated to these rates should be applied only to the demand charges. The current non-fuel energy charges should not change. Similarly, any rate decrease should be used to reduce the current non-fuel energy charges.

Interruptible Demand Credits

Q **WHAT ARE INTERRUPTIBLE DEMAND CREDITS?**

A Interruptible Demand credits are payments made to customers that purchase interruptible power. These customers agree to curtail service when capacity is needed to serve firm customers. As described below, the utility may shut these customers off with no notice when capacity is needed. Thus, they receive a lower quality of service than do firm customers and therefore pay a lower rate.

Q **WHAT IS INTERRUPTIBLE POWER?**

A Interruptible power is a tariff option that allows a utility to curtail interruptible load when resources are needed to maintain system reliability; that is, when there are insufficient resources to meet customer demand, a utility can curtail interruptible load. This allows the utility to maintain service to firm (*i.e.*, non-interruptible) customers. Interruptible power, thus, is a lower quality of service than firm power. PEF does not include interruptible load in determining the need for additional capacity. Thus, PEF does not plan capacity additions to serve interruptible load.

Q **CAN INTERRUPTIBLE POWER PROVIDE ANY OTHER BENEFITS?**

A Yes. The Florida Reliability Coordinating Council (FRCC) requires that all reserve sharing groups and balancing authorities maintain adequate Contingency Reserves to cover the FRCC's most severe single contingency, which is currently 910 MW. Of this amount, PEF's contingency reserve requirement is currently 179 MW (*FRCC Handbook*, FRCC Contingency (Operating) Reserve Policy, Appendix A, November 2008). PEF must supply this reserve when called upon to replace reserve capacity that is no longer available due to sudden forced outages of major generating facilities or the loss of transmission facilities.

Contingency reserves may be comprised of those generating resources and Interruptible Load that are available within 15 minutes. Thus, PEF could count interruptible power in meeting its contingency reserve obligations.

Q IS INTERRUPTIBLE POWER AN IMPORTANT RESOURCE FOR THE STATE OF FLORIDA?

A Yes. The interruptible tariffs have been in place for decades. They have been (and currently are) a valuable resource to PEF and to the State as a whole. When capacity is needed to serve firm load customers, interruptible customers, statewide, may be called upon (with or without notice and without limitation as to the frequency and duration of curtailments) to discontinue service so that service will be maintained for the firm customer base. Such interruption often causes production processes of interruptible customers to be shut down resulting in economic losses for the interruptible customer.

Q IS THE VALUE OF INTERRUPTIBLE POWER AFFECTED BY THE FREQUENCY AND DURATION OF PHYSICAL INTERRUPTIONS?

A No. Interruptible power provides "insurance" in the event that the utility experiences extreme weather, understates load growth, or sustains forced outages of a major resource. As the FERC has found:

> *61804 **[E]ven a limited right of interruption**, if it enables the Company to keep a customer from imposing demands on the system during peak periods, **gives a Company the ability to control its capacity costs.** Therefore, that customer shares no responsibility for capacity costs under a peak responsibility

> method.
>
> It is, thus, the right to interrupt that is critical to the analysis, and *not the actual interruptions or even the number or length of such interruptions*. If a Company can keep a customer from imposing its load on the system at system peak, as Entergy can do here, then, under the peak responsibility method of cost allocation that Entergy uses, "that customer shares no responsibility for capacity costs...."
>
> 75. . . .When *a utility makes a commitment* to *serve firm* load, it commits to serve that load at all times (absent a force majeure event on the system). When a utility makes a commitment to serve interruptible load, it does not commit to serve that load at all times. **To the contrary, it expressly reserves the right to interrupt (even if there is no force majeure event on its system).** Moreover, when it curtails interruptible load, it does so to *protect its service to its firm load. That is, it curtails interruptible* load precisely because it has not undertaken to construct or otherwise acquire the necessary facilities to serve interruptible load at all times and most particularly when use of the system is peaking; for firm load, in contrast, it has undertaken to construct or otherwise acquire such facilities. (106 FERC ¶61,228, at 14 16; emphasis added).

Q **HOW CAN THE COMMISSION NURTURE THIS VALUABLE RESOURCE?**

A The Commission should not reduce the interruptible credit by 44% as PEF proposes for Schedule IS-1 customers. As explained below, the credit should be increased to at least $10.49 per kW-month based on PEF's most recent cost-effectiveness analysis.

Q **DESCRIBE PEF'S PROPOSAL TO REDUCE THE INTERRUPTIBLE DEMAND CREDIT BY 44%**

A Schedule IS-1 customers currently receive a $3.62 per kW-month credit. The corresponding credit for Schedule IS-2 customers is $3.31 per kW-month of load factor adjusted demand. PEF is proposing to eliminate Schedule IS-1 and move customers to Schedule IS-2. The combined IS-1/IS-2 class is projected to have an average billing load factor of about 61%. This would result in an average load-factor adjusted credit of $2.02. Thus, the Company's proposal would result in a 44% reduction in the interruptible credits currently paid to Schedule IS-1 customers, despite the fact that even the current credits are too low.

Q IS IT APPROPRIATE TO REDUCE INTERRUPTIBLE DEMAND CREDITS BY 44% FOR ANY INTERRUPTIBLE CUSTOMER?

A No PEF's proposed reduction would significantly discourage continued participation in this valuable service. In fact, such credits should be increased.

Q HAS PEF CALCULATED THE LEVEL OF INTERRUPTIBLE DEMAND CREDIT THAT WOULD BE COST-EFFECTIVE?

A Yes. PEF provided an updated cost-effectiveness test that shows that the *resulting credit for interruptible* customers should be $10.49 per kW-Month (*PEF's Response to FIPUG's Production of Documents Request No.34*). A copy of this response is provided in **Exhibit JP-11**.

Q SHOULD THE INTERRUPTIBLE DEMAND CREDIT BE INCREASED?

A Yes. PEF is projecting a need for additional cost-effective non-firm load. It is unreasonable to expect an increase in non-firm load by paying only $3.31 per load factor adjusted kW. The present cost-effective interruptible credit is $10.49 per kW-month. This credit should be implemented in the new Schedule IS.

Q **SHOULD THE INTERRUPTIBLE DEMAND CREDIT BE REDUCED BY A CUSTOMER'S LOAD FACTOR?**

A No. The customer should be paid the full credit based on the amount of load available for curtailment.

Q **IS A LOAD FACTOR ADJUSTMENT VALID?**

A No. First, PEF's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This approach assumes that load factor and coincidence factor are the same. They are not. The interruptible class has a 61% billing load factor. However, the average coincidence factor (with PEF's monthly system peaks) is 68%. Thus, the Interruptible Demand Credit should not be less than $7.13 per kW-Month ($10.49 x 68%) of billing demand.

Second, curtailments can occur at any time, not just during the system peaks. Thus, the Interruptible Demand Credit should apply to the amount of load that PEF is not obligated to serve during an interruption event.

Q **HOW SHOULD THE INTERRUPTIBLE DEMAND CREDIT BE STRUCTURED?**

A To measure this benefit, the amount of interruptible demand subject to the Credit should be based on customer's normal operating demand for a defined "base line" period using actual data from a prior critical period. For example, a customer that operated an average load of 10,000 kW during on-peak hours of the prior calendar year would receive a Credit based on 10,000 kW. Some utilities use this methodology.

Q **IS THERE ANOTHER ALTERNATIVE TO DETERMINE THE AMOUNT OF INTERRUPTIBLE LOAD?**

A Yes. Another alternative would be to directly measure the amount of interruptible demand *in real-time for each customer*. The interruptible demand would be average of the daily maximum on-peak demands for the billing month. This process is similar to determining the Generation and Transmission Capacity charges in Rate SS.

Q **WHICH OF THESE TWO ALTERNATIVES DO YOU RECOMMEND IN LIEU OF A LOAD FACTOR ADJUSTMENT?**

A PEF already measures the daily maximum on-peak demand for billing standby customers. Thus, it should not be burdensome to require the same process in determining the Interruptible Demand Credit.

5. DEPRECIATION

Q WHAT DEPRECIATION ISSUES WILL YOU ADDRESS?

A I will address:

- The life spans of coal and combined cycle (CC) units. Life spans are integral in determining the appropriate depreciation rates;
- Other measures to reduce PEF's large depreciation surplus.

<u>Background</u>

Q WHAT IS DEPRECIATION?

A Depreciation reflects the consumption or use of assets used to provide utility service. Thus, it provides for capital recovery of a utility's current or original investment. Generally, this capital recovery occurs over the *average service life* of the investment or assets. The most commonly used definition of depreciation is found in the Code of Federal Regulations (CFR):

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of plant in the course of service from causes which are known to be in current operation and against which the *utility* is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, *inadequacy*, *obsolescence*, changes in the art, changes in demand and requirements of public authorities. (*18 CFR Part 101*)

In addition, the American Institute of Certified Public Accountants in Accounting Research and Terminology Bulletin #1 provides the following definition of depreciation accounting:

> Depreciation accounting is a system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is

> allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

This definition recognizes depreciation as an allocation of cost to particular accounting periods over the life of assets.

Q **WHAT ARE THE KEY PARAMETERS THAT DETERMINE THE AMOUNT OF DEPRECIATION RECOGNIZED FOR RATE-MAKING PURPOSES?**

A Depreciation accounting provides for the recovery of the original cost of an asset over its life span adjusted for net salvage. As a result, it is critical that appropriate average life span be used to develop the depreciation rates so that present and future ratepayers are treated equitably. In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is the value of the scrap or reused materials less the removal cost of the asset being depreciated. A utility will reflect in its rates the net salvage over the useful life of the asset.

Q **HOW ARE DEPRECIATION RATES CALCULATED?**

A Depreciation rates are essentially calculated using the following formula:

$$Remaining\ Life\ Rate = \frac{100\% - Reserve\ \% - Avg.\ Future\ Net\ Salvage\ \%}{Avg.\ Remaining\ Life\ in\ Years}$$

The above formula is prescribed in Rule 25-6.0436, Florida Administrative Code. Under this method of developing depreciation rates, the un-depreciated portion of the plant in service, adjusted for net salvage, is recovered over the average remaining life of the asset or group of assets. Therefore, at the end of the useful life, the asset is fully depreciated.

<u>PEF's Depreciation Study</u>

Q HAVE YOU REVIEWED THE DEPRECIATION STUDY FILED BY PEF IN THIS PROCEEDING?

A Yes.

Q WHAT DOES THE DEPRECIATION STUDY SHOW?

A The study recommends higher depreciation rates, which would generate an additional $97.4 million of depreciation expense (*Direct Testimony and Exhibits of Earl M. Robinson,* Exhibit ERM-2, Table 1F). Of this amount, $70 million of the increase is due to increased production depreciation rates, which can be attributed to assumed life spans for production investments.

Q WHAT ELSE DOES PEF'S DEPRECIATION STUDY SHOW?

A The study also shows that, based on the assumed average and remaining service lives of its investments and the projected book value as of December 31, 2009, PEF's book depreciation reserve is $789 million higher than the "theoretical reserve." (*Id.* at Table 5F). The theoretical reserve is the amount necessary to allow recovery of the existing investments over their projected remaining life spans. In other words, PEF has accrued a $789 million reserve surplus.

Q IS THERE ANYTHING NOTEWORTHY ABOUT THE $789 MILLION DEPRECIATION RESERVE SURPLUS?

A Yes. The $789 million surplus reserve is dependent on PEF's proposed life and salvage parameters. The theoretical reserve calculation is based on PEF's remaining life proposals. If the remaining life is understated, the theoretical reserve will be overstated causing the reserve surplus to be understated. My testimony will address two areas where PEF has understated the remaining lives of assets causing the reserve surplus to be even higher than stated.

Q WHAT IS THE SIGNIFICANCE OF THE SURPLUS?

A The purpose of depreciation is to recover capital investment, including removal costs. Such recovery should, to the extent possible, come from the customers that use the utility service. With the large depreciation surplus, the current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. Thus, PEF's depreciation rates are neither fair nor equitable.

Life Spans

Q HAVE YOU REVIEWED THE LIFE SPANS THAT PEF USED TO DETERMINE ITS PROPOSED DEPRECIATION RATES?

A Yes. PEF's proposed life probable retirement years for coal and CC units are shown in Exhibit ERM-2 (Table 2-Loc-Total, p. 2-125 through p. 2-130, and p. 9-60, p. 9-71) and produce average life spans summarized below:

Plant Type	PEF's Proposed Average Life Spans
Coal	52
Combined Cycle	31

Q ARE PEF'S PROPOSED LIFE SPANS APPROPRIATE?

A No. PEF has understated the life spans for these plant types.

Q ON WHAT DO YOU BASE YOUR OPINION THAT PEF'S PROPOSED LIFE SPANS ARE SIGNIFICANTLY UNDERSTATED?

A My opinion is based on actual plant lives, life spans used by other utilities for similar assets, and decisions by regulatory commissions.

Q WHAT LIFE SPAN DOES PEF ASSUME FOR ITS COAL UNITS?

A PEF owns Crystal River Units 1 and 2 and Crystal River Units 4 and 5. The depreciation study assumes that these facilities will be retired in 2020 and 2035, respectively (*ERM-2* at p. 2-125 through p. 2-126). This translates into an average life span of 52 years.

Q HAS PEF PROVIDED ANY JUSTIFICATION FOR THE PROPOSED LIFE SPANS?

A No. The Company has not indicated when it will retire these units (*PEF's 2009 Ten-Year Site Plan*, Schedule 1).

Q ARE 52-53 YEAR LIFE SPANS REASONABLE FOR COAL UNITS?

A No. PEF's proposed life spans are shorter than the average lives of coal-fired plants as determined in proceedings. For example:

- 60 years for Indiana-Michigan Power company's Tanner Creek Units 1 through 4 and for its Rockport Unit 1 (Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order,* 6/13/2007);
- 55 years for coal plants operated by Southwestern Public Service Company (New Mexico Public Regulatory Commission, Case No. 07-00319-UT, *Order*, August 26, 2008);
- 59 to 68 years for coal units owned by AmerenUE (Missouri Public Service Commission, Cause No. ER-2007-0002, *Order,* May 22, 2007);

- 61 years for coal units owned by Rocky Mountain Power (Wyoming Public Service Commission, Docket No. 20000-257-EA-6, *Record No. 10794*, June 12, 2008);
- 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission, Cause No. PUD 200600285, *Order No. 545168*, October 9, 2007); and
- 55 years for Georgia Power Company's Plant Scherer Units 1-3 (Georgia Public Service Commission, Docket No. 25060-U, Document 103566, 2007 Rate Case).

Thus, PEF's proposed life spans are shorter than the life spans of actual coal-fired plants. Further, the two biggest operators of coal units in the nation, American Electric Power Company and The Southern Company, have determined that life spans of 60 years or more are achievable (Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order,* 6/13/2007, Florida Public Service Commission, Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007).

Q DO OTHER FLORIDA UTILITIES USE LONGER LIFE SPANS THAN PEF FOR THEIR COAL UNITS?

A Yes. Gulf Power Company extended the lives of the Plant Crist and Plant Smith units to 65 years (Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007).

Q WHAT CONCLUSIONS CAN BE DRAWN FROM INDUSTRY EXPERIENCE AND THE SPECIFIC EXAMPLES YOU HAVE DESCRIBED?

A It appears that PEF has understated the life span of its coal units, which results in increased depreciation costs which PEF wants ratepayers to bear. PEF's coal units represent a $2.4 billion investment. Given this significant investment, it stands to reason that these capital intensive investments should be operated as long as possible to obtain the greatest level of economic benefit. Thus, it should normally be cost effective to maintain such equipment in operating condition over the long term.

For all of the above reasons, the Commission should use a life span of *at least* 55 years for PEF's coal units.

Q WHAT IS THE IMPACT OF INCREASING THE LIFE SPANS OF PEF'S COAL UNITS TO 55 YEARS?

A The impact of increasing the life spans would be to decrease the depreciation accruals for the coal plants by approximately $4.1 million annually as shown in **Exhibit JP-12**.

Q HOW DID YOU CALCULATE THE CHANGE IN ANNUAL ACCRUALS?

A I recalculated the depreciation rate by first calculating the ratio of my recommended life spans to PEF's proposed life span by unit. This ratio was then multiplied by the corresponding whole life (by unit by FERC account) to determine the adjusted whole life. The revised remaining life is the sum of (1) the difference between the adjusted whole life and PEF's proposed whole life and (2) PEF's proposed remaining life. The revised depreciation accrual is the ratio of the PEF's proposed remaining life to the revised remaining life multiplied by PEF's proposed accrual.

Q WHAT LIFE SPANS DOES PEF PROPOSE FOR ITS COMBINED CYCLE UNITS?

A The average life span for PEF's CC units is 31 years. This ranges from 29 years for Hines Energy Complex to 41 years for Tiger Bay. The new Bartow CC units are projected to have 30-year life spans (*Direct Testimony and Exhibits of Earl M. Robinson,* Exhibit EMR-2, p. 9-60, p. 9-71).

Q HAS PEF JUSTIFIED THE LIFE SPANS OF ITS COMBINED CYCLE UNITS?

A No. There are no expected retirement dates for these units (PEF's *2009 Ten-Year Site Plan* at Schedule 1). PEF has not explained why it cannot operate these units for much longer than 31 years (30 years for its newest, most efficient Bartow units). The CC units represent a combined $1.8 billion investment. Since these are the most efficient units on PEF's system, it should be economic to maintain them in good operating condition for much longer than 31 years.

Q WHAT IS THE BASIS FOR YOUR OPINION THAT COMBINED CYCLE UNITS ARE CAPABLE OF OPERATING MUCH LONGER THAN 31 YEARS?

A My opinion is based on industry projections and practices, including the following:

- 40 years for PacifiCorp/Rocky Mountain Power's CC units (Utah Public Service Commission, Docket No. 07-035-13 and Public Utility Commission of Oregon UM 1329, *Order No. 08-327*, June 17, 2008);
- Over 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission Cause No. 200600285, *Order No. 545168*, October 9, 2007);

- 35 years for Nevada Power Company's Silverhawk and Lenzie CC units (Nevada Public Utilities Commission, Docket No. 06-11023, Modified Order of July 17, 2007);
- 35 years for Georgia Power Company McIntosh CC units (Georgia Public Service Commission, Docket No. 25060-U Document 103566, 2007 Rate Case).

Further, in a study of capacity needs, the Michigan Public Service Commission (MPSC) used a 40-year life span for new CC units (MPSC Docket No. U-14231).

Q DO ANY OTHER FLORIDA UTILITIES USE LONGER LIFESPANS FOR THEIR COMBINED CYCLE UNITS?

A Yes. Gulf Power recently extended the life of Plant Smith Unit 3 to 34 years (Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007). While conservative in light of the non-Florida examples cited above, this Florida example further demonstrates the unreasonableness of PEF's proposed life spans.

Q WHAT LIFE SPANS DO YOU RECOMMEND FOR COMBINED CYCLE UNITS?

A Based on industry practices and recognizing PEF's $1.8 billion investment, the Commission should increase the life span to *at least* 35 years.

Q WHAT IS THE IMPACT OF INCREASING THE LIFE SPANS OF PEF'S COMBINED CYCLE UNITS TO 35 YEARS?

A The increase of the life spans would decrease the depreciation accruals for the combined cycle plants by approximately $13.1 million annually as shown on **Exhibit (JP-12)**. This adjustment was quantified using the same methodology as described previously.

Q SHOULD THE COMMISSION TAKE ANY FURTHER STEPS TO RESTORE GENERATIONAL EQUITY?

A Yes. To compensate for the huge reserve surplus, the Commission should order PEF to implement a $100 million annual depreciation expense adjustment. That is, PEF should credit depreciation expense and debit to the bottom line depreciation reserve by at least $100 million per year. This treatment should continue until PEF files its next depreciation study. Assuming PEF's next depreciation study is filed in 2012 (three years from the filing date of this case), the book reserve would be reduced by an additional $300 million. This would still leave nearly $0.5 billion in excess book depreciation reserve.

Q IS THERE ANY PRECEDENT FOR REQUIRING PEF TO TAKE MEASURES NECESSARY TO ELIMINATE THE HUGE (OVER $789 MILLION) SURPLUS IN ITS DEPRECIATION RESERVE?

A Yes. My recommendation to correct a reserve surplus is the same in concept as prior Commission actions allowing Florida Power & Light Company (FPL) to correct reserve deficiencies. For example:

- FPL was to book $126 million (in accord with preliminary implementation approved in Order PSC-95-0672-FOF-EI), an additional $30 million commencing in 1996, and additional expense in 1996 and 1997 equal to 100% of base rate revenues produced by retail sales between its "low band" and "most likely sales forecast" for 1996, and at least 50% of the base rate revenues produced by retail sales above FPL's most likely sales forecast for 1996 to correct a $175.3 million deficiency in the nuclear depreciation reserve and to correct the reserve deficiency existing in FPL's other production facilities, which was calculated to be $60.3 million as of January 1, 1994 (Docket No. 950359-EI, *Order No. PSC-96-0307-PHO-EI*); and
- FPL was ordered to amortize the gain realized from the sale of a combustion turbine from Port St. Joe to be used to offset the

> reserve deficiency at the Suwanee Peaking Plant. (Docket No. 971570-EI, *Order No. PSC-98-1723-FOF-EI*).

More recently, the Commission also adopted a similar approach for FPL to correct a reserve surplus. The Order stated that:

> FPL has the option to amortize up to $125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of the Stipulation and Settlement and as specified therein. Depreciation rates and/or capital recovery schedules will be established pursuant to the comprehensive depreciation studies as filed in March 2005 and will not be changed during the term of the Stipulation and Settlement. (FPSC Docket No. 050188-EI, *Order PSC-05-0902-S-EI* Paragraph 8)

Since PEF also has a huge reserve surplus, similar adjustments are appropriate and necessary to restore generational equity and to help mitigate the impact of the proposed base rate increases.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON DEPRECIATION EXPENSE.

A My recommendations are as follows:

Adjustments	Amount ($Millions)
Increase Coal Plant Life Spans to at Least 55 Years	$4.1
Increase Combined Cycle Plant Life Spans to at Least 35 Years	$13.1
Credit Depreciation Expense; Debit Depreciation Reserve	$100.0

6. CAPITAL STRUCTURE

Q **WHAT CAPITAL STRUCTURE IS PEF PROPOSING IN THIS PROCEEDING?**

A PEF's proposed regulatory capital structure is shown in the first column of the chart below:

Component	MFR Schedule D-1A	PEF Test Year Adjusted for PPA	PEF Test Year Unadjusted for PPA
Long-Term Debt	42.28%	45.10%	48.61%
Short-Term Debt	0.62%	0.66%	0.71%
Common Equity	50.52%	53.90%	50.31%
Preferred Stock	0.32%	0.34%	0.37%
Customer Deposits	1.81%		
Deferred Taxes	4.40%		
Investment Tax Credits	0.06%		

The first column is the proposed jurisdictional regulatory capital structure. The common equity percentage reflected in this column includes an adjustment for off-balance sheet obligations associated with purchased power agreements (PPAs). The second and third columns reflect PEF's adjusted 2010 capital structure (*Direct Testimony Thomas Sullivan* at 19), which exclude customer deposits, deferred income taxes, and investment tax credits. The second column shows PEF's adjusted capital structure with the imputed PPAs. The PPA obligations are removed in the third column.

Q WHAT IS THE PROPOSED ADJUSTMENT FOR PURCHASED POWER OBLIGATIONS?

A PEF's proposed regulatory capital structure includes $711.3 million of imputed debt for purchased power obligations. As can be seen in the third column of the above chart, without this imputed debt, PEF's common equity ratio would be 50%. A 50% equity ratio is higher than the industry average. For the reasons explained below, the Commission should set rates based on an adjusted capital structure that excludes imputed debt.

<u>Imputed Debt for Purchased Power Obligations</u>

Q WHY DOES PEF IMPUTE $711 MILLION OF DEBT RELATED TO PPAS?

A PEF asserts that the financial community commonly takes into account obligations associated with PPAs. Since PEF has certain long-term PPAs, it is obligated to make certain fixed payments, which, it asserts, the rating agencies regard as equivalent to long-term debt (*Id.* at 17).

Q DO YOU AGREE WITH THIS ADJUSTMENT?

A No. It is unnecessary to impute debt for PPA obligations. The Commission's approval of PPAs is governed by Rule 25-17.0832, Florida Administrative Code (for standard offer and negotiated contracts). Once approved, PEF is allowed full and direct recovery of firm energy and purchased power capacity costs under the Fuel and Capacity Cost Recovery (CCR) clauses. Though such contracts are reviewed in the annual fuel adjustment proceeding, there is minimal recovery risk associated with PPAs.

Second, Moody's does not treat PPAs in the same way as Standard & Poor's (S&P).

Finally, the Commission has very recently addressed precisely this issue. In the Tampa Electric (TECO) recent rate case, TECO made the same argument that PEF puts forth here and it was rejected by the Commission.

Q DO ALL RATING AGENCIES IMPUTE THE FIXED OBLIGATIONS UNDER PPAS IN EVALUATING A UTILITY'S FINANCIAL STRENGTH?

A No. PEF's imputed debt adjustment reflects the methodology outlined by S&P. It is noteworthy that another ratings agency, Moody's, does not make a similar adjustment.

Q HOW DOES S&P RECOGNIZE THE DEBT EQUIVALENT OF PPAS?

A S&P quantifies the debt equivalent as the product of (1) a risk factor and (2) the net present value of the remaining capacity payments under each PPA. The risk factor is based primarily on the method of recovery of capacity payments.

Q WHAT RISK FACTOR HAS PEF USED IN ITS IMPUTED DEBT ADJUSTMENT?

A PEF has used a 25% risk factor (*Id.* at 18). This choice is based on general criteria explained by S&P:

> In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs. (Exhibit No. TRS-9, Standard & Poor's *Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements* at 3).

Q **DOES THIS ACCURATELY REFLECT THE RISKS ASSOCIATED WITH THE RECOVERY OF PURCHASED POWER CAPACITY COSTS IN FLORIDA?**

A No. Purchased power capacity costs are subject to dollar-for-dollar recovery through the Capacity Cost Recovery clause (CCR). This includes a true-up procedure that establishes a forward-looking charge, which is then reconciled based on actually incurred costs, with interest. The recovery mechanism is nearly identical to PEF's Fuel Charge.

Q **DOES S&P RECOGNIZE THE RELATIONSHIP BETWEEN RISK AND THE TYPE OF COST RECOVERY MECHANISM?**

A Yes. S&P states that:

> The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. (*Id.*)

Thus, S&P does not provide an objective standard for determining the appropriate risk factor. Dollar-for-dollar recovery of purchased power capacity costs is a very strong mechanism with no practical risk. PEF's PPAs have been previously approved for recovery. In fact, the above discussion from S&P, in conjunction with the policies and previous findings in Florida strongly suggest that the obligations under Commission-approved PPAs are risk free, so long as the utility properly manages the contracts.

Q DOES MOODY'S CONSIDER PPAS AS INHERENTLY MORE RISKY FOR ELECTRIC UTILITIES?

A No. Moody's specifically recognizes that the risk of PPAs is directly related to the applicable cost recovery mechanism as well as market dynamics:

> Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly. (Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005 at 9.)

Thus, it is clear that Moody's does not regard PPAs as inherently risky and therefore, it imputes no debt for these contracts where recovery is guaranteed.

Q DOES PEF HAVE THE ABILITY TO PASS THROUGH THE COSTS OF ITS PPAS?

A Yes. As explained earlier, PEF has the ability to directly pass through purchased power capacity costs. In the case of certain purchases mandated by state statute, such as those from renewable energy sources, up-front approval is required for non-standard offer contracts, while standard offer contracts are considered reasonable.

Q DOES MOODY'S CONSIDER PPAS AS BEING LESS RISKY IN CERTAIN CIRCUMSTANCES?

A Yes. Unlike S&P, Moody's recognizes that PPAs can be less risky for a utility:

> Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature. *(Id.)*

Q ARE YOU SAYING THAT MOODY'S WILL NOT IMPUTE DEBT ASSOCIATED WITH PPAS?

A No. Moody's states:

> *Methods of accounting for PPAs in our analysis*
>
> According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total obligations for the utility using one of the methods discussed below.
>
> Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

Based on the above statements by Moody's, it seems unlikely that debt will be imputed to PEF based on the cost recovery mechanisms applicable to purchased power capacity costs.

Q IS THE DEBT THAT PEF PROPOSES TO IMPUTE FOR PPA OBLIGATIONS ACTUAL DEBT ON THE COMPANY'S BOOKS AND RECORDS?

A No. PEF does not reflect its PPA obligations as debt in the normal course of accounting.

Q HAS THE COMMISSION PREVIOUSLY RULED ON THIS ISSUE IN A RECENT CASE?

A Yes. The Commission rejected TECO's proposal to impute additional equity in determining its capital structure to recognize the so-called risks associated with PPAs. The Commission stated that:

> The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. If this adjustment is approved for purposes of setting rates in this proceeding, the Company would essentially be allowed to earn a risk-adjusted equity return without having actually made the equity investment. The revenue requirement impact of recognizing this pro forma adjustment to equity in the capital structure is approximately $5 million per year. (*Order No. PSC-09-0283-FOF-EI* at 35)

The Commission went on to find:

> Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. As the following passage explains, the Standard & Poors' (S&P) practice with respect to PPAs described in witness Gillette's testimony is strictly for the rating agency's own analytical purposes:
>
> We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility

> that relies on PPAs is the recovery of the financial obligation in rates. (*Id.*)

Further, in rejecting TECO's adjustment, the Commission held:

> With this proposed adjustment, we find that the Company is attempting to take a portion of S&P's consolidated credit assessment methodology and use it for a purpose it was never intended. (*Id.* at 36).

Q SHOULD DEBT ASSOCIATED WITH PPAS BE IMPUTED IN ASSESSING THE PROPER CAPITAL STRUCTURE FOR PEF?

A No. For all of the reasons stated above, imputed debt should not be included in assessing the reasonableness of PEF's capital structure.

Common Equity Ratio

Q DOES PEF PROPOSE TO ADJUST ITS EQUITY RATIO TO RECOGNIZE IMPUTED DEBT?

A Yes. PEF includes an adjustment to its capital structure of $711.3 million to increase common equity. PEF seeks to use the imputation argument to support an increase in its common equity ratio. The PPA adjustment increases the common equity ratio to 53.9%. As discussed below, the cost of common equity is greater than the cost of debt so the adjustment causes an increase to PEF's proposed rate of return. Thus, the Commission should eliminate the PPA adjustment in determining PEF's capital structure. This would reduce PEF's common equity ratio to 50.3%.

Q HOW DOES PEF'S COMMON EQUITY RATIO COMPARE WITH OTHER ELECTRIC UTILITIES?

A **Exhibit JP-13** is a comparison of common equity ratios for the 2006 to 2009 (1st

Quarter) time frame published by SNL Financial. For this period, average common equity ratios for all electric utilities range from 46.1% to 47.6% (line 85). On a comparable basis, the adjusted 2010 test year common equity ratio of 50.3% would be well above the average. Thus, PEF's test year common equity ratio is 345 basis points higher than the electric utility average.

Q WHAT IS THE CONSEQUENCE OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?

A Common equity is more expensive than debt. In this instance, PEF is asking for a common equity return that is over 600 basis points higher than its embedded cost of long-term debt. A utility having too much equity in its capital structure has a higher cost of capital than a utility with a more balanced common equity ratio. All else being equal, the higher the overall common equity ratio, the higher the rates all PEF ratepayers will bear.

Q IS A 50% COMMON EQUITY RATIO SUFFICIENT TO MAINTAIN PEF'S CURRENT BOND RATING?

A Yes. PEF is currently rated "A3" by Moody's and "A-" by Fitches and "BBB+" by S&P. The chart below provides a comparison of the common equity ratios for other A-rated electric utilities. I included all electric utilities that had "A" or equivalent bond ratings from at least two of the three bond rating agencies.

Year	All Electric Utilities	A-Rated Electric Utilities
2006	47.6%	50.9%
2007	47.3%	51.0%
2008	46.4%	49.5%
2009 (Q1)	46.1%	49.5%
Average	46.9%	50.2%

Thus, PEF's 50.0% projected test year common equity (without including off balance sheet obligations) is consistent with comparable A-rated electric utilities.

Q WHAT IS YOUR RECOMMENDATION FOR A COMMON EQUITY RATIO FOR PEF?

A PEF's adjusted common equity ratio of 50.3% *(excluding the PPA adjustment)* should be the basis for setting its cost of capital in this proceeding. This translates into a 46.93% regulatory common equity ratio. Reducing the regulatory common equity ratio to 46.93% lowers PEF's requested 2010 base revenue increase by about $32.9 million, as shown in **Exhibit JP-14**.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, it does.

CHAIRMAN CARTER: Mr. Melson, Ms. Kaufman moves the errata sheet. Do you have any objections?

MR. MELSON: No objection.

CHAIRMAN CARTER: Without objection, show it done, and we'll just go ahead on and admit now so we don't have to deal with it at the end.

(Exhibit No. 308 admitted into the record.)

CHAIRMAN CARTER: You may proceed, Ms. Kaufman.

MS. KAUFMAN: Thank you.

BY MS. KAUFMAN:

Q Mr. Pollock, bearing in mind the light system, do you have a summary of your testimony?

A I do.

Q Please give it.

A Good afternoon.

This case is about Progress's request for a 500 million or 34.2 percent base rate increase. OPC and FIPUG agree that this request is excessive. If you agree with us that a 34.2 percent increase is simply too high, you should also consider the fact that the proposed base rate increases to certain classes would exceed one and a half times a system average increase when taking the changes in the cost recovery clauses into account.

The rate shock of such a proposal is obvious, and it's even more disturbing as businesses try to pull out of the recession. This result is also contrary to the Commission's long-standing practice of limiting base rate increases to not more than one and a half times the system average to refect the principle of gradualism. You recently reiterated this important principle in the TECO rate case decided just a few months ago.

While FIPUG is a strong advocate of cost-based rates, the Commission must also bear in mind the tremendous shock that will result if certain classes are moved immediately toward cost. I suggest to you that the magnitude of an increase like that is wholly inappropriate and should be rejected.

Our recommendation if an increase is granted, move all rates as closely as possible to costs, but limit the increase to about one and a half times the system average, taking into account any changes that may occur in the cost recovery clauses.

Progress's proposed rate design is also problematic. Non-fuel energy charges would be two to four times higher than actual costs. If rate design is cost-based, non-fuel energy charges should reasonably reflect costs and demand charges should recover demand costs.

Our recommendation: Hold the non-fuel energy charges the same and apply all the increase to the demand charge to move closer to cost.

Inappropriately raising energy charges further compounds the already enormous increases that Progress is seeking for its high load factor customers, taking service on the GSD and IS classes. High load factor means you have a steady demand, day in, day out. The high load factor customer is the most efficient, least costly customer to serve, and further, to the extent that a high load factor customer is also willing to curtail load, they're also less costly to serve.

Interruptible load is an extremely valuable resource to Florida. Customers must curtail usage at any time, without limit, without duration, whenever the company's available capacity is needed to maintain service to its firm customers or to supply emergency interchange to another utility.

As a result, Progress does not plan or build capacity to serve interruptible load. Paying interruptible customers to provide the capacity is less costly than building new capacity, but despite the lower cost, Progress is proposing especially harsh treatment for most of its interruptible customers.

Without cause, Progress is proposing to close the IS-1 rate and move these customers to IS-2. This would have the effect of reducing the credits by 44 percent. Progress has not shown that IS-1 is no longer cost-effective. In fact, Progress has provided a study saying that paying the interruptible customers the capacity equivalent of $10.49 of KW is cost-effective. This would translate into an average interruptible demand credit of $7.13 per billing KW, so increasing the credit is both timely and appropriate.

You should also reject the proposal to load factor adjust the interruptible credit, because interruptions can occur at any time, not just coincident with the system peak, which is what coincidence factor measures.

Progress is also proposing to reintroduce the equivalent peaker method in this case, although it goes by a different name, 12 CP and 50 percent average demand. This method seriously de-emphasizes the role of peak demand, rejects cost causation as the gold standard for conducting cost studies, is contrary to system planning principles and double-counts peak demand, as recognized by your colleagues in Texas.

Further, Progress has failed to apply the same theory to variable costs, such as ancillary services and unit commitment, which serve to provide reliability even though they're recovered on a KWH basis.

And finally, you previously rejected the equivalent peaker method. This method is wrong from Progress, it's still wrong for Florida, and it should be, again be rejected. However, if you decide to go in the same direction as in the Tampa Electric rate case, you should adopt the average and excess method.

This method weights energy by 53 percent and it recognizes the dual functionality of generating plants, that is, to provide both base and cycling loads without double-counting peak demand.

This company is spending big money on plants that can cycle up and down to meet changing hourly loads, not to save fuel costs.

And finally, my testimony addresses various revenue requirement issues which other witnesses have addressed in this case.

CHAIRMAN CARTER: Outstanding on the time.

MS. KAUFMAN: The witness is available for cross-examination.

CHAIRMAN CARTER: Thank you.

Ms. Bradley?

MS. BRADLEY: No questions.

CHAIRMAN CARTER: Mr. LaVia?

MR. LaVIA: No questions, Mr. Chairman.

CHAIRMAN CARTER: Mr. Melson?

MR. MELSON: Just a few.

CHAIRMAN CARTER: You are recognized.

CROSS EXAMINATION

BY MR. MELSON:

Q Mr. Pollock, Rick Melson, representing Progress Energy.

A Good afternoon.

Q How are you doing?

A Good, thanks.

Q Let's talk first about the cost allocation methodology for production plant.

You would agree that the purpose of a class cost of service study is to allocate the utility's costs to its various rate classes, is that correct?

A Yes, to allocate costs in a way that reflect cost causation.

Q And your recommendation is for the Commission to continue to use the 12 CP and 1/13th AD method for allocating production plant, is that correct?

A That is correct.

Q And at page 12 of your testimony, starting at line 17, you identify several reasons that you believe the company's proposal to use a 12 CP and 50 percent AD method is flawed, is that correct?

A Yes.

Q And would you agree that each of those items would also be flaws with a 12 CP and 25 percent AD methodology?

A They would be to some degree, but to a much lesser extent with a 25 percent AD method.

Q And you testified in the recent Tampa Electric Company rate case, is that correct?

A I did.

Q And that was also on behalf of FIPUG?

A Yes.

Q And in that case you made mostly the same criticisms of the 25 percent AD method that you're making of the 50 percent AD method in this case, is that right?

A Yes, mostly.

Q Let's talk for a minute about depreciation.

Are you a certified depreciation professional?

A No, I have never been certified in my 30-some-odd years of practice.

Q And are you a member of any professional depreciation organization?

A No.

Q Except in the FPL case and this current case, you have not testified on depreciation since at least

January of 1994, is that correct?

A That's correct.

Q And at the time of your deposition you could not recall whether you had ever testified on depreciation, is that right?

A That's true.

Q Now, in your testimony you recommend average lives for Progress's coal and combined cycle units that are longer than what the company has projected in its filing, is that right?

A Yes, it is.

Q And in supporting your recommendation you cite to Commission orders and other jurisdictions where longer lives have been approved, is that right?

A Correct. I was looking for instances where utilities were demonstrating best practices.

Q And let's focus for a minute on Progress's coal and combined cycle units. Have you looked at any capital improvements that have been made to those units?

A I have not.

Q Have you inspected any of the plants?

A No.

Q Have you talked with PEF operating personnel about the operation of any of the plants?

A No.

Q Have you discussed with anyone at Progress the factors that Progress considers when it estimates the expected retirement date for those plants?

A Only to the extent that those factors have been articulated in various planning documents.

Q So you have not talked with anybody at Progress?

A No.

Q Have you looked at the specifics of the plants covered by the orders that you cite in any more detail than what you just described you have done for Progress?

A Pretty much the same level of analysis.

Q Would you agree with me that several of the orders that you cite were the result of stipulations or settlements?

A I would agree, several of them were.

Q I would like to talk for a minute about the theoretical reserve variance, and I'm going to apologize, this first question is quite a mouthful, but I think you may have heard it before.

Would you agree with me that theoretical reserve variance is the difference between, first, the depreciation expense collected from prior and current customers under rates previously approved by the Commission, and second, the depreciation reserve would have been depreciation that would have been collected under proposed depreciation rates if they had been in effect since the assets were placed in service?

A You're right, that is a mouthful, but if you go to the Commission's rules there is a definition in 25.60436(k) of the theoretical reserve, which is theoretical reserve equals book investment minus future accruals minus future net salvage.

Q But the basis of the reserve variance is the difference between rates that had been collected in the past and what rates theoretically would have been collected if the current rates were in effect, is that right?

A Right. The rates collected in the past reflects what the reserve is; the rates looking forward indicate what the reserve would have to be at that same point in time.

Q And you are not claiming in this case that the theoretical reserve variance is a result of Progress' charging unauthorized depreciation rates, are you?

A No, it's not an issue of retroactive ratemaking at all. It's simply an issue that the number has grown to such a large degree that it can be usefully used to mitigate the rate shock in this proceeding.

Q Do you recall my taking your deposition?

A Yes.

Q Do you have a copy of it in front of you?

A No, I do not.

Q Let me loan you one.

Would you turn to page 54 of the deposition, please, sir?

A Okay.

Q And look at lines 7 through 10. Do you recall that I asked, quote, "You are not claiming that the theoretical reserve variance was the result of Progress' charging unauthorized depreciation rates, are you," and your answer was no?

A Right. That was my answer and still is.

Q And it's not the result of any accounting error that you're aware of, is that correct?

A That's correct.

Q And are you claiming that any of the depreciation rates approved by the Commission in the past were wrong or unreasonable at the time they were approved?

A No.

Q I believe your recommendation on depreciation is that Progress should be required to implement a $100 million annual depreciation reserve adjustment for the next three years, is that correct?

A Yes. Actually the next four years, until the next depreciation study is filed.

Q All right. Would you agree that, all other things being equal, the effect of this proposal will be to increase Progress's rate base at the end of each of those years?

A Rate base will go up by the amount of the additional book, the reduced amount of the book reserve times the pretax cost of capital, so roughly total 11 and a half, 12 cents on the dollar.

Q And in order to capture the effect of your recommendation, it would be necessary to recalculate depreciation rates, is that correct?

A The rates would have to be calculated -- recalculated.

Q And is it true that you have not made any attempt to quantify the revenue requirement effect of either the rate base change or the change to depreciation rates, and hence depreciation expense?

A I've not looked at any revenue requirements beyond the test period in this case.

Q Have you made any analysis of the impact that the adjustment you propose would have on Progress's financial ratios?

A I have not, although it's hard to conceive how it would affect the major ratios.

Q But you have not done an analysis?

A I have not.

Q And have you made any analysis of the impact it would have on Progress's ability to attract capital?

A I have not.

Q That's all I've got. Thank you, Mr. Pollock.

A Thank you.

CHAIRMAN CARTER: Thank you, Mr. Melson.

Staff?

MR. SAYLER: Yes, Mr. Chairman, we have a few questions for the witness.

CHAIRMAN CARTER: You are recognized.

CROSS EXAMINATION

BY MR. SAYLER:

Q Mr. Pollock, my name is Erik Sayler with Commission legal staff. How are you today?

A Good, thanks.

Q And like Mr. Melson, we met via telephonic deposition on September 11th, is that correct?

A Yes.

Q I've got a series of questions for you. For the most part they're yes/no, but if you feel you need to expand on them, feel free.

A All right.

Q With regard to your testimony, a portion of your testimony concerns the appropriate lifespans for Progress's generating units, is that correct?

A Yes.

Q And what is your expertise and experience in estimating the lifespans for production facilities?

A Well, as I mentioned before, I've been in this profession for about 34 years. I've been involved in a countless number of rate cases. Depreciation is likely an issue in most of those rate cases. I've become familiar with the issues on depreciation over the 34 years of my career. I've read testimonies and Commission orders on lifespans of various production plants.

Q Thank you. And for your review for FIPUG, did you review Progress's depreciation study which was submitted by Progress Witness Earl M. Robinson?

A Yes.

Q And that was Exhibit EMR-2, is that correct?

A I don't recall the number now.

Q All right. And when you reviewed the depreciation -- excuse me. And did you review the depreciation study as it relates to Progress's proposed lifespans?

A Yes. Of course the study didn't really talk about lifespans, which is why we did a further analysis.

Q And does Progress's study include specific information supporting Progress's proposed lifespans for its production facilities?

A No.

Q And did you find any analysis as to how the trends regarding decreased reliance on fossil fuels and increased regulation of carbon emissions are impacting the operation of any of the Crystal River coal units and their respective lifespans?

A I have not done a specific analysis of that, but like any kind of legislation, when it's being crafted it's really uncertain at this point in time what the outcome might be and how it might affect particularly the lifespan of coal units.

Q But did you find any analysis related to that in Progress's depreciation?

A I did not.

Q And in your review of their study, did you find any specific information regarding the condition of Progress's generating facilities with respect to their proposed lifespans?

A I did not.

Q The same question again: Did the study include any information regarding Progress's expertise in the operation of each generating unit?

A I didn't see any analysis of that in the depreciation study.

Q The same question: Does the study include any specific information regarding Progress's experience with maintenance of these units with respect to proposed lifespans?

A I don't recall seeing that in the study, either.

Q The same question and same study: Did you see any specific information substantiating that Progress's plants have unique load demands or how load demands impact the lifespans of Progress's generating facilities?

A I did not see anything in the study to shed light on that issue.

Q Does the depreciation study include any specific information regarding updates, changes and reconfigurations made at each plant?

A I don't think so.

Q And what about how each affects the operating characteristics of the generating units with respect to proposed lifespans?

A I don't recall seeing that information, either.

Q Did the study include any specific information on how renewable energy requirements may impact the lifespans of these generating facilities?

A No.

Q The same question and last question on this line: Did the study include any specific information with respect to environmental risks that Progress faces or how these risks may impact the lifespans of generating facilities?

A I don't recall that discussion.

Q Thank you.

Switching to another line of questioning, with regard to Progress's reserve imbalance, do you believe that Progress's calculated reserve imbalance is material?

A Yes, particularly in light of the magnitude of the increase that they're seeking in this case. I think you need to put, always put that issue in context to the fact that when you're raising rates by half a billion dollars, are there things that can be done to try to offset that huge increase. And the fact that there is almost a 15 percent surplus in depreciation reserve suggests that there is a tool that can be used to try to mitigate some of this increase.

Q And are you aware of any Commission decision, either here in Florida or elsewhere, which has defined *material* in this particular circumstance?

A I don't recall any such decisions, but I do recall instances when utilities, for example, were allowed to accelerate depreciation and did so, and when competition didn't come, the first thing they did was they used the excess reserve to offset a future rate increase to help out ratepayers.

So I just think it's one of the things that you do in the time that you think it's right under the circumstances, but when the circumstances have changed and you no longer need to have that kind of imbalance, it's a good tool to use to help ratepayers.

Q And if you were to suggest a definition for this Commission to define *material*, how would you define *material* under this particular circumstance?

A Well, I would define it in two dimensions. One is 645 million plus, I say plus, because that doesn't take into account the longer lifespans that I'm recommending and others have recommended. I would take that into the context of the $500 million, almost half a billion dollar rate increase and say that is material.

Q Thank you, Mr. Pollock, for your time.

MR. SAYLER: Staff at this time has no further questions, Mr. Chairman.

CHAIRMAN CARTER: Commissioner Skop?

COMMISSIONER SKOP: Thank you, Mr. Chairman. Good afternoon, Mr. Pollock.

THE WITNESS: Good afternoon, Commissioner.

COMMISSIONER SKOP: Just a few follow-up questions.

On page 49 of your direct testimony, and starting with lines 1 through 10, please.

THE WITNESS: Okay.

COMMISSIONER SKOP: In that portion of your testimony you discuss your recommendations with respect to the steps the Commission should take to restore the generational equity regarding the depreciation imbalance, is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: And your recommendations are a hundred million dollar annual depreciation expense adjustment that would be amortized over four years, is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: And that is more conservative than what was recommended by OPC Witness Pous, is that correct?

THE WITNESS: Yes, I believe that's right.

COMMISSIONER SKOP: And he recommended a

higher expense adjustment of, subject to check, of approximately $161 million per year, amortized over four years, is that correct?

THE WITNESS: I think that's right, yes.

COMMISSIONER SKOP: And in addition to that he recommended $113 million of annual normal depreciation adjustments, also, is that correct?

THE WITNESS: I did recommend adjustments to the depreciation to reflect the longer lifespans, as shown on page 50 of my testimony.

COMMISSIONER SKOP: How much were those additional adjustments?

THE WITNESS: Combined, about $17 million.

COMMISSIONER SKOP: And I asked the OPC witness this question and I'm going to ask it of you, also.

With respect to considering the weight to give to the respective testimony of the witnesses, why should this Commission adopt your testimony and recommendations over those of Mr. Robinson with respect to the company's position?

THE WITNESS: I think for several reasons.

First of all, Mr. Robinson doesn't really address lifespans. Those are a given. I think it's important for the Commission, in setting policy, to make sure that the utilities are depreciating their plants with the proper assumptions, and the key most important assumption in doing any kind of depreciation analysis, major input, is the lifespan. So that has to be front and center and the most important issue in a depreciation study.

As you can see, it does matter what lifespans you select for this study. Whether you select my recommendation or Mr. Pous's recommendation, which is, for the longer lifespans, that's the most important assumption to make. So that's the first thing.

The second thing is also to balance. I think you know your job, but as we often look at it, you're balancing the interests of the utility and the interests of the ratepayers. And the fact that the utility has $645 million plus of reserve that's really not doing the utility anything and is asking at the same time for a half a billion dollar rate increase, I think you can definitely use one to offset the other and help ratepayers and still give the company ample revenues so they can meet the credit metrics they need.

COMMISSIONER SKOP: And just one final question: With respect to your recommended proposals to address the depreciation reserve imbalance versus that of the OPC witness, I guess Pous, what was the key driver, if you're able to articulate it, between the differences, in terms of what was recommended? He recommended more of a credit be afforded to the ratepayers and you're recommending approximately $61 million less than that, so it looks to be 100 million versus 161 over four years.

THE WITNESS: Right. And I think that's largely for two reasons. One, he did a more in-depth analysis than I did and actually recalculated the theoretical reserve where I did not. I just said it's 645-plus because you have to take into account the longer lifespans.

And I think the second reason is, and again, I can't read his mind, but the Narick Depreciation Practices Manual suggests that whenever you have an imbalance of this magnitude the choices are either you do the remaining life method and basically ignore the problem, or you do a short amortization, and I think Mr. Pous was looking for a short amortization.

COMMISSIONER SKOP: Very well. Thank you.

CHAIRMAN CARTER: Thank you, Commissioner.

Commissioners, anything further from the bench?

Ms. Kaufman, any redirect?

MS. KAUFMAN: I have no redirect, Mr.

Chairman.

CHAIRMAN CARTER: Exhibits, starting on page 40.

MS. KAUFMAN: FIPUG would move 186 through 201.

CHAIRMAN CARTER: Are there any objections?

Without objection, show it done.

(Exhibit Nos. 186 through 201 admitted into the record.)

CHAIRMAN CARTER: You may be excused. Thank you very much.

MS. TRIPLETT: Progress Energy calls Masceo DesChamps.

CHAIRMAN CARTER: You may proceed.

MS. TRIPLETT: Thank you, sir.

Whereupon,

MASCEO S. DesCHAMPS

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

DIRECT EXAMINATION

BY MS. TRIPLETT:

Q Could you please reintroduce yourself to the Commission?

A Yes. My name is Masceo DesChamps. I'm

Director of Compensation and Benefits. I'm employed by Progress Energy Service Company, at 410 South Wilmington Street, Raleigh, North Carolina.

Q Thank you, Mr. DesChamps. And you realize that you're still under oath, correct?

A Yes.

Q Have you filed rebuttal testimony in this proceeding?

A Yes.

Q Do you have that prefiled rebuttal testimony with you?

A Yes, I do.

Q Do you have any changes to make to that testimony?

A No, I do not.

Q If I ask you the same questions in your prefiled rebuttal testimony today, would you give the same answers that are in your prefiled rebuttal testimony?

A Yes.

MS. TRIPLETT: Mr. Chairman, we request that Mr. DesChamps' prefiled rebuttal testimony be entered into the record as though read today.

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

MS. TRIPLETT: Thank you.

In re: Petition for rate increase by Progress Energy Florida, Inc. Docket No. 090079-EI

REBUTTAL TESTIMONY OF MASCEO S. DESCHAMPS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position.

A. My name is Masceo S. DesChamps. I am the Director of Compensation and Benefits for Progress Energy Service Company, LLC.

Q. Are you the same Masceo S. DesChamps that provided direct testimony in this proceeding?

A. Yes, I am.

Q. Have you reviewed the Intervenor Testimony filed in this Docket?

A. Yes, I have. I have reviewed and I will provide rebuttal testimony to the following intervenor direct testimony: (1) Helmuth Schultz, III ("Schultz") and (2) Martin J. Marz ("Marz"). Specifically, I will rebut the portions of these testimonies related to incentive compensation, payroll levels, and employee benefits.

Q. Do you have any exhibits to your rebuttal testimony?

A. Yes. I have supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (MSD-8), Order PSC-92-1197-FOF-EI, *In Re: Petition for a rate increase by Florida Power Corporation* (Oct. 22, 1992);

- Exhibit No. ___ (MSD-9), Order PSC-02-0787-FOF-EI, *In re: Request for rate increase by Gulf Power Company* (June 2, 2002);
- Exhibit No. ___ (MSD-10), which contains the results of a July 2009 survey conducted by the Company;
- Exhibit No. ___ (MSD-11), Watson Wyatt survey results press release;
- Exhibit No. ___ (MSD-12), which is a composite exhibit of the summary of the findings from the Company's 2008 and 2009 job value studies;
- Exhibit No. ___ (MSD-13), June 2009 Top 5 Proxy Analysis completed by Hewitt Associates LLC; and
- Exhibit No. __ (MSD-14), Average Healthcare Costs Per Member (including dependents) – Progress Energy vs. Fortune 500.

All of these exhibits are true and accurate.

II. INCENTIVE COMPENSATION.

Q. Please generally explain the importance of the incentive compensation piece of the total compensation package that Progress Energy Florida offers to its employees.

A. As I explained in my direct testimony, Progress Energy Florida ("PEF") is committed to providing a competitive total rewards package that enables the Company to attract, retain and reward employees who work to high standards. Its compensation program is market-based at the 50th percentile within national, regional, and local comparative markets and aligns with a pay-for-performance philosophy. Incentive compensation is an integral part of the total compensation package. When the Company benchmarks jobs with similar peer utilities, it benchmarks the value of the total compensation package. Similarly, when the Company benchmarks its employee benefits, it is a comparison of the total benefits program.

Q. Please briefly describe the components of the Company's various incentive compensation plans.

A. The Company has four different incentive compensation plans. As a part of total compensation, the Company sponsors the Employee Cash Incentive Plan (ECIP) for all non-management and non-supervisory employees. The ECIP is an annual short-term cash incentive plan that rewards eligible employees with cash bonuses when strategic company and business goals are achieved. The plan is designed to ensure a close link between pay and performance and to share the company's financial success with the employees who make it happen. Each year senior management establishes an Earnings Per Share (EPS) range and ten strategic goals by business unit, such as safety, budget adherence, electric service reliability, plant production and efficiency, and other similar goals.

The EPS component applies equally for all employees and is statused on a quarterly basis. The ten operational goals have equal weighting and are also monitored on a quarterly basis. The plan is designed to pay at higher levels for superior operational performance. There is also a component to allow for CEO Discretion which may be used to help offset extenuating factors such as weather or general economic conditions that may affect operational goal or EPS achievement, or recognize positive overall company financial and operational achievements. Although the ECIP is based on total company and business unit performance, employees receive awards only when individual performance meets certain expectations.

The Management Incentive Compensation Plan (MICP) and Executive Incentive Plan (EIP) were designed to work together to ensure that the Company's annual incentive program would be compliant with section 162 (m) of the Internal Revenue Code. The EIP, an umbrella plan, is for the Company's senior executive officers and is intended to enable the Company to preserve the tax deductibility of incentive awards. The MICP provides annual incentive opportunities to executives, managers, and supervisors to promote the achievement of annual performance objectives. MICP performance targets are designed to appropriately motivate the participants to achieve the desired corporate financial and operational objectives.

The Company also sponsors a long-term incentive plan to provide equity awards to managers and executives. These awards are intended to focus managers and executives on sustained achievement of financial and operational goals.

The purpose of the annual and long-term incentive plans is to provide competitive incentive compensation in attracting, retaining, and rewarding managers and executives when warranted by individual and company performance. The incentive plans' target award opportunities approximate the 50th percentile of the peer group for all of the companies' incentive compensation plans.

Q. What do witnesses Schultz and Marz claim with respect to the Company's requested incentive compensation?

A. Schultz and Marz both testify that the Company's incentive compensation plans do not benefit the customers. Specifically, they claim that the incentive compensation plans with goals linked to the financial performance of the Company should be paid for by shareholders and not customers. Schultz further challenges the inclusion of incentive compensation given the economy. Finally, Schultz suggests that incentive compensation is not a significant factor in attracting and retaining employees. As I discuss below, none of these arguments have merit. Thus, the Company's request for incentive compensation should be approved in its entirety.

Q. How do all the Company's incentive compensation plans benefit customers?

A. Progress Energy's incentive compensation plans are designed to promote and encourage superior performance by its employees. As described above, Progress Energy measures the performance of its employees in a variety of ways, including the performance of the parent company and PEF specific goals such as cost management, operational efficiency, reliability, safety, and customer satisfaction. Contrary to Witnesses Schultz and Marz's testimony that the goals linked to overall Company performance only benefit shareholders, maintaining a financially strong Company also benefits customers. As PEF witnesses Dolan, Toomey, and Sullivan describe in their testimony, a financially strong company can access capital more easily at a lower cost. This reduced cost of capital benefits customers by lowering rates. The fact that the Company's shareholders also benefit from these incentive compensation goals is irrelevant to whether the costs of the incentive compensation plans should be included in base rates. Actions the Company takes to provide reliable and efficient electric service to its customers benefit the shareholders, by allowing the shareholders to earn a return on their investment in the Company's electric business. Simply because shareholders also benefit does not mean that those costs should not be charged to customers. Because the Company's incentive compensation costs allow PEF to provide efficient and reliable electricity they are properly charged as a cost of providing electric service to customers.

Q. Do Witnesses Schultz and Marz recommend any adjustment to the Company's requested incentive compensation costs?

A. Yes. Witness Schultz recommends that all of the Company's request for incentive compensation expense and $12,094 million of the Company's requested long term incentive compensation expense be excluded from base rates. (Schultz Testimony p. 30) This represents approximately 72% of the Company's long-term incentive compensation request, as reflected on Schedule C-35. Witness Schultz gives no indication how he came to this calculation for the long-term incentive compensation adjustment. Witness Marz recommends that all of the Company's incentive compensation budgeted for executives and senior management, as well as 50% of the incentive compensation for management and non-management employees, be excluded from the Company's rate request. (Marz Testimony p. 22).

Q. Do you agree with these proposed adjustments?

A. No, I do not. Incentive compensation (both annual and long term) is an essential part of the Company's total compensation package, which is necessary to attract and retain qualified employees. If Progress Energy did not provide incentive compensation, it would be forced to increase its base pay to compete with other utilities and industries on a total compensation basis for the workforce it needs to provide the reliable and efficient electric service that its customers have come to expect. And unlike incentive compensation, which provides the Company with flexibility to adjust compensation depending on the achievement of goals, the Company would lose the flexibility to adjust compensation based on performance. As explained above, all aspects of Progress Energy's incentive compensation (both annual and long term) programs provide tangible benefits to the customers.

Q. What about Witnesses Schultz's and Marz's assertions that other jurisdictions disallow incentive compensation?

A. First, I think the most relevant prior orders are from Florida, where this proceeding is pending. Historically, Florida has recognized the value of incentive compensation plans and has approved its inclusion in rates. For example, in Florida Power Corporation's 1992 rate case, the Commission specifically included the utility's request for incentive compensation, stating, "Incentive plans that are tied to the achievement of corporate goals are appropriate and provide an incentive to control costs." (Order PSC 92-1197-FOF-EI, page *117, attached as Exhibit No. ___ (MSD-8) to my rebuttal testimony). In addition, in Gulf Power's 2002 rate case, Witness Schultz testified that Gulf's incentive compensation expenses should be disallowed. The Commission rejected those arguments and approved Gulf's incentive compensation plan, recognizing that Gulf employees were paid based on market value and that as result "customers will receive quality service and low rates." (Order PSC-02-0787-FOF-EI, page *71, attached as Exhibit No. ___ (MSD-9) to my rebuttal testimony).

Witness Marz discusses the Florida Commission's most recent consideration of incentive compensation in the TECO rate case. (Marz Testimony p. 28) In the Tampa Electric proceeding, the PSC excluded only the portion of Tampa Electric's incentive compensation tied to the financial goals of its parent, TECO Energy. While peers in the utility industry, Progress Energy can be distinguished from TECO Energy. For example, TECO Energy has many more non-regulated subsidiaries upon which its financial performance is based. In contrast, Progress Energy, Inc. primarily receives revenue from two electric utility subsidiaries, PEF and Progress Energy Carolinas ("PEC"). Furthermore, many of the incentive compensation goals under discussion are tied specifically to PEF performance, with only the EPS goal tied to the parent, Progress Energy, Inc.

With respect to the orders from other jurisdictions that Witnesses Schultz and Marz cite, there are important distinctions between the utilities involved in those proceedings and PEF. For example, the economic factors that impact compensation levels can vary depending on the geographic location of the utility. So a utility in Vermont, as included in Schultz's testimony (p. 18) may have different compensation requirements to attract and retain employees within its service territory than PEF would have. The size, generation mix and complexity of operations of a utility will also impact the type of employees that utility requires. That is why PEF benchmarks against peer utilities, which are similar in size, generation mix, and strategy.

Q. Are PEF's incentive compensation plans reasonable in light of the economic conditions facing the State of Florida and the country?

A. Yes. Customer demand for superior electric service that relies on high quality employees has not changed. For the 2010 test year and beyond we believe that PEF's incentive compensation costs are reasonable and necessary to continue to retain and recruit quality employees.

Contrary to Witness Schultz's sweeping statement that the Company should not pay any incentive compensation given the economy, the Company cannot take such a narrow, short-sighted view with respect to the economic conditions. PEF competes in Florida and nationally for talented employees, and I am not aware of other utilities eliminating incentive compensation from their total compensation packages. Such incentive compensation costs are necessary so that the Company can continue retaining and attracting quality employees, in the future. The Company takes a more long-term strategic approach to continue to provide the safe and reliable electric service our customers have come to expect.

In addition, the Company has continued to benchmark its compensation plans against its peer utilities to ensure that its budgeted compensation expenses are within the 50^{th} percentile. In a survey conducted by the Company in July, 2009, all of the twenty-one responding utilities provided information regarding aspects of their current short-term management and employee incentive programs, an indication that they are continuing to provide this type of compensation to their employees even with the state of the economy. The survey results are attached to my rebuttal testimony as Exhibit No. __ (MSD-10). In addition, according to the latest update to an ongoing series of surveys by

Watson Wyatt, a leading global consulting firm, the number of employers planning to reverse salary cuts and freezes has increased in the past two months. The survey found that 33 percent of employers that froze salaries plan to unfreeze them within the next six months, up from 17 percent two months ago. Forty-four percent plan to roll back salary cuts in the next six months, compared with 30 percent two months ago. Watson Wyatt's latest bimonthly survey was conducted in August 2009 and includes responses from 175 large employers. The press release describing the results of this survey is attached to my rebuttal testimony as Exhibit No. ___ (MSD-11).

Q. Speaking of the market studies at which Progress Energy targets the 50th percentile, what does Witness Schultz assert with respect to those market studies and how do you respond?

A. Witness Schultz challenges the fact that Progress Energy is actually at the 50th percentile. (Schultz Testimony p. 24). He has two main arguments in support of this testimony. First, he claims that the compensation studies are skewed by a few organizations. (Schultz Testimony p. 25). Second, he asserts that because many of the utilities that participate in these studies do not include incentive compensation in the rates charged to customers, it is inappropriate to compare these utilities to Florida. (Id.) Both these arguments are without merit.

Although we have provided to OPC in discovery each of the compensation studies in which PEF participates, Schultz does not undertake any specific analysis as to our particular studies. Nor does he provide any analysis as to whether a particular peer utility in our study "skewed" the results of the study. He also does not give any analysis as to whether the utilities in our studies are allowed to include incentive compensation in the rates it charges customers. Rather, Schultz makes sweeping generalities with respect to market studies without focusing on the only relevant studies in this proceeding, which are the ones in which Progress Energy participates. More specifically to Schultz's first contention, we use a sample of peer utilities that reflect the most appropriate and comparable employment markets. We continue to evaluate and monitor the peer group to ensure that it remains appropriate for such comparisons, provides representative data, and to avoid the possibility that one or two organizations will skew the results.

Schultz's second assertion, that the utility companies included in the studies do not have all their incentive compensation included in rates, is simply irrelevant to this particular point. With this assertion, Schultz does not challenge the validity of the numbers in these market studies. His real issue is that incentive compensation should not be paid for by the customers. This is the same argument he makes elsewhere, that other jurisdictions have disallowed incentive compensation and thus so should Florida. I respond to that argument elsewhere. But for purposes of evaluating the market studies and the data contained in them, it is irrelevant whether a utility charges its incentive compensation to customers, shareholders, or otherwise. The purpose of these market studies is to compare the total compensation **paid to** employees, not to compare how different jurisdictions treat the recovery of portions of that compensation paid to employees. To be competitive with its peer utilities, Progress Energy must compare its compensation to the total compensation paid by those other utilities.

Q. Does the Company use any other mechanisms by which to confirm that its compensation is within the market?

A. Yes, the Company routinely conducts job value studies to ensure that each particular position is appropriately valued within the market. Progress Energy conducts market and internal reviews on all jobs below vice president in the company on a continuous basis. These reviews happen annually to about a quarter of the job classifications in the company. All jobs are reviewed on approximately a three to four year cycle. The market review entails collecting and validating job content for each classification and benchmarking that content to external survey databases within the appropriate peer group. Similar internal jobs are compared against each other to ensure an appropriate amount of equity exists between like work. The findings of the market and internal equity analysis are validated and approved through a process of review with business units' management. A summary of these findings from 2008 and 2009 is attached as composite Exhibit No. __ (MSD-12) to my rebuttal testimony.

Furthermore, we annually review the market values of the vice president positions by performing an analysis of the survey data on similar positions of our peers. From those analyses, we recommend a market value to the CEO for approval. The executive compensation consultant provides the Organization and Compensation Committee of the Board of Directors ("Committee") with an analysis comparing base salaries, annual incentives, and long-term incentives to compensation opportunities provided to the executive officers of our peers. The Committee reviews these analyses and, with input from the consultant, approves the relevant market values. The results of the most recent analysis completed by Hewitt Associates LLC, the Company's executive compensation consultant, is attached as Exhibit No. ___ (MSD-13) to my rebuttal testimony.

Q. Witness Schultz also claims that incentive pay is not a significant factor in attracting and retaining employees. Do you agree with his opinion?

A. No, I do not. Witness Schultz relies on the results of a Towers Perrin survey that ranks the top drivers an employee uses to choose an employer. Because that survey shows the ranking of drivers like competitive base pay, competitive health care benefits, and competitive retirement benefits, but not incentive compensation, Schultz challenges whether incentive pay is even an important factor in the decision that an employee makes when choosing an employer. (Schultz Testimony pp. 25-26) Again, Witness Schultz does not acknowledge that incentive compensation is just one part of Progress Energy's total compensation package. The entire package must be competitive, because current and potential employees look at the entire compensation package when evaluating and comparing jobs. If PEF did not offer incentive pay, it would have to increase base pay to compete for skilled employees on a total compensation basis with its peer utility groups.

Q. Does Witness Schultz challenge the goals upon which the Company's incentive compensation plans are based?

A. Yes, he claims that various operational goals are set at inappropriate levels. Other Company witnesses will address how these operational goals are set and why they are appropriate. Witness Schultz also points to the fact that incentive awards were made to 99.7% of employees, as evidence of the fact that the goals are set too low. (Schultz

Testimony p. 29) This is an inaccurate characterization of this percentage figure. 99.7% of all employees received some amount of incentive payment, but that does not mean that every person received the target amount for which they were eligible under their incentive compensation plans. Employees received a payment commensurate with their individual and business unit performance.

II. EMPLOYEE BENEFITS.

Q. What does Witness Schultz assert with respect to the Company's employee benefits costs?

A. Witness Schultz recommends an adjustment to the Company's requested average benefit per employee expense by reducing the number of employee positions. His arguments regarding the number of employee positions included in the Company's filing will be addressed in the rebuttal testimony of Mr. Peter Toomey. Witness Schultz also makes an adjustment based on changes to the Company's MFR C-35. (Schultz Testimony pp. 31-32) Then Witness Schultz makes some observations about the Company's health care costs and retirement plans, yet he does not make any specific adjustments. He recommends that the Commission somehow take these additional expenses into account when reviewing the Company's overall compensation request. (Schultz Testimony pp. 32-33)

Q. So with respect to the Company's health care costs, does Witness Schultz do any specific analysis of the requested costs?

A. No, he does not. He states that the healthcare increase "appears excessive" and "could be attributed" to the fact that employee share of the cost has not been as high as the projected healthcare cost increase. Schultz then cites the fact that employee contributions increased by 3%, while healthcare costs have been increasing 10-12% annually. (Schultz Testimony p. 32). Schultz has taken data from our interrogatory response out of context. The 3% figure is for Bargaining Unit Plans only and only reflects the increase from 2008 to 2009. Schultz does not acknowledge that PGN's benefit strategy, which includes the introduction of consumer-driven health plans, has limited its health care cost increases per employee to well below the national average over the past several years. Although PGN's cost increases have fluctuated from year to year, it still remains below the national average, as reflected in Exhibit No. ___ (MSD-14) attached to my rebuttal testimony. Furthermore, Schultz does not analyze what employee contributions should be, nor does he assess whether increasing employee contributions would limit the Company's healthcare cost increases.

Schultz's reference to health care costs increasing 10 -12 % annually is based on the company's budget projections. Those projections are based in part on national trends. In contrast, employee contributions are set based upon review of prior year's experience as compared to projections for the next year. To the extent the prior year's actual claims experience is less than the budget projection, employee contributions will not relate directly to the corresponding budget projection. In addition, the company must consider its need to remain competitive with other utilities and other large employers when setting employee rates.

Q. Likewise, with respect to Witness Schultz's testimony regarding the Company's retirement plans, does he do any specific analysis as to the costs for those plans?

A. No. Schultz makes statements about the Company's "generous benefit package" and claims that many of PEF's customers do not enjoy similar benefits. Yet, Progress Energy's benefits packages are part of a carefully designed and benchmarked total compensation package. Not only is Progress competing against other utilities for highly skilled employees, Progress also competes against other non-regulated companies for many of those employees. For example, while an employee may be able to make a higher salary in a non-regulated company, they may give up some of that salary for a more robust pension plan or better health benefits. Again, it is important to remember that Progress Energy approaches compensation and benefits on the basis of a total rewards package. That complete package is carefully designed to be competitive while remaining at the 50th percentile of peer utilities. If a significant piece of the package, such as pension or incentive compensation is eliminated, other portions of the total rewards package may require increases. The Commission recognized the value of a total compensation approach in Gulf's 2002 rate case proceeding which I reference above. (See Exhibit No. ___ (MSD-9), pages *68-72). Accordingly, the Company's total compensation package, and all the expenses included in this rate case for the package, should be approved as reasonable.

Q. Does this conclude your testimony?

A. Yes.

BY MS. TRIPLETT:

Q Mr. DesChamps, do you have a summary of your rebuttal testimony?

A Yes, I do.

Q Would you please provide that?

A Okay.

Good afternoon, Mr. Chairman and Commissioners. The purpose of my rebuttal this afternoon is to address the Intervenors' testimony of Mr. Helmuth Schultz and Mr. Martin Marz concerning portions of their testimony related to incentive compensation, payroll levels and employee benefits.

First, Mr. Schultz and Mr. Marz both testified that the company's incentive compensation plans do not benefit the customers and thus they make adjustments to the expense. None of their arguments, however, have merit.

Progress Energy Florida's incentive compensation plans are designed to promote and encourage superior performance by employees. PEF measures employee performance through cost management, operational efficiency, reliability, safety and customer satisfaction goals that ultimately build a strong company.

In return, a financially strong company can access capital more easily at lower costs, which result in lower rates that benefit customers. Incentive plans are an essential part of Progress Energy's total compensation package. These plans are both reasonable and necessary to attract and retain high quality employees. Progress Energy benchmarks its compensation plans against peer utilities to make sure that its compensation expenses are within the 50th percentile in the market. In addition, Progress Energy routinely conducts job value studies to ensure that the positions are appropriately valued in the market.

Witness Schultz also raises a concern regarding the company's employee benefits costs, specifically regarding the company's health care costs. However, Mr. Schultz does not provide any analysis as to what the health care costs should be. He also doesn't consider that the company, through its benefits strategy, has limited its health care cost increases per employee to well below the national average over the past several years.

The company's health care costs along with its entire benefits package is competitive and carefully designed to ensure that the company will attract and retain the employees it needs to provide a safe and reliable electric service to its customers.

This concludes my summary and I'm happy to answer questions that you might have.

MS. TRIPLETT: Madam Chair, we tender the witness for cross-examination.

CHAIRMAN McMURRIAN: Mr. Rehwinkel?

CROSS EXAMINATION

BY MR. REHWINKEL:

Q You're going to be surprised when I ask you to turn to page 3 of your rebuttal testimony.

A Okay. There's a page 3.

Q I'm surprised you're not already there.

Would you -- do you refer to EPS as goals of the incentive compensation plan, EPS, earnings per share?

A Earnings per share as a goal?

Q Yes, sir.

A As one of the goals under the employee cash incentive plan?

Q Yes.

A Yes.

Q Ratepayers do not receive any direct financial benefit from an improvement in EPS, do they?

A I would say customers do receive a benefit, and I would put that in the context of any actions that the company take that improves the delivery of safe and reliable electric service to our customers benefits our shareholders, and as a result that helps us provide a fair return to our shareholders.

Q Isn't it true that what you just described to me was more in line of an indirect benefit that customers receive?

A I would not describe it as indirect.

Q You would say that it is a direct benefit?

A Yes.

Q Do customers receive dividends as a result of improvement in EPS in the form of stock dividends?

A Only if those customers own -- if those customers own our shares, they would receive a dividend.

Q So by that answer you're saying, isn't it true, that non-PEF or PGN stockholding customers do not receive dividends if there's an improvement in EPS?

A If we're using the term, my understanding, the definition of dividends being paid on the ownership of the company's common stock, I would say yes.

Q Nor do non-PGN stockholding customers receive any appreciation in the value of PGN stock, correct?

A That's correct.

Q On page 3, lines 19 and 20, isn't it true that you indicate that the company's incentive plan is designed to pay at a higher level for superior operational performance?

A Yes, the plans are designed to incent employees to perform at superior levels, and with that performance they are thereby compensated similarly.

Q Based on your testimony on page 14 of your rebuttal, isn't it true that 99.7 percent of PEF employees received some level of incentive compensation payment?

A That's correct.

Q If 99.7 percent of employees receive some level of incentive compensation payment, would it be correct, then, that 99.7 percent of employees provided some level of superior performance in some area in order to qualify for an incentive payment?

A I would describe that as those 99.7 percent of employees received some level of incentive payment. They may not have performed totally at what we would describe as superior performance, but the payout is driven by, of course, business year performance and individual performance, and those two factors play into their receiving a payment.

Q And I know that you're mindful of the yes or no and then explain rule?

A Yes, sir.

Q Was the answer to my question yes, that it would be correct that 99.7 percent of PEF employees provided some level of superior performance in some area of their job duties to qualify for an incentive payment?

A My answer would be yes, with the previous explanation I provided.

Q On page, the same page, lines 20 to 23, do you indicate there that the CEO has the discretion to allow for payment of incentive compensation for extenuating factors, such as general economic conditions that may impact operational goals and overall financial achievements?

A You're saying page 14?

Q I'm sorry, I'm still on page 3, I'm sorry.

A I'm with you now.

Q Do you want me to ask that again?

A Yes, please.

Q Don't you indicate there on lines 20 through 23 that the CEO has the discretion to allow for payment of incentive compensation for extenuating factors such as general economic conditions that may impact operational goals and overall financial achievements?

A I would answer that yes, but with this explanation. The CEO has discretion with regard to the discretionary component of the earnings per share measure to make certain adjustments to recognize for weather or general economic conditions that may affect operational goals and EPS achievement.

Q So doesn't that mean that if the economy is bad and planned financial results are not going to be achieved, that the CEO can still approve payment of incentive compensation to employees?

A Yes, the CEO has that opportunity, but I think that's in the CEO's discretion with regard to whether he would decide to exercise that discretion.

Q Wouldn't it be safe to say or wouldn't you agree with me that no matter what, that some level of incentive compensation will be paid in each and every year to PEF employees?

A I would say no, and I would make that on the basis of speculating that we would make a payment under any conditions. Our incentive plans, as I have emphasized earlier, are based on our individual and business unit performance, so I think if we did not perform, we would not receive a payment.

Q Can you point to me to any year where there were no payments of incentive compensation to PEF employees?

A With regard to year ever since the inception of the plan, or are you talking about a specific time period?

Q Well, first let's go with inception of the plan.

A There has not been a year where we've not had a payment under the employee cash incentive plan. There has been an occasion where a group did not receive a payment due to their performance.

Q And you say "group," are you talking like a business unit?

A It was a, at that time it would have been, I think if I remember correctly it was at one of our nuclear plants, so that was probably three or four, five hundred employees.

Q This would have been in Florida?

A It would not have been in Florida.

Q So that question was asked about PEF --

A With respect to PEF, no, not to my knowledge. There has always been -- there has been a payment for the applicable years that the plan has been in effect.

Q All right, let's move to page 4 and ask you to turn, if you would, to lines 3 through 5.

Isn't it your testimony here that the design of the incentive compensation plans for management and executives is to ensure that the company's annual incentive program will be compliant with Section 162(m) of the Internal Revenue Code?

A That is correct. Putting in the employee incentive program, that's the intent of that program.

Q Isn't it also true that Section 162(m) applies to the deductibility of executive compensation being limited to $1 million a year?

A I didn't follow your question.

Q Isn't it true that for payments of executive compensation under the incentive compensation plans, for them to be deductible under the Internal Revenue Code they have to be limited to $1 million per year per employee?

A The way I interpret 162(m), 162(m) sets out the parameters or the design features of our plan which would allow for deductions of compensation above the $1 million to be tax-deductible.

Q So if you design your plan right you can deduct, for tax purposes, payments under the executive compensation incentive comp plan if they're over a million dollars per recipient?

A Right, if that payment were to exceed the million dollars.

Q Is the use of the incentive plan to allow for deductibility of added compensation in the form of bonus type pay, but only if there are performance goals?

A One more time on that question.

Q Is the use of the incentive plan to allow for deductibility -- let me ask it to you this way. Is the incentive plan designed to allow for deductibility of added compensation in the form of bonus type pay, where there -- but only with their performance goals?

A Are you referring to the executive incentive plan?

Q Yes, the 162(m) compliant plan.

A If I understand your question, did we put this feature in for the purposes for allowing us to pay additional incentive compensation?

Q Let me ask it to you this way. For payments over $1 million, under the executive, this management incentive, executive incentive compensation plan, the EIP, for payments to individuals greater than a million dollars, isn't it a requirement for the tax deductibility that there be performance goals?

A Yes.

Q So stated another way, if you had an executive incentive plan that didn't have performance goals, then payments over $1 million would not be tax-deductible if you did not have the performance goals?

A If you're trying to achieve 162(m) compliance, that's true, but I don't think you would have an incentive program without incentive goals.

Q On page 5, if you could turn to page 5 of your rebuttal testimony, and let me direct you to lines 11 through 22. Do you see that?

A 11 through 22, page 5?

Q Yes, sir. Do you state there that the plan design of the goals is for the benefit of customers as well as shareholders?

A Is that your question?

Q Yes, sir.

A Yes.

Q Mr. DesChamps, do you dispute Mr. Schultz's testimony that there are goals that have not been adjusted despite being achieved?

A Yes, and I dispute it on the basis that the measures of the goal may not have changed, but, as has been discussed by prior witnesses, in particular from the operating side of our business, the dynamics or the calculations that go into establishing those measures can be significantly different from year to year.

Q Okay. So we heard testimony that, I think it was from Mr. Sorrick, about the math behind the environmental and safety goals?

A I do remember.

Q That the math had changed despite the fact that the objective numerical criteria had not. Is that a fair characterization of what he said?

A That's fair.

Q Are you saying that, beyond that example, that each and every other situation where your goals, your numerical objective goals had not changed, there was something else that had changed, such that the comparability of the goals from year to year wasn't readily apparent?

A If I understand your question, if the metrics of the goal did not change from year to year?

Q Yes, sir.

A And then the rest of it?

Q Well, my question is, let's put aside Mr. Sorrick's environmental and safety goals. Are you saying that they're -- anywhere else that the metrics did not change from year to year, that there was some other factor that had changed, such that in effect the goals had changed?

A Well, first, let me say with regard to the scope of my responsibility, my expertise with regard to goal-setting, that's not my expertise with regard to how the business units set their goals. I would think we had heard discussions about, with regard to the process of goal-setting which includes a series of steps that, before the goal is finalized, they go through that process and it meets the criteria of that process.

I'm not the person who can really get into how all the business units really establish what is the appropriate measures of achievement in a particular goal.

Q Well, my question is more along the lines of, did the goals change. And let me make sure I understand, and I'm going to ask the question again, because I'm not sure we're kind of talking in sync.

My question is, do you dispute Mr. Schultz's testimony that there are goals that have not been adjusted despite being achieved?

A No.

Q You don't dispute his testimony?

A Wait a minute.

Q I'm not trying to trick you up.

A I'll take it this way. With regard to certain of our goals, safety is always the goal, but with regards to the measure of safety, I would rebut Mr. Schultz's position with regard to are we showing, are the goals being designed such that to ensure that we have ongoing improvement or whatever with respect to that goal.

And I will cast my answer with regard to, as I have said earlier, with respect to who is the best persons for establishing those goals is really the business units, and that's really beyond my expertise, but with respect to the basics of is there a safety goal, is there an environmental goal from year to year, yes.

Q And in the end, though, you're the compensation and benefits expert of the company, correct?

A Yes.

Q So what we talked about with respect to what the business units do are inputs to the compensation plans that you design and that you approve, I guess, if you will, through your chain of command, to govern the pay and performance of your employees, correct?

A That's correct.

Q So I'm asking more in an objective sense rather than kind of subjectively how the goals were made, are there goals out there that have not changed from year to year?

A I would just have to say I don't know with regard to being able to be specific with regard to an answer there.

Q Are you aware of any SAIDI type goals that may not have changed from year to year?

A No, sir. Again, similar answer.

MR. REHWINKEL: Mr. Chairman, I have an exhibit that I would like to pass out.

CHAIRMAN CARTER: Do you need a number?

MR. REHWINKEL: Yes.

CHAIRMAN CARTER: 309. Short title?

MR. REHWINKEL: This would be Response to OPC POD 31.

CHAIRMAN CARTER: Response to OPC POD 31?

MR. REHWINKEL: Yes, sir.

(Exhibit No. 309 marked for identification.)

MR. REHWINKEL: And, Mr. Chairman, I provided a copy of this exhibit to the witness and to his attorney in advance. And I think what Mr. Poucher is explaining to him is I inadvertently included page, Bates-stamp page 41 when I meant to put Bates-stamp page 46 in there, so Mr. Poucher has been kind enough to clip on page 46 at the back of this document, and then page 41 in here is really not relevant to my questions.

CHAIRMAN CARTER: Mr. Poucher is wearing his number one tie today.

MR. REHWINKEL: And he's wearing it proudly. I'm glad he's wearing the orange and blue. He's been in a prayer vigil for Mr. Tebow.

CHAIRMAN CARTER: We all have, we all have been in a prayer vigil for that young man for his outstanding work off the field as well as on the field.

MR. REHWINKEL: Yes, sir, and I think he's doing quite well, thank you.

If I could inquire of the witness?

CHAIRMAN CARTER: Yes, sir, you may proceed.

BY MR. REHWINKEL:

Q Mr. DesChamps, are you familiar with this document with the addition of the last page?

A Yes.

Q I apologize for the messiness, that was my error.

Can I ask you to refer to Exhibit 309, and I would like you to look first at the last page, which is Bates stamp page 46 of OPC POD 31. Are you familiar with this document?

A Yes.

Q For 2007, what is the target core business EPS goal?

A The dollar amount, $2.80.

Q And then if I could ask you to turn forward a couple of pages to Bates stamp 177, this is the same goals, but for 2008, correct?

A Yes.

Q And what is the corresponding target core business EPS?

A $3.05.

Q And how about if you can turn to Bates 234 for 2009, what is that target?

A $3 -- one more time the Bates, 234?

Q 234, yes, sir.

A $3.06.

Q For 2009?

A Right.

Q Can you explain to me why the customer reliability performance goals remain the same but the earnings goals change and require improvement?

A I don't have an answer for that.

Q Are the earnings per share goals that are contained in Exhibit 309, are they dependent upon your regulated rate of return on equity?

A I don't know with respect to the influence of the ROE on that number. Our process is such that our chief financial officer along with our senior management committee establishes or makes a recommendation of these goals under this particular plan, and they're in turn set by our Organization and Compensation Committee of our Board of Directors.

Q Now, I think you have said to me and I think you told me in your deposition that you do not develop these goals, these are developed by the appropriate business unit or level of management, any of the goals that are in the plans, is that correct?

A Yes. I would draw a distinction, though, between the plans. With the employee cash incentive plans, those goals are established by our business units. With respect to our management incentive compensation plan, those goals are established basically through our chief financial officer via the chief executive officer and the senior management committee, and thereby -- and then approved by our Organization and Compensation Committee of our Board. So I want to make that distinction between the plans.

Q So am I hearing that there are some aspects of goals that are approved in your organization?

A When we say my organization, are you talking about the Human Resources Department?

Q Yes, sir.

A No, none of the goals are approved by the Human Resources Department.

Q But you are the company witness on incentive compensation, correct?

A Yes, sir.

Q As part of your rebuttal testimony here, are you taking exception to Mr. Schultz's questioning of the reasonableness of the company's goals?

A Yes, I am, with regards to Mr. Schultz's position about -- with respect to the goals, yes, I am.

Q But if you cannot testify as to how the goals were established or determined, how can you question Mr. Schultz' taking exception to the development and/or the setting of these goals?

A I was referring in general to Mr. Schultz's position, and that's where I focus my rebuttal.

Q On page 7, if you will, of your rebuttal, if I could get you to look at line 12, isn't it true that you contend there that the exclusion of incentive compensation in other jurisdictions by other Commissions has no bearing on PEF's request as it is based on incentive compensation payments?

A Yes.

Q And on page 8 of your testimony, isn't it true that you indicate that the orders identified by the Intervenors where incentive compensation is not included in its entirety in rates is not applicable to PEF, because those companies are not peer companies?

A I take the position with regard to that -- are you referring to a specific line or just page 8 in general?

Q Page 8 in general.

A I was looking at with regard to TECO. I will just use that as an example with regard to the disallowance with regard to TECO's incentive pay and the reasoning as compared to Progress Energy Florida.

Q So the fact that allowances may have occurred in other states, the peer or non-peer status of those companies is irrelevant to your objection to those orders' being considered?

A That's correct, because I take the position, with regard to establishing our levels of compensation we're looking at, what the market says versus what the regulatory practice is with regard to that particular company.

Q Well, if I look at the bottom of page 8 and I think at the tail end of the contrast to the Vermont situation, I think on lines 21 through 22, you state, "That is why PEF has benchmarks against peer utilities which are similar in size, generation, mix and strategy." Did I read that correctly?

A Yes, sir.

Q So is it your testimony there that there is some aspect of whether the companies are peers with respect to their comparability for purposes of judging the appropriateness of incentive compensation for ratemaking purposes?

A If I understand your question, what I'm addressing here is with respect to our peers in establishing our incentive levels, we do not bring into the equation the regulatory recovery of incentive expenses. You will see that in line 21 and 22 I do not mention regulatory recovery of the incentive expenses.

Q Do you think that the Commission should not look to the Vermont order because the characteristics of that company in Vermont are different from PEF, is that correct?

A That would be correct, sir.

Q Now, you identified in Exhibit MSD-13, I believe at page 4, the peer companies against which PEF benchmarks itself for incentive compensation purposes, is that correct?

A Yes, sir.

Q Now, are these the same companies that you're referring to on page 9 of your rebuttal testimony?

A Yes, sir, these are what we consider our peer companies for compensation.

Q Is Ameren, A-m-e-r-e-n, Corporation on that list?

A Yes, sir, it is.

Q Would you accept, subject to check, that Ameren operates in Missouri and Illinois?

A To the best of my knowledge, subject to check.

Q And would you accept, subject to check, that there have been decisions in each of those states to remove some or all of the incentive compensation costs from the ratemaking process?

A I will accept your position there, subject to check.

Q Would you accept, subject to check, that almost every peer company that you have listed here is located in a state that has made some adjustment to incentive compensation in the ratemaking process?

A Subject to check.

Q Would you accept that American Electric in Arkansas has had incentive compensation adjustments in the ratemaking process?

A American Electric Power?

Q Yes, sir.

A Subject to check, yes.

Q What about Dominion Resources in Connecticut and Illinois?

A Subject to check.

Q How about DET Energy in California, Illinois, New York, Arizona and Utah?

A Subject to check.

Q And finally, Edison International in California, Minnesota, Illinois, Washington, New Mexico, Utah and New York?

A Subject to check, yes.

Q Have you ever heard of the phrase, *apples-to-apples comparison*?

A Yes.

Q If the peer companies you benchmark against have incentive compensation removed when their respective jurisdiction sets rates, wouldn't it be appropriate for PEF to compare its ratepayer-funded payroll to the peer company ratepayer-funded payrolls?

A I would describe that as back to your apples-to-apples. The apple I'm looking at here is market-based compensation and not regulatory recovery practices in these jurisdictions.

Q When you say "here," you're on MD-13?

A With regard to these peers.

Q 13?

A Yes, with regard to page 4, MSD-14.

Q Can you look at back to page 9, lines 7 through 9 of your rebuttal testimony? Am I reading this correctly that you believe that Mr. Schultz states that the company should not pay incentive compensation?

A Mr. Schultz, yes.

Q So you read his testimony to say that it should not be paid to the employees, is that right?

A Yes -- well, wait a minute, hold on. The way I would interpret Mr. Schultz's comments is with respect to it should not be recovered through rates. Let's just get that clear on the record.

Q That was going to be my next question. So you don't believe that in his testimony he is saying that the employee should not receive any of the compensation that you have proposed, is that correct?

A That's correct.

Q His only point is that the cost should be disallowed for ratemaking; that if shareholders believe the costs are justified that they should pay the costs, is that how you read his testimony?

A That's the way I interpreted Mr. Schultz's position.

Q Is it your position that incentive compensation is appropriate along with the base pay increases that are proposed in this case because the peer companies that you benchmark against do the same?

A My position is -- the answer would be yes, and I will explain in this context.

I believe that the increases that we're requesting with regard to base pay and incentive compensation should be allowed in our objective of making sure that we have a market-based compensation to attract and maintain the qualified employees that we need to deliver the service to customers.

Q In your exhibits, and I think it's MSD-11, isn't it true that you reference an update to an ongoing series of surveys by Watson Wyatt that says employers, some employees are unfreezing salaries that were frozen previously?

A Yes, sir.

Q Aren't there a number of different surveys by different compensation companies that you respect that deal with different compensation trends?

A Yes, there are other surveys that we reference, yes, sir.

Q So on page 13 of your rebuttal testimony you reference a Hewitt Associates as an executive compensation consultant that you respect?

A Yes.

Q And in fact has done some work, compensation for the company?

A Yes, Hewitt is our -- Hewitt Associates also serves as our executive compensation consultant.

Q So I assume that since they are of that status as a vendor, you consider them a reliable source of payroll data?

A Yes. Hewitt, along with some of the others that I have made reference to in my testimony, are globally recognized human resource and compensation consulting type firms.

Q Would you be surprised if Hewitt issued a U.S. salary increase survey, survey findings 2009 and 2010, in August of 2009?

A Would I be surprised?

Q Yes, sir.

A I really don't have an answer yes or no to surprise.

Q Have you reviewed any Hewitt studies?

A With respect to the MSD-13, here is one analysis that Hewitt provided to us on the top five proxy analysis.

Q Have you read the U.S. salary increase survey, survey findings for 2009 and 2010, issued in August of 2009 by Hewitt?

A U.S. salary, no, not yet.

Q Is that something that you would --

A We will probably be -- it will probably be referenced later when I start focusing more in the compensation area with regard to what we will be doing later for 2010 forward.

Q Would you accept, subject to check, that on Roman numeral IV of that survey that Hewitt stated that salaried exempt overall budgets were 1.8 percent in 2009, down significantly from last year's 2009 projection of 3.8 percent?

A Subject to check, yes.

Q You would accept that. How does that level of salary increase compare to the level of salary increase that the company has proposed for setting rates in this docket, 1.8 percent?

A 1.8 percent for year 2009?

Q 2010.

A 2010?

Q Yes.

A With respect to what we're proposing for 2010, as I've said earlier, we're, again, looking at it from the perspective of what we believe we need to ensure that we can provide the market-based compensation to attract and obtain the type of employees that we need in delivering electric service.

Q So numerically how does it compare? What is your budget for salary increases for 2010?

A I heard you said 1.8.

Q Yes, sir.

A Now, when you say "salary," are you saying salary increase or merit increase?

Q Overall salary increase, the budget, your overall salary.

A The overall salary increase of the total budgeted salary amount is 3.75 percent.

Q Thank you.

A As opposed to the merit increase. That's the bottom line, the change in the bottom line salary from one year to the next.

Q Without merit increases, correct?

A Well, merit increase is built into that, along with promotional increases, any special salary adjustments, any special market adjustments.

So historically our trend has been to use about 3.75 year over year increase in our total salary, and we're in line with that 3.75 percent increase.

Q Isn't it true that your benefit costs are increasing?

A Yes.

Q Can you, and on MSD-11, can you read aloud the fourth paragraph on MSD-11 on page, I guess it's a single-page document.

A Is this the Wyatt document?

Q Yes, sir.

A Starting with the survey?

Q Yes, sir.

A Indulge me a little bit there. The copy is not very good here.

"The survey found that 65 percent of respondents that increased their percentage that employee pay for health care premiums do not expect to reverse that decision, and also 40 percent of respondents are planning to shift more health care benefit costs to workers by increasing the percentage of premium they pay. Another 41 percent of companies expect to increase the deductible, co-pays or out-of-pocket maximums for the 2010 health care plans."

Q Does the MFRs that were filed by the company for 2010 reflect the possibility that PEF will be included in that 40 percent that were surveyed that are planning to shift more health care costs to workers by increasing the percentage of premiums they pay?

A With regard to our health care cost strategy, we have done a number of cost savings. We've made a number of cost saving plan designs over the year.

One of the things we are implementing further in Florida with regard to our bargaining units is bringing in what we call high deductible health care plans. These are plans that have a significantly high deductible compared to our other plans, which we've found with regard to our strategy and the impact in our cost is there's been deductions in our overall costs in our medical plans.

In addition, we've looked at things with regard to, we're continuing to strongly manage our disease management program to make sure that employees are dealing with certain diseases that they have.

So in addition we continue to do very strong vendor management to ensure that we also are managing our vendors to make sure that we get a high value for the dollars that we're spending there as well.

Q So I think I understand what you're saying, but I would like to understand with respect to the dollars that are included in MFRs under employee benefits, do those dollars reflect the strategy that you describe with respect to -- do they reflect that strategy?

A Yes, the dollars that we're reflecting in the MFRs reflect our current medical plan strategy.

Q And when you say "current strategy" --

A It includes some of the things I just mentioned.

Q Are there any other planned initiatives to shift more of the costs to the employee that are not included in the MFRs?

A Not that I can think of right offhand, if I understand your question correctly. We are continuing, if I was to go further, we're going to continue to be very vigilant to make sure that we include as much what we term, in the health care business, it's called consumerism, to make sure that we price our plans appropriately to the cost of those particular plan options. We will continue to monitor that and make adjustments accordingly if we see cost increases that are outside of what we would expect to be the norm.

Q Do you have OPC Interrogatory 136 with you?

A OPC, just give me a second.

Q Sure.

A 136. Okay, got it.

Q For 2010, do you show the amount of increase in the employee, for the employee, that's assigned to employee relative to the total cost?

A For 2010?

Q Yes, sir.

A If we're talking about the chart in the middle of the page?

Q Yes, sir.

A Where we show 2009, we go from 19 million to 20 million?

Q Yes. And does that -- does that employee share of the health care costs, are there any plans to change that relative percentage for 2010 and beyond?

A At this time I'm not aware of any, but we will certainly stay on top of that. A lot of that is that employee contribution is driven by our collective bargaining agreements, and that's not up for review or renegotiation, I guess, for another two years.

Q Can I get you to turn to page 16 of your rebuttal testimony?

Do you take exception on this page to Mr. Schultz' labeling the company's benefit package as generous?

A Yes, I do.

Q To the extent --

A And when I say "generous," generous in comparison to our peers.

Q So in your expertise in the human resources field, do you believe that most companies have more than one retirement plan?

A Most companies?

Q Yes, sir.

A I would say most companies do not have more than one retirement plan.

Q What about the State of Florida, do they offer their employees multiple retirement plans?

A State government?

Q Yes, sir.

A I do not know.

Q You don't know?

A I don't know how many plans they may offer to employees.

Q Thank you, Mr. DesChamps, that's all the questions I have.

MR. REHWINKEL: Mr. Chairman, that's all the questions I have.

CHAIRMAN CARTER: Thank you, Mr. Rehwinkel.

Ms. Bradley?

MS. BRADLEY: Just a couple.

CROSS EXAMINATION

BY MS. BRADLEY:

Q Sir, you talk in your testimony about needing this rate increase because a financially strong company can access capital more easily at a lower cost, correct?

A Yes.

Q Will you agree with Mr. Oliver that any time you're looking at a project you have to look at the cost of the benefit to see if it's really worth it?

A Yes. That's a general business approach to evaluating a project, yes.

Q You also talk in your testimony about the company's shareholders also benefit from incentive programs, and that that's irrelevant to whether it should be included in base rates, correct?

A Yes, ma'am.

Q Is all of that included in base rates?

A Today?

Q In your proposal.

A Yes, I'm proposing that all of it be included and recovered through the base rate, yes.

Q Don't you think your customers would think it was a little bit more fair if that was prorated so that the portion that the shareholders benefit from is allocated to them versus the customers having to pay all of it?

A My response to that would link back some to previous comments from Mr. Dolan with regard to, our company, we have three key stakeholders, customers, shareholders and employees, and our approach to those three stakeholders is to be fair to all of them with respect to how we conduct our business.

So with that premise I would say with respect to your question, yes, I think that I do not believe that the costs should be prorated across customers and shareholders.

Q Even though your customers are having to pay for all of it?

A Yes.

Q You said something else about it was necessary to have this increased pay and all of that in order to retain good employees, correct?

A Yes.

Q You do not feel like your customer, I mean, excuse me, your employees in this really tough economic time have any loyalty to the company?

A Yes, I believe our employees are very loyal to our company.

Q And you don't think loyalty would keep them with the company without having to increase their pay at a time when others are having to cut pay and lose jobs and this type of thing?

A Well, I would say with regard to that, and I'm not going to get too far into what establishes the loyalty, but back to my other comments with regard to our employees' performance, when they perform, we believe that it's fair to compensate them for their performance.

Q And you don't see any difference in what's fair when the economy is really good and what's fair when the economy is really bad for a lot of your customers?

A I think, as I was saying, I think the fair thing with regard to customers is to provide them the safe and reliable electric service that they have come to expect, and I think that's fair with regard to the cost of providing that service.

Q Are you aware of the testimony at the customer service hearings where some of your customers specifically thought -- I'm sorry -- specifically testified that they thought the company should have to share some of the sacrifices that they're currently suffering from?

A No. I did not attend those hearings.

Q You did not see it?

A I did not see it, no, ma'am.

Q No one told you about that?

A No, ma'am.

Q What percentage of your employees did you say receive incentive pay?

A Over 99 percent receive some level of incentive compensation, or were paid some level of incentive compensation.

Q Is that true for 2008?

A Yes.

Q And what about 2007?

A Yes.

Q And 2006?

A I think similarly, yes.

Q If everyone is getting, not everyone, but if the majority of your people are getting incentive pay every year, do you think maybe you need to increase the goals so that they don't come to expect that?

A Well, I think, as I said earlier with regard to the goal-setting process, I think we have a very appropriate goal-setting process. I think with regard to the process it yields goals that meet and maybe in some cases maybe exceed our business needs. And from there I think with regard to that, if our employees perform and achieve those goals, then I think it's appropriate that they're paid according to their individual performance and their business unit performance.

Q Do you not feel that it would be more of an incentive if the goals were high enough that not everyone was meeting those goals, that that was kind of more for the people that are really exceeding?

A I can't speak with regard to the goal-setting process and how they establish their measures, but I would speak from the perspective that in setting our goals we wanted to make sure that goals are attainable, because if the goals aren't attainable, I think goals turn out to be a demotivator as opposed to a motivator.

Q So why would you not consider that as just part of the pay rather than an incentive pay, if it's set low enough that pretty much everyone is going to attain it every year?

A Yes, I do not agree with you that they're set low enough that everybody can achieve. I would say they're set appropriately for their business units, and with regard to those measures as I said earlier, I don't get involved with setting what the measure of performance should be.

Q But you indicated that over 95 percent of your employees get incentive pay each year?

A Receive some level of incentive pay. That doesn't mean they receive their target. A group could be paid less than their target, and similarly, a group could be paid more than their target, based on their performance.

Q So a person that does not meet their goals can still receive some incentive pay?

A Some level of incentive pay commensurate with their performance, yes.

Q You mentioned a minute ago the people that were getting increasing rates because you wanted to keep your good employees.

Are you aware of the number of people in your agency that make more than the Governor and Cabinet?

A No. I don't know how much the Governor's Cabinet makes.

Q You haven't looked at the Internet sites or looked up state government any?

A No.

MS. BRADLEY: Mr. Chairman, can I ask that you take judicial notice of the fact that the Governor and Cabinet members make less than $135,000 a year salary-wise?

CHAIRMAN CARTER: We can let the record reflect that.

MS. BRADLEY: Thank you.

BY MS. BRADLEY:

Q Do you think the Governor and Cabinet of the State of Florida, who are running all aspects of the state and overseeing that, have that responsibility, does it seem fair that your employees, so many of them are making so much more than the Governor and Cabinet?

A Well, I would respond to that this way. Based on our approach of looking at market-based comparisons to establish our compensation, we're not comparing against the Governor and the Governor's Cabinet, we are comparing against similar employees in the market. That's what we're using as a basis for establishing our compensation to be competitive in the market in which we're recruiting those employees from.

Q That kind of sounds like the excuse that kids give sometimes: Well, Johnny did it, so I did it, too.

Do you ever think about looking at that to see if maybe you need to reset your goals?

A Reset my goals with regard to?

Q Pay increases, that type of thing; compensation.

A Well, I don't know if I would describe it as "reset my goals." We have a compensation philosophy and strategy that we employ in attracting and retaining the workforce that we need to operate an electric utility, so that's the context in which we approach our compensation programs.

Q In this tough economic times, have you looked at those -- philosophy to see if it needs to be adjusted?

A No, I have not looked at it from the perspective of it needing to be adjusted, but I still stand by that it's still appropriate and reasonable for our business.

MS. BRADLEY: No further questions.

CHAIRMAN CARTER: Thank you, Mr. Bradley.

Ms. Kaufman?

MS. KAUFMAN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Good afternoon again, Mr. DesChamps. How are you?

A Very good.

Q I just wanted to follow up on a response that I thought I heard you give Ms. Bradley.

Is it your testimony that if the company doesn't receive the requested increase in its compensation, including the long-term incentive packages, that the company won't be able to provide safe, reliable electrical service?

A I don't think I responded to a question --

Q Is that your testimony?

A One more time. Let me make sure I understand that question.

Q Absolutely. Is it your testimony today that if the company doesn't receive its requested compensation increase, including the increase requested in your long-term incentive packages for your executives, that the company will not be able to provide safe and reliable electric service?

A That I do not know.

Q You don't have a view on that one way or the other?

A No, I do not.

Q I want to talk to you a little bit about the different compensation plans that the company has, and I was not here this morning, but apparently page 3 is a very popular page in everyone's testimony, so, not wanting to buck the trend, we're going to start there.

And on this page I guess in going over to the next you kind of give us an overview of the different types of incentive plans that the company has, am I right?

A Okay.

Q The first one is what is called executive incentive compensation plan, is that correct?

A That's correct.

Q And as I understand that, that plan pays out in cash, correct? It's a cash payout?

A Yes, our annual incentive plans pay out in cash.

Q And am I also correct that one of the metrics that is evaluated in deciding whether there should be a payout or what portion of a pay out under that plan is corporate earnings per share?

A Yes.

Q Of course, we're talking about the earnings of the parent company, Progress Energy, Inc., correct?

A That's one of the measures, yes.

Q And the people that participate in this plan, am I correct, are the top ten employees?

A They are eligible to participate in this plan, yes, ma'am. Basically it's a senior executive type plan.

Q What percentage of their long-term compensation is related to the earnings per share of the parent?

A Long-term as opposed to annual?

Q Well, let's do annual first and then we can do long-term. What percentage is related to the earnings per share of the parent company?

A Earnings per share.

Q Didn't you just say that was one of the metrics that was evaluated?

A Yes, it's one of the metrics. Let me see if I understand the question. With regard to our management incentive compensation plan, it has two metrics, corporate earnings per share and legal entity EBITDA.

Q Yes.

A Now with regard to percentage, are you talking the total compensation they would receive and the percentage of that?

Q Well, I'm interested, when you say total compensation, they get a base salary?

A Yes.

Q Which is what it is, I'm assuming.

A Right.

Q It's not affected by the incentive program, correct?

A Right.

Q So I'm trying to find out what percentage of their incentive compensation is related to how they do on earnings per share.

A I was interpreting your question, when you say percentage of their compensation, are you saying percentage of their total percentage, or are you saying what is their target percentage for the management incentive plan that drives their incentive compensation?

Q The latter. I think we can leave their base pay out of it because that's not affected, right?

A Are you talking with respect to a specific individual?

Q Is it different for each of the top ten?

A Yes, it could be. Like for the CEO, his management incentive target percentage is 85 percent. That would be roughly 85 percent at the target level of his base pay, if I understand your approach.

Q Who is the next executive under, I guess it's

Mr. Johnson?

A Who is under Mr. Johnson?

Q Just trying to go in descending order to get an idea.

A If you give me a moment and let me find those persons. By way of the incentive target?

Q Yes, sir.

A The next incentive target, annual incentive target is 55 percent for John McArthur.

Q What is his position?

A He is Executive Vice-President.

Q And who is the next executive in line?

A And then there is Mr. Mark Mulhearn, he's at 55 percent, he's our Chief Financial Officer.

Q So at least for these top three officers of the parent, a goodly portion of their incentive is tied to the earnings per share, would you agree?

A Yes.

Q Now, the second plan you've already talked about, we have touched on, that's the long-term incentive plan?

A Yes.

Q And as I understand it, that has two parts to it, the metrics do. First of all, this applies to the vice-president level and above, is that correct?

A The long-term incentive plan, the long-term incentive plan has two compensation elements: Performance shares, which the eligible participants for performance shares are vice-president and above; the second element is restricted stock units, and that's sort of middle management and above.

Q The first part, the performance share plan that applies to the vice-presidents and above, the metrics that you look at for that plan are relative total share return, correct?

A Relative total shareholder return, yes.

Q And that means how the shareholder returns of the parent compare to other companies, correct?

A Other peer companies, yes.

Q Other peer companies.

And then the other metric is earnings growth of the company, correct, the parent?

A Yes, that's correct.

Q Now, the third kind of compensation plan you have is the management incentive compensation plan, correct?

A Well, just let me clarify with regard to our annual incentive plans for our senior executives.

The EIP plan, the executive incentive plan, is there for the sole purpose of preserving the tax deductibility of our annual incentives. Then the management incentive plan, that's where the committee would look with regard to those senior executives for performance metrics with regard to establishing -- performance metrics for establishing the payouts under the management incentive plans for the senior executives.

So I just want to make sure you understand that the EIP plan is really part of our tax strategy as opposed to our total bonus strategy around these plans.

Q Well, the executives get a cash payout under the EIP plan, don't they?

A Well, when we talk about that, it's really that the EIP serves as an umbrella over our annual cash incentive plans.

Q And cash incentives are paid out under the EIP plan, correct?

A Under the provisions of the EICP plan, so that you can meet the provisions of the 162(m) there.

Q Right, I understand that, but -- I understand that there are tax consequences to it, but you're still paying out cash incentives to top management under the EIP plan related principally to earnings per share?

A Yes.

Q And then we just talked about the management incentive compensation plan and the metrics. One of the metrics in that plan also looked at earnings per share, correct?

A Right.

Q And then you have the fourth plan, is it called the employee cash incentive plan?

A Yes.

Q And that is for non-management, non-supervisory personnel, right?

A That's correct.

Q And that's the only plan that doesn't take into account the earnings of the parent, correct?

A The employee cash incentive plan does have a metrics tied to earnings per share.

Q So the non-management and non-supervisors also have the metrics of earnings per share?

A Yes. Along with the other metrics that the employee cash incentive plan includes are the incentive goals per the business units, the applicable business units.

Q Right. It's not the total component of what's looked at, but it's a part of it?

A It's basically, the employee cash incentive plans have two equally weighted performance measures: business unit incentive goals and earnings per share of the parent.

Q Now on page 5, at lines 20 to 22, Mr. Rehwinkel or Ms. Bradley may have asked you about this, but you say, "The fact that the company's shareholders also benefit from these incentive compensation goals is irrelevant as to whether the cost of the incentive compensation plan should be included in base rates." Do you see that?

A Page 5?

Q Page 5, starting line 20, in the middle.

Basically what you're saying is the fact that -- let me ask you if what you're saying is the fact that shareholders benefit from these compensation plans, that's irrelevant to whether or not the ratepayers ought to be paying for them?

A Yes. I will put that in the context I mentioned earlier. We view our three key stakeholders and we want to make sure that we're fair by those three key stakeholders, yes.

Q We talked about this I think on your direct, but let me just ask you again, is it your testimony today that the interests of the customers or ratepayers and the shareholders is 100 percent aligned all the time?

A Not necessarily, but I think with regard to, as I said earlier, in managing, I think our corporate strategy in running our business, we want to make sure we're fair with regard to all our key stakeholders.

Q And I guess your testimony is that it's fair for the ratepayers to pick up 100 percent of this incentive compensation, even though clearly it's also benefiting the shareholders, is that your testimony?

A Yes.

Q And it's your testimony that when the shareholders benefit by an increase in stock prices for example, the ratepayers get the same kind of benefit?

A Could you restate that one more time?

Q Yes, I will try. Is it your testimony that when the shareholders benefit because, for example, the price of their stock increases, that ratepayers are also getting the same benefit? That's a yes or no question.

A Yes, with the explanation that with regard to operating our business, what we do, the actions we take with respect to delivering the service to the customers that they deserve or they expect, does benefit the shareholders, because in delivering that service, that allows us to provide a return on the investment of the shareholders for the investment that they have made in our company.

Q So when I'm a shareholder and I'm lucky enough to sell my Progress Energy, Inc., shares and make a profit, it's your testimony that the ratepayers are equally benefiting from that?

A Well, I think with regard to the shareholder, the shareholder may have a different objective when it comes to selling their shares, but I think with regard to when an investor invests in our company, they expect a fair and reasonable return on their investment.

Q I would agree with you totally. And my question just is that when the shareholder either sells or sees their asset appreciate, is it your testimony that the ratepayer is getting the same benefit? Because I thought you said --

A I would think that from the standpoint that we're taking the actions to deliver the quality of service to the customers, they're getting the benefit, and in operating our business such that we can deliver that to customers, we can in turn pay our investors a fair return on their investment.

Q How does my stock appreciation relate to you delivering the reliable service that the ratepayer expects?

A Well, I think with regard to that, and I'm not going to get into the financial and economic aspects of what might drive the stock price up technically, but I would say from the standpoint that we can have satisfied customers, that we are in turn operating our business such that we can provide returns to our investors.

Q I'm going to ask one more time and then I'm going to move on.

When I, as a stockholder, shareholder in the company, see my stock appreciate or sell it at a profit or leave it to my grandchildren or whatever, how does that confer a benefit on the ratepayer? How does that give you a satisfied customer, how does that make your service more reliable?

A Well, let's just step back to what I said earlier with respect to the three key stakeholders here. I think with regard to how do you infer, is that your question, or confer benefits?

Q No, let me restate my question again and then we are going to move on.

I'm a shareholder. My stock is doing great. How does that lead to a satisfied ratepayer, which I think is what you had said earlier.

A Yes. That I think I've given you my best answers with regard to how we manage our business and how we try to operate our business to be fair by our three key stakeholders there.

Q If you flip over to page 7 of your testimony, beginning at line 10?

A Page 7, line 10?

Q Yes. And in that question and answer, it goes on over to the next page, I'm correct, am I not, that you are criticizing Witness Schultz and OPC Witness Marz in regard to their discussion of disallowance of incentive compensation in other jurisdictions, is that correct?

A Yes.

Q And I know you discussed this with Mr. Rehwinkel, but if you turn over to page 8, beginning at line 16, where it begins, "For example."

A Yes.

Q And going on to the next sentence, you're criticizing Mr. Schultz for his reference to a utility located in Vermont?

A Yes.

Q And you say they may have different compensation requirements, et cetera.

Do you have any information on the utility in Vermont that Mr. Schultz talks about in his testimony? Do you know anything about them?

A No specific information with regard to Vermont, but the point I was trying to drive home there was with regard, my responses with regard to the types of employees we may need with regard to the company, our company generation mix, our size and those types of factors in making our comparisons.

Q Well, do you know the generation mix of the Vermont utility?

A No, I do not.

Q Do you know the size of the Vermont utility?

A No, I do not.

Q Do you know anything about the operations of the Vermont utility?

A No, I do not.

Q Am I correct --

A However, it's not one of our peers, so the fact it's not considered one of our peers, I don't think it's fair to make that comparison.

Q But you don't know anything about it, correct?

A I don't know anything about it, but I do conclude that it is not one of -- it doesn't meet the thresholds of being one of our peer companies, so I would conclude from that certain characteristics of that company.

Q Is it your testimony on this passage on page 7 and 8 that the Commission shouldn't look to any regulatory decisions outside of Florida in regard to incentive compensation?

A Yes.

Q I take it you reviewed Mr. Marz's testimony?

A Yes.

Q And would I be correct that you didn't look at any of the orders that he cited on executive compensation because they were from outside of Florida? It's on page 27 of his testimony. He cites a Texas order, a Wyoming order.

A No, I did not look specifically at those orders, no.

Q Did you read those orders at all?

A I did not read those orders.

Q So you really can't give us a view as to what those Commissions thought about incentive compensation, correct?

A No, none other than what he may have cited here, no.

Q You don't have any reason to disagree with what he said there, do you, his description of what those other Commissions did?

A Not with regard to this.

Q So what your view is that the Commission ought to look to its Florida orders, correct, in regard to incentive compensation?

A Yes. In the instant case, yes.

Q And you cite, on page 7 you cite two orders there. One is a 1992 Florida Power Corporation order, correct?
A Yes.
Q And the other is a 2002 Gulf Power order, correct?
A That's correct.
Q Do you know when the Commission's most recent discussion of incentive compensation was? I should say, its most recent order.
A The most recent order to my knowledge is the TECO order.
Q The Tampa Electric case?
A Beg your pardon?
Q The Tampa Electric rate case?
A Yes.
Q And that's order PSC-09-0283?
A Right.
Q Now, that's a Florida order, right?
A Yes.
Q But you don't think the Commission should look at that order, either, correct, in terms of thinking about executive compensation? You don't think they should consider that order, either?
A I think with respect to my understanding of

that order, I think what I understand -- and I will say here I'm speaking just factually from what I read and not to confuse us with a legal interpretation -- but the Commission ruled that the disallowance of incentive compensation was relative to the portion of the incentives that were tied to the earnings that -- from diversified businesses and not regulated businesses.

So if the Commission is looking with regard to Progress Energy and making a certain corollary to Progress Energy, being that the vast majority of our revenues are from our -- basically all of our revenues are from our two, are from regulated entities, then I would take the position that if the Commission was looking at it in that context, that then all of our incentive compensation should be allowed and recovered through the base rates that we're here seeking.

Q Is it your position that the Tampa Electric order has no applicability to Progress Energy in terms of incentive compensation?

A With regard to the Commission's decision to look to the regulated businesses in its decision with regard to the recovery of the incentive compensation, I would say it's applicable here in the sense that all of our revenues or income is from a regulated entity here.

Q Do you have the Tampa Electric order or the excerpt that relates to the incentive compensation disallowance?

A Yes, I do.

Q Just that section, that's all that you're going to need. I think this is on page 58 of the order, but -- and you agree with me that the Commission did disallow a portion of Tampa Electric's incentive compensation?

A Yes.

Q And what the Commission said is, "We also find, however, that the incentive compensation should be directly tied to the results of TECO," TECO being the parent company, "and not to the diversified" -- I mean, TECO being the electric utility, excuse me -- "and not to the diversified interests of its parent company, TECO Energy."

So would you agree that in that case the Commission said, what we think we ought to look at is what the electric utility is doing and not what's going on at the parent?

A Well, I would say to that answer, yes, but I would also explain that what is making up the corporate EPS for Progress Energy, Inc., is basically all of it is coming from its two electric utilities.

Q But the Commission doesn't make the

distinctions you're making in the Tampa Electric order, does it? It's talking about the electric utility versus what the parent company, TECO Energy, is doing?

A I don't see the difference between how you're explaining it and how I'm interpreting it.

Q If you look at that on page 58, it seems to me that the Commission is saying, we want to focus on the electric utility's operations and we want any benefits tied directly to what happens at the electric utility, not to what happens at the parent corporation. Do you agree with that?

A I could agree that that could be one interpretation of the reading, but I would also say that with regard to the source of those revenues or the source of that income, they're a regulated business.

Q Right, but the order doesn't say that, does it?

A Well, let me read it again.

Q Take your time, please.

A With respect to when it says that the incentive compensation should be directly tied to the results of TECO, I don't know how you define results, but I would say results being the earnings of TECO.

Q And TECO is the regulated utility, correct?

A Yes, and that's the position I'm taking.

MS. KAUFMAN: Mr. Chairman, I'm getting ready to end my questions and I'm going to ask Mr. DesChamps a few questions about his exhibits.

I'm going to let you know that I'm going to object on the same basis that I did. I don't think that we have to go through a long argument about it, but I just wanted to make that objection before I asked him the questions so everybody would be aware.

CHAIRMAN CARTER: Let me give you a legal answer: okey-dokey.

MS. KAUFMAN: Okey-dokey. Thank you.

BY MS. KAUFMAN:

Q Mr. DesChamps, if you would look at your MSD-10, please?

CHAIRMAN CARTER: Also, Ms. Kaufman, just for the record, is that we're going to be giving the court reporter a break at 4:45 and we will come back on the hour, just to kind of give you a heads-up on that.

MS. KAUFMAN: I think I should be able to do that by then.

CHAIRMAN CARTER: Take your time.

BY MS. KAUFMAN:

Q Are you with me, Mr. DesChamps?

A Yes.

Q MSD-10. As I understand it, this is a survey that the company commissioned?

A Yes.

Q And it was performed by EAP Data Information Solutions?

A That is correct.

Q And it was a survey that was sent out to utilities in regard to incentive compensation?

A Yes, incentive compensation was one of the items.

Q How many utilities was it sent to?

A I think, ultimately, I think it's about 22.

Q That's how many responded, correct?

A Responded, yes. I don't know exactly the number it was sent to, but those that ultimately responded was 22.

Q And you don't know how many the surveys were sent to?

A No. With regard to the protocol of surveys, we consulted with the firm to send out the survey to utilities, and basically these are the numbers, these are the companies that responded, so you're at the mercy of companies responding to your survey.

Q Were you involved in commissioning of this study?

A Yes, I supervised, through one of my managers, yes.

Q And you didn't ask them how many companies they were going to send the survey to?

A The exact number, I don't know the exact number, but we went to a broad number of companies. I don't know if it was 50, 60 or whatever, but generally we ask, when we're doing this kind of survey, to ask the consultant to send it out to a broad base of utilities, and we hope that these utilities take the time to respond.

Q So 22 companies responded?

A Yes.

Q And you don't know if it went to 100 or 50 or 20?

A Not offhand. We might can get you that number, but I don't know an exact number.

Q Is there anybody here from EAP Data Information to tell us about this survey?

A No.

Q Now, when you look at the survey, down the left-hand side there is a code I guess which represents each of the companies that responded, correct?

A Yes.

Q But we can't tell at all, can we, for example, who is company number 1?

A Yes. That's just part of the general protocols of surveys. When you participate in one of these types of surveys, one of the things you're agreeing to do is to keep the information confidential, and so -- and part of keeping the information confidential, you use these codes.

Q So we can't tell from the list of utilities that's on page 11 of 11, who I guess are the companies that responded, we can't tell which is which by these codes on the survey, correct?

A That's correct.

Q What does it mean -- if you would just look at page 1 of 11, I'm just trying to understand this. What does the third column over mean, "Provides program"? That means they have some kind of incentive program?

A Yes.

Q And what does the next number mean, like on company number 1, 14, what is that?

A That refers to that heading, average number of days on level of management given to approve. That's the number of days you have generally from the time -- generally you're looking at the end of the performance year and the time they take to decide on what the payout is actually going to be.

Q So that's the time to decide on what the bonuses will be?

A Right.

Q And can we tell from looking at, for example, number 4, the type of program there is called "Structure Adjustment." Is there any information in this survey about what that is?

A Structure adjustment --

Q Is there any information in this survey about what that is?

A No, there's no definition written in the survey with regard to what a structured adjustment, but if you want me to explain it I can explain it for you.

Q Company number 13 in the comment -- oh, I guess that's on the number of days. Basically there's no number of days given for that company.

A Uh-huh.

Q For example, company number 21, can you tell if it's 20 or 21, this is on page 6 of 11, it's kind of in the middle, it says "Stock Option Grant," do you see that?

A Yes.

Q And we don't know what kind of grant that is, how much it is or anything like that, do we, from this information?

A Not from here, no.

Q Take a look at MSD-13, I guess back on the survey we were just looking at. It would be fair to say you didn't review any of the data that underlies that survey?

A With regard to the protocols of the survey, we used the firm to collect the data. What I did supervise was any data that we entered into the survey, but with regard to other companies' data, no, I did not see it and I did not supervise its collection.

Q And you didn't review it, did you?

A When you say "review it" --

Q You didn't have any access to any of the other data other that Progress's?

A No, I did not. Just think about it in this context. With the protocol of answering surveys by other company, you do not have the opportunity to review their data. As I said earlier, that data is confidential.

Q So you just accepted the results of the survey as they were presented to you?

A Yes, on the basis that this is a credible company for doing surveys, yes, and I had no reason to doubt the validity of the process.

Q If you turn to MSD-13, this is the analysis done by Hewitt Consulting, correct?

A Yes.

Q And again, we know we don't have a Hewitt witness here, correct?

A That's correct.

Q Did you review any of the data that underlies this proxy analysis?

A Yes. I supervised the collection of the data for Progress Energy.

Q Other than Progress Energy's data, did you review any of the other data that underlies this analysis?

A Similarly, I did not review the data that went into this survey.

Q And then, similarly, MSD-14 I guess was prepared by Mercer National Survey of Employer-Sponsored Health Plans?

A Yes.

Q So am I correct that this chart was prepared by Mercer and not by yourself?

A With regard to --

Q Average health care cost per member.

A Yes. I'm just pointing out with regard to the Mercer Fortune 500 number, that came from Mercer's reports.

With regard to the Progress Energy cost line, that was prepared under my supervision.

Q And as to the Mercer cost line, you didn't review any of the information that makes up that portion of the survey, is that right?

A All of the Progress Energy data that went into the survey, I would have supervised the preparation of that data.

Q Go ahead.

A And, as I was saying, and what is reflected on the Progress Energy line.

Q But you didn't review any of the data reflected on the Mercer Fortune 500 line, correct?

A No, I could not have reviewed any of that data.

MS. KAUFMAN: Thank you, Mr. Chairman. Thank you, Mr. DesChamps.

CHAIRMAN CARTER: Thank you, Ms. Kaufman, outstanding on the time.

We'll be back on the hour.

(Brief recess at 4:43 p.m.)

(The transcript continues in sequence with Volume 24.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)

COUNTY OF LEON)

I, CLARA C. ROTRUCK, do hereby certify that I was authorized to and did stenographically report the foregoing proceedings at the time and place herein stated.

IT IS FURTHER CERTIFIED that the foregoing transcript is a true record of my stenographic notes.

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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 2nd day of October, 2009, at Tallahassee, Leon County, Florida.

CLARA C. ROTRUCK