BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080317-EI

In the Matter of:

PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY.
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VOLUME 11

Pages 1545 through 1740

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PROCEEDINGS: HEARING

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

DATE: Wednesday, January 28, 2009

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

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APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
110	CLT Project Review	1570	1570
111	Comparison of 2007 Projected vs. Actual Plant Balances	1570	1570
112	(Late-filed) Revenue Impact of removing September CTs from 2009 Test Year	1588	
29			1607

P R O C E E D I N G S

(Transcript continues in sequence from Volume 10.)

MR. REHWINKEL: The exhibit that I am passing out for -- to ask this next series of questions contains an exhibit to his late-filed, a late-filed deposition exhibit and a document that is generated from the Late-filed Deposition Exhibit Number 1. And this is a hand-numbered four-page exhibit.

BY MR. REHWINKEL:

Q Mr. Chronister, if I could ask you -- Pages 2 through 4 of this exhibit, are you familiar with that document?

A Yes.

Q And this is a document that staff requested of you at your deposition, is that right?

A Yes.

Q And on Page 1 of this exhibit is a presentation of the numbers included in Late-filed Deposition Exhibit 1, and I would ask you if you would agree, subject to check, that the presentation on Page 1 of this exhibit is a fair presentation of what is contained in late-filed deposition exhibit for the months January of 2007 through December of 2007 without the removal of ECRC TECO projected plant-in-service balances.

A Yes, there is a lot of numbers on this page, but the first two columns, the dollars do seem to match my late-filed exhibit.

Q Okay. And I understand from your deposition that you believe that the ECRC plant-in-service balances should be taken into account in looking at whether any overprojected budget balances exist. Is that a fair presentation of your testimony in deposition?

A Yes, that is correct, because any assets associated with the Environmental Cost-Recovery Clause are excluded from rate base, so from an MFR perspective, any plant-in-service associated with the environmental clause would not be included in rate base. So if you include those in this analysis, then it doesn't really paint a fair picture.

Q Would it be fair to say that Tampa Electric Company projects plant balances for budgeting purposes and when they do so they include all costs of plant construction regardless of where the revenue support will come from?

A Yes.

Q And you don't project or budget with more precision for items that would be recovered through a clause versus items that would be recovered through a base rate filing, is that correct?

A Correct.

Q So the level of precision or accuracy in projecting plant balances should be the same regardless of the type of plant, is that fair?

A That is fair.

Q Doesn't this exhibit show that the company overprojected the plant-in-service balances for each and every month of 2007 except May?

A That is what this exhibit shows. In Mr. Larkin's original exhibit he examined 2008, which I think -- yes, you have included here, and the thing I would point out about the budgeting process is there is an ebb and flow between the actual and budgeted balances. And really where you end up is important, and as Mr. Larkin reflects in his original exhibit, the difference between our $5 billion of plant-in-service that we projected in September of '08 and the actual plant-in-service, those two $5.4 billion balances are within $625,000 of each other.

Q Okay. Isn't it also true that overprojections in nine of the 12 months for 2007 range from between 15 and $61 million?

A Yes.

Q Isn't it also true that the company overprojected by less than $10 million in only one month?

A On the page that you have in front of me, yes, that is true. Again, I think there is a natural ebb and flow in the budgeting process. The other thing I would point out is that you really don't want to cherry-pick certain items that have one particular direction when, in fact, you may have other items that go in another direction. And, you know, from my view there is a balance between items that have been overprojected and items that have been underprojected.

MR. REHWINKEL: Okay. Thank you.

Mr. Chairman, at this time I don't have any further questions for Mr. Chronister.

Thank you, Mr. Chronister.

CHAIRMAN CARTER: Mr. Rehwinkel, you look over your notes while I go to Commissioner Argenziano to make sure that you don't have any.

Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Thank you.

Another question. It comes from a question that Mr. Rehwinkel had asked you before about the compensation of 1.3 for Huron Consulting.

THE WITNESS: Yes.

COMMISSIONER ARGENZIANO: You had answered before the question was that some of TECO's board members also sit on Huron's board, and that they are not an affiliated company, but it brings about a question that I have. What does the company do to ensure that they are getting the best, you know, bang for their buck in hiring this consulting firm? And, of course, since people sit on the same board it makes me wonder even more are there any RFPs put out, or how would you then know what is a comparable rate to pay?

THE WITNESS: Right. There was a process of evaluating potential firms that could help us in the rate case. Different firms came in and presented their skills and their abilities and there was an evaluation done and eventually a selection. I'm not sure if it would be described specifically as a bid process, but there was a competition among the potential providers.

COMMISSIONER ARGENZIANO: So basically you had other companies in.

THE WITNESS: Yes.

COMMISSIONER ARGENZIANO: And looked at the services.

THE WITNESS: Yes.

COMMISSIONER ARGENZIANO: And you feel certain that you got the best bang for the buck.

THE WITNESS: Yes. And I guess part of it is you want consultants that are familiar with your company, you want consultants that are familiar with the Florida Public Service Commission, and the ratemaking process, and even down to the rules and regulations. You know as we talked about before, FERC accounting, uniform system of accounts, but the Florida Public Service Commission has some specific accounting that is different than other states, so it is good to get consultants that are familiar with the PSC.

COMMISSIONER ARGENZIANO: And I understand that, and I think that is an important aspect of it. But, again, sitting here trying to figure out and hearing that some of the board members sit on another board which happened to get the contract of 1.3 million plus I think another 260 begs the question from me anyway in trying to -- and I know in the grand scheme of all the money that we are talking about here it is probably minute compared to the larger amounts that we are talking about, but to me it is a substantial amount of money. And asking in any business decision how do I know. And, again, I am stuck with how do I know that that is -- and maybe I can ask of OPC and maybe FIPUG and others how you find out what is a comparable, because I am going to take your word for it that you called other companies in. Do you have an idea how many other companies you called in?

THE WITNESS: I don't. You know, if I had to guess I would say five or six. But one thing that I would point out is that these individuals from Huron that are helping us now, they helped us in the '80s and '90s before there was any board affiliation. So we are really going back to a company that helped us before this affiliation was created.

COMMISSIONER ARGENZIANO: And I understand that, I really do. I'm just trying to look at it and say, okay, I'm sure there are other companies that can do that work, and I know that the company would feel better knowing they have some kind of an understanding of the process, and especially if they have worked with the company before. I'm just trying to figure out if another company said, well, we can give you the same services for half that amount, if we got the best bang for the buck because after all the ratepayers are going to pay for that.

THE WITNESS: Right.

COMMISSIONER ARGENZIANO: So maybe it is advisable to ask other witnesses that come up, but I did want the company's point of view also and not just to ask -- I want all sides. So, I appreciate it.

CHAIRMAN CARTER: Thank you.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

A little while earlier Mr. Rehwinkel asked you some questions about the proposed annualization of the five CT units and the rail project. If those projects were not to be included in the base rates as proposed or only in part, what would be the accounting treatment that TECO would use on a go-forward basis?

THE WITNESS: The accounting treatment?

COMMISSIONER EDGAR: Uh-huh.

THE WITNESS: I'm not sure if I follow your question. You are talking about on the reimbursement?

COMMISSIONER EDGAR: I am talking about on the -- okay. I guess what I'm trying to ask is would TECO come back to the Commission and ask for those projects to be included at the point that they were implemented, since as I see it one of the issues is that the implementation date is a little out from the time that the rates would go into effect.

THE WITNESS: Yes. If not included in this particular proceeding's rates, then we would come back because they are significant projects and ask for recovery of them, you know, as they went in service. So, you know, I know everybody -- we have been talking about rate case expense and no one wants to come back in for rates. You know, there is an interim step that you can do, too, where you can have a step increase, you know, when a facility goes in after a rate case, and that is an option available, as well.

COMMISSIONER EDGAR: And on a different point, one of the witnesses we heard, I think, yesterday although my days are blurring a little bit. Earlier in this proceeding was Witness Abbott, and in her written testimony she discusses the need for the perception of financial integrity, access to capital, and makes a specific statement that it is important to understand the magnitude of TECO's capital spending program. And I was directed to you as the right witness to ask about that. So my question is how can you help me understand the magnitude of TECO's capital spending program, and is there a document that you would also point me to.

THE WITNESS: Sure. Hang on one second.

COMMISSIONER EDGAR: Sure.

THE WITNESS: Our future capital expenditures are disclosed in our 10K each year, and then the rate case is put together sort of as you move through time. So I can tell you that in our 2007 10K we anticipated the next five years to be about $2.9 billion of expenditures. For the rate case we put together a new projection, and from 2008 to 2012 there is $2.7 billion of capital expenditures that we are projecting to incur.

COMMISSIONER EDGAR: Okay. So you said 2.7 from 2007 to 2012?

THE WITNESS: No, 2008 to 2012, that five-year period there is 2.7 billion in capital expenditures.

COMMISSIONER EDGAR: And that is over five years.

THE WITNESS: That is over five years, yes.

COMMISSIONER EDGAR: Thank you.

THE WITNESS: You're welcome.

CHAIRMAN CARTER: Anything further from the bench?

I did tell Mr. Rehwinkel I would give him an opportunity to look over his notes.

MR. REHWINKEL: I'm fine. Thank you.

CHAIRMAN CARTER: Now, Mr. Kelly is back. I want you to make a good impression on your boss back there.

MR. REHWINKEL: Thank you, Mr. Chairman. I was afforded full opportunity and I appreciate it.

CHAIRMAN CARTER: Thank you.

Ms. Bradley, you're recognized.

MS. BRADLEY: Thank you.

CROSS EXAMINATION

BY MS. BRADLEY:

Q Were you at the public hearing that they had on this case?

A No, I was not.

Q Have you reviewed the testimony?

A From the public hearing? No, I have not.

Q Subject to check, there was a father who indicated that he had a sick child, and had lost his job, and despite the fact that he had always been on time with his payments, he missed a payment during this heavy financial burden, and he indicated you have a policy that requires somebody that misses a payment to pay about a month and a half, I guess an average month and a half payment as a deposit. Is that true?

A We have a policy of customers providing deposits for roughly a one to two month period to secure their account, yes.

Q Would it be fair to say that somebody that is already having trouble trying to meet their financial burdens is going to have an even harder time paying an extra month and a half to two months?

A Yes, I agree with what you are saying. I guess what I would point out is that one of the expenses that we do incur and that is included in the rate case is bad debt expense, and to the extent that we can get deposits from our customers, it allows us to keep that bad debt expense down. So for the overall body of customers it is a good thing to collect these deposits.

Q You looked at the capital leadership team exhibit and I believe you indicated you are not on that, or did you indicate you are --

A Correct, I'm not on the capital leadership team.

Q Do you know who is?

A I couldn't reel off a list of folks, I'm sorry. I mean, I know a couple, but I don't know the whole list.

Q Who are the couple that you can think of?

A Phil Barringer (phonetic), the VP Controller of Operations for TECO Energy and I think Sandra Callahan (phonetic), who is our Treasurer for TECO Energy.

Q Okay. I know you are providing some additional information about salary breakdowns and that type of thing, but can you tell me right now to the best of your knowledge how many of your executives make over half a million a year? And I am talking about complete compensation packages with base rates, and incentives, and stock, and everything.

A Let me get my glasses. At Tampa Electric there are no officers who make over a million dollars a year in compensation.

Q What about Mr. Gillette, I think he indicated the other day that he did?

A I'm sorry, I was reading from the Tampa Electric list.

CHAIRMAN CARTER: Hang on a second. Did you ask about a half million or --

MS. BRADLEY: Yes, sir, I did say half a million.

CHAIRMAN CARTER: That's what I thought.

THE WITNESS: Oh, I'm sorry. Sorry about that. I apologize. I am looking at the 2009, and there is one Tampa Electric officer who makes more than 500,000 in total compensation, and for TECO Energy --

BY MS. BRADLEY:

Q Let's just keep it to TECO.

A Okay.

Q And I believe Mr. Gillette the other day testified that he makes over a million?

A Yes, that is correct.

Q Are there any others that make over a million?

A Well, Mr. Gillette is a TECO Energy officer.

COMMISSIONER ARGENZIANO: Excuse me.

CHAIRMAN CARTER: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: You said there are no other persons or officers making over 500,000 in total?

THE WITNESS: Let me make sure.

CHAIRMAN CARTER: That is with salaries and benefits.

COMMISSIONER ARGENZIANO: Yes, that is in total, all stock options, everything.

THE WITNESS: Total compensation for 2009. Yes, only Mr. Black at Tampa Electric makes more than $500,000 total compensation.

COMMISSIONER ARGENZIANO: For 2009, did you say?

THE WITNESS: Yes. And that is also true for 2007 and 2008.

COMMISSIONER ARGENZIANO: Well, wasn't your general counsel making 826,000.

THE WITNESS: That is a TECO Energy officer.

COMMISSIONER ARGENZIANO: I'm sorry.

THE WITNESS: That's okay.

COMMISSIONER ARGENZIANO: It does get easy to get mixed up. Okay. So then it was just Mr. Black.

THE WITNESS: Correct.

COMMISSIONER ARGENZIANO: Thank you.

BY MS. BRADLEY:

Q I understood that -- well, let me ask you this. In your 2009 budget, did you include a base rate increase for any of your executives?

A In the 2009 budget, yes.

Q And I understood from one of your witnesses, it may have been Ms. Wehle yesterday, that they had determined that they would not award that?

A Correct. There will be zero increase in '09.

Q So we can essentially subtract that amount from your request right now, correct?

A Correct, that is my understanding. And just some rough calculations, I think that is about $300,000.

Q Okay.

A Is what that equates to.

Q We will take every bit we can get.

CHAIRMAN CARTER: Excuse me, may I interrupt you for a second?

MS. BRADLEY: Certainly.

CHAIRMAN CARTER: On the staff exhibit that he used for cross examination -- I forgot what witness it was.

MR. YOUNG: Witness Merrill.

CHAIRMAN CARTER: Because she was showing a 4.84 percent increase.

THE WITNESS: 4.84 --

CHAIRMAN CARTER: Increase for salaries. Is that right?

THE WITNESS: That is the percentage increase in the average pay per employee. That average pay is that MFR calculation where we take gross payroll and all the employees, so it can move around a little bit.

CHAIRMAN CARTER: Okay. And for the bargaining she said 46 percent of the employees were under a collective bargaining agreement, and that was 3.85 percent. But then she said for officers and other general employees it was a 4 percent increase.

THE WITNESS: Yes.

CHAIRMAN CARTER: Did I just miss something? Did you just say there was no increase?

THE WITNESS: The MFRs reflect our projected labor expenses, and the zero increase for officers is something that occurred after we prepared the MFRs.

MR. YOUNG: Mr. Chairman, if I could.

CHAIRMAN CARTER: Mr. Young.

MR. YOUNG: Yes, sir. If I could interject for one second. TECO is going to revise that MFR, and they are going to -- it is Exhibit Number 107 that shows a zero percent increase to the base salaries, and the projected incentive compensation will be determined on the 4th of February, and they are going to revise that and provide that to us.

CHAIRMAN CARTER: Okay. I was with you that because yesterday we were going through that whole process, and that is why I was like -- I remember reading something on that. Sorry to interrupt you, Ms. Bradley. You may proceed.

MS. BRADLEY: No problem. Thank you.

BY MS. BRADLEY:

Q As Mr. Young just mentioned, she also mentioned that on February the 4th, I believe, they would be meeting on the incentive packages?

A Yes.

Q Do you make any recommendations to that committee?

A No. No, I don't.

Q Would you be willing to recommend in light of the economy that they not award that incentive package to your executives?

A Me personally, I would not advocate that.

Q I read something yesterday in the paper about one of the utility companies making or coming out a lot better last year than they had anticipated. In light of some of those issues, and in light of the economy becoming so bad since you filed your request, have you gone back and made any adjustments or looked at any possible adjustments that you could make to reduce that for your customers?

A Well, I only know about our company, and I know that our company would not be doing well. As you described, some companies got to the end of '08 and said that they did better than they expected. That was not the case for us.

I need to be careful here, because there are financial statement public disclosure regulations that prevent me from being able to talk about our fourth quarter or year end information because we are not releasing earnings to the public until February 6th. But I can tell you that, for instance, through September of '08 our base revenue was $37 million below budget. So, we have had a significant decline in revenue. So, from my vantage point any reprojection would be a reprojection that would include anticipated lower base revenues for us.

CHAIRMAN CARTER: Excuse me, Ms. Bradley.

MS. BRADLEY: Certainly.

CHAIRMAN CARTER: You are saying at the end of the third quarter was 32 million less?

THE WITNESS: $37 million below budget in base revenues, yes.

CHAIRMAN CARTER: And when you were talking to Mr. Rehwinkel you were saying as you go down about the budget projections per month is that you said those would be different anyway, right? You said that sometimes they are lower, sometimes they are higher. So I am just trying to get my mind around how do you quantify that. Can I quantify that --

THE WITNESS: I think that is a fair point, and I think what you have to take into account is items that you think are going to be better in the future and worse than a prior projection you may have made. And from my vantage point, I do think there is a balance of items out there. There are capital expenditures that we are going to be making that is over and above what we have in our filing, expenses that are going to be higher, revenue that is going be lower, but I'm not proposing to make those changes.

I am just making note of the fact that there is a balance between some items that, for instance, we were talking about the salaries being lower. You know, you have an example of an expense that might be lower, but there are also some other expenses that are going to be higher. So I'm not proposing an adjustment, I am just making note of the fact that she was asking sort of how we are doing, and I would describe it as our revenues are off.

And the other thing would be in terms of the projection process, you have to look at the underlying data that is driving that foundationally, and I think for us we are seeing declines in our customer growth as well as our usage per customer, which sort of ensures that there is going to be a decline of revenue in the future.

CHAIRMAN CARTER: Ms. Bradley you may proceed.

MS. BRADLEY: Thank you.

BY MS. BRADLEY:

Q Actually that wasn't what I asked. I did mention the other company, but my question was in light of the way the economy has gone so bad since you prepared your rate request and your budget, have you gone back to look to see if there is any adjustments and modifications that could be made to provide less expensive services to your customers?

A There has been some sort of cursory relooks, and I would describe it that we have seen an equal amount of expenses that are probably going to be larger than what we have in our filing and some that are going to be smaller, but we have done a relook.

MS. BRADLEY: Can you give me just a minute?

CHAIRMAN CARTER: Yes, ma'am. Take your time. I interrupted you and probably threw you off your game. I apologize for that.

MS. BRADLEY: It didn't take much.

CHAIRMAN CARTER: Do you want to do this -- we are within ten minutes, do you want to look at everything and --

MS. BRADLEY: I just have one more question.

CHAIRMAN CARTER: Okay.

MS. BRADLEY: Really.

CHAIRMAN CARTER: That's fine. I just wanted to make sure that you have the opportunity ask your questions.

MS. BRADLEY: I appreciate that.

CHAIRMAN CARTER: You may proceed.

BY MS. BRADLEY:

Q In your testimony you talk somewhere about trying to benefit your customers with all of this that you are doing, and would it be fair to say that if your customers can't afford to pay their utilities they are not really going to care about all of these things you are proposing to do?

A I guess I would say, for instance, the rail facility. If the rail facility allows us to lower fuel costs for years to come that is something our customers would want us to be committed to so that they can have lower electric bills now and in the future.

Q You said you did not attend the hearing, and -- just one more follow up on this.

CHAIRMAN CARTER: You may proceed.

Q (Continuing) You said you didn't attend the hearing, but we had testimony from people that said they are making decisions already about do I eat, or do I buy my medication, or do I pay my utility bill. And if you raise it this substantially as you have requested, that is going to be even more of a burden for these people. Do you really think they care about any of these future proposals if they just can't afford your services, they can't afford to pay their utilities?

A Well, I think that they also need reliable electric service and the company has to be able to recover its investments and its costs to be able to provide that reliable electric service. And I think if we can't provide reliable electricity that that would be another burden on them, as well.

Q Don't you have a duty to provide affordable utility?

A Yes, and I think we do.

MS. BRADLEY: No further questions.

CHAIRMAN CARTER: Do you want to take a minute to look over your notes? Okay. Commissioners, we are really close -- before we have another person come on, we are really close, and that may give us time to kind of think about our questions, too. I mean, there may be a few questions from the bench on that, so let's do -- we will just go to lunch now and come back at 12:45.

(Lunch recess.)

CHAIRMAN CARTER: We are back on the record. And when we left we had a witness on for cross-examination. We had some questions from the bench, and at this point in time, I think Ms. Kaufman -- Ms. Bradley, you had completed your cross-examination, correct?

MS. BRADLEY: Yes, sir.

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

MR. REHWINKEL: Mr. Chairman.

CHAIRMAN CARTER: Mr. Rehwinkel.

MR. REHWINKEL: Can I beg your indulgence to take up an administrative matter that I overlooked?

CHAIRMAN CARTER: Okay, no problem.

MR. REHWINKEL: And I am also going to put the company on notice of what I would like to do with respect to two of the three exhibits that I crossed on. I did not ask for those to be given a number, but they probably should.

CHAIRMAN CARTER: Okay.

MR. REHWINKEL: The first exhibit, the CLT, or capital leadership team review document, which is the seven-page document.

CHAIRMAN CARTER: Hang on a second. Let me find that one.

MR. REHWINKEL: That was the first one that I handed out, and it probably should be given a number for identification purposes.

CHAIRMAN CARTER: Let me flip over to my little list here.

MR. YOUNG: Mr. Chairman.

CHAIRMAN CARTER: Mr. Young.

MR. YOUNG: It will be marked as Exhibit Number 110.

CHAIRMAN CARTER: Commissioners for your records, 110. A short title, Mr. Rehwinkel?

MR. REHWINKEL: I would call it CLT Project Review.

CHAIRMAN CARTER: Great. CLT Project Review. Great title. Okay. Now, you had another document?

MR. REHWINKEL: The third document that I offered for cross-examination purposes was the -- it was the adjustments to plant-in-service accounts.

CHAIRMAN CARTER: Is that the one that says comparison of 2007 --

MR. REHWINKEL: Yes, Mr. Chairman, that is a four-page document.

CHAIRMAN CARTER: So, Commissioners, that will be 111. Mr. Young.

MR. YOUNG: If we can get an extra copy of that.

MR. REHWINKEL: I have one. And that's all. Those are the only two. And I apologize for the oversight.

CHAIRMAN CARTER: Hang on. Just hang on for a second. Give me a short title.

MR. REHWINKEL: That would be plant-in-service projections.

CHAIRMAN CARTER: Okay. Plant-in-service projections. Okay.

MR. YOUNG: We have a copy.

CHAIRMAN CARTER: Most of this was in evidence already, right?

MR. REHWINKEL: I believe that --

CHAIRMAN CARTER: And the basis for my question is that I was going to go ahead on and see if there was any objections to admitting it into evidence.

MR. REHWINKEL: Pages 3 through 4 already are because they are a late-filed exhibit to Mr. Chronister's deposition.

CHAIRMAN CARTER: Let's hear from the companies.

MR. WAHLEN: No, we have no objection.

CHAIRMAN CARTER: Any of the parties? Okay. Commissioners, for the record, Exhibit 110 and 111 are entered without objection. Mr. Rehwinkel.

MR. REHWINKEL: Thank you.

(Exhibit Number 110 and 111 marked for identification and admitted into the record.)

CHAIRMAN CARTER: See there, I told you to check your notes. That's all right. Anything further?

MR. REHWINKEL: No. Thank you.

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

MS. KAUFMAN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Good afternoon, Ms. Chronister.

A Good afternoon.

Q I'm Vicki Kaufman. I am going to ask you a couple of questions on behalf of the Florida Industrial Power Users Group. And I want to ask you just a few questions about rate case expense that we have had some discussion about before lunch. You tell us in your direct testimony at Page 40 that you want to collect $3,153,000 in rate case expense, correct?

A Yes.

Q So a little bit over $3 million we are talking about?

A Yes.

Q That the ratepayers -- you want the ratepayers to pick up that relate to you bringing this case for the rate increase?

A Yes.

Q I just wanted to clarify some questions that Commissioner Argenziano had in regard to the Huron amount that is included in your rate case expense, and that is about a third of the $3 million, right?

A Yes.

Q I am correct, am I not, that that project was not the subject of a competitive bid or an RFP?

A I'm not familiar with the exact details of how. I know they evaluated different companies to work with and then chose a company.

Q I might be misremembering this, but I thought you told Commissioner Argenziano that the companies came and made some sort of presentation.

A Right, but I'm not familiar with the details of, you know, exactly the mechanics of it.

Q Would I be correct that the company hasn't provided any information in the record for the parties or the Commissioners to compare the services and prices that Huron is charging versus these other companies that you looked at?

A I don't know the answer to that.

Q Are you aware of there being anything in the record on that?

A I'm not aware of anything.

Q Does Tampa Electric have a tax department?

A Yes.

Q Do you know how many employees are in that department?

A I'm not sure of the exact number.

Q Do you have any feel for how many are in the department?

A Maybe 10 or 12 people.
Q Okay.
A I'm sorry, did you say Tampa Electric, because the tax department is actually a TECO Energy department.
Q So in the TECO Energy tax department they have maybe ten or so employees?
A Yes.
Q Did those employees work on the rate case?
A Not many of them.
Q Did some of them work on the rate case?
A I think a couple of the staff members worked on the rate case, yes.
Q I think you told Mr. Rehwinkel that you were of the view that the company employees could have handled putting together the rate case filing?
A No, I didn't answer that.
Q Do you believe that the current staff could not have put together the rate case filing in this case?
A Yes, I believe that the current staff could not have put together the rate case filing by itself.
Q Okay. But didn't you also testify that many of the employees at Tampa Electric worked on the rate case?
A Yes.
Q How many of the Tampa Electric employees would you guess worked on the rate case filing?

A Well, you're asking me for a guess, so --

Q How about an estimate, if you know.

A I think it has probably touched four or five hundred people.

Q And these are Tampa Electric employees?

A Yes, and some TECO Energy employees.

Q And would I be correct that all the salaries of the Tampa Electric employees are included in your rate case filing here?

A In our normal operating costs, not in the rate case expense bucket.

Q Exactly. Their salaries are included in the rates that you are seeking from the Commission?

A Yes.

Q We also heard about Mr. Harris, who was previously on the stand. Was the project that Mr. Harris participated in regarding the hurricane, was that competitively bid, do you know?

A I don't know.

Q You don't know one way or the other?

A Right, I don't know one way or the other.

Q Is there another witness that might know that?

A I'm not aware of a witness that would know that particular piece of information.

Q And so I guess I would be safe to assume that there is nothing in the record that addresses whether you looked at other companies to perform that work or not?

A Correct.

Q I wanted to talk to you just for a minute about the amortization of the rate case expense as opposed to the actual dollar amount that we have spent some time on. You have suggested a three-year amortization period, right?

A Correct.

Q And Mr. Pollock, FIPUG's witness, and as also Mr. Schultz have suggested five years, right?

A Yes.

Q You agree, don't you, that the last time Tampa Electric was in for a rate case was about 16 years ago?

A Yes.

Q And you also agree, don't you, that we should be trying to match expense -- we should be trying to match expense with the period of time the rates are going to be in effect?

A Yes.

Q You say in your rebuttal testimony at Page 42, Line 16 and 17 --

A Yes.

Q You say you are relatively certain that -- and I am going to just paraphrase it -- Tampa Electric is going to be in for a rate case sooner than five years, right?

A Yes.

Q You don't know when Tampa Electric is going to be in for its next rate case, you do?

A No, not exactly.

Q You don't know if it is going to be five years, or ten years, or 16 years, do you?

A No, I don't. But the reason that I said the sentence that I have here that you pointed out is in relation to my response to Commissioner Edgar, and the fact that we are going to be spending $2.7 billion in capital over the next five years, and so that is what motivated that sentence for me.

Q But you haven't had any discussion with upper management about when TECO might be back for its next rate case?

A No.

Q Mr. Pollock also suggests in his testimony that rather than basing your rate case expense on projections that you should provide the actual invoices, correct?

A Correct.

Q And if I am understanding Exhibit 109, which is going to be late-filed, you are going to be providing the actual expenses and breakdowns of your experts and consultants?

A Correct.

Q And if the Commission chose it could use the actual expenses rather than projected to determine rate case expense and any disallowances, correct?

A Yes, they could, but I wouldn't agree with that methodology, because there is expenses still to be incurred, and it would be more appropriate in a projected test year to use the projected expenses which would include expenditures that haven't been made yet.

Q But you would agree that actual expenses have to be by their nature more accurate than projected expenses, correct?

A No, I think the projection of expenses is more accurate of what the projected total will be in the future. If you use actual now you are actually guaranteeing to have the wrong number if you are planning on having more expenditures in the future.

Q Right, but if the Commission required the company to file its actual expenditures for the rate case, that has to be more accurate than a projection, correct?

A Well, more accurate is a relative term. If you say actual expenditures at this point in time would equal actual expenditures at this point in time then, yes, that would be the most accurate. But if you are saying I have projected expenditures, then the most accurate version of that projected expenditure wouldn't be what I have spent so far, it would be the projected expense.

Q I understand. Let me try to make my question more clear. I'm sorry if I wasn't. If the Commission were to require the company to provide all of its actual expenses whenever they were incurred, at the conclusion when you received your invoices, those numbers would by necessity be more accurate than projections because we know projections are never right on point, right?

A Yes.

Q I just want to follow up on a question or two that Mr. Rehwinkel asked you about the Big Bend rail facility, because I was a little bit confused. If we assume that that facility is not going to come into service until January 2010, would you agree that it is not properly included in a 2009 test year? If you could answer yes or no and then explain, that would be great.

A Okay. Can repeat the question?

Q I can. If we assume that the Big Bend rail facility is not going to come into service until 2010, would you agree that it is improper to include it in a 2009 test year?

A No, I wouldn't agree with that. I still think it is appropriate to evaluate investments and operating costs that will incur during the time proposed rates are in effect. And if that is a significant enough investment or operating cost to affect your return, then it is something the Commission should consider even if the first month of operation was January. I think it would still be proper to have an annualization adjustment.

Q What if it doesn't come into service until June of

2010?

A Based on your hypothetical, it goes back to something that we referred to before, which is that it is within the ability of the Commission to do step increases, and so that affords the opportunity to the Commission to do a step increase at the time the rail facility would go into service.

Q I didn't ask you about a step increase. I am just trying to understand or to explore with you the concept of the test year. And you would agree with me that the test year is supposed to reflect your normal expenses for the test year that the company has chosen, correct?

A Correct, I agree.

Q So if the rail facility doesn't come into service until June 2010, for example, would it still be your view that it is appropriate to include it in the 2009 test year?

A No.

Q It would not be appropriate, correct? A double negative.

A Right. Well, I'm trying to follow -- I'm trying to say yes or no to whatever your question is.

Q And I appreciate that.

A But I think the way I would describe it is if our original projection had the unit being placed in service in the latter part of 2010, that probably would have discouraged us from considering an annualization adjustment. However, the reality for us is that the facility is going into service in December of '09, which makes it an absolutely proper candidate for us to consider annualization for.

Q That is what you are projecting to happen at this point, right?

A It is what we project to happen, what I expect to happen.

Q Do you have the document that I guess it has now been marked Exhibit 110, the capital leadership team project review, do you still have that up there?

A Yes.

Q If you would turn to -- it is the third page, it is Bates-stamped 41052. And are you there?

A Yes.

Q If you look at the third full paragraph it talks about the primary risks of the project?

A Yes.

Q Okay. And would you agree that one of the primary risks of the project that is set forth in this document is the tight schedule to complete the project in time to accommodate the January 1, 2010 start date?

A Yes.

Q I also want to spend a moment talking with you about the transmission base rate adjustment clause. You talked about that in your testimony, correct?

A Correct.

Q And we discussed this some with Mr. Haines yesterday. Did you hear that testimony?

A Bits and pieces.

Q Well, just to be clear, the purpose of the transmission base rate adjustment clause is to allow the company to recover costs for transmission in between rate cases, correct?

A For 230 kV projects, yes.

Q Now, if you turn to Page 44 of your direct testimony, there is a question that begins on Line 12.

A Page 44? Yes.

Q And in your testimony you say that the transmission clause that you are requesting approval for is similar to the generation base rate adjustment clauses approved by the Commission in two other dockets, correct?

A That is correct.

MS. KAUFMAN: Commissioners, I have just distributed, or Mr. Wright is distributing two orders from the two dockets Mr. Chronister has mentioned in his testimony. I think I recall Ms. Helton saying that we don't give these exhibit numbers any longer, and whatever your pleasure is is fine with me. If you would like to mark it, that is fine; if you don't find it necessary, that is fine, as well.

CHAIRMAN CARTER: No. You may proceed.

MS. KAUFMAN: Okay.

BY MS. KAUFMAN:

Q Mr. Chronister, take a look at the Florida Power and Light order, first of all, which is Order Number PSC-05-0902.

A Yes.

Q And this is the final order in the docket that you are referring to in Lines 15 through 17 on your testimony, correct?

A Correct.

Q If you would turn to Page 2 of this order where it is Roman numeral two. Do you see that?

A Yes.

Q And there is basically a summary of the terms of the order there. And would you agree that this order was in the last rate case that Florida Power and Light had before the Commission?

A Yes.

Q And what happened in that case, or the way that case was resolved was a stipulation, correct?

A Correct.

Q And as part of the stipulation, would you agree that Florida Power and light froze its base rates for four years?

A Yes.

Q And would you also agree that as a part of the stipulation Florida Power and Light agreed to a revenue sharing plan with customers?

A Yes.

Q In this case is Tampa Electric offering to freeze its base rates?

A No.

Q Is it offering a revenue sharing plan?

A No.

Q And there certainly hasn't been any settlement between the parties, has there?

A No.

Q Would you agree that in the course of a stipulation settlement there is generally give and take among the parties?

A Yes.

Q And, again, we haven't had that happen in this case, have we?

A Correct.

Q Take a look at the other order, which is in the Progress Energy case. It is Order Number PSC-05-0945. And if you will turn to Page 2, there is a similar summary of what occurred in the last Progress rate case. And as in the Florida Power and Light rate case, you would agree that the Progress case was resolved via a stipulation among the parties?

A Yes.

Q And you would agree that Progress froze its base rates for four years?

A Yes.

Q And you would agree that there was a revenue sharing plan?

A Yes.

Q And in that case would you also agree that the generation adjustment clause applied only to the Hines plant?

A Yes.

Q Now, again, in this case, you are seeking a $228 million increase, right?

A Yes.

Q And there is no stipulation or revenue sharing plan?

A Yes, correct.

MS. KAUFMAN: Thank you, Mr. Chronister. That's all I have.

CHAIRMAN CARTER: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Thank you.

Just one other question on the bad debt issue. The 2009 test year, of course, is higher than the historical average, and I understand why. But, don't we expect that if the economy changes, or when the economy changes, and if it does in 2010 that the expenses will go back down to those historical levels, and what occurs then? Does it drop back down and how does that impact the rates?

THE WITNESS: I can say that there are a lot of factors that affect the write-off percentage. The economic downturn would be one. We actually saw customer behavior begin to change before the economic downturn. We saw our write-off percentages going up even before these recent events.

As of the end of 2008, the write-off percentage was .333, which is very near the write-off percentage that we projected for the year 2009, and much higher than what we projected for the year 2008. So the actual write-off percentage is even outpacing what we had projected.

So, you know, I would expect for there to be an ebb and a flow, but as I understand -- and, again, I'm not an expert in customer service and write-offs, but that even though there is an ebb and a flow, the customer service folks are telling me that there has been a shift towards a higher write-off percentage.

COMMISSIONER ARGENZIANO: So I guess your answer would be you don't think it will drop back down to historical levels?

THE WITNESS: No, I don't think it will drop back down.

COMMISSIONER ARGENZIANO: Thank you.

CHAIRMAN CARTER: Thank you, Commissioner.

Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good afternoon, Mr. Chronister.

A Good afternoon.

Q I don't have very many questions, but I think all of them follow along questions you have been -- follow on either earlier testimony or questions you have been asked already. This is a holdover from yesterday. I asked Mr. Carlson the question what happens if the company were to reach the target level for the storm reserve. My real question is would you then stop accruing money to the reserve or would you keep accruing the 4 million a year assuming that that is where we are?

A The accrual is based on the Commission's instructions to us, and so we are making the accrual from a regulatory accounting standpoint based on the Commission's instructions, but the target is a target and not a cap. And so the idea would be that we would continue to make these accruals. When we got near the target, we would consult with the Commission and really receive instructions from them as to what to do at that point.

Q Okay. Just from my perspective as a representative of customers, if in a given year the accrual were to hit 57 or $58 million, you would keep accruing until the Commission told you to do otherwise?

A Yes, and I would say for two reasons; one is that the

Commission asked us to come back periodically and talk about what a new target should be. And our most recent studies, of course, show that the target should be 120 million. So I think the process was designed -- even back in 1994 when we established the accrual process was designed to revisit that target with the Commission. So as we approached the target there would naturally be interaction with the Commission as to what the proper accrual would be.

Q Thank you. Who either in terms of persons or a company actually prepared the company's tax returns?

A Our tax department prepared our tax returns.

Q And that is the tax department of TECO Energy?

A The TECO Energy tax department, yes.

Q And why did not someone from within the 10 or 12 person tax department of TECO Energy testify in support of the company's tax returns?

A Again, we had the director of our tax department was on a medical leave during this past year, '08.

Q And nobody else in the department could do it in your judgment, is that the fair conclusion?

A I would say that the company decided in her absence that it was appropriate to bring in somebody from the outside, yes.

Q I think you are the man I need to ask this question. You have either been here or been listening in to the whole hearing, have you not? You have either been present or been listening from a remote location to the whole hearing, have you not?

A Yes. I have got to confess that sometimes the Internet connection didn't sync up, so I haven't heard every word.

Q All right. Do you recall hearing Mr. Black testify that the company is reconsidering whether to bring the three CTs that are presently scheduled to become in service in September of this year to a later date?

A Yes, I heard that.

MR. WRIGHT: Mr. Chairman, I would like to ask this witness or the company under whosever sponsorship to prepare a late-filed exhibit that would show the revenue requirement impact if those three combustion turbines were taken out of rate base for the test year altogether.

CHAIRMAN CARTER: That would be Number 112?

MR. WRIGHT: Yes, sir.

CHAIRMAN CARTER: And the title, a short title?

MR. WRIGHT: Revenue impact of removing September CTs from 2009 test year.

CHAIRMAN CARTER: Very well. You may proceed.

MR. WRIGHT: Thank you, Mr. Chairman.

(Late-filed Exhibit Number 112 marked for identification.)

BY MR. WRIGHT:

Q I think it is true that the rest of my questions relate to the discussion we have had about the services provided by Huron Consulting. You did testify that you considered other vendors to provide the services that Huron provided, correct?

A That is correct.

Q Do you know whether any of the other vendors considered have common directors with Tampa Electric or TECO Energy?

A I don't know the answer to that.

Q Can you tell us what -- back up, just a predicate. Mr. Felsenthal testified that he sponsored the seven specific MFR schedules shown in his exhibit, correct? And my question for you following that is can you tell us, the Commission, what, if any, other MFRs Huron prepared for this case?

A It is my understanding that they didn't prepare any other MFRs, but they did review, and check, and consult on the entire population of MFRs.

Q Did Huron assist in witness preparation for this case?

A Yes, I believe they did.

Q Mr. Felsenthal testified in response to a question I asked him on cross that he discussed with company personnel how to respond to discovery requests. Do you recall hearing him give that answer?

A I recall hearing him say that, yes.

Q Would it be fair to say that those discussions had a focus on how to respond in the best light to the company?

A No, I wouldn't describe it that way.

Q What benefit did Huron provide to my members, the retail federation's members, or to the AARP's members? What benefit did they provide to your customers, our members, that justifies over a million dollars of expense?

A The benefit they provided was to make sure that we had an accurate and complete filing, and I think the Commission needs us to do that. And so through their checking and verification process and their consulting it allows us to put together the best case that we can put together, and for customers it is important for there to be a complete and accurate level of detail.

MR. WRIGHT: Thank you. That is all the questions I have, Mr. Chairman.

CHAIRMAN CARTER: Thank you, Mr. Wright.

Mr. Twomey, good afternoon.

MR. TWOMEY: Good afternoon, Mr. Chairman and Commissioners.

CROSS EXAMINATION

BY MR. TWOMEY:

Q Good afternoon, sir.

A Good afternoon.

Q I've got just a couple of questions on your rate case expense and your rate case amortization period. Let me ask you first, are you aware of the fact that in water and sewer cases that rate case expense is amortized over a set number of years and that the collection of the expense ceases once the authorized expense is collected?

A I was not aware of that.

Q Well, that is not the case in the handling of electric utilities in this state, correct?

A I'm sorry, repeat the question.

Q Let me be more clear. That is to say, whatever the approved annual accrual for rate case expense is for the amortization, you get that every year until you have a new case, correct?

A That is correct.

Q So I am advised that in your last rate case the Commission approved rate case expense of $1.4 million and that it was to be amortized over a period of four years, is that correct?

A Yes.

Q And if that is correct, then the approved amortization would be 1.4 million divided by four, which is $350,000, right?

A Correct.

Q Now, you didn't stay out just four years.
A That is correct.
Q You stayed out 16 years, or four times that amount, right?
A That is correct.
Q And then it necessarily follows, does it not, that you would have collected through your rates customer money earmarked for rate case expense four times the 1.4 million, or 5.6 million, correct?
A Yes, in addition to all of the extra costs that occurred over that 16 years as we continued to serve customers.
Q You didn't have any additional rate case expense?
A No.
Q Now, as I understand it, your requested rate case expense in this case is just a little bit more than $3 million?
A Correct.
Q 3.03 or something in that range, right?
A Yes, 3.15.
Q Let's call it $3 million for purposes of discussion here. And the company's requested amortization period is three years which would make a recovery of a million dollars a year if your request is approved.
A Correct.
Q Now, I understand you said just a few moments ago, or you said several times now that you expect to be back in for

another rate case in less than five years, correct?

A Correct.

Q But if that doesn't come to pass and for some reason you stay out for 16 years again, isn't it true that under your requested rate case expense and amortization you would collect $16 million?

A Under the premise of your question, yes.

Q A million dollars a year?

A Yes.

Q And that irrespective of how long you stay out, if you stay out more than three years you will collect a million dollars a year of monies not actually expended on a rate case, this rate case, and not approved by the Commission, correct?

A That is correct.

Q Now, the company as I understand it is requesting a three-year amortization, staff is recommending a four-year amortization, and the intervenors, including AARP, are requesting a five-year amortization, correct?

A Correct.

Q Which number of those three is closest to 16?

A Five.

Q This is not a trick question. Thank you. Now, on the dollar amount, it may not seem like a lot of money in contrast to some other things, but my calculation is that we have already discussed that if you get what you have requested from the Commission in the dollar amounts, and I'm not going to argue with you about what should be approved or not. AARP is supporting the Public Counsel adjustments, but as far as the amortization goes, if you get your approved 3 million and you get your amortization period of three years, we have already said it is one million, right?

A Right.

Q If the staff's number is accepted by the Commission, I believe it would come out to $770,000 a year.

A Correct.

Q And if the intervenors get their requested number, I believe it would come out to -- I wrote down 660,000, but now it looks wrong.

A No, that sounds right.

Q Okay. Well, the point I wanted to make is that -- I'm sorry, it is 600,000, I think. The difference I calculated between your requested amortization and the intervenors' amortization is $400,000 a year, right?

A That sounds correct, yes.

Q Okay. Which is going from our number to your number, your number is roughly 66 percent larger than ours, right?

A You're talking about 400 over the 600?

Q Yes.

A Yes.

Q So that part just in terms of the short number of years and so forth, that is an increment the Commission could look at and say, okay, if we believe the customers' number was correct, the customers would save $400,000 a year?

A Correct.

Q It wouldn't mean you wouldn't recover all the approved rate case expense, it would just occur over an additional period of years?

A Well, no, not if we come back in in three years. In other words, if we pick a four or five-year amortization and we come in in three years, then we would not recover all of the expenses.

Q Well, if you recall, how many years did you tell the Commission 16 years ago that it would take before you came in for a new case?

A I don't know the answer to that question.

Q Okay. Now, if you did come in, let's say the Commission accepted the intervenors' five years, and you came in after three years, your point is that you would have only collected three-fifths of your approved rate case expense, right?

A Correct.

Q If you know, what would your requested treatment be of the unamortized rate case expense if you had a new case and you had two-fifths of your rate case expense not collected?

A I think we would ask for recovery of the amount.

MR. TWOMEY: Thank you. That's all.

CHAIRMAN CARTER: Thank you, Mr. Twomey.

Commissioners, I am going to go to staff. Staff, you're recognized.

MR. YOUNG: Thank you, sir.

CROSS EXAMINATION

BY MR. YOUNG:

Q Good afternoon, Mr. Chronister.

A Good afternoon.

Q Earlier you had a discussion with Mr. Rehwinkel about the comparison of projected versus actual plant balance, and I think that was marked and entered into the record as Exhibit Number 111.

A Yes.

Q Do you remember that discussion?

A Yes.

Q Okay. Let me ask you a question. Would you agree that the variances between projected plant balance and actual plant balance changed the 13-month average of plant balances?

A Not for the test year. The test year is going to be the 13-month average from December of '08 to December of '09, and those exhibits were 2007 and 2008. I think it was through September of 2008. And as I mentioned, when you get to September of 2008, those two $5 billion figures are only different by about $625,000. So, I mean, 625,000 divided by 13 could be the amount you could say that plant-in-service was off by.

Q Okay.

A So maybe $50,000.

Q Okay. Keep that in mind. We are going to come back to that. Let me ask you a question moving to the storm reserves. Mr. Chronister, currently Tampa Electric collects $4 million a year from its customers to accrue in the storm reserves, right, for storm damages?

A Well, we don't collect it directly, but there is a storm damage accrual of 4 million that was set after our last rate case.

Q Okay. And currently Tampa Electric has a target storm accrual reserve of 50 million and has requested it to be raised to a target of 120 million, correct?

A Yes, correct.

Q And is the money -- let me ask you this. Is the money collected from customers each set -- is it set aside and made available for storm restoration use?

A No, it is not set aside. It is an unfunded reserve.

Q Okay. And how is the money collected from the customers for the storm actual -- the actuals used, how is the money used?

A Well, when you have this unfunded reserve, then that liability is the account out of which you would book costs associated with storm restoration. So, there wouldn't be any money collected from your customers at the time the storm occurred. So it is very similar to what happened in 2004 for us where there was $74 million of storm costs. Our reserve at the time had about 42 million, and I need to follow up. We did have a negative storm damage reserve back in 2004, because we had 42 in there and we spent 74. So it went negative by about 30 million. But then we reached a settlement stipulation in which we took $38 million of those storm costs and booked them to capital. And so when you made that $38 million booking, the storm reserve went back to positive, but the storm reserve was significantly negative after the hurricanes of 2004.

But that is how it would work. You would incur storm costs and it would be booked against this liability. There wouldn't be any charge to ratepayers.

Q Okay. Now, the money that you collected, let me ask you this, the money that you collected, is it possible that some of that money was used to pay dividends to the parent company?

A Well, the money that is collected in relation to a storm accrual being part of your operating costs when you set base rates, that base rate collection comes in and it is used for general operations of the business which would include any source or use of cash.

Q And that includes dividends, possibly dividends, paying dividends?

A Possibly, yes.

Q Mr. Chronister, are you familiar with the Uniform System of Accounting as prescribed by electric companies such as Tampa Electric for both the Florida Public Service Commission and FERC, are you familiar with it?

A Yes.

Q Could you please explain where in the system of accounting a company such as Tampa Electric would be allowed to split freight discount or refunds between the credit to utility plant account and the fuel account as you are proposing in this case?

A I can provide a late-filed exhibit that shows you that part of the Code of Federal Regulations that has the U.S. of A in it, but whenever you get a construction reimbursement you are required to book it against the capital account where you spent the money. So, in this particular case you have capital costs that you have incurred and you put it in a particular capital expenditure account. It is a 300 account that flows into Account 101, but you would put it in that 300 account, then when you get the reimbursement you book the reimbursement against that 300 account to create a net number.

It is important to note here it is not CIAC, because CIAC is construction reimbursement that comes from your customer. If your customer asked you to do something like move a pole next to their driveway and they say I am going to pay for that, that is CIAC when a customer asks the electric utility to do that. If it is not a customer, in the case of CSX, it is just called construction reimbursement. It is not CIAC, so there is different accounting for that.

MR. YOUNG: If I can have one second, Mr. Chairman.

CHAIRMAN CARTER: You may.

BY MR. YOUNG:

Q My technical staff analysts just -- I misheard you. Did you state that you had to book it through the technical plant account, it is required? That is what you just stated, right?

A Construction reimbursements need to be booked against the plant account where you put the actual capital expenditures in the first place, yes.

Q Okay, great. Now, let me ask you this. If that is the requirement, how can you move it to the fuel account? Why is TECO proposing to use some of the refund through the fuel account?

A Well, it would be based on the Commission's decision. FAS 71 allows you to do regulatory accounting, which is to say that you have the Uniform System of Accounts, you have your debits and credits the way they are supposed to go, but if the Commission makes a decision for a treatment, then you would follow -- your debits and credits would follow the treatment the Commission told you to use.

So in this particular case, if the Commission said, yes, we agree, take the first part of the construction reimbursement against the capital costs, then take the rest of it through the fuel clause to help our ratepayers, then we would book it against the fuel clause based on the Commission's directive.

Q Do you have your testimony in front of you, sir?

A Direct?

Q Both direct and rebuttal.

A Yes.

Q Looking at Page 26 and 27 of your direct testimony. We are changing subjects, too, by the way. Are you there?

A Yes, I am.

Q All right. On Page 26 and 27 of your direct testimony you discuss the benchmark comparisons for sales expense, correct?

A That is correct.

Q And let me ask you, do I understand your testimony correctly that if certain reclassification of expenses that were ordered by either the FERC or the PCS are taken into consideration, sale expense would be under the benchmark comparison?

A That is correct.

Q And with respect to just the advertising portion of sale expense, is it under the benchmark comparison?

A Yes.

Q Now, the MFR Schedule C-14 --

A Yes.

Q This is a benchmark, right?

A C-14?

Q Yes, the MFR C-14, which is --

A No, C-14 is just a summarization of your advertising expenses.

Q Yes. Now, if MFR Schedule C-14 provides the advertising expenses by subaccounts for the test year and the most recent historical year for each type of advertising that is included in the base rate base cost -- the rate cost, excuse me, of service, is that correct?

A Can you repeat that, I'm sorry?

Q MFR C-14.

A Yes.

Q Okay. MFR Schedule C-14 provides the advertising expense by subaccounts for the test year and the most recent historical year for each type of advertising that is included in the base rate cost of service, correct?

A Correct.

Q These advertising expenses are included more than just -- they include more than just the sales expense category that we discussed before, right?

A That is correct.
Q Okay. Do you know if all of these advertising expenses are under the benchmark analysis?
A Yes, they are.
Q Can you please explain how economic development expense is treated for the test year?
A What we did was we projected our economic development expenses and then followed the rules established by the Commission on what was allowable. And the Commission has various rules, some are allowed 100 percent, some are allowed 95 percent, some are zero percent. So, with each category we projected we flowed that through and only allowed the allowable percentage, the allowable dollars to be included in the filing.
Q Now, earlier you discussed -- you talked about budgets with Mr. Rehwinkel and -- I think with Mr. Rehwinkel. Do you remember that discussion in terms of your budgeting process and all of that stuff?
A Yes.
Q Okay. I'm going to ask you a few questions on that, okay?
A Okay.
Q Who develops TECO's budget?
A It is under my direction, and it is actually an accumulation of input that comes from all over the company.
Q Okay. And would you agree that a major reason for

the budget is to keep expenditures under control?

A That is an important reason for budgeting, yes.

Q And would you agree that -- let me ask you this. What role does the budget play in the rate case?

A I think it is a depiction for the Commission to see the projected operating costs and investment amounts that the company is going to make.

Q What role does the budget play -- what role does the budget play when creating TECO's MFRs?

A It provides the foundational data for populating the MFRs.

Q Would you agree that not every dollar budgeted for the 2009 payroll will be spent?

A You said payroll?

Q Yes, the 2009 payroll.

A Yes, that is true.

MR. YOUNG: If I could have a minute to check my notes, Mr. Chairman. I think I'm almost through.

CHAIRMAN CARTER: Take a moment. Nobody leave. Everybody hold your place.

BY MR. YOUNG:

Q Can we return to Exhibit Number 111?

A I'm sorry, which one is that?

Q Exhibit Number 111 is the actual versus projected plant-in-service balances.

A Yes, okay.

Q Looking at Page 1, do you have that in front of you, sir?

A Page 1, the handwritten Number 1?

Q Yes.

A Okay, yes.

Q All right. For 2007, if you took the average of Column 1 and the average of Column 2, would there be a difference?

A Yes.

Q Okay. Would you agree that even though the actual plant was almost equal to the projected for May and June, the average for the year would be different?

A For 2007, yes.

MR. YOUNG: Thank you, sir. No more questions.

CHAIRMAN CARTER: Hang on a second before we go further. Let me do this. You asked for a placeholder for a late-filed exhibit. Did I understand you to say that? Take a moment, or do you need it?

MR. YOUNG: Yes. I was reminded for the FERC rule.

CHAIRMAN CARTER: Okay. So that will be Exhibit Number 113, and that will -- give me a short title. Let's take a moment.

Commissioner Argenziano, you're recognized.

COMMISSIONER ARGENZIANO: Yes. In Issue Number

97 and 98, one is regarding the $5 late fee. What is the current late fee and what -- let me make sure I've got the right --

MR. WAHLEN: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: I think I'm asking the wrong witness. I'm sorry.

MR. WAHLEN: Mr. Ashburn will be glad to answer that.

COMMISSIONER ARGENZIANO: Actually, I am asking the wrong issue. And the one I wanted to ask has been answered, so that is why -- I will wait. Sorry. I turned two pages instead of one.

THE WITNESS: No problem.

CHAIRMAN CARTER: Mr. Ashburn is next.

MR. YOUNG: Yes, we would like to have that provided. And that will be the FERC rule of accounting.

CHAIRMAN CARTER: FERC rule of accounting. The FERC accounting rule.

MR. WRIGHT: Mr. Chairman.

CHAIRMAN CARTER: Yes, sir. Oh, Mr. Wright.

MR. WRIGHT: If I may, just as a clarifying point on that. Do I understand that the staff are asking for that section of the Code of Federal Regulations that contains the entire FERC Uniform System of Accounts for electric utilities?

CHAIRMAN CARTER: Do you guys need the entire thing or just a section of it?

MR. WRIGHT: If so, you can call it FERC USOA.

CHAIRMAN CARTER: You have been waiting to say that all day long, haven't you?

MR. WRIGHT: Only for about two minutes, Mr. Chairman. Thank you.

MR. YOUNG: Talking to staff, staff can come up with the rule. I think staff can come up with the rule, so we will withdraw that request for the late-filed exhibit.

CHAIRMAN CARTER: And Mr. Wright worked so hard on this. We will just use 113 for something else.

Okay. Commissioners, anything further for the witness? Redirect?

MR. WAHLEN: No redirect. Tampa Electric moves Exhibit 29 into the record.

CHAIRMAN CARTER: Exhibit 29, any objections? Without objection, show it done.

(Exhibit Number 29 admitted into the record.)

CHAIRMAN CARTER: Now, did this witness have any -- he is playing offense and defense. Did he have any rebuttal?

MR. WAHLEN: He had rebuttal testimony, no rebuttal exhibit.

CHAIRMAN CARTER: Okay. You may be excused.

MR. WILLIS: Thank you.

CHAIRMAN CARTER: Call your next witness.

MR. WILLIS: We call Mr. Ashburn.

CHAIRMAN CARTER: William Ashburn.

WILLIAM R. ASHBURN

was called as a witness on behalf of Tampa Electric Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WILLIS:

Q Have you previously been sworn, Mr. Ashburn?

A I'm sorry, say that again.

Q Have you previously been sworn?

A Yes, I was sworn earlier today.

Q Could you please state your name, business address, occupation, and employer?

A My name is William R. Ashburn. My business address is 702 North Franklin Street, Tampa, Florida. I am Director of Pricing and Financial Analysis for Tampa Electric Company.

Q Did you prepare and cause to be prefiled on August 11th the prepared direct testimony of William R. Ashburn consisting of 78 pages?

A Yes.

Q Do you have any additions or corrections to your direct testimony?

A No.

MR. WILLIS: We would request that Mr. Ashburn's direct testimony be inserted into the record as though read.

COMMISSIONER EDGAR: The prefiled testimony of the witness will be entered into the record as though read.

BY MR. WILLIS:

Q Did you prepare an exhibit to your direct testimony entitled Exhibit of William R. Ashburn containing five documents which has been identified as Exhibit 30?

A Yes.

Q Do you have any additions or corrections to your exhibit marked Exhibit 30?

A Yes. My Document Number 1 lists the MFR schedules that I sponsor, and revisions to certain of the A and E MFR schedules which I sponsored were filed on September 9th, 2008. That is specifically the A-2, A-3, E-13A, and E-13C; November 11th, 2008, the E-7 and E-14; on December 1st of 2008, the A-2 and E-14; and on December 29th, the MFR E-13D. In addition, my Document Number 4 was corrected and refiled on December 31st of 2008.

Q Did you prepare and cause to be prefiled on November the 26th the rebuttal testimony of William R. Ashburn?

A Yes.

Q Do you have any additions or corrections to that testimony?

A I made a revision to my rebuttal testimony on December 31st that corrected the location of a bullet on a list that was presented on Page 21, but none of the words changed. It was just an organizational look.

MR. WILLIS: We have provided the court reporter a revised page that conforms with that change.

BY MR. WILLIS:

Q If I were to ask you the questions contained in your rebuttal testimony today, would your answers be the same?

A Yes.

MR. WILLIS: I would ask that the rebuttal testimony of William Ashburn be inserted into the record as though read.

COMMISSIONER EDGAR: The prefiled rebuttal testimony will be entered into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
FILED: 08/11/2008

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM R. ASHBURN

Q. Please state your name, business address, occupation and employer.

A. My name is William R. Ashburn. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director, Pricing and Financial Analysis for Tampa Electric Company ("Tampa Electric" or "company").

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Creighton University with a Bachelor of Science degree in Business Administration. Upon graduation, I joined Ebasco Business Consulting Company where my consulting assignments included the areas of cost allocation, computer software development, electric system inventory and mapping, cost of service filings and property record development. I joined Tampa Electric in 1983 as a Senior Cost Consultant in the Rates and Customer Accounting Department. At Tampa Electric I have held a series of positions with responsibility for embedded and marginal cost of service studies, rate filings, rate design, implementation of new conservation and marketing programs, customer surveys and various state and federal regulatory filings. In March 2001, I was promoted to my current position of Director, Pricing and Financial Analysis in Tampa Electric's Regulatory Affairs Department. I am a member of the Rate and Regulatory Affairs Committee of the Edison Electric Institute ("EEI") and the Rate Committee of the Southeastern Electric Exchange ("SEE").

Q. Have you previously testified before the Florida Public Service Commission ("FPSC" or "Commission")?

A. Yes. I have testified or filed testimony before this Commission in several dockets. I testified for Tampa Electric in Docket No. 000061-EI regarding the company's Commercial/Industrial Service Rider tariff and in Docket No. 020898-EI regarding a self-service wheeling experiment. In Docket Nos. 000824-EI, 001148-EI, 010577-EI and 020898-EI, I testified at different times for Tampa Electric and as a joint witness representing Tampa Electric, Florida Power & Light Company ("FP&L") and Progress Energy Florida Inc. ("PEF") regarding rate and cost support matters related to the GridFlorida proposals. In addition, I have testified for Tampa Electric numerous times at workshops and in other proceedings regarding rate, cost of service and related matters. I have also provided testimony and represented Tampa Electric before the Federal Energy Regulatory Commission ("FERC") in rate and cost of service matters.

Q. Please state the purpose of your direct testimony.

A. The purpose of my direct testimony is to present the proposed rates and service charges that will produce the company's proposed jurisdictional revenue requirement increase of $228,167,000. Specifically, I:

1) Present the development and application of billing determinants and the forecast of base revenues from the sale of electricity and revenues from service charges for the 2008 and 2009 projected periods using present rates, and for 2009 under proposed rates to achieve proposed class revenues;
2) Present the Jurisdictional Separation Study and resultant jurisdictional separation factors utilized for the 2007 historical period and the 2008 and 2009 projected periods that determine the portion of Tampa Electric's system rate base and operating

expenses subject to the jurisdiction of the FPSC and form the basis for the company's proposed revenue requirement;

3) Present the 2009 projected period Retail Class Allocated Cost of Service and Rate of Return Studies that utilize a 12 Coincident Peak ("CP") and 25 Percent Average Demand ("AD") production capacity cost allocation methodology, which I will refer to as 12 CP and 25 Percent AD;

4) Describe the methods employed, facts considered, and principles upon which the Jurisdictional Separation Study and Cost of Service Study were prepared;

5) Provide conclusions regarding the adequacy of the aforementioned studies and the reasonableness of the resulting costs being used to support the proposed rate design; and

6) Explain the development of the company's proposed rate structure modifications, rate designs and new permanent rates, service charges and schedules to be implemented.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, I am sponsoring Exhibit No. ___ (WRA-1) consisting of five documents, prepared under my direction and supervision. These consist of:

Document No.	1	List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By William R. Ashburn
Document No.	2	Proposed Rate Schedule Changes
Document No.	3	Comparison Of Class Allocated Cost Of Service Study Results Test Period: 2009
Document No.	4	Development Of Target Proposed Revenue Increase By Class Test Period: 2009
Document No.	5	Summary Of Resultant Proposed Class Parity Ratios And Rates Of Return Test Period: 2009

Q. Are you sponsoring any sections of Tampa Electric's Minimum Filing Requirements ("MFRs")?

A. Yes. I am sponsoring or co-sponsoring the MFRs shown in Document No. 1 of my exhibit.

Q. Are Tampa Electric's billing determinants, forecast of base revenues from the sale of electricity and service charges, Jurisdictional Separation Study, Cost of Service Study, proposed rate design and new permanent rate schedules provided as part of Tampa Electric's MFRs?

A. Yes, they are provided within the portion of the MFRs designated Section E, "Rate Schedules". I have provided the Jurisdictional Separation Study and two sets of Cost of Service Studies as well as work papers in separate bound volumes due to their voluminous size. Volume I contains the Jurisdictional Separation Study and workpapers. Volume II contains the Cost of Service Studies utilizing the MFR required 12 CP and 1/13 AD methodology with present and proposed rates. Volume III contains the Cost of Service Studies utilizing the company's proposed 12 CP and 25 percent AD methodology with present and proposed rates. Volume IV contains the company's Lighting Incremental Cost Study prepared in support of the lighting rate design, which is a supplement to MFR Schedule E-13d.

Q. What are the company's primary goals for the proposed rate design changes in this case?

A. While many specific changes are proposed, there are three primary goals. The first goal is to provide interruptible service to all general service customers desiring to take such service on a cost-effective rate schedule. This will be accomplished by permanently eliminating the company's present interruptible service rate schedules, which are closed to new business, and transferring all customers to firm base rate service with the opportunity to take service under the company's interruptible conservation programs, GSLM-2 and GSLM-3. All present demand rate schedules, which consist of General Service - Demand ("GSD"), General Service - Large Demand ("GSLD"), and Interruptible Service("IS") will be combined into one new proposed GSD rate schedule. The effect of this proposal has consequences to both cost of service and rate design, including the cost recovery clauses, which normally would not be affected within a base rate filing. This alternative costing treatment for IS customers originated from the company's last rate case (Docket No. 920324-EI) when Tampa Electric was ordered (Order No. PSC-93-0165-ROR-EI) to file in this proceeding "…a cost study which allocates costs to this class(es) [IS] based on their load characteristics and a study which develops a Coincident CP kW credit based on avoided cost…".

The second goal is to implement a conservation-oriented price incentive through an inverted rate structure for the standard residential service ("RS") rate schedule. This two-block, inverted rate design provides an appropriate price signal to customers regarding their energy usage and serves as motivation for increased energy conservation.

The third goal is to create a single lighting service ("LS-1") rate schedule under which all customers currently served would take service. This consolidates the High Pressure Sodium ("HPS") General Outdoor Lighting Service ("OL-1"), Premium Outdoor Lighting Service ("OL-3") and HPS Street Lighting Service ("SL-2") rate schedules. This consolidation into one rate schedule provides a more uniform rate application for similar or like facilities offered presently under three rate schedules.

Document No. 2 of my exhibit provides a diagrammatic overview of the changes described above as well as other changes I describe later and their impacts on present rate schedules.

BILLING DETERMINANTS

Q. Please explain the term billing determinants.

A. Billing determinants are the parameters for billing to which prices are applied to derive billed revenues. They include: 1) the number of customers (*i.e.* bills) to which the customer charges are applied, 2) the amount of energy or kilowatt-hours ("kWh") sold to which the energy charges are applied, and 3) the amount of demand or kilowatts ("kW") to which the demand charges are applied. They also include the number of units to which any additional charges, discounts and/or penalties are applied. Some rate schedules are only billed using customer and kWh billing determinants, while others may include a kW billing determinant as well. Lighting schedules are billed based on lighting facility billing determinants (*e.g.* pole and fixture) along with kWh.

Q. Where are the billing determinants found in the company's filing?

A. Billing determinants for present and proposed rates are contained in MFR Schedules E-13c and E-13d.

Q. How were the billing determinants derived?

A. The basis for the billing determinants by rate schedule is historical billing data maintained by Tampa Electric's Customer Information System. Details of the derivation of these numbers are explained in MFR Schedule E-15. The foundation for the billing determinants was the company's customer, peak demand and energy sales forecasts for test year 2009, which are supported in Tampa Electric witness Lorraine L. Cifuentes' direct testimony. The forecasts produce the number of customers, energy consumption and demand by revenue classifications of residential, commercial, industrial, public street and highway lighting, and sales to public authorities. Witness Cifuentes also forecasts the expected requirements for phosphate industry load which is volatile year over year and is a significant portion of energy sales by the company.

The next step was to distribute the forecasts of customers and kWh sales to rate schedule classifications. This distribution was made in proportion to customer and sales relationships of revenue classifications to rate schedule classifications that were experienced in recent years by analyzing data for the years 2003 through 2007.

Historical customer and kWh sales relationships were also established for other billing units in each rate schedule. These relationships were applied to the apportioned number of customers and sales of each respective rate schedule to derive the various other billing units, including billing demands, time-of-day rate billing quantities, and metering and service voltage level distinctions, as well as various other billing quantities subject to additional charges or credits.

Q. Were the projected billing determinants impacted by the recently approved net metering Florida Administrative Code rule, Rule No. 25-6.065?

A. No. The development of the billing determinants was not impacted by the new net metering rule. Tampa Electric currently only has 13 customers for which the rule applies. The impact of net metering is not expected to materially affect the projected 2009 billing determinants. However, should net metering become more prevalent in future periods, the impact on the billing determinants will be captured.

Q. How were these billing determinants used?

A. The forecasted billing determinants were applied to current rates to calculate the base revenues from the sale of electricity for the 2009 test year based on present rates.

Q. Were these same billing determinants used to derive the base revenues from the sale of electricity for the 2009 test year based on proposed rates?

A. In part, yes. They provided the initial basis for the derivation of billing determinants; however, they were adjusted to reflect the proposed rate design, which combines certain current rate schedules, eliminates others, and creates some new differentiation in charges. In addition, because of the proposed changes in rate design, certain customers were transferred from their current rate schedule to a new rate schedule, either because of schedule parameters or because of other rate options.

Q. Will customers who are transferred or who may benefit from transfer under the proposed rate changes be informed of the proposed changes in order to assist them with making the appropriate rate choice?

A. Yes. Multiple means will be employed to inform customers of these changes and their options, depending on the size of the customer group being affected and the type of choices available. Some customers will be contacted directly by company representatives through phone calls or visits as well as by bill inserts. Others will be informed through direct mail letters and bill inserts.

FORECAST OF BASE REVENUES AND SERVICE CHARGES

Q. Did the company prepare a forecast of base revenues from the sale of electricity for 2009? If so, how was the forecast of base revenues derived?

A. Yes. The base 2009 revenue forecast for present and proposed rates is presented in MFR Schedule E-13a. The rates currently in effect were applied to the forecasted billing determinants to derive total annual base revenues forecasted for the 2009 test year before the proposed change in rates were considered.

Q. What is the projected retail billed electric revenues for 2009?

A. The projected retail billed electric revenues shown in MFR Schedule E-13a for 2009 is $837,851,000 under present rates and $1,059,231,000 under proposed rates, an increase of $221,380,000.

Q. The revenues you just described are for billed sales. Does the company make a calculation for unbilled sales?

A. Yes. For the 2009 test period, an amount of unbilled revenues has been determined to be a negative $1,139,000 under present rates, and a negative $1,440,000 under proposed rates, resulting in a negative $301,000 for unbilled sales.

Q. Did the company prepare a forecast of service charge revenues? If so, how was the forecast of service charge revenues derived?

A. Yes. The 2009 forecast of service charge revenues for present and proposed rates is presented in MFR Schedule E-13b. The current effective rates were applied to the forecasted billing determinants to derive service charge revenues. This represents the forecasted amount of service charge revenues before any proposed change to rates is considered.

Q. What is the projected billed service charge revenue for 2009?

A. The projected retail billed service charge revenue shown in MFR Schedule E-13b for 2009 is $12,785,000 under present rates and $19,902,000 under proposed rates, an increase of $7,117,000 million.

Q. What is the total amount of additional base revenues from the sale of electricity and service charges the company is requesting as a permanent increase?

A. The total amount is $228,167,000 in additional revenues in 2009. This is comprised of $221,380,000 of additional billed electric base sales revenues, negative $301,000 of additional unbilled electric base sales revenues, and $7,117,000 of additional service charge revenues.

JURISDICTIONAL SEPARATION STUDY

Q. What is a Jurisdictional Separation Study?

A. A Jurisdictional Separation Study allocates costs between the company's wholesale and retail customers or jurisdictions. While all costs are allocated, the allocation of joint costs is the focal point of the study. Joint or common costs are costs that serve many customers at the same time. One example is a generating plant that provides power not only to one customer or one group of customers, but to the aggregate load requirements of all power customers on the company's system. The joint costs of the generating plant are recorded on the company's books and records in total and the Jurisdictional Separation Study allocates the joint costs between retail and wholesale customers. Only the costs associated with retail customers are applicable in this proceeding.

The Jurisdictional Separation Study allocates revenue, rate base and operating expense items, whether jointly or specifically assigned to a single jurisdiction, to derive the company's retail jurisdiction cost of service for the test period. Costs are first functionalized, then classified, and finally allocated between the wholesale and retail jurisdictions. These allocations utilize load and other factors that best represent each jurisdiction's cost responsibility to achieve this purpose. A description of how costs are functionalized, classified and allocated is provided below. The overall methodology is the same in both the Jurisdictional Separation Study and the Retail Cost of Service Studies, which I discuss later.

Q. Why is it necessary to prepare a Jurisdictional Separation Study for Tampa Electric?

A. Since early 1991, Tampa Electric has provided wholesale and transmission service to some municipalities in Florida at rates that are under the jurisdiction of the

FERC. Although the company operates in two regulatory jurisdictions, its investments, revenue, and expenses are maintained on a total company basis in accordance with the Uniform System of Accounts prescribed by the FERC and the FPSC. The Jurisdictional Separation Study is designed to directly assign or allocate total system costs.

Q. Is the Jurisdictional Separation Study provided in this proceeding consistent with Tampa Electric's previous Commission filings and industry practice?

A. Yes. Tampa Electric provided a Jurisdictional Separation Study in its last base rate proceeding that led to an approved methodology by the FPSC. That methodology has been utilized to produce separation factors for the annual projected surveillance reports, which are the same factors that have been used as separation factors for the 2007 and 2008 MFRs. Some specifically identified changes to the previous methodology have been utilized for the 2009 test year.

Q. What are the changes?

A. The majority of the changes incorporated in the company's

2009 Jurisdictional Separation Study relate to the transmission function and were made to comply with current FERC and FPSC orders and practices. The first change is to treat generator step-up facilities as a production capacity related function rather than a transmission capacity related function where they are booked in the accounting records. In addition, the previous functions of transmission and subtransmission have been consolidated and their associated costs are jurisdictionally separated based on a total rolled-in allocation approach rather than attempting to establish direct assignments. Finally, firm transmission service provided under the Open Access Transmission Tariff ("OATT") is treated as having cost responsibility and is allocated costs and assigned revenues rather than being treated as a revenue credit.

Both the FERC and this Commission have used the coincident peak loads for the 12 monthly peaks ("12 CP") methodology for allocating power supply and transmission costs and the 12 CP methodology was used for the jurisdictional separation in this study. MFR Schedule E-1 directs that the Jurisdictional Separation Study utilize the 12 CP methodology.

Q. What were the major steps followed in performing the Jurisdictional Separation Study?

A. There are several steps in preparing the Jurisdictional Separation Study. First, the company's accounting information provided by FERC account, shown in the MFR Schedules B, C and D, is adjusted for the test period. The accounts are then functionalized into production, transmission, distribution, and general functions. Next, they are classified into demand, energy or customer groups. After classification, the groupings are allocated into the retail and wholesale jurisdictions using allocation factors. The allocation factors are predominantly based on demand data for the retail and wholesale jurisdictions during the time of the company's projected system monthly peaks, although other factors are utilized that directly allocate certain costs to the specific jurisdiction for which the costs are incurred. In addition, other metrics such as energy sales and number of customers are utilized.

Q. What wholesale customers are included in the test period?

A. For the 2009 test year, Tampa Electric will provide wholesale requirements electric power and transmission service to the cities of Reedy Creek, St. Cloud and Wauchula as well as to Progress Energy Florida, Inc. ("PEF") for a contract that was originally provided to the City of Sebring that PEF took over in 1993. In addition, transmission service provided under the OATT and a pre-OATT transmission agreement with Auburndale Power Partners are included as wholesale customers for jurisdictional separation.

Q. Please summarize the results of the Jurisdictional Separation Study.

A. In 2009, the retail business represents the vast majority of the electric service provided by Tampa Electric. As the results show in Volume I, Jurisdictional Study, the retail business is responsible for 96.3 percent of production plant, 82.3 percent of transmission plant and nearly 100 percent of distribution plant.

COST OF SERVICE STUDY

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

A. The Cost of Service Study is an extension of the Jurisdictional Separation Study. It starts with the retail separated costs derived from the Jurisdictional Separation Study and further allocates and assigns costs to individual retail rate classes. These rate classes represent relatively homogeneous groups of customers having similar service requirements and usage characteristics. Typically, the prices charged for service to different rate classes vary based upon cost of service as well as other factors. Allocations of costs to each of these groups, like the jurisdictional separation, are based upon the results of cost analysis. The Cost of Service Study results are considered, along with other factors described below, in the allocation of the revenue requirement among rate classes when designing rates. The study provides class rates of return at present and proposed rates, class revenue surplus or deficiency from full cost of service, and functional unit cost information for use in rate design. Thus, the study serves as an important factor in determining the revenue requirement by rate class, as well as the specific charges for each rate schedule.

Q. What retail rate classes were used in the preparation of the Cost of Service Study?

A. For purposes of preparing the Cost of Service Study using present rates, existing retail rate classes were used. The rate classes utilized are: 1) Residential, 2) General Service Non-Demand, 3) General Service Demand, 4) General Service Large Demand, 5) Interruptible, and 6) Lighting Energy and Facilities.

For purposes of preparing the proposed rates, the Cost of Service Study presents a different set of retail rate classes. They are: 1) Residential, 2) General Service Non-Demand, 3) General Service Demand, and 4) Lighting Energy and Facilities.

Q. Why are there two columns of information presented under the present and proposed rates in the Cost of Service Studies for lighting service - Lighting Energy and Lighting Facilities?

A. Dividing the lighting rate class into the two components provides better unit cost information for designing the energy and facilities components of this rate class.

Q. Why are the GSLD and IS rate classes omitted in the proposed rates Cost of Service Study?

A. As I previously stated, the company is proposing to combine the GSD, GSLD and IS rate schedules into a new GSD rate schedule. The proposed rates Cost of Service Study shows only the new GSD class to reflect the proposed rate design as well as the combined class rate of return results.

Q. How is the Cost of Service Study used as a guide in rate design?

A. Cost of service studies are useful in the design of rates to help ensure that the prices customers pay for electric service bear a reasonable relationship to the costs of providing that service. Costing and pricing are two distinct and separate steps in the rate making process. Costing attempts to objectively determine costs incurred in rendering service to the rate classes. While economic considerations and other subjective factors may be considered in the ultimate design of rates, cost of service should be the paramount consideration and the Cost of Service Study provides this information. I describe more fully the rate design process later in my direct testimony.

Q. What were the next steps in the Cost of Service Study process?

A. Similar to the Jurisdictional Separation Study, the development of cost of service studies consists of: 1) grouping all costs by function (functionalization), 2) classifying the functionalized costs by causal service characteristics (classification), and 3) apportioning the resulting classified costs to rate classes (allocation).

Q. How were Tampa Electric's costs functionalized?

A. The Uniform System of Accounts divides utility plant into the broad functions of production, transmission, distribution, and general. O&M and other expenses are functionalized in a comparable manner. This approach was utilized to functionalize Tampa Electric's costs.

Q. How were Tampa Electric's costs classified after they were functionalized?

A. Tampa Electric's operations are classified into three categories - demand, energy and customer cost. Demand cost is a function of the capacity of plant, which in turn depends on the maximum kW for power by customers. Energy cost is a function of the kWh volume consumed by customers over time. Customer cost is a function of the number of customers service is provided to by the company.

Similarly, Tampa Electric's cost of service is measured by these same three cost categories: demand, energy, and customer and the three categories are appropriately called cost causations. The assignment of costs to these cost causation categories is called classification. Once classified, Tampa Electric's costs are then allocated to retail rate classes based upon cost behavior.

Q. Are all of the company's production plant facilities classified as demand related?

A. No. For purposes of jurisdictional separation, all production plant facilities are classified as demand-related consistent with prior jurisdictional separation practices. However, there are portions of two production facilities that are reclassified as energy related for purposes of allocating the FPSC jurisdictional component of these facilities on an energy basis. These facilities consist of the gasifier train equipment ("gasifier") for Polk Unit 1 and the scrubber portion of the environmental equipment for Big Bend Unit 4. Polk Unit 1 is an Integrated Gasified Combined Cycle ("IGCC") plant which has two main sections - the power block, which produces the power through gas turbines and heat recovery steam generators, and the gasifier, which converts coal as the fuel feedstock into gas used in the power block. The gasifier performs a fuel conversion function that is completely associated with the provision of fuel to the unit and not the supply of capacity.

The classification of the Big Bend Unit 4 scrubber as energy-related was applied in Tampa Electric's last approved cost of service study. This treatment remains appropriate because the main purpose of the plant investment is related to energy output. Since the decision to classify the scrubber investment as energy-related, additional scrubber and Selective Catalytic Removal ("SCR") investments made by the company have been recovered through the Environmental Cost Recovery Clause ("ECRC") where they have been classified and allocated on an energy basis. Customers benefit from lower energy costs as the result of these investments, not primarily because of their contribution to system peak.

Q. How were costs allocated after they were functionalized and classified?

A. After determining the functionalization and classification of costs based upon causation, the tools for cost apportionment to classes were determined. These tools, called allocation factors, were used to measure demand, energy and customer cost responsibilities. The derivation of the allocation factors used in the 2009 Cost of Service Study is documented in MFR Schedule E-10.

Q. What are the principal considerations when allocating demand costs?

A. The principal considerations in allocating demand costs include: 1) customer demand usage characteristics and their related responsibility for system coincident and non-coincident peaks, 2) the design and configuration of production, transmission and distribution facilities, and 3) unique customer service and/or reliability requirements and system operating data. These considerations provide guidance in determining what components should be used to derive the demand factor. Coincident peak demands, non-coincident peak demands ("NCP"), customer demands, and percentage of energy have been used to best represent those considerations.

Q. Please explain CP, NCP and customer peak demand.

A. Coincident Peak or CP demand reflects a class contribution to the total system monthly peak demand. For example, at the hour of the system peak in one particular month, the CP demand for the residential class would be that class' proportion of that hour's peak demand. NCP demand reflects the monthly peak demand of a class on its own as a group, regardless of when the system peak occurs. For example, a class may peak during the nighttime hours, while the system may peak during the late afternoon. The NCP for that class would be the demand during that nighttime hour. Customer peak demand is the aggregation of all individual customers' monthly peak demands, regardless of when they occur. These different measurements of demand are utilized to allocate different cost elements because those elements represent the best way of identifying what causes certain costs to be incurred.

Q. Please explain the treatment of demand allocated costs in the Cost of Service Study.

A. The Cost of Service Study required by the MFRs allocates production demand costs according to the 12 CP and 1/13 AD methodology. This was the approved methodology in the company's last rate proceeding. Under this method, approximately 92 percent or 12/13 of the production demand classified costs are allocated on a 12 CP basis (i.e. the 12 coincident peak demands for the projected test year) and approximately eight percent or 1/13, is allocated on an energy basis. However, the company proposes that the Cost of Service Study used for rate design be modified from the MFR methodology to the 12 CP and 25 percent AD methodology applied to the production demand classified costs to better reflect cost causation. For both methods, transmission demand classified costs are allocated on a 12 CP basis while distribution demand classified costs are allocated on a mixture of NCP and customer demand bases. These allocation approaches are consistent between the two studies.

Q. Why is the company proposing a 12 CP and 25 percent AD methodology for allocation of production demand classified costs?

A. This proposed methodology provides a more appropriate classification and allocation of production plant within the Cost of Service Study when considering how power plants are planned and operated in Florida in response to customer energy and demand needs. The appropriate percentage of production demand classified plant to be allocated on energy has been a debate in Florida for many decades. The percentage in prior Commission-approved studies for Tampa Electric have ranged from eight percent (derived using the 1/13 portion of the 12 CP and 1/13 AD methodology) to over 70 percent (derived from the Equivalent Peaker method approved in 1985). The debate over what is the appropriate percent to be allocated is about how much of the fixed production plant cost is incurred to meet system peak demand and how much is incurred to reduce variable operating costs, primarily fuel, by running the plant beyond peak demand periods. The higher the percentage of average demand applied, the more cost responsibility is allocated to higher load factor customers, and to IS customers under the current rate structure.

Q. Is the type of generation installed important in the selection of the appropriate production demand allocation methodology?

A. Yes, most definitely. The company has installed a significant amount of base- and intermediate-load generation which was more expensive to install than peaking generation, but less expensive to operate over time (including fuel). The base- and intermediate-load generators provide lower fuel costs for each unit of energy produced compared to peakers. Investment in more expensive generating units and associated equipment to provide more efficient fuel conversion for the generation of electricity drives the need to use a greater energy allocation (*i.e.* 25 percent) within the production demand classified cost allocator. The 25 percent represents a balance between the inadequate 12 CP and 1/13 AD and Equivalent Peaker methodologies. Use of the 12 CP and 25 percent AD methodology allocates production demand classified costs to classes in closer proportion to the energy-based benefits those classes receive from those costs. The 12 CP and 25 percent AD methodology, together with the energy classification to certain investments such as the gasifier and Big Bend scrubber equipment described earlier, are essential in capturing the production cost impact of higher load factor and interruptible customers who benefit from the lower variable costs of base- and intermediate-load units.

Q. Would the adoption of the 12 CP and 25 percent AD methodology have implications for other cost recovery mechanisms?

A. Yes. Environmental investment recovered through the ECRC should continue to be classified and allocated on the energy allocator and the remaining production demand classified costs should be allocated on the basis of 12 CP and 25 percent AD methodology. Similarly, this methodology should be utilized in the other cost recovery clauses for allocation of production demand classified costs to classes.

Q. Has the Commission previously deviated from the 12 CP and 1/13 AD methodology in a base rate proceeding?

A. Yes. As I referred to previously, the Commission relied on the Equivalent Peaker method in Docket No. 850246-EI, Tampa Electric's 1985 base rate proceeding. Also, in FP&L's base rate proceedings, in Docket Nos. 770316-EU and 830465-EI, the Commission approved the allocation of a portion of new nuclear unit production demand classified costs on an energy basis to recognize the fuel savings afforded by their nuclear investment.

Q. Have you prepared an exhibit that compares the results of the two methodologies?

A. Yes. Document No. 3 of my exhibit provides a summary comparison of the class cost of service results of the 12

CP and 1/13 AD and 12 CP and 25 percent AD methodologies, and calculates the difference in class revenue requirements for the RS, GS, GSD, and LS rate classes.

Q. Please explain how transmission and distribution costs were treated in the Cost of Service Studies versus how they were treated in the company's last base rate proceeding.

A. The effects of the transmission facility changes that were made in the Jurisdictional Separation Study are further extended to the allocations within the retail classes. These changes include: 1) a total rolled-in cost allocation of Tampa Electric's transmission and subtransmission facilities, 2) generator step-up facilities treated as production capacity related cost, and 3) wholesale firm transmission service sharing in cost responsibility rather than being treated as a revenue credit to cost of service. The changes reflect current Commission practices and are consistent with the cost support provided by the company before FERC in establishing its OATT.

One particular refinement that has been incorporated in the Cost of Service Studies prepared for this case is associated with the treatment of distribution plant. The new Cost of Service Studies eliminate consideration of directly assigning costs to rate classes for specific service from the distribution networks installed and operated by the company in the downtown and Tampa International Airport areas. Previous efforts to perform such analyses were difficult, incomplete, and did not provide measurable benefit to the cost of service analysis. For the studies presented in this case, an average cost allocation of all distribution facilities to the retail classes has been applied and is a more appropriate methodology.

A number of other refinements were made to the classification of costs utilized in previous cost of service studies to be more consistent with the classifications suggested by National Association of Regulatory Utility Commission guidelines in their Electric Utility Cost Allocation Manual. These refinements were primarily related to the classification of production O&M and administrative and general costs.

Q. How were energy and customer costs allocated?

A. Annual energy consumption of the classes is used for allocating energy-classified costs. Such consumption must reflect the level at which it is consumed for allocation, either at the meter or generator. The weighted number of customers or customer bills during the year is used for allocating customer-related costs.

Q. Do Tampa Electric's 12 CP and 25 percent AD methodology Cost of Service Studies reasonably allocate costs between rate classes within the retail jurisdiction?

A. Yes. All of the filed studies comply with Commission rules and regulations. The 12 CP and 25 percent AD methodology Cost of Service Studies produce reasonable and appropriate allocations of the costs to serve the retail rate classes.

Q. In preparing the Cost of Service Studies, did the company consider demand-side management ("DSM") programs as an alternative costing treatment for IS customers?

A. Yes. As previously stated, in Tampa Electric's last rate proceeding, the company was ordered in Commission Order No. PSC-93-0165-ROR-EI, as it relates to the IS rate class, to file in the company's next rate proceeding:

"…a cost study which allocates costs to this class(es) based on their load characteristics and a study which develops a Coincident CP kW credit based on avoided cost…".

Q. What DSM treatment is the company providing as an alternative to cost of service treatment for IS customers in complying with this prior order?

A. The company is providing and proposing that the GSLM-2 and GSLM-3 interruptible conservation programs, which are service riders to the GSD rate schedule, be utilized to provide current and future service to general service interruptible customers. Consequently, the IS class in the 2009 proposed rates Cost of Service Study has been eliminated to reflect the transfer of all such customers to the GSD rate schedule and the GSLM-2 or GSLM-3 service riders. By transferring IS rate schedule customers to the firm GSD rate schedule and their taking service under the two interruptible conservation programs, GSLM-2 and GSLM-3, the current IS customers are combined with the GSD customers in the 2009 proposed rates Cost of Service Studies. I provide a detailed description of this rate treatment later in my direct testimony.

Q. In the present rates Cost of Service Study, there is a column for GSLD that is not in the proposed rates Cost of Service Study. Please explain this change.

A. Because the company is also proposing to combine the GSLD rate into the GSD rate schedule, there is no longer a need to include a GSLD column in the Cost of Service Study for proposed rates. The present GSD and GSLD base rate charges for energy and demand are nearly identical, with the only real difference being the customer charge that reflects the different percentage of customers taking service at a higher voltage level, and the application of a power factor clause for GSLD. The customer charge difference becomes moot with the proposed design of voltage level customer charges for the combined GSD rate, and it better reflects the metering costs to the customers who cause them. The power factor can be accommodated in the newly combined GSD rate by simply making it applicable to customers who exceed the 1,000 kW threshold that was applied under the present rates. With these rate design changes, it is reasonable and appropriate to combine the rate schedules.

RATE DESIGN

Q. What criteria and objectives were used in designing the new rate schedules and how were they used in the rate design?

A. The basic criteria used in designing Tampa Electric's new rate schedules included: 1) cost to serve the various classes, 2) rate history, 3) public acceptance of rate structures, 4) customer understanding and ease of application, 5) consumption and load characteristics of the classes, and 6) revenue stability and continuity. This Commission has recognized these criteria as appropriate rate design criteria.

Cost to serve is a major consideration in rate design and in the preparation of the Cost of Service Study. The utilization of derived unit cost is a major tool utilized in the design of the company's proposed rates.

Rate history is another important tool. This includes understanding how Tampa Electric rates were designed in the past, whether they have achieved their intended objectives and what rate structures have been successfully applied in Florida and around the country by other utilities. I have worked in the regulatory area at Tampa Electric for almost 25 years and am well aware of the company's rate history. In addition, I track rate decisions made by the Commission that affect other jurisdictional electric utilities and participate frequently in EEI and SEE rate committee meetings where alternative rate designs, as well as successes and failures of such rates, are discussed.

Public acceptance of rate structures, customer understanding, and ease of application are important considerations. I obtain information from frequent contact with the company's customer service team members and interaction with some customers that I factor into my work.

Class consumption and load characteristics are utilized both within the Cost of Service Study as well as in the proposed design in developing appropriate projected billing determinants to assure successful recovery of revenue requirements. Revenue stability and continuity are criteria that factor into the rate design when selection of appropriate billing units to apply under the rates is considered, as well as the appropriate forecast of those billing units.

Q. With these criteria in mind, did the company have specific objectives that were considered in the proposed rate design?

A. Yes. First and foremost, rates should be designed for each rate schedule such that their application to the test year billing determinants produces the target class revenues. There are five other specific objectives that the company sought to accomplish: 1) to design rates, especially for the residential class, that produce conservation-oriented price signals, 2) to provide interruptible service to new and existing customers on a cost effective rate, 3) to eliminate duplicative demand billed rate schedules and combine these under a single rate schedule, 4) to establish time-of-day rates for GS and GSD service to provide a greater incentive to shift energy consumption to the off-peak period, and 5) to reorganize the company's three lighting service rate schedules into a single lighting rate schedule that will facilitate more efficient and understandable rates and services while recognizing the common cost of providing that service.

Q. Were these objectives met in the design of the company's proposed rates and tariffs?

A. Yes. The proposed rates and tariffs incorporate all five of these objectives.

Q. Were the new rates designed to produce the requested additional revenues?

A. Yes. The proposed rate schedules shown in MFR Schedule E-14 present new rates designed to produce $228,196,000 in additional revenues. This consists of $221,380,000 of additional billed electric base sales revenues, negative $301,000 of additional unbilled electric base sales revenues, and $7,117,000 of additional service charge revenues. The proposed rates total the company's revenue requirements.

PROPOSED SERVICE CHARGES

Q. What was your first step in designing rates and charges to produce the company's revenue requirement?

A. The first step was to determine service charges. Cost support for all service charges is provided in MFR Schedule E-13b. The service charges requested include three new tariff charges along with revisions to the existing tariff charges. In total, the requested changes produce $7,117,000 in additional revenue. These revenues serve as a credit to offset a portion of the revenue requirement that would otherwise increase the company's base rates.

Q. Please describe the three new service charges.

A. Two of the new charges provide a convenience service option for customers seeking to reconnect electric service on an accelerated basis or after normal business hours. The first is a Connection Charge applied to the re-establishment of service to accommodate a special customer request for same day service. Such special requests must be made prior to 6:00 P.M. of that day. Currently customers receive re-establishment of service on the next business day. This Connection Charge will cost $40 more than the proposed fee for standard connection, but will provide a convenience option for customers who are in need of more immediate service.

The second new charge is for the re-establishment of service on Saturdays from 8:00 A.M. to 12:00 noon, to accommodate special customer requests. Such special requests must be made by 12:00 noon on the prior Friday. Currently, connections are only made during normal business days and providing this new service for a Saturday connection will necessitate calling out crews to perform the work. While this option is being offered at a price that is $275 more than the proposed fee for standard connection, it will provide another option for customers who desire more immediate connection service and are willing to pay the additional cost.

The third new charge is a Tampering Charge applicable to customers whose unauthorized use of service is discovered and associated investigative costs and damages are limited and minimal. The current tariff provides that charges may be assessed based on unauthorized or fraudulent use, but this charge is not intended for instances where a detailed and full investigation is required to determine the exact amount of such use. In these instances, Tampa Electric will continue its practice of identifying the actual costs and assessing them as authorized by the tariff. The new charge is designed to recover the costs of discovering and confirming tampering where the cost of investigating and estimating is greater than the damages. This charge is being established to simplify the calculation of charges in cases when investigation and further analysis is not cost effective or warranted.

Q. What changes are being proposed for the company's existing service charges?

A. With the exception of the Late Payment and Returned Check charges, all existing charges have increased to reflect the increased cost of providing the services. The proposed increases result in reasonable service charges.

While there is no proposed change to the Late Payment charge itself, the company is proposing that a $5.00 minimum charge be established for all bills subject to a late payment of $10.00 or more. Such a minimum has already been approved by the Commission for PEF, FP&L and, most recently for, Florida Public Utilities Company.

The company is also proposing a change to the tariff language for the Returned Check Charge to read, "A Returned Check Charge as allowed by Section 68.065, Florida Statutes, shall apply for each check or draft dishonored by the bank upon which it is drawn." Tampa Electric's current Returned Check Charge is set at the limit allowed by law, but this language change will facilitate future changes to the charge should that limit be changed without the need for tariff changes.

PROPOSED BASE RATES

Q. After setting prices for service charges, what was the next step in designing rates?

A. The next step was to design base rates. In designing new rates, the company first attempted to move unit prices toward unit costs for the various classes to determine parity. Parity is a comparison of a class rate of return to the system average rate of return and the term is used interchangeably with the term rate of return index. Since parity is calculated by dividing the rate of return for a particular class by the system average rate of return, a class with parity of 100 percent would be earning the same rate of return as the system average and a class with parity below 100 percent would be earning less than the system average. Parity is useful when determining the development of class revenue targets associated with the proposed base rate revenue increase.

Q. Please describe the procedure used to determine what portion of the company's proposed base rate revenue increase should be assigned to each rate class.

A. The starting point in determining the portion or percentage of the company's proposed base rate revenue increase to be assigned to each rate class is the Cost of Service Study. For this purpose, the Cost of Service Study using the 12 CP and 25 percent AD methodology at present rates was relied upon. In this Study, the IS class was retained but was allocated full production capacity costs like all the other classes based on their full load characteristics. The goal was to compare present revenue for each class to the class cost of service requirement and distribute the revenue increase to classes in proportion to their deficiency to the extent practical.

Q. Did you prepare a document that sets out the procedure used to develop the target revenue increase for each of the company's rate classes?

A. Yes, Document No. 4 of my exhibit was prepared for that purpose. Column (A) shows the allocated cost of service resulting from the Cost of Service Study for each class. These amounts are reduced by additional revenues that are projected to be realized from an increase in service charges as shown in column (B). This net revenue requirement for each rate class (column C) forms the basis for comparison to revenues calculated under present rates for each class.

At this point, present revenue for each class could have been subtracted from the cost of service requirement to establish any class deficiency or surplus of revenue from cost. However, it is better to first recognize that, independent of any rate change due to the company's proposed revenue increase, base revenue for each class would need to be adjusted to recognize the rate treatment being proposed for IS customers. Under the proposed treatment, the base cost requirement for non-IS customers is reduced and the IS customers' base cost requirement is increased to reflect the full sharing of production demand related costs by the full load responsibility of the IS customers. Associated with this treatment is the increased cost responsibility to the non-IS rate classes of the cost for the proposed increase in conservation credits made to the transferred IS customers and recovered through the Energy Conservation Cost Recovery Clause ("ECCR"). This change of cost recovery between base rates and the ECCR should result in no change in each class' total revenues, but does result in an effective different level of present base revenues and should be adjusted prior to applying the requested increase in base revenues. The results of this effect are shown in column (F).

Next, column (G) shows the calculation of the revenue deficiency or surplus for each class after comparing the class cost requirement to the adjusted present class sales revenue. Again, the goal is to distribute the proposed revenue increase in proportion to the revenue deficiency for each class to the extent practical. This distribution is shown in column (I) with three noteworthy considerations. First, since the base rates of the GS class have traditionally been set equal to the RS class, these two classes have been combined into one for purposes of this calculation. Second, the present rate classes of GSD, GSLD and IS have been combined to represent the proposed changes to the GS rate structure, and therefore, are treated as one grouping for this calculation. Third, a specific amount of revenue change for the facilities portion of the lighting class revenues has been assigned to reflect the revenue effect related to the proposed restructuring of the lighting rate schedules.

The final step is to add the proposed increase for each class, presented in column (I), to the adjusted present revenue of column (F) while taking into account the effect of proposed rates on unbilled revenue, which is shown in column (M). This results in the final target sales revenues for each class shown in column (N). These are the class sales revenues used to design the proposed rate charges.

Q. Does your proposed rate design move rates closer to parity?

A. Yes. In effect, the billing determinants for each unit price can be considered a class of customers. Moving the unit price for each billing determinant closer to cost is consistent with considering the cost to serve each rate class. Thus, in designing the unit prices to recover the targeted revenue for the rate schedule, the unit prices were moved toward the unit costs. This maintains consistency between the philosophy adopted for allocating the increase among the classes and the philosophy adopted for allocating the increases among the unit prices paid by customers within the classes.

Q. Was the company able to design each rate at 100 percent of parity under the cost methodology selected?

A. No, not fully. However, consistent with the rate design criteria discussed above, each rate class was designed to move as close to 100 percent of parity as practical as defined by the 12 CP and 25 percent AD methodology Cost of Service Study. It is important to note that full moves to parity can cause disproportionate increases to some classes. While cost of service is a very important consideration in rate design, it is not the only factor the Commission should use to determine the level of rates.

Q. How close to parity are the rate classes for the proposed rates?

A. Overall, most rate classes are close to parity. A parity ratio of 1.00 indicates rates are set exactly on the cost of service as measured by the particular cost study selected. A ratio of less than 1.00 indicates that class is served below cost and a class ratio of more than 1.00 indicates that class is served above cost. The results are shown in Document No. 5 of my exhibit.

CONSERVATION-ORIENTED PRICING

Q. Please discuss how the proposed rate design meets the objective of providing conservation-oriented price signals in rate design for the residential class.

A. Tampa Electric is restructuring its residential rate schedule offerings to meet this objective. First, the company is proposing that the RS standard service rate schedule be changed from a flat base energy rate to a two-block, inverted base energy rate design, with the break point at 1,000 kWh and a $0.01 per kWh differential between the two blocks.

Second, the company is proposing that the base rate energy charge for the Residential Service Variable Pricing ("RSVP") rate, the recently approved rate schedule supporting the company's critical peak pricing conservation program, remain flat to help customers focus on shifting usage patterns and reducing usage in the higher price periods.

Third, the company is proposing that the Residential Service Time-of-Day ("RST") rate schedule be eliminated and the 40 customers currently taking service under that schedule be transferred to either the RSVP or the standard RS rate, at their choice. These rates are more conservation oriented than the RST rate. For purposes of this filing, the billing determinants assume that all customers will choose to transfer to the RSVP rate schedule.

Q. Why is the company proposing that the RS rate schedule be changed from a flat energy rate to an inverted energy rate?

A. An inverted base energy rate is becoming a standard in Florida with the Commission having approved such rates for FP&L and PEF. The higher rate at the second block, above 1,000 kWh, provides a price signal to customers about energy use that can serve as a way to encourage energy conservation while the lower first block rate provides a billing benefit to lower use customers.

To fully take advantage of this conservation-oriented rate design and provide a further incentive, the company will seek Commission approval for an inverted fuel factor with a 1,000 kWh inversion point and a $0.01 per kWh price differential to be effective in January 2009. The proposed inverted base and fuel charges were used for the purposes of showing bill impacts in MFR Schedule A-2.

Q. Why is the company proposing only two blocks for the inverted rate design?

A. The two block rate design has received broad acceptance in Florida and applying this design for Tampa Electric's initial inverted rate design should achieve similar customer acceptance and ease of understanding.

Q. What is the RSVP rate schedule?

A. The RSVP rate is a critical peak pricing conservation program offered by Tampa Electric. RSVP was piloted in 2006 and 2007 and was approved by the Commission for full implementation in 2007. Under this program, a customer is provided time differentiated pricing signals as well as a critical peak pricing signal that can occur at any time although it is limited to no more than 134 hours per year. The program includes a programmable thermostat that links up through the home wiring with control devices on the customer's water heater, heating and cooling equipment, and pool pump. This provides the customer an automated process to control high energy consuming equipment and reduce or increase energy usage in reaction to pricing signals. The program has proven to be an effective program that achieves conservation of demand and energy.

Because the RSVP rate already has substantial price differentials designed to induce conservation and load shifting behavior by the customer, the proposed rate does not include the two-block inverted rate design. Making such a change would not be cost effective and could lead to customer confusion. Consequently, a flat base energy rate is still appropriate for the RSVP rate.

Q. Why is the company proposing to eliminate the RST rate and transfer customers currently served under this rate to either the standard RS rate or the RSVP rate?

A. The RST rate schedule has never been popular since its inception in the 1980s, and it does not make sense to maintain it for the 40 or so customers who are on it. The company's RSVP rate has strong customer acceptance and the company believes that most, if not all, of the current RST customers will find the RSVP rate schedule a more than satisfactory replacement. If any RST customer does not desire to transfer to the RSVP rate schedule, they may select the RS rate.

Certain customers who take service under the RST rate schedule do not reside in single-family homes, a current requirement for service, so they will not be eligible to be transferred immediately to RSVP. Tampa Electric is working on a technology advancement that will ultimately enable these customers to take service under this rate schedule. This technology advancement is expected to be available in 2009 but, in the event it is not available when the proposed rate change goes into effect, Tampa Electric will transfer these current RST customers to the standard RS rate schedule until RSVP is available and can be offered.

PROPOSED INTERRUPTIBLE SERVICE RATE DESIGN

Q. What rate restructuring is the company proposing to meet its rate design objective of providing interruptible service to new and existing customers on a cost-effective rate?

A. As previously described, the company is proposing to: 1) eliminate the currently closed to new business IS rate schedules, 2) transfer these customers to the appropriate GSD, GSDT or Standby Firm ("SBF") rate schedule, and 3) provide the customers with interruptible service options under the appropriate currently open GSLM-2 and GSLM-3 riders.

Q. Why is the company proposing to make this change?

A. The IS-1 rate schedules were closed to new business in 1985 and the IS-3 rate schedules were closed to new business in 2000 when the GSLM-2 and GSLM-3 conservation programs were opened. The Commission has allowed customers served under the IS-1 and IS-3 rate schedules to continue service under these rate schedules even though they are no longer cost effective. This proceeding provides the best opportunity to accomplish a transfer and permanently eliminate the IS-1 and IS-3 rate schedules with limited impact to the customers still served under those schedules.

The primary benefit of transferring IS customers to the GSLM-2 and GSLM-3 interruptible conservation programs is to ensure that such load is provided under a cost-effective rate schedule so that firm customers will not be required to provide a long-term subsidy to interruptible load. Under the GSD rate and the GSLM-2 and 3 conservation programs, the credit for interruptible service will track avoided cost and be commensurate with the benefits IS customers provide to the overall ratepayers.

Q. How is the responsibility for allocation of production capacity costs determined for IS customers?

A. Historically, IS customers have received a minimal allocation of production capacity cost under a 12 CP and 1/13 AD methodology. This minimal allocation is a result of assuming zero 12 CP load responsibility and an average demand load responsibility for 1/13 or approximately eight percent of the production capacity costs. As described earlier, the company is proposing a more appropriate cost of service approach that increases the weighting of average demand to 25 percent. Absent any other changes proposed by the company with regard to interruptible service, this change would result in IS customers sharing in an increased percentage of the production capacity cost, with all other customers responsible for the remaining production capacity costs.

Q. You have described the allocation of production capacity costs to IS customers through the cost of service study. How will production energy costs be allocated?

A. Unlike production capacity costs which have a limited allocation, IS customers receive a full allocation of production energy costs. As described earlier, the company has identified and classified certain production investments, such as the Big Bend Unit 4 scrubber and IGCC gasifier as energy, to better reflect their use in providing service to all customers. This results in a higher energy cost allocation to IS customers and supports higher rate levels absent any further changes.

The changes in allocation of both production capacity costs and energy costs are reflected in the Cost of

Service Studies presented by the company reflecting its present rate structure. In the Cost of Service Studies that reflect the proposed rates, the load of these current interruptible customers is transferred to the new GSD class and full 12 CP load is recognized in the production capacity cost allocation. As a result, the non-interruptible customers are then allocated a lower portion of those costs.

Q. With this proposed change, how will the IS customers being transferred to GSD receive a benefit for being interruptible?

A. The customers previously served under IS rates and being transferred to the GSD rate schedule will receive a credit under the GSLM-2 or GSLM-3 conservation program rate riders.

Q. What is the basis for the credit under the GSLM-2 and GSLM-3 riders?

A. As a conservation program, the credit provided under these riders is based on the cost of the company's latest avoided unit. By tracking avoided cost rather than an allocation process in a cost of service study, the benefits of interruptible service provided by these transferred customers to the system will be commensurate with a lower bill via a conservation credit. For 2009, the applicable credit is proposed to be a load factor adjusted $10.91 per kW and it has been utilized in this filing.

Q. Will IS customers face annual changes to the credit offered under GSLM-2 and GSLM-3 as new avoided units are designated?

A. No. Under the GSLM-2 and GSLM-3 conservation programs, the credit applied in the first year is locked-in for a three-year period, which coincides with the three-year commitment required under the current program. Therefore, customers under the new program can plan for this credit level for up to three years. In addition, at any point during the three-year period, the customer may choose to lock-in at the then current credit for a new three-year period.

Q. Will transferred interruptible customers still have Optional Provision purchased power available to them and, if so, is the company proposing any changes to this provision?

A. Yes. The Optional Provision purchased power that has been available to customers under the IS rate schedules in the past to help minimize interruptions will be available under the GSLM-2 and GSLM-3 riders. The only change the company is proposing to make is to update the charge for associated administration from two mills per kWh to three mills.

Q. Under the proposed rate restructuring for interruptible customers, should these customers also be responsible for their full 12 CP load share of production capacity costs being recovered in the company's cost recovery clauses?

A. Yes. The interruptible customers should not be treated differently than other customers regarding their share of production capacity costs, whether the costs are being recovered through base rates or cost recovery clauses. The compensation being afforded for their interruptibility is being provided fully by credits under the GSLM-2 and GSLM-3 riders. This is consistent with the treatment afforded residential load for customers receiving payments under the RSVP-1 rate and the Prime Time load management program.

Q. Does this mean that the recovery factors for all rate classes in the company's cost recovery clauses need to change when the proposed base rate changes go into effect?

A. Yes. Recovery factors for the Capacity Cost Recovery Clause ("CCRC"), ECRC and ECCR need to be revised when the proposed changes become effective. These revisions are necessary for three reasons. The first is that CCRC, ECRC and ECCR are designed to recover costs, including production capacity related costs. Under the proposed restructuring, transferred interruptible customers will now be responsible for their full 12 CP load share of production capacity related costs. This has the effect of reducing the recovery factors for non-interruptible customers.

Second, since the proposed treatment for interruptible load is a conservation program, the credits being paid to interruptible customers are additional costs that must be recovered from all customers through the ECCR. Thus, all ratepayers will incur a higher ECCR charge. However, the associated non-interruptible customers' increase is offset primarily by a lower cost responsibility in the Cost of Service Study allocation of production capacity costs to be included in their base rates.

Third, with the proposed change in production capacity cost allocation method in the Cost of Service Study to 12 CP and 25 percent AD methodology, a concurrent change in allocation of production capacity cost in the clauses is proposed to maintain consistency in allocation. In MFR Schedule A-2, the CCRC and ECCR recovery factors, which are proposed to become effective with the revised rate structure, have been designed to be applicable to GSD standard rate customers' billing demand rather than kWh use.

Q. Why is the company making this recovery methodology *change for this rate group?*

A. The customers under the proposed GSD standard rate are the only customers for which demand is measured and for which demand charges can be assessed. Since CCRC and ECCR costs are predominantly demand related costs, it is appropriate to recover these costs on a billing demand basis. This recovery methodology has been deemed appropriate by the Commission in its decision to approve FP&L's request to recover costs in this manner. The company is proposing this change become effective at the same time that the base rates under the new GSD rate schedule become effective.

Q. Have the effects of all these proposed changes been presented in the company's filing?

A. Yes. The proposed charges utilized in the billing comparisons provided in MFR Schedule A-2 incorporate revised billing adjustments that reflect these changes. The billing comparisons shown on MFR Schedule A-2 for interruptible customers include the proposed conservation program credit as a reduction to the proposed base rate charges.

PROPOSED GSD RATE DESIGN

Q. How does the proposed GSD rate design meet the company's objective of combining duplicative demand billed rates under a single rate schedule?

A. The present design of GSD and GSLD rates has both schedules priced at the same base demand and energy rates with different customer charges, although only GSLD has a power factor penalty/credit mechanism. The break point between the two schedules is 1,000 kW in billing demand. The company is proposing that these two rate schedules, along with the IS customers being transferred to GSD service and subject to the GSLM riders, be served under a single GSD rate schedule. Power factor penalties and credits would be applied only to transferred customers in excess of 1,000 kW because the risk of poor power factor affecting other customers is greater from customers with large demand requirements. Combining all demand billing customers under one rate schedule will simplify the provision of service to this important customer group and provide a better matching of the cost of providing service.

Q. Is the company proposing to continue offering an optional, energy only rate for GSD service?

A. Yes. As approved in the company's last rate order, the company is proposing to continue offering an optional, energy only rate for GSD service. The proposed base energy charge for this optional rate is set equal to 120 percent of the GS energy charge as was established by the Commission.

Q. Are there any other rate design changes the company is proposing for the combined GSD rate schedule?

A. Yes. The company is proposing different customer charges based on the voltage level at which the customer is metered: secondary, primary or subtransmission.

Q. What is the basis for the proposed voltage level customer charges for GSD?

A. The proposed GSD customer charges are designed to recover the cost of metering, meter reading, billing, and customer service. The largest component of these is the metering cost, which can vary greatly depending on the voltage level established for metering. Higher voltage metering requires more expensive metering equipment as well as associated instrument transformation equipment. These costs are the basis of the difference in the design of the current GSD and GSLD customer charges. Combining the GSD, GSLD and IS customers into the new GSD class without a differentiation in customer charge would lead to inequity in the rate design for the combined group. The company is proposing a $57 customer charge for secondary customers, $130 for primary, and $930 for subtransmission compared to the current charges of $42 for GSD, $255 for GSLD, and $1,000 for IS. The new voltage level charges are cost based and they appropriately recognize the cost of service differences to customers under the new combined GSD rate schedule.

Q. Are there other rate changes proposed for the GSD tariff rate terms and conditions?

A. Yes. The company is proposing an increase in the transformer ownership discounts and the emergency relay service charges based on updated costs. The company is also proposing a change to the application of the transformer ownership discounts. Transformer ownership discounts will apply to service voltages as newly defined in the tariff. This approach changes the prior application of transformer ownership discount for primary service by making such discounts applicable to all customers who take primary service.

Q Are there any changes proposed for the standby rate schedules?

A. Consistent with the changes being proposed for the interruptible rate schedules, the standby rate schedules SBI-1 and SBI-3 are being eliminated and customers under these rate schedules will take service under SBF or SBFT, along with the GSLM-3 rider. The proposed charges for SBF and SBFT have been determined in the manner prescribed by the Commission for the design of standby rates.

Q. Are there portions of the current GSD rates, terms and conditions the company is proposing to remain the same?

A. Yes. The company is proposing that the meter level discount of one percent for primary service and two percent for subtransmission service remain the same. These percentages are intended to recognize transformation losses and are typical of values used for this purpose. The company is proposing that this discount should also apply to the transformer ownership discount, emergency relay charge, and power factor penalty and credit billings. In addition, after analysis on the cost of capacitor investment which was the basis for the current charge, the company is proposing that the power factor charge of $2.00/kVARh and credit of $1.00/kVARh remain the same.

Q. Are there proposed changes to the applicability section for Rate Schedules GS and GSD?

A. Yes. Currently, the upper threshold under Rate Schedule GS is for customers "…whose highest measured 30-minute interval demand has not exceeded 49 kW for twelve (12) consecutive monthly billing periods…". A similar lower threshold applies to Rate Schedule GSD. The kW threshold schedule necessitates that many GS customers be put on a demand registered meter simply to determine when they have passed this threshold. The company is proposing that this threshold and the related threshold for GSD be changed to a kWh level above which the customer would take service under GSD. The proposed threshold is 9,000 kWh for a billing period. Establishing this energy threshold for GS and GSD customers will facilitate transition from one rate class to another and will reduce the need for demand meters for this purpose.

Q. Will the company's proposed rate changes to its general service rate schedules (GS, GSD, GSLD and IS) result in any customers being transferred to another rate schedule other than the IS and GSLD changes previously discussed?

A. Yes. The company's proposed restructuring will necessitate some customers being transferred from their current designated rate schedule due to the proposed applicability for the GS and GSD rate schedules changing to a 9,000 kWh threshold to replace the prior threshold of 50 kW. This change requires a transfer of some customers from GS to GSD and others from GSD to GS. The GSD rate has an optional rate offering that allows customers with low load factors to be billed on an energy only rate that would be more beneficial. This allows some customers who must transfer to GSD from GS to be able to take advantage of the optional rate while others would be more advantaged under the standard rate. Due to this revision to the applicability criteria between GS and GSD, transfers between GS and GSD are somewhat difficult to ascertain and will require individual analysis.

To assist in the analysis of projected customer transfers between GS and standard or optional GSD under the proposed rates, a database was created consisting of 12 months of billing information from 2007 and 2008 for each general service customer. Each customer was analyzed to determine which general service rate schedule would apply under the proposed rate structure, and where options are available as described above, which rate would be most beneficial. The analysis shows that about 1,100 customers would be required to transfer from the present GS to the proposed GSD rate schedule as a result of exceeding the 9,000 kWh threshold. Of these, 300 would be benefited by transfering to the GSD optional rate. The analysis also shows that about 1,000 of the present GSD customers do not exceed the 9,000 kWh threshold and should not elect to remain under the GSD rate schedule, and therefore should transfer to the GS rate. Tampa Electric has in the past, and will continue to permit any customer who would normally be served under the GS rate to take service under GSD if such service results in lower bills. All of the transfers determined from this analysis have been reflected in the proposed billing determinants, cost of service analysis, rate design and proposed revenue projections.

Because of the numerous proposed changes, it is important to note that, if some of the proposals are not adopted as proposed, the company requests that it be permitted to test the impacts that the revision(s) would have on transfers. Where transfers are likely to occur, the billing determinants for the affected rate schedules should be revised to reflect the post-transfer effect. This process is laborious and iterative, but it is essential before the final general service rate charges are established to ensure the achieved rates will recover the approved revenue requirement.

TIME-OF-DAY AND LIGHTING SERVICE RATE DESIGN

Q. Please discuss how the proposed general service time-of-day rate design meets the company's objective of designing time-of-day rates to better reflect the cost of providing service.

A. The proposed time-of-day rate calculations result in greater price differentials between on-peak and off-peak periods, which provide a greater incentive for customers to shift their usage. In addition, the proposed total time-of-day demand charges no longer exceed the standard rate demand charge.

Q. How does the proposed rate design meet the company's objective of consolidating its three lighting service rate schedules into one?

A. Tampa Electric presently provides street and area lighting service under three rate schedules: OL-1, OL-3 and SL-2. OL-1, the company's original area lighting tariff, provides standard lighting offerings. OL-3, which came about after OL-1, provides premium lighting offerings including decorative lighting fixtures and poles. SL-2 provides street lighting offerings, many of which are the same as provided under OL-1. Since the current schedules were first established, the separate tariff agreements associated with these rate schedules have been replaced with a single agreement for use under all three schedules. In addition, the business of providing lighting for street and area service has become more intertwined such that fixtures and poles offered under one rate schedule for one purpose are desired by customers for another purpose. At times, fixtures and poles originally provided under one rate schedule change use when they are acquired by a subsequent customer. For example, a private road served under OL-3 might be acquired by a county and become a public road, which would normally be served under SL-2, but the current fixtures and poles are not listed for service under SL-2. Sometimes the same fixture and pole are provided under different rate schedules. This has led the company to propose that all lighting service be combined under one lighting rate schedule. Each type of fixture and pole will have one rate regardless of use. Such a change will improve efficiency and understanding for customers and company personnel who market, install and maintain the lights.

Q. Earlier in your direct testimony, you discussed splitting the lighting service into two components, lighting energy and lighting facilities, in the Cost of Service Study. How are the rates for lighting energy designed?

A. The Cost of Service Study shows that lighting energy requires a revenue increase to move closer to parity while lighting facilities are well above parity. The proposed lighting rate design reflects these results.

Specifically, the company is proposing an increase in the lighting energy rate to move that portion of lighting service closer to parity, and to ensure more appropriate cost recovery from customers who take lighting energy but utilize their own facilities (metered lights). In addition, to better reflect the cost of service for these metered customers, the company is proposing the imposition of a separate customer charge for metered lights to cover the cost of metering and billing.

Q. How are the rates for lighting facilities designed?

A. With respect to lighting facilities, the company is proposing that, in instances where multiple rates are offered for the same facilities, the lowest of these rates be applied to all such facilities, with one exception; the presently reduced rate for additional lights on a pole. The company is proposing the elimination of such reduced rates and all lights of the same type, whether the first or an additional light on a pole, be priced at the same rate. In addition, the company is proposing to reduce the rates of certain offerings because the current rate exceeds incremental costs. Finally, certain lighting facility offerings and the revised Tri-Partite Agreement have been eliminated or restricted to reflect the lack of customer interest or feasibility of offering. Various changes to the terms and conditions language of the Bright Choices Outdoor Lighting Agreement are being proposed to the company's tariff including the General Rules and Regulations and the proposed LS-1 rate schedule.

Although lighting facilities remain above parity in the Cost of Service Study, the company anticipates replacement of lighting facilities in the near term with newer, more expensive facilities, which will move the cost of that service closer to parity.

With respect to maintenance charges related to lighting facilities, the company proposes to increase charges to reflect maintenance costs shown in the Lighting Incremental Cost Study provided as a supplement to MFR Schedule E-13d. It is important to set maintenance charges at the current incremental cost.

Q. Are there any other miscellaneous tariff changes being proposed?

A. Yes. The tariff now includes a Facilities Rental Agreement that includes a monthly rental factor and annual termination factors applicable to facilities that the company may agree to lease to customers. These proposed factors reflect the company's proposed cost of capital in this proceeding. The revisions would only apply to new Facilities Rental Agreements and, since the company enters into very few of these agreements, no additional revenues have been projected in the test year.

As part of the rate design process, certain administrative changes have been proposed for language in the tariff to better reflect the design and clarify operations of the rate schedules, including some new term definitions.

Q. Where can the results of the company's total rate design be found?

A. The revenue distribution by rate schedule is shown on MFR Schedule E-13a, supported by the detailed billing calculations in MFR Schedules E-13c and E-13d. The effect on customers' typical bills is shown on MFR Schedule A-2.

Q. Please provide a summary of the company's proposed rates Cost of Service Studies and rate design.

A. The company identified three primary goals for the proposed rate design changes in this case: 1) provide cost-effective interruptible service offerings, 2) implement a conservation-oriented price incentive for residential service, and 3) create a single lighting service rate schedule for all lighting customers of the company. These goals have been achieved in the cost of service and rate design work described herein.

The company proposes that a 12 CP and 25 percent AD cost of service methodology be utilized for the Cost of Service Study used to support the rate design because it appropriately captures the production cost impact of Tampa Electric's investment in generation and associated variable cost of operation represents cost allocations when considering how power plants are planned and operated in Florida. Further, the company used the cost of service results to move rate classes close to overall system return parity which is an important factor considered in designing the proposed rates.

It is important that the new rate schedules consider 1) cost to serve the various classes, 2) rate history, 3) public acceptance of rate structures, 4) customer understanding and ease of application, 5) consumption and load characteristics of the classes, and 6) revenue stability and continuity. With these considerations in mind, Tampa Electric is proposing to: 1) invert base rate energy charges for standard residential service, 2) close the IS rates and transfer current IS customers to service under a new GSD rate schedule with interruptible credits provided under the GSLM-2 and GSLM-3 interruptible rate riders, 3) eliminate duplicative demand billed general service rate schedules and combine all such service under one rate schedule, 4) design time-of-day rates for the GS rate schedules to provide a greater incentive to shift energy consumption off-peak, and 5) combine the three existing lighting rate schedules into one with more efficient and understandable rate offerings.

The company's proposed service charge rate design provides three new service charges, including two that, if approved, will provide a beneficial convenience service option for customers seeking to reconnect electric service after normal business hours.

Overall, the proposed rate schedules present new rates designed to produce $228,196,000 in additional revenues consisting of $221,380,000 of additional billed electric base sales revenues, negative $301,000 of additional unbilled electric base sales revenues, and $7,117,000 of additional service charge revenues. The proposed rates total the company's revenue requirements.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

WILLIAM R. ASHBURN

Q. Please state your name, business address, occupation, and employer.

A. My name is William R. Ashburn. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director, Pricing and Financial Analysis for Tampa Electric Company ("Tampa Electric" or "company").

Q. Are you the same William R. Ashburn who filed direct testimony in this proceeding?

A. Yes I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain errors and shortcomings in the prepared direct testimony of Mr. Jeffry Pollock, testifying on behalf of the Florida Industrial Power User's Group ("FIPUG").

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes, I am sponsoring Rebuttal Exhibit No.__ (WRA-2), consisting of five documents, prepared by me or under my direction and supervision. These consist of:

Document No. 1	Average Monthly Load Factor, Average Monthly Coincidence Factor and Monthly Coincidence Factor *vs.* Monthly Load Factor Scattergrams for GSD, GSLD and IS
Document No. 2	Average Monthly Load Factor Scattergrams for GSD, GSLD and IS by Rate Schedule
Document No. 3	Revised Pollock Exhibit JP-7
Document No. 4	Discount Being Realized by General Service Interruptible Customers under the Company's Proposed Rates
Document No. 5	Comparison of IS Credit Rate Designs

Q. Please summarize the key concerns and disagreements you have regarding Mr. Pollock's testimony addressing Tampa Electric's proposed retail cost of service study and rate design.

A. My key concerns and disagreements with his testimony are as follows:

- Mr. Pollock's criticisms and recommended revisions to Tampa Electric's proposed retail cost of service study are not substantiated and should be rejected.

- His recommendations on how to cost support and price interruptible service are regressive, provides too generous a benefit for such service and attempts to lock in this overgenerous benefit to the detriment of all other customers until Tampa Electric's next base rate change.

- Mr. Pollock's revised class revenue allocation is based on his inappropriate revised retail class cost of service study, and should be rejected.

- His recommendation to move all energy and demand rates completely to unit cost is drastic and the Commission should not adopt it as a policy.

- His criticism of Tampa Electric's calculation of transformer ownership discounts is incorrect.

- Mr. Pollock's criticism of the method of measuring and applying the interruptible credit is unfounded and should be rejected.

RETAIL CLASS COST OF SERVICE STUDY

Q. What are Mr. Pollock's criticisms with regard to Tampa Electric's proposed retail class cost of service study?

A. Mr. Pollock disagreed with three elements of the company's proposed study: 1) consolidating the GSD, GSLD and IS classes, 2) classifying the Big Bend scrubber and Polk Unit 1 gasifier investments to energy rather than demand, and 3) utilizing the 12 Coincident Peak and 25 Percent Average Demand ("12CP and 25% AD") method for allocating production plant.

Q. What reason does Mr. Pollock give for his disagreement with Tampa Electric's proposed consolidation of the GSD, GSLD and IS classes?

A. Mr. Pollock claims Tampa Electric failed to show that there are no significant differences in either service characteristics or usage patterns of these classes.

Q. Did the company consider differences in service characteristics in its proposed consolidation?

A. Yes, absolutely. First, the differences in service characteristics within the three current classes are not significant enough that they cannot be combined as proposed. Each of the service characteristics are appropriately considered in the various applicable tariff provisions proposed for the new consolidated GSD rate schedule. Second, the company has addressed the differences in service characteristics of customers in these three classes by including special rate features in the proposed consolidated GSD rate schedule. Specifically:

- **Metering cost differences** are addressed through proposed customer charges which have been tiered by metering voltage to recognize service level differences;

- **Service voltage cost differences** are addressed by the design of proposed charges for service at secondary distribution, the lowest voltage level, and providing transformer ownership discounts when service is taken at higher voltage levels;

- **Billing determinant differences** due to losses between voltage levels are reflected in the rate design by the application of metering level adjustments; and,

- **Power factor differences** are addressed by including the power factor clause in the proposed combined GSD rate schedule for customers whose demand is in excess of 1,000 kW, as was previously included under the GSLD rate schedule.

The proposed rate design for GSD, which includes the aforementioned features recognizing service level differences, accommodates all of these differences to permit the use of a single set of GSD rate schedules.

Q. Please address Mr. Pollock's concern regarding usage pattern differences.

A. On page 23 of his rebuttal testimony, Mr. Pollock presents the average characteristics of customers in various rate classes. However, as depicted in the scattergrams in Document No. 1 of my rebuttal exhibit, there are few customers in each of the existing rate classes that possess the exact average characteristics. In fact, the graphs show that there is a wide dispersion of coincident factors and load factors for all three of the rate classes, most particularly the IS class. Cost-based rates are developed using an average cost of service for each class. However, since only a subset of customers in any particular class possess average load characteristics, only this same subset actually pays the "true" cost of service. Rather than focusing on multiple general service demand rate classes that are only cost-based for customers possessing the average characteristics in the class, it is more important to improve on a general service demand rate structure that better tracks cost recovery over a wide range of usage characteristics.

For GSLD customers, the primary usage difference from GSD is the size of the customer's load or kW demand. Load size should not be the sole basis for establishing a separate rate schedule. By incorporating the previously described service features in the GSD rate schedule, the GSLD schedule is unnecessary and should be eliminated, and the customers should be combined into the new proposed GSD rate schedule.

With respect to the current IS rate class, this group as a whole may currently portray some usage patterns that differ from the population of demand metered general service customers. However, as shown in Document No. 1 of my rebuttal exhibit, the customers making up this group have a wide range of usage patterns similar to the usage patterns of present GSD and GSLD customers.

It is important to recognize that prior to being closed to new business, demand metered GSD or GSLD customers could elect to take service under the IS schedule. Certain phosphate customers did so during Tampa Electric's 1985 base rate proceeding in Docket No. 850050-EI. The original purpose for the construct of this class had nothing to do with level of service or load characteristics; it was a means to segregate customers and provide a discount for customers agreeing to be interrupted.

The interruptible credit, currently being provided through the GSLM-2 and GSLM-3 conservation programs, should be the only differentiation provided to interruptible service customers under their base rate design. The company's proposed consolidated GSD rate schedule, with the option to select interruptible service under the GSLM-2 and GSLM-3 riders, fulfills this objective.

Q. On pages 23 and 24 of Mr. Pollock's testimony, he describes the significance of a customer's or a class' coincidence factor. Do you agree with Mr. Pollock that differences in coincidence factor are important to recognize in rate design?

A. Yes, very much so. A primary cost causation for power supply capacity costs (i.e., production and transmission capacity costs) is the monthly system peak load. Thus, a customer's contribution to the system peak is important to recognize for cost recovery. Mr. Pollock's table on the top of page 24 of his testimony demonstrates the inequity that results in a rate design where coincident factor is not recognized in rate design, and when these types of costs are recovered solely on the basis of a customer's billing demand. Under such a rate design and using his example, the $30,000 total demand costs in his table would be recovered by the total of the three customers' billing demands (2,000 + 1,430 + 1,175 = 4,605 kW), resulting in a rate of $6.51 per kW of billing demand. This compares to a more reasonable cost responsibility, which recognizes the coincidence factors of $5.00, $6.99, and $8.51 per kW for customers one, two and three, respectively.

What Mr. Pollock ignores is that the same coincidence factor/cost relationship that is so important in equitably allocating costs to rate classes should and can also be recognized in the rate design for application to customers within a rate class. Intra-class rate equity can be achieved with a proper rate design such that it would be unnecessary to establish additional general service rate classes simply to recognize groups of customers having different coincident factors within that rate class. In other words, instead of attempting to preserve a rate class consisting of a group of demand billed, general service customers who have elected interruptible service and who happen to have slightly different coincident factors than the entire population of demand-billed general service customers as a whole, Mr. Pollock could have focused on developing one general service demand rate structure that captures the *coincident factor/cost relationship of customers over a* wide range of usage characteristics like Tampa Electric has proposed. Document No. 2 of my rebuttal exhibit illustrates how customers served under the current GSD rate schedule are distributed into optional rates within the class that provide recognition of customers' usage characteristics. There is no justifiable reason why GSLD and IS customers must remain in separate classes just to recognize usage characteristics.

Q. What is the basis of Mr. Pollock's disagreement with the classification of the Big Bend scrubber and Polk Unit 1 gasifier investments to energy?

A. He addresses the two investments differently. With respect to the Big Bend scrubber, he suggests that the investment is directly related to the associated power plant providing capacity to the system and thus should be classified to demand. Further, he dismisses prior Commission-approved energy classification treatment from Tampa Electric's last rate proceeding as merely the result of a stipulation. However, he fails to recognize that the Commission approved the subsequent Big Bend scrubber investment classification to energy for environmental cost recovery purposes. Finally, he refers to Progress Energy Florida ("PEF") and Florida Power & Light's ("FPL") treatment of similar environmental investments as being classified to demand but he does not appear as concerned that both were results of stipulations. Mr. Pollock suggests that the entire Polk power plant and all of its components including the gasifier are designed to convert fuel into energy and asserts that the gasifier should naturally be classified to demand.

Q. Mr. Pollock asserts that since the Big Bend scrubber and Polk Unit 1 gasifier are physically connected to the power plants, they are a part of the plants' function to serve load and maintain reliability and thus should be classified on a demand basis. Is he correct?

A. No. While the scrubber is physically connected to the power plant, there is no engineering requirement that the scrubber must operate for the unit to operate. In fact three of the Big Bend units were built and operated without scrubbers for many years and the fourth unit, while built with a scrubber, often operated without the scrubber. The scrubber captures unwanted emissions from the plant and does not serve load or help maintain reliability.

The operation of the gasifier is also not an engineering requirement for the operation of Polk Unit 1. In fact, Polk Unit 1 has dual fuel capability and can operate using oil should the gasifier be out of service. The gasifier converts one fuel type to another for use in the power block, not to serve load or maintain reliability.

Q. What about Mr. Pollock's other assertions regarding the classification of the scrubber and gasifier?

A. Mr. Pollock tries to have it both ways. He attempts to dismiss the decision in the stipulation approved by the Commission in Tampa Electric's last rate proceeding as having no merit while, at the same time, citing PEF and FPL's stipulations as precedent setting. Mr. Pollock's position is in basic conflict with itself. The Commission has carried forward the energy classification treatment of the Big Bend scrubber in Tampa Electric's base rates to the energy classification of the Big Bend scrubber in the environmental cost recovery clause rates, and should continue to do so.

Another way to look at his argument is by way of an example. If somehow the coal at Big Bend could be supplied "pre-cleaned" of the elements currently being removed by the scrubber, then the "pre-cleaned" fuel cost would be recovered on an energy basis. A similar example could be made for the gasifier since it converts one fuel source to another. Mr. Pollock's arguments that the scrubber and gasifier should be allocated on a demand basis is flawed and incorrect.

Q. After reviewing Mr. Pollock's testimony regarding the appropriate methodology for production cost allocation, do you have any general observations?

A. Yes. First, Mr. Pollock acknowledges capital substitution principles in generation planning which recognize that energy utilization plays a significant role in determining the type of, and capital investment in, production plant. Second, his main criticism of a fully recognized capital substitution method for generation facilities, which he refers to as the Equivalent Peaker ("EP") method, is simply the extent (i.e., how high a percentage) that energy usage is being recognized. Lastly, Mr. Pollock advocates the continued use of the 12CP and 1/13th AD method that merely utilizes a smaller percent AD than the 25 percent AD proposed by the company.

All of his points demonstrate that the selection of the appropriate cost of service study methodology is a judgment of what amount/percentage of energy classification should be applied to the production plant revenue requirements. The 25 percent AD approach is a more appropriate weight to be assigned.

Q. Is Mr. Pollock's main criticism that the EP method allocates capital substitution costs to all energy usage rather than only that amount of energy usage required for an economic breakeven between types of generation valid?

A. Yes, this seems to be his main concern. Although Mr.

Pollock's mathematics in his example to support his premise are correct, the conceptual premise is flawed and inconsistent with equitable principles that are generally employed in average cost ratemaking practices. His example is closer to a marginal costing analysis since, under his concept, usage beyond the economic breakeven makes no contribution toward the capital substitution cost that afforded the benefits. His example also represents a renting of the car, which ignores investment. This Commission, for the most part, has practiced average, embedded costing and pricing principles in order to avoid inequities and practical difficulties that can result from the use of marginal costing when setting electric rates. Under average pricing, whether it is the first kWh used or the last, each kWh is a beneficiary of the system's lower operating cost and should share equally in the capital substitution investment that afforded the benefit. Finally, it is important to note that the company has not advocated the full EP method, which would have allocated as much as 70 percent of production capacity costs on an energy basis. Rather it proposes a weighting of only 25 percent, which greatly mitigates some of Mr. Pollock's assertions regarding the extent that energy usage is considered.

Q. Do you have a simple example to demonstrate why it is more equitable that all energy use, not just the energy required for breakeven consideration, should bear capital substitution costs?

A. Yes. Consider the decision to purchase a new high efficiency home air conditioning system for $2,000. Assume that this high efficiency system will have a 10-year life and it will result in $500 per year lower electric energy usage. Therefore, the purchase results in anticipated savings in electric energy usage of $5,000 over the life of the system. This is a good economic purchase because the $5,000 savings less the $2,000 cost produces a net benefit of $3,000. Using Mr. Pollock's approach, he would take the $2,000 cost and divide it by the $500 annual savings to calculate the breakeven point of four years. He would then claim that during the first four years, the customer would realize no net savings; however, there would be $500 per year net savings in the six remaining years.

Although Mr. Pollock's concept may be mathematically correct, this assignment of costs does not represent an equitable or even realistic viewpoint. Costs should be matched with savings. In this example, the $2,000 cost should correspond to the full usage period that savings are realized which is all 10 years, not just the first four years. This results in an allocated cost of $200 per year compared to the annual energy usage savings of $500 for an annual net savings of $300 over the 10-year life. This is the most equitable treatment of matching costs and savings.

The flaw in Mr. Pollock's breakeven analysis can be demonstrated in another way using this same air conditioning system example. If the purchaser of the more efficient system were to sell his home after four years, he would expect a greater sales price for the home by virtue of having the more efficient air conditioning system as compared to a home without such a system. Likewise, a purchaser should be willing to pay more for this home with the expectation of lower electric energy costs. Under Mr. Pollock's concept, the seller should not expect to increase the value of his home because he would conclude that he has fully recovered the additional cost. However, the purchaser, without paying a premium for the house, would realize all the remaining electric energy savings. Costs and benefits are not matched. If a ratepayer were the seller in this case, he would not opt to adopt Mr. Pollock's marginal cost perspective.

Q. Did Mr. Pollock provide any justification for the Commission to support 12CP and 1/13th AD method for allocating production capacity cost?

A. No. I could not find any real justification other than his labeling this method as the "currently approved" methodology. I actually find his testimony supportive of my position in that he states on pages 36 and 37 of his testimony that "It is my understanding that the Commission originally adopted the 12CP and 1/13th AD method to recognize the same economic theory that Mr. Ashburn associates with the 12CP and 25% AD. Although the 12CP and 1/13th AD allocates production investment beyond the break-even point, it does so only minimally. It also recognizes that load duration is a driver that determines utility investment decisions." I agree with his entire statement, especially that the current method only minimally allocates investment beyond the breakeven point. This is my point. As Mr. Pollock states, the 12 CP and 1/13th AD methodology recognizes energy "too minimally". The appropriate energy classification deserves a much greater weighting than the minimal eight percent afforded by the 12 CP and 1/13th AD method.

Q. In Mr. Pollock's Exhibit JP-7, he attempts to show that using Tampa Electric's methodology for allocating production plant investment results in an above average cost per kW of demand for the high load factor classes without the benefit of less than average fuel cost. Please comment on this exhibit.

A. It appears that Mr. Pollock's calculations are simply for effect. He unitizes plant costs on a 12 CP basis to illustrate the math that higher load factor classes are paying more than average for production capacity costs on this basis. In Document No. 3 of my rebuttal exhibit, I reproduce Mr. Pollock's exhibit but add a calculation that illustrates that higher load factor customers are actually paying less than average production capacity costs on an energy basis. I do not find any significance to either my calculation in column four or his in column three regarding the company's cost allocation methodology.

Q. Mr. Pollock recommends that the class coincident peak demands for the summer and winter peaks be used in lieu of the average of the 12 monthly coincident peaks to establish cost responsibility for production capacity costs. Do you consider this method to be appropriate for Tampa Electric?

A. No. Tampa Electric's capacity needs in the summer and winter months are mitigated by the greater amounts of available load management at the time of peak due to greater extreme temperatures. In addition, the company experiences higher generator capability ratings in the winter that helps mitigate the winter peak load. The company strives to plan its generation outages during the spring and fall months, resulting in fairly levelized generating reserve margins in all months. For these reasons, Tampa Electric considers contributions to the average of the 12 monthly peaks to be an appropriate basis for the demand component in the allocation of production capacity costs.

Q. Is an examination of historical peaking demands and resulting achieved reserve margins dispositive of this issue as contended by Mr. Pollock?

A. No. Tampa Electric plans its system to meet normal weather and to achieve a future reserve margin requirement. The past several years have exhibited abnormally warm winter weather resulting in lower than expected winter peaks thus resulting in higher actual achieved winter reserve margins. These results are not useful in determining whether using 12 monthly peaks is appropriate; only weather normalized results are useful.

TREATMENT OF INTERRUPTIBLE SERVICE

Q. Mr. Pollock identifies interruptible power as a primary option for demand response resources. Do you agree with that assessment?

A. Yes, interruptible service is one of Tampa Electric's demand response resources used to reduce load while continuing to provide service to firm customers. Other demand response resources include:

- Residential and commercial load management ("PrimeTime") which involves direct load control of space heating and cooling equipment, water heaters pool pumps, and other such equipment;
- GSLM-2 and GSLM-3 interruptible service conservation programs, which provide the same interruptible service as is provided under the current IS rate schedules;
- Residential price responsive load management ("Energy Planner"), which utilizes a tiered pricing structure with a smart thermostat;
- Standby generator program which provides credits to customers for load transfer during critical periods; and,

- Commercial/industrial demand response, which is facilitated through a third party vendor.

Q. Are the load characteristics of interruptible power customers similar to the load characteristics of customers participating in these other demand response programs?

A. Yes, particularly among commercial customers engaged in manufacturing. The company has many customers participating in its standby generation and third party demand response programs that have high load factors with significant demands available for response.

Q. How has the Commission allowed Tampa Electric to manage these various demand response programs?

A. Since 1982, the Commission has consistently recognized the value of demand response programs and approved Tampa Electric's management of these programs through the Energy Conservation Cost Recovery ("ECCR") clause. The approval process has included reviews of program cost-effectiveness, incentive levels, and administration and marketing costs.

Q. How have the incentive levels varied over the life of these demand response programs?

A. Since 1982, the incentive levels for these various demand response programs have consistently increased. This upward trend has occurred in spite of annual cost-effectiveness reviews using volatile costs associated with avoided unit construction. This upward trend is also evident in the level of the contracted credit value ("CCV") established since the inception of GSLM-2 and GSLM-3 in 2000. Mr. Pollock's only reference to this is on page 62 of his testimony where he acknowledges that the values have been subject to change. He fails to mention that the values have increased in each of the seven years he brackets except for one when there was a minor reduction. This upward trend reflects the increasing cost of generation.

Q. Is Mr. Pollock's assessment of the CCV for 2009 correct?

A. No. The CCV for 2009 was approved by this Commission in Order No. PSC-08-0783-FOF-EG, issued on December 1, 2008 in the 2008 ECCR proceeding. The CCV methodology used was consistent with prior determinations and similar to other Commission-approved credit and program cost effectiveness measurements. Mr. Pollock's concerns about the CCV and related issues would have been more appropriately addressed in the aforementioned docket, a docket to which FIPUG was an active participant. It is not appropriate to review the CCV, the avoided unit selection, the timing of capacity benefits, the appropriate benefit-cost ratio, and the application of the CCV to the load reduction achieved by customers in this base rate proceeding. These issues should have been and still can be addressed in the ECCR proceeding.

Q. Mr. Pollock has presented the results of a cost of service study that he sponsors as Exhibit JP-10. How is the IS rate class treated in this study?

A. Mr. Pollock treats the IS customers as a separate rate class in his study and allocates costs to the class as though they have firm load characteristics. However, his rate treatment of interruptible demand credits is not clear. On pages 61 through 63 of his testimony, Mr. Pollock expresses concern regarding the treatment of payments and cost recovery of interruptible credits through the ECCR and he proposes that these payments and costs be set in base rates. Yet, I find no such treatment in his cost of service study in Exhibit JP-10.

I would presume that his presentation assumes the interruptible credits are being treated as costs for recovery in the ECCR clause.

Q. Mr. Pollock asserts the company has understated the value of the interruptible credit. Should the credit be revised to a higher level as he has calculated?

A. No. As stated previously, the calculation of the CCV should remain within the conservation docket and associated with GSLM-2 and GSLM-3 service to which the current IS customers, after being consolidated into the GSD rate class, should subscribe. It should be recognized that the company's 2009 approved CCV of $10.91 per coincident peak kW used for the GSLM-2 or GSLM-3 rider represents a 46 percent increase over the prior CCV. This is a significant increase in value for interruption and should not be increased any further through base rates.

It is also important to note that the interruptible credit based on the 2009 CCV results in interruptible customers realizing a 62 percent discount in cost for production capacity as compared to firm GSD customers. This is a very fair discount for valuing interruptible load. It is entirely unnecessary to go beyond this level of discount to encourage or maintain interruptible customers. To do so would unfairly shift costs to other customers.

Document No. 4 of my rebuttal exhibit shows the development of the resultant discount being realized by general service interruptible customers under the company's proposed rates. If Mr. Pollock's recommendation of a CCV of $13.60 were adopted, the exhibit shows the value would represent a 78 percent discount to interruptible customers for production capacity service. This type of discount is excessive and unnecessary to encourage and maintain general service interruptible load.

Q. Mr. Pollock expresses concern regarding the load factor adjusted credit structure of the CCV. Is his concern justifiable?

A. No. The use of a load factor adjusted credit is an equitable rate design for application to the wide range of usage characteristics inherent in the group of interruptible customers. PEF has consistently used this design for establishing credits since 1995.

Since the CCV is an amount established per kW of demand coincident with the company's monthly system peaks, this full credit value should only be applied to a customer's demand coincident with the system peak. The load factor approach utilized in the GSLM-2 and GSLM-3 conservation programs is a proxy for estimating a customer's load coincident with the system peak.

Mr. Pollock's suggestion to estimate customers' coincident load by establishing and monitoring loads during "base line" periods, or alternatively measuring interruptible customers' demand in real-time, would impose a burdensome analysis requirement and would result in billing delays, without providing any assurance of a meaningful improvement in the estimation of coincident demand.

The load factor adjusted demand approach can be compared to another method proffered by Mr. Pollock for establishing a fixed credit amount based solely on billing demand. Document No. 5 of my rebuttal exhibit depicts the two methods of crediting over the full range of customer load factors and compares these to an estimated desired credit based on empirically estimated utility load research relating coincidence factor and load factor. It is obvious from this exhibit that the load factor adjusted rate design is a superior rate design to the fixed credit amount based on billing demand.

Q. On pages 41 and 42 of his testimony, Mr. Pollock asserts that interruptible customers should not have to share in the cost recovery of credits paid to them. Do you agree?

A. No. This is an incredible assertion that reveals Mr. Pollock's complete misunderstanding of the purpose of the credits. Interruptible customers are paid credits because, in effect, they have the capability of providing additional production capacity to the system. Having the capability to interrupt service and to dispatch other demand response programs all provide alternative resources to real generating capacity or purchased power capacity from another system. The mechanism for recovering the cost of credits provided to interruptible service customers should be no different from the cost recovery of real generating capacity, purchased power payments, or credits paid for effective capacity provided from other demand response programs.

The only intended difference in the general service rate structure between firm service and interruptible service is the credit. There is no basis for interruptible customers being exempt from any costs that establish the costs for firm service. If interruptible customers were afforded such treatment, which is over and above the cost-supported credit, the rate difference would exceed the interruptible credit and would not yield the desired rate design result.

In Mr. Pollock's cost of service study in JP-10, he did not exempt interruptible customers from sharing in the cost of the company's generating facilities when establishing base rate cost responsibility. He has not sought exemption for interruptible customers sharing in the cost of purchased power. He has also not sought exemption from interruptible customers sharing in the capacity costs of other demand response programs. Interruptible customers supporting the costs of the general service interruptible demand response program is no different.

Further, to demonstrate the ridiculousness of his assertion, I'll use another example. Assume the owners of a 10-unit condominium complex need to have their building painted. A painting contractor estimates the work will cost $1,000. Clearly, each unit owner should pay $100. However, assume the condominium selects a painter who also happens to be a unit owner. Under Mr. Pollock's reasoning and assertion, the unit owner providing the painting service should receive $1,000 for his services **and** should not be required to pay his $100 share. This is outlandish reasoning and the type of confused thinking Mr. Pollock has tried to create with this issue.

CLASS REVENUE ALLOCATION

Q. What are Mr. Pollock's conclusions and recommendations with regard to class revenue allocation?

A. After making many statements supporting the application of cost-based ratemaking, many of which I agree with in theory, he alleges that Tampa Electric is proposing a revenue increase for IS customers of 134 percent compared to an overall increase request of 26.4 percent. However, he immediately admits that Tampa Electric's proposed treatment for existing IS customers would result in an "effective" base revenue increase of 35.5 percent. He also explains that under his revised cost of service study, the IS class would merit a rate decrease along with the Lighting Facility rates. After stating that he would not recommend any class receiving a decrease, he provides a recommended class revenue allocation in his exhibit JP-14.

Q. Do you agree with Mr. Pollock's recommended class revenue allocation?

A. No. As I described in the first section of my testimony, I do not agree with Mr. Pollock's proposed revisions to the retail class cost of service study. I also do not agree with his proposed rate design for current IS service. Consequently, I do not agree with his recommended class revenue allocation.

Mr. Pollock's revenue allocation approach, while moving proposed revenues closer to cost under his cost of service model, serves to reduce revenue collected from IS customers and increase revenue collected from all other classes, most importantly and substantially the residential service class. The appropriate value of interruptible service is recognized in Tampa Electric's proposal through cost of service, rate design and revenue allocation. Mr. Pollock's proposal is not a reflection of gradualism, as he suggests, but recidivism.

FIRM RATE DESIGN

Q. What are Mr. Pollock's conclusions and recommendations with regard to Tampa Electric's proposed rate design for firm service?

A. On page 51 of his testimony, Mr. Pollock states "TECO has underpriced the demand charge and overpriced the energy charge (based on the company's proposed revenue levels). The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in the retail class cost of service study." He recommends that the non-fuel energy charge for the IS rate schedule be set at the per unit energy cost from his proposed cost of service study. Later, Mr. Pollock discusses meter level and transformer ownership discounts as appropriate mechanisms to reflect the lower cost of providing primary and subtransmission service. He appears to take no issue with how Tampa Electric applied the meter level discount; however, he does criticize the company's calculation of the transformer ownership discount credits, alleging that ratcheted rather than billing demand was used as the divisor, thus inappropriately understating the resulting credits.

Q. Do you agree with Mr. Pollock's recommendation regarding the appropriate non-fuel energy rate for IS rate schedule?

A. No. First, his proposed energy charge applies to the IS rate schedule, which the company has proposed to eliminate and his proposed energy rate for the IS rate schedule is derived from his unreasonable cost of service. Second, his recommendation addresses the energy charge alone without addressing the demand, customer, or other rate charges. Rate design for electric service, both in theory and as practiced at the Commission, has focused on first setting the more fixed components, the customer charge and demand charge, and then setting the more variable component, the energy charge. Finally, his recommendation for the IS non-fuel energy rate did not address how to design the rate for time of use. This limited approach of rate design is inappropriate and his recommendations should be rejected.

Q. Do you agree with Mr. Pollock's conclusion that Tampa Electric understated its proposed transformer ownership discounts by dividing the avoided cost by the ratcheted demand rather than the actual billing demand?

A. No. He is incorrect. The transformer ownership discount for the proposed, combined GSD class was actually calculated by dividing the avoided cost by the projected billing demand as shown in MFR Schedule 14, Supplement B, page 169 of 175. Ratcheted demand was not used in these calculations and the proposed transformer ownership discounts were not understated.

Q. Mr. Pollock claims there are no demand ratchets in Tampa Electric's tariffs. Do you agree?

A. No. The company's tariffs for Standby Service contain monthly reservation charges for local facilities. These charges are derived and applied on a ratcheted demand basis. Where applicable, a transformer ownership discount is also applied to the same ratcheted demand measurement. Therefore, the development of the transformer ownership discount for standby customers must be derived by dividing the avoided cost by the ratcheted demands. The company appropriately utilized ratcheted demand only to calculate the transformer ownership discount for the standby rate schedule.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addresses key concerns and disagreements with Mr. Pollock's testimony. I reject his criticisms and recommended revisions to Tampa Electric's proposed retail class cost of service study. I provide further support that the GSD, GSLD and IS classes can and should be consolidated into one GSD class. I rebut his arguments about the proper classification of the scrubber and gasifier investments and clarify why they are properly classified to energy. I show why his objections to the 12 CP and 25% AD method for allocating production plant are not reasonable in this case. I also demonstrate how Mr. Pollock's recommendations on cost support and the pricing of interruptible service are regressive, provide too generous a benefit, and attempt to lock in this overgenerous benefit to the detriment of all other customers. Finally, my testimony rejects Mr. Pollock's revised class revenue allocation, his recommendation to move all energy and demand rates completely to unit cost as well as his criticism of Tampa Electric's calculation of its transformer ownership discounts and method of measuring and applying the interruptible credit.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BY MR. WILLIS:

Q Did you prepare an exhibit attached to your rebuttal testimony titled Rebuttal Exhibit of William R. Ashburn containing five documents and identified as Exhibit 86?

A Yes.

Q Do you have any additions or corrections to your exhibit?

A Yes. My original Documents Number 3 and 4 were refiled on December 31st to reorder the number they were numbered.

Q Please summarize your direct and rebuttal testimony.

A Good afternoon, Commissioners. The purpose of my direct testimony is to present the proposed rates and service charges that will produce the company's proposed jurisdictional revenue requirement increase of $228,167,000. In my direct testimony, I present the development and application of billing determinants and the forecast of base revenues from the sale of electricity and revenues from service charges for the 2008 and 2009 projected periods using present rates, and for 2009 under proposed rates to achieve proposed class revenues.

I present the jurisdictional separation study and resultant jurisdictional separation factors that determine the portion of Tampa Electric's system rate base and operating expenses subject to the jurisdiction of the FPSC and that forms the basis for the company's proposed revenue requirement.

I also present the 2009 projected period retail class allocated cost of service and rate of return studies. I provide conclusions regarding the adequacy of the aforementioned studies and the reasonableness of the resulting costs being used to support the proposed rate design.

The company proposes that a 12 coincident peak and 25 percent average demand cost of service methodology be utilized for the cost of service study used to support the rate design because it appropriately captures the production cost impact of Tampa Electric's investment in generation and associated variable cost of operation. Further, the company used the cost of service results from that study to move rate classes close to overall system return parity, which is an important factor considered in designing the proposed rates.

I explain the development of the company's proposed rate structure modifications, rate designs, and new permanent rates, service charges, and rate schedules to be implemented. With regard to proposed rates, Tampa Electric is proposing to invert base rate energy charges for standard residential service; eliminate the present closed interruptible rates and transfer the current customers under those rates to service under a new GSD rate schedule with interruptible credits provided under existing GSLM-2 and GSLM-3 interruptible rate riders; eliminate duplicative demand billed general service rate schedules and combine all such service under one rate schedule; design time of day rates for the GS rate schedules which provide a greater incentive to shift energy consumption off peak; and combine three existing lighting rate schedules into one with more efficient and understandable rate offerings.

The company's proposed service charge rate design provides three new service charges including two that will provide a beneficial convenience option for customers seeking to reconnect electric service after normal business hours.

The purpose of my rebuttal testimony is to address certain errors and shortcomings in the prefiled direct testimony of Mr. Jeffry Pollock where he addresses Tampa Electric's proposed cost of service and rate design. I reject Mr. Pollock's three revisions to Tampa Electric's proposed cost of service. I reject his assertion that the differences in the service or usage characteristics of the GSD, GSLD, and IS classes are not significant enough that they cannot be combined as proposed. I reject his arguments against classifying the Big Bend scrubber and the Big Polk Unit 1 gasifier investments to energy and provide further support for the company's proposed classification. And I reject Mr. Pollock's criticism of the 12 CP and 25 percent methodology for allocating production investment.

I address several points Mr. Pollock made regarding the appropriate treatment of interruptible service pointing out the shortcomings of his arguments. I reject Mr. Pollock's proposed class revenue allocation. Finally, I show that certain firm rate design proposals he makes in his testimony are inappropriate or just plain incorrect.

And that concludes my summary.

MR. WILLIS: I tender the witness.

COMMISSIONER EDGAR: Ms. Christensen.

MS. CHRISTENSEN: No questions.

COMMISSIONER EDGAR: Ms. Bradley.

MS. BRADLEY: No questions.

COMMISSIONER EDGAR: Ms. Kaufman.

MS. KAUFMAN: Thank you, Madam Chair.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Good afternoon, Mr. Ashburn. How are you?

A I'm fine. Good afternoon to you.

Q You told us in your summary that you are the company's witness on rate design and cost of service, right?

A That's correct.

Q And just so we are all on the same page at kind of a high level, the purpose of your testimony is to address how after the Commission makes its revenue decisions, you know, what costs it will or will not allow, how much of the $228 million requested increase it will allow, your testimony addresses how to spread any increase among the customer classes, correct?

A How to collect it from them, I think, might be a better way than spread. I mean, I'm proposing a rate design that will collect the $228 million that we have proposed, but you are correct, the same approach to how to collect it from customers would be applied if it was reduced.

Q So the purpose of your testimony is to decide how to collect or allocate whatever the ultimate revenue requirement is?

A That's correct.

Q And you would agree, would you not, that when we assign or when you assign costs to various rate classes that your goal is to group the customers into relatively homogeneous groups?

A That is an objective, yes.

Q And so you would want to try to get customers with similar service requirements and usage characteristics in the same group?

A That is an objective, yes.

Q And I think you mentioned that you propose some changes and you want to consolidate some classes and you want to eliminate the interruptible class entirely, correct?

A That is my proposal, yes.

Q I just want to ask you some general questions regarding the nature of interruptible service in comparison to firm service so we can get a handle on what you are suggesting.

You would agree with me, wouldn't you, that for customers that take firm service, when they flip their switch or turn on their lights or whatever, the power is there and Tampa Electric stands ready to serve them at all times barring a hurricane or some sort of natural disaster?

A That is the objective, yes.

Q And you would also agree, wouldn't you, that in contrast, when a customer is on the interruptible rate, Tampa Electric can cut off or curtail power to that customer when it needs that power to serve its firm customers?

A That is correct.

Q So, for example, if you have a large interruptible customer, a large industrial customer who is on an interruptible rate, Tampa Electric has the ability to sort of instantaneously cut off their service if you need the capacity to serves firm customers?

A That is correct, too.

Q And you can also interrupt or curtail interruptible customers if resources are needed to meet the reliability needs in other service territories in the state, correct?

A We have that option, yes.

Q And you would agree with me that currently that ability to immediately interrupt is reflected in your interruptible tariffs?

A It is included in the language in the tariff, yes.

Q And you don't have to give the customer any notice to do that, correct?

A That is correct, although we do, if we can.

Q But you certainly are not required to in your tariff?

A We are not required to, but we have procedures in place where if we anticipate that there may be interruptions coming, for example, a hot day, and we know at some point later in the day the heat might drive the load up to a point where we would not have enough generation to serve, and, therefore, might have to interrupt, we provide notice to our interruptible customers in advance that that may happen, and they can take action to prepare for that.

Q So you do it if you can, but you are not required to?

A That is correct.

Q You also would agree, wouldn't you, that when Tampa Electric is planning for its system and for its next capacity addition in terms of type of capacity and timing, it does not take into account any needs of the interruptible customers?

A I'm sorry, complete the question again.

Q When Tampa Electric is doing its generation planning, deciding what its next addition is going to be, it does not consider the demands of the interruptible customers?

A The demands, correct. The peak demand needs of them. We do consider the energy needs of those customers in that planning.

Q But not the demand needs?

A Not the demand.

Q Now, Mr. Ashburn, Tampa Electric has had interruptible load on its system for a long time, hasn't it?

A Yes.

Q I think you told me in your deposition for at least as long as you have been with the company?

A Quite a ways before I joined the company back in 1983. I think it goes back to the '40s or '50s even.

Q So you would agree, wouldn't you, that interruptible customers have provided a benefit to Tampa Electric and to its ratepayers?

A They provide a benefit to our ratepayers, that is correct.

Q And part of the benefit that they provide is this ability to allow you to defer the addition of generation capacity?

A That is correct.

Q And you would agree with me that if interruptible customers had chosen to take firm service rather than interruptible service, then Tampa Electric would have had an obligation to either build or to acquire capacity to serve them?

A It they had, that is true. If they chose to today, that would be true, as well.

Q I just want to -- keeping in line with how some customers take service and how they may be different from other customers, I want to talk a minute about how power is delivered particularly to subtransmission level customers. Can you tell us what a subtransmission level customer is, how they take service?

A We have several levels of voltage to which customer service is provided. Most customers are served under what is called the secondary voltage, and that is the typical home or small business that has service delivered at a lower voltage, 120-volt, something like that coming out of a transformer off the distribution system. The next level up is customers who take service directly from the primary system, 13,000 volts, and, therefore, the meter is connected at that point.

Subtransmission for Tampa Electric is 69,000 volts, 69 kV. Which as you may know there is another voltage is up to 230, 500, 1,000 volts. 69 kV is out subtransmission voltage, and we have a number of customers who take service at 69,000 volts.

Q And a customer that takes service at 69,000 volts at the subtransmission level receives the power, has to have its own transformer to step it down, has to have its own distribution lines to send it to its site, correct?

A Most. Assuming they can't use it at 69,000, but I think most of the customers we have, if not all, have to step it down at some point.

Q And for those customers, Tampa Electric as to them avoids the cost, for example, of poles and towers, conductors, step down transformers, and things like that, correct?

A We avoid costs by not having to serve it at the lower voltage, that is true.

Q And you don't have to install or purchase or be responsible for any of those other facilities, correct?

A The facilities are whatever the customer needs behind the meter. We provide the service to the meter and what the customer needs behind the meter is up to them.

Q Right. So, for example, these customers, they receive the service, they step it down, and as I said they have their own distribution system on site.

A They may or they may not, however they need it after that voltage that they request.

Q In your cost of service study, did you exclude subtransmission load from the allocation of primary and secondary distribution plant?

A Say the question again. I didn't follow it all the way.

Q Yes. Let me try that again. I think it is true, and let me know if I am incorrect, that in your class service study you excluded subtransmission load from the allocation of primary and secondary distribution plant.

A I don't think that is exactly right. I mean, customers who are served at secondary and primary also have load at the subtransmission level. If you mean if we excluded customers who were served at the subtransmission level their load, then that is correct.

Q Okay. So for those customers at that level you excluded the primary and secondary distribution costs?

A We excluded their load from the allocators, yes.

Q I want to switch gears a little bit here and talk to you about the change that you are requesting in the cost of service methodology that you want the Commission to use in this case. And you are suggesting, as you mentioned in your summary, that the Commission use the 12 coincident peak and 25 percent average demand methodology, correct?

A That is correct.

Q Now, you would agree that in Tampa Electric's last rate case that we have heard so much about 16 years ago, Tampa Electric used the 12 coincident peak and 1/13th demand methodology, correct?

A That is what we proposed, that is correct.

Q And would you also agree that generally the Commission has used the 12 CP and 1/13th methodology in rate cases?

A The Commission has in its MFRs requires that you file a cost of service based on the 12 CP and 1/13th, and it has used that methodology in the past.

Q And you would agree it has never used the methodology that you are proposing?

A The 12 CP and 25 percent?

Q Right.

A The Florida Commission has not approved such a methodology in the past, that is correct.

Q Now, in your direct at Page 32 you give us some reasons that you think the Commission should change methodologies. And beginning at Line 9 you talk about some cases where you say the Commission has deviated.

A Yes. That is the question, yes. And the answer is on Line 12, though, right?

Q Right. The question is on Line 9, the answer goes from Line 12 to 19.

A That is correct.

Q Okay. The first example you give is Tampa Electric's 1985 rate case, correct?

A That is correct.

Q And Tampa Electric did not propose -- let me back up. In your 1985 rate case you proposed and the Commission used the 12 CP and 1/13th method, right?

A I'm sorry, say that again.

Q In your 1985 rate case that you are referring to on Line 13.

A Yes.

Q Tampa Electric proposed and the Commission used the 12 CP and 1/13th cost of service methodology, correct?

A No. In the 1985 rate case the company proposed a 12 CP and 1/13th, but the Commission relied on the equivalent peaker methodology.

Q Thank you for correcting me, but the company proposed the 12 CP and 1/13th?

A Yes, the company did.

Q And Tampa Electric did not support the equivalent peaker method in that case, did it?

A It did not at that time, no.

Q And in your 1992 rate case you proposed and the Commission used the 12 CP and 1/13th?

A That is correct.

Q Now, you talk about FPL's base rate case there on Line 15, correct, and the fact that there was a deviation from the 12 CP and 1/13th?

A Yes.

Q Would you agree that that had to do with FPL's nuclear plant?

A The deviation or the case?

Q Yes, the deviation.

A I'm not sure about the entire case, but as part of that case and the cost of service analysis, the deviation had to do with how the allocation of a portion of the nuclear unit would be made.

Q Right. And that allocation is no longer being applied to that.

A I believe it is not.

Q Let's talk for a moment about the class consolidation that you are proposing. It is your proposal to the Commission that they combine the GSD, the GSLD, and the interruptible class, correct?

A That is correct.

Q As far as you are aware, the IS, or the interruptible class has never been combined with any other class, has it?

A I would have to say no, and the reason I'm saying no is that at one point there was a single IS class, and then there was two IS rates. There was an IS-1 and IS-2. At some point, I believe in the '85 case, the IS-2 rate customers were combined into what became the IS-3, I believe, or maybe IS-1. I don't remember, but there were multiple IS rates which were then combined together. It is also important to recognize that many of the IS customers prior to becoming IS customers were GSD or GSLD customers and chose to go to the IS class. So there are many customers in that group that previously were in a different class.

Q Right, but the IS class, or if you want to say the IS or the interruptible classes have never been combined with the

GSD or the GSLD class?

A I think it is fair to say that when the IS rates were created at some point prior to my time, since that time they have remained an IS class and have never been recombined with anybody else other than themselves to some extent.

(Transcript continues in sequence with Volume 12.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 29th day of January, 2009.

Jane Faurot

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Official FPSC Hearings Reporter
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