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 7

Pages 875 through 1080

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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: Tuesday, January 27, 2009

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REPORTED BY: MARY ALLEN NEEL, RPR, FPR

APPEARANCES: (As heretofore noted.)

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P R O C E E D I N G S

(Transcript continues in sequence from Volume 6.)

CHAIRMAN CARTER: We are back on the record. When we last left, Ms. Christensen, you're recognized.

MS. CHRISTENSEN: Thank you. Good afternoon, Commissioners, again. Good afternoon again, Mr. Hornick.

CHAIRMAN CARTER: Excuse me, Ms. Christensen. Before you go, I just had one of my over-50 moments.

Commissioners, for planning purposes, and also to the parties for planning purposes, I had told you we were going to go to 8:00, but we'll do a dinner break around 6:00, from about 6:00 to 6:30. That way -- I mean, I wouldn't want you to pass out or anything like that. So just as kind of a housekeeping matter.

Commissioner Argenziano.

COMMISSIONER ARGENZIANO: A question. 6:00 to 6:30, will there be anyplace close by where everybody can get something to eat?

CHAIRMAN CARTER: Mike Twomey has a little wagon out back. He sells sandwiches on the side. That's his retirement plan.

Oh, yeah, you guys can't get back in. Well, there's that too.

MR. MOYLE: That would really move it along.

COMMISSIONER SKOP: You broke the code, Commissioner.

COMMISSIONER ARGENZIANO: That was the plan.

CHAIRMAN CARTER: Yeah, yeah, that was the plan. That's why we'll break at 6:00. But we'll just have to see what we can -- muddle through it as best we can, but those are the plans. Mr. Wright?

MR. WRIGHT: Are we off the record, Mr. Chairman?

CHAIRMAN CARTER: Yes, we're off the record.

(Discussion off the record.)

CHAIRMAN CARTER: With that, Ms. Christensen, you're recognized. You may proceed.

Thereupon,

MARK J. HORNICK

a witness on behalf of Tampa Electric Company, continues his testimony under oath as follows:

CROSS-EXAMINATION

BY MS. CHRISTENSEN:

**Q.** Again, Mr. Hornick, good afternoon. Regarding dredging, my understanding was one of the options that Tampa Electric was considering for the disposal issue was the possibility of building up the dikes to extend the useful lives of the disposal areas; is that correct?

**A.** Yes, that is correct. That is one of our options that we're looking at.

**Q.** Okay. And what useful life would you expect to get out of those disposal areas if you choose to build up the dikes?

**A.** Currently, that's not our preferred option. We've looked at that and came up with a cost estimate actually some time back to extend the height of those dikes enough for one additional dredging.

The most likely scenario right now is to remove enough material from the existing spoil areas to allow for that next dredging to occur. That looks like the most cost-effective activity or choice of project.

**Q.** Okay. Is the dredging the company states that it's going to do in 2009 similar to the areas that were dredged in 2002 and prior years? Is that correct?

**A.** Yes, they're similar. There's some variation. The inlet canals are a different scope, but the shipping channels, the dock areas, the turning basins, those are all the same scope.

**Q.** And would you agree that the 2002 company dredging costs, the most expensive areas were those that were shared between Tampa Electric and IMC Agrico, which used to be Mosaic?

**A.** Yes, I believe that's true. The majority of the cost was involved with dredging the shipping channel and the turning basin, which are shared facilities between Tampa Electric and Mosaic in that area of the port.

**Q.** Okay. And just so that I'm clear, it would be correct that Tampa Electric has not obtained a bid or an estimate for the dredging cost for 2009 or that you included in this rate case from an outside source other than those that were done for 2002?

**A.** No, that's not exactly correct. We don't have a current competitive bid for the 2009 scope, but we do have a cost proposal that was given to us in December of 2006 that we used as the basis of the estimate, so we do have a more recent cost proposal than 2002.

**Q.** Okay. Let me turn your attention to the company's MFR Schedule C-6, page 2.

**A.** Bear with me a second.

**Q.** Certainly.

**A.** Unfortunately, I've only got selected MFRs here, and I don't have that C-6, the one you referenced.

MS. CHRISTENSEN: Permission to approach the witness?

CHAIRMAN CARTER: You may do so.

MS. CHRISTENSEN: Thank you.

BY MS. CHRISTENSEN:

Q. Now, what I've just handed you is a copy of Schedule C-6, page 2 of 6; is that correct?
A. Yes, that's correct.
Q. Okay. Now, would you agree that the actual steam power maintenance expense from 2003 through 2007 ranged from a low of 46.074 million in 2005 to a high of 57.715 million that occurred in 2003?
A. Could you reference a line number on that MFR?
Q. Certainly. Referring to line 21.
A. Okay. It's a total of steam power maintenance. Okay?
Q. Correct. And would you agree that the low was in the year 2005, actual of approximately 46 million, and that the high for steam power maintenance in 2003 was a high of 57 million, approximately?
A. Yes, those are the numbers that I see.
Q. Okay. And would you also agree that the amount of expense for steam power maintenance has fluctuated from year to year?
A. Yes.
Q. Now, looking at the schedule, for 2004, 2005, 2006, and 2007, the actual steam power maintenance expense is less than 2003; is that correct?
A. Yes, that's correct.
Q. Okay. And would you also agree that it's not

realistic to assume that as each year passes, that the amount of the expense will automatically be higher than the previous year?

**A.** Yes, I would agree that it's not necessarily true that expense in that particular category would be higher in every year. That's true.

**Q.** Okay. And in 2008, the budget for the steam power maintenance expense is approximately 51 million; is that correct?

**A.** Yes, that is correct.

**Q.** Okay. And would you agree that the 51 million is approximately the midpoint of the previous years, 2003 through 2007, actuals, high and low?

**A.** Yes. I haven't done the exact numerical average, but it seems to be reasonable, subject to check.

**Q.** Now, looking at the 2009 budgeted amount for the steam power maintenance expense, that is 71 million, is that correct, approximately?

**A.** Yes.

**Q.** And would it be correct that the increase is attributed in part to the dredging cost included in Account 511?

**A.** Yes, the dredging expense is categorized in 511, maintenance of structures, steam power generation.

That's my understanding.

Q. Okay. And on page 16 of your rebuttal testimony, did you indicate that a pro forma adjustment was made to remove the 5.5 million of this 2009 expense?

A. Yes, I believe that's correct. I did indicate that. What page again?

Q. Page 16 of your rebuttal, looking at line 15, or -- excuse me. It might be slightly higher.

A. Uh-huh.

Q. That was correct?

A. Yes, at line 14. Yes, the company subsequently made a pro forma adjustment to remove 5.5 million of the 6.9 million.

Q. Okay. Now, do you have in front of you Schedule C-2, page 3, of the MFRs?

A. Let me see here. No, that's not one of the ones I have here with me.

MS. CHRISTENSEN: Permission to approach the witness?

CHAIRMAN CARTER: You may approach.

BY MS. CHRISTENSEN:

Q. Now, Mr. Hornick, I've just handed you Schedule C-2, page 3 of 7; is that correct?

A. Yes.

Q. Okay. Looking at column 4, isn't it correct that under the company's adjustment, column 4, number 4, that the dredging adjustment is 5.32 million?

**A.** Yes, that is the number I see here.

**Q.** Okay. Can you tell us which one is correct? Is it the 5.5 million referred to in your rebuttal testimony or the 5.32 million adjustment referred to in the MFR?

**A.** I'm not certain. This Schedule C-2, I did not prepare that schedule, and I'm not familiar with the calculations involved. Our witness, Jeff Chronister, would be better able to answer that, the specifics of the accounting treatment and the calculation there.

**Q.** Okay. But isn't it correct that even by removing, assuming that the schedule is correct, the 5.32 million from the steam power maintenance expense, which would result in approximately 66.5 million, that's still considerably more than the historical expense level? Isn't that correct?

**A.** Yes, within that category of expense, it is higher.

**Q.** Okay. And even accounting for the $5.32 million adjustment, the budgeted 2009 steam power maintenance expense is approximately 8.8 million more than the last highest year of 2003?

**A.** I don't have a calculator with me, but the mathematics, it looks appropriate, subject to check.

**Q.** Okay. And wouldn't you agree, or isn't it correct -- let me rephrase that -- that the cause for this increase in 2009 is the number of major outages?

**A.** I would say that's one of the contributors to that increase in expense. These accounts go from Account 510 to Account 514. They include a number of expenses, not solely based on planned outages.

**Q.** Okay. Would you agree that in 2009 -- that the 2009 work outages are atypical?

**A.** Could you repeat that question?

**Q.** Would you agree that the 2009 work outages are atypical?

**A.** I would agree they are perhaps atypical, but certainly not unprecedented. We've had years in the past where we've had planned outages at the Big Bend Station, which I think is the subject of your question, that have been -- you know, we've had up to three planned outages per year.

**Q.** Wouldn't you agree that it is reasonable to base the maintenance expense in rates on an average that takes into account the fluctuation from year to year rather than to ask ratepayers for maintenance costs that are atypical?

**A.** No, I wouldn't necessarily agree, first of all, that they're atypical. You asked me about the number of outages. And the overall cost is not just planned outages, but maintenance expense involved with forced outages and routine maintenance. And when you look at our spending over time and into the future, you can see that the overall maintenance expense in 2009 is not out of the ordinary and atypical for what we would expect to see going forward.

**Q.** Now, do you recall taking a deposition? Do you recall having your deposition taken?

**A.** Sure. Yes, I do.

**Q.** Okay. And do you recall being asked this question and providing this answer?

"All right. But given your experience, being with the company since 1981, is it not typical to have multiple major outages at Big Bend Plant in a one-year time frame, is it?"

And your answer was, "That would be something that would be atypical, since we try to spread the maintenance out, but it is not -- I don't know that it's unprecedented."

Do you recall giving that question, the response?

**A.** Yes, I did. And I did say in the subject of that deposition that -- I believe I was asked since

1981, had there been three outages at Big Bend Station, and that's just not a statistic that would stay with me.

We typically try to sequence our outages so that we don't have more units off in a year than will allow us to reliably provide power. Certainly the units need to be running in order to do that. It's probably not a normal or an average situation, but it's not unprecedented. And as I said, in 2005, I believe, and in 2006, we had a situation where we had three major outages at Big Bend Station.

**Q.** But those weren't years in which you were setting rates; is that correct?

**A.** That's correct.

MS. CHRISTENSEN: No further questions.

CHAIRMAN CARTER: Thank you. Ms. Bradley.

CROSS-EXAMINATION

BY MS. BRADLEY:

**Q.** Sir, a few months ago when the economy went bad, did you personally look at possible postponements or modification of these projects to see if you could reduce your rate request?

**A.** No, I did not.

MS. BRADLEY: Thank you.

CHAIRMAN CARTER: Thank you, Ms. Bradley. Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. MOYLE:

**Q.** I have some questions for you today. I'm Jon Moyle representing FIPUG.

Were you here when the opening statements were given and Mr. Twomey recounted his story about the gentleman from Century Village who talked about the view of rate cases where the utilities ask for twice as much they need and the regulators cut it in half, and everybody just kind of goes on? Did you hear that?

**A.** I was not here. I was listening, and I did hear that.

**Q.** Okay. In reviewing your testimony, a lot of it has a lot of fine detail, but Mr. Pollock, who is a FIPUG witness, suggests that the appropriate amount of recovery is 12.2 million, and you contend it's 20.2 million; correct?

**A.** That's correct, for the planned outage expense, I believe at Big Bend Station is what he looked at.

**Q.** Okay. And I'm going to ask you some questions about that. It's not every day in my line of work where I get to ask questions and argue and litigate over an $8 million number. That's a pretty big number. So bear with me, if you would, as I try to dig in a little bit on some of these outage questions.

MR. MOYLE: What I would like to do, if I could, Mr. Chairman, is have a document distributed which was -- it's already part of the record. I think Ms. Kaufman may have it.

CHAIRMAN CARTER: You're just going to use it for cross-examination?

MR. MOYLE: Yes, sir. And it's part of the record. It's an exhibit to Mr. Pollock's testimony. It may not be in the record yet, but I think I can clear that up with the witness briefly.

CHAIRMAN CARTER: Okay.

BY MR. MOYLE:

**Q.** Mr. Hornick, I've just distributed a document that is entitled "TECO Planned Big Bend Outage Weeks, Exhibit JP-2." Can you identify this document for the record?

**A.** Yes, I see that designation on the top, "TECO Planned Big Ben Outage Weeks, Exhibit JP-2."

**Q.** And this is a document that TECO created; correct?

**A.** Yes.

**Q.** And isn't it the business plan, the business plan outage summary for the years 2007 to 2013?

**A.** Yes. The title on this particular page is "Big Bend Station Business Plan, 2007 to 2013, Outage summary." I believe it's a portion of a document that's created annually at each power plant location to summarize the business plans in the near term and intermediate term.

**Q.** Okay. And looking at the chart there, it has units on it, and then it has the initials FS and MO. MO stands for major outage; correct?

**A.** Yes, that's correct.

**Q.** And in looking at the chart, it looks like at this point in time when this document was prepared that there were major outages scheduled for Big Bend, one per year from 2005 to 2013. Am I reading that correctly?

**A.** Yes. That's what this matrix represents, the forecasted outages in the future, yes.

**Q.** Okay. So at this point in time, it was one major outage per year. As we sit here today, isn't it true that the company is asking for this Commission to grant them rate relief that would account for two-and-a-half major outages for Big Bend in 2009?

**A.** Yes. In 2009, our present maintenance schedule would include the major outage that's listed here, a 98-day outage in 2009. That was originally planned for the SCR, selective catalytic reduction, installation. That's moving forward as planned. I would say that that outage actually started last year in November and is carrying on as we speak.

We also will take Unit 1 off. Now, in this particular plan, it listed it as an FS, which is a fuel system outage. It was expected to be a 14-day interval. And I believe this document -- we talked about it in my deposition. I believe this document appears to be prepared in 2006, so it was some time ago. We had made the decision to sequence the timing of the SCR outages such that they start at the end of the previous year, if you will -- for Big Bend 2, that was 2008 -- and continue into 2009. The same will occur in 2009 going into 2010 for the Big Bend 1 SCR tie-in. We've got four units at Big Bend. They're all required to install these SCR systems, and they've got to be in place by rule by 2010.

So this 14-day fuel system outage will actually be about a five-week interval. It's the start of the SCR work on that unit, and I think that's the one you referred to as -- or I would refer to as half a major. It's the smaller portion of the major outage, which will continue in 2010.

In addition, we have an extended outage. There was a planned maintenance period on Big Bend Unit

4, a 21-day interval described as a fuel system outage. We have extended the scope on that based on some work that is necessary for reliable operation and actually came to light or came to our understanding after this business plan was created under some superheater work that's causing us issues with reliability on the unit, and we need to perform maintenance on that unit in 2009.

**Q.** Thank you for that. I was not going to get into all that level of detail, but, you know, I understand that things change and whatnot. I'm kind of looking at it maybe from the perspective of the gentleman that Mr. Twomey referenced in the opening.

You could possibly see how it might raise an eyebrow if the major outage schedule went from one to two-and-a-half or three, depending on how you count that, over a couple of years' course in time, couldn't you?

**A.** Well, from 2006 to 2009, those plans certainly changed. I would say they were forecast from that business plan early on, and as things became more clear and the timing of outages developed, that plan was jelled together. I would say it is necessary and prudent work, clearly, that needs to be performed in 2009.

**Q.** Okay. And I understand that plans can change.

I thought Mr. Black, the president of the company, also indicated that there may be a change in plans with the combustion turbines coming online. I think you were asked a question about that earlier. Mr. Black testified that there may be some consideration of deferring a couple of the CTs. You don't have any reason to disagree with his testimony that he gave to this Commission earlier this week, do you?

**A.** I don't have a reason to disagree with Mr. Black's testimony. I will say that as director of engineering and construction, my department's charge is to move forward with all those machines.

The machines that are being installed and will go in service in May are largely completed. The combustion turbines, the generators, and the generator step-up units are in place. If you looked at the machines, you would say they're essentially mechanically complete. We're doing piping and wiring. We expect first fire on those machines in April. So there has been a substantial amount of effort. The other machines are pretty far along as well, so --

**Q.** Some of them are coming in in May and the others in September; is that right?

**A.** That's correct. There are two machines that are scheduled to go in service at the Bayside Station, Units 5 and 6, in May, two more machines in September at Bayside, and the fifth machine at Big Bend in September.

**Q.** All right. And we discussed this in the deposition, but I just want to make sure I'm clear. You guys plan for a 20 percent reserve margin; correct?

**A.** That's correct.

**Q.** And if none of these CTs went in in 2009, wouldn't you have over a 20 percent reserve margin in 2009?

**A.** As we discussed in my deposition, if you look at the latest load forecast, which was part of the rate case filing, without the two May CTs, we would be slightly over the 20 percent reserve margin for the summer 2009 peak. We would need them for the winter 2010 peak, based on our last forecast.

I would add, just last week we had a new system peak, winter peak record that was set on Wednesday that was 180 megawatts higher than our previous winter record. So we are seeing peak demand growth, and the need for those machines is there, and as I said earlier, they have other operating benefits.

**Q.** No, I understand. But with respect to the 20 percent reserve margin, if you don't put any of the CTs in, you're still over 20 percent; correct?

**A.** Based on our latest load forecast, which was not the load forecast that we made the decision under, that is true. We were slightly over the 20 percent margin.

**Q.** Okay. And also, it's true that Tampa Electric Company for a number of years operated at a 15 percent reserve margin; correct?

**A.** Yes, that's my understanding.

**Q.** Now, you answered Public Counsel's question by indicating that in your view, you didn't think it was typical to have three outages in one year at Big Bend; correct?

**A.** That's correct. I believe it's probably not the norm if you look at the overall average, but it is not unprecedented.

**Q.** And for ratemaking purposes in rate cases, don't you try to, you know, kind of factor in the norm for the purposes of recovering rates and present testimony and facts on the norm as compared to the atypical?

**A.** That's my understanding of selecting a test year. However, that's not really my area of expertise. I would say that selecting only the planned outage expense is a narrow view and represents probably only 20 percent of our total O&M for energy supply.

**Q.** All right. I have a few more questions, and then I think I'll be done with you in terms of the questions.

You were asked questions about dredging. I want to explore the dredging issue a little bit with you.

**A.** Yes, sir.

**Q.** Currently, you dredge that material up. Commissioner Argenziano asked you about its characteristics. I mean, none of that stuff that you land apply is hazardous or has any properties that are problematic from a DEP perspective; correct?

**A.** Yes. From an environment characterization, that material is not classified as a hazardous waste. It doesn't reach that level.

There are characteristics of it, as we discussed in my deposition. Part of that material is sandy and granular, as you would expect. Part of it is silty and clay-like. So if you went out and looked at the material that has been deposited in our disposal areas, some of it is -- I'm not sure of a good technical term, but gooey. It would -- it's sticky. And in terms of fill, fill material, it's really not appropriate for purposes of fill, backfill. But, no, it is not a hazardous waste.

**Q.** Isn't it true that you in the past have either given it away or sold it to third parties for purposes that they would make use of it?

A. Yes, it is true. Some of the material is of that sandy, granular nature, and in certain areas of our disposal area, we were able to reclaim only the appropriate material that's useful, that's not contaminated with the clay and softer material. Unfortunately, the majority of that has been mixed and is kind of homogenized, and it's not possible to separate it.

So we've had limited success. And certainly that's something we would like to do more of, is to find a beneficial reuse for it.

Q. And you mentioned conversations with landfills. Isn't it your understanding that this material can also be used for alternate daily cover at landfills, which means they put it on top of the garbage that's disposed of on a daily basis to kind of keep the flies and the smell down?

A. Actually, we did discuss that in the deposition. I was unaware at the time of the investigations that had gone on. Subsequently, I've talked to our folks, and we have offered that as daily cover at a landfill. The stickiness, the clay material makes it unsuitable for that purpose. The landfills have an issue with their vehicles. That material will stick to the tires and create an issue, and it's really not suitable, and they're not interested in that material for daily cover. They will take it as a waste, but it's not suitable for the daily cover purpose.

**Q.** Which landfill was that that told you that?

**A.** I believe it's the Okeechobee landfill. That's subject to check.

**Q.** Okay. Another issue related to this dredging is the frequency of the dredging. And I think in response to a question from Commissioner Skop, you said that hurricanes might accelerate the silting-in process; is that correct?

**A.** Yes, that is correct. The wave action in the bay, particularly at the deep levels, has certainly an influence on how rapidly the channels will silt in. They're quite a bit deeper than the average depth around them.

**Q.** And the hurricanes in Florida, the most recent years we had a lot of hurricanes were 2004 and 2005; correct?

**A.** 2004 sticks out in my mind in particular, yes.

**Q.** And this was dredged in 2002?

**A.** Yes.

**Q.** Okay. And then you're looking to dredge it again seven years later in 2009?

A. Yes. It's actually a little over six years.

Q. Okay. I think there has been a suggestion that the cost of dredging be amortized not over five years, but over a longer period of time. Wouldn't that seem to make sense, you know, if we had storms in '04 and '05 and you were able to go seven years dredging that channel, that at least for recovery purposes, that you amortize it over a longer period of time?

A. As I said, it would be in the six-year time frame this time. If you look back at our previous three dredging intervals, though, they average a five-year interval. We were able to defer it on this last one, but we feel it's most appropriate -- if you look at history and our typical experience, a five-year interval is appropriate.

Q. Okay. Just a few more questions. We talked in the deposition. I just wanted to spend a couple of minutes on SCR. Would you just briefly tell the Commission what the SCR is?

A. Uh-huh. SCR is a pollution control device. It's selective catalytic reduction. There's a catalyst that's -- a catalyst matrix that's installed in the duct between the boiler and the air preheater. We inject ammonia ahead of that. In that process, the ammonia with the flue gas will take nitrogen oxides and convert that to elemental nitrogen, which is not a pollutant. SCRs are a fairly common technology now for $NO_X$ control.

**Q.** And SCRs, they came about as a result of a settlement you guys had with DEP and the EPA; correct?

**A.** That's correct, the installation of the SCRs, not the SCRs themselves. That technology has been around for some time, but our plans and the requirements to install SCRs was as a result of those orders you referenced.

**Q.** The moneys that you spend on SCRs, that's nonrecurring, correct, because you put them in once?

**A.** That's correct.

**Q.** Okay. And --

**A.** Well, just let me add that there's maintenance that goes on in addition. Once you install the catalysts, they need to be replaced periodically, but the initial capital is a one-time event.

**Q.** And you guys are seeking to recover days of outage associated with maintenance. Isn't it true that the average time to put the SCR in is four to five weeks?

**A.** No, it's longer. It's a longer period than that for an SCR outage.

**Q.** How long is it?

**A.** The Big Bend 2 outage that started in November of 2008 will finish in April. I believe it's 130 days for the total duration of that outage work.

**Q.** And what you're trying to do just so you're efficient is, you also perform regular scheduled maintenance on these units when they're down for the extended time for the SCR installation; correct?

**A.** Yes. To be prudent, it would make sense for us to perform other planned maintenance within that window. The critical path, the duration of the outage is set by the SCR work. That's the longest duration task, and we can complete the other planned maintenance within that time frame.

**Q.** So wouldn't it make sense, from your perspective, that if the -- and I'll just use these numbers as hypotheticals -- if the SCR time is five weeks and the time that the plant would be down for normal, otherwise scheduled maintenance is three weeks, that you would use the three-week time period for calculating expenses that should be recovered from ratepayers as compared to the five-week time, because that's a one-shot, nonrecurring time frame? Would you agree with that?

**A.** If I understood your question correctly, the calculation of costs and budgets associated with those activities, the SCR installations are stand-alone capital projects, approved environmental cost recovery projects.

The planned maintenance work is identified by scope, by activity, and by the dollars spent on each one of those projects, and that would be the breakdown, the appropriate breakdown in terms of budget and estimating expenses.

**Q.** Okay. Isn't it true that the units are permitted, the Big Bend units are permitted to run without the SCRs pursuant to the settlement agreement?

**A.** That is true, but it will no longer be the case at the completion of the SCR installations.

MR. MOYLE: No further questions, Mr. Chairman. Thank you.

CHAIRMAN CARTER: Thank you, Mr. Moyle. Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. WRIGHT:

**Q.** Good afternoon, Mr. Hornick.

**A.** Good afternoon.

**Q.** I just have a few questions for you.

I'm looking at the single-page document from Tampa Electric's earlier Big Bend Station business plan that Mr. Moyle had distributed earlier. It appears to me that the normal modus operandi for Tampa Electric with regard to planned major outages at Big Bend Station was to take one unit out for a major outage each year in sequence. Is that an accurate characterization?

**A.** I think that outage planning has changed over time. One of the things that's significant -- has been a significant challenge for us is the completion of these SCR installations. And with the length of those outages, we've had to very carefully plan when that work would take place and sequence them accordingly, because they are long outages, and we've got to make sure we've got adequate generating units in service to cover the demand of our customers.

So as this plan indicates -- and I think what this represents is really the schedule for the SCRs and the work, subsequent work for other units in those time frames. We are moving in the direction of more frequent outages and in fact are moving in the direction of a two-year interval, major outage interval on the Big Bend units in the future. We think that's going to provide greater reliability and probably overall lower costs in the future.

**Q.** This plan did project the SCR retrofits at all the Big Bend units, did it not?

A. Yes, it does project the retrofits in the year. As I stated earlier, there was some minor change in terms of the sequencing. I think when this plan was put together, there was an expectation that we would start the outage around the beginning of the calendar years, and we've slid the total duration so they cross from December of the previous year into April, roughly, of the following year.

Q. In your prior response, you said you are moving in the direction of an outage, I guess, every other year for each of the -- a major outage every other year for each of the Big Bend units. Did I understand that correctly?

A. Yes.

Q. What's that going to do to the capacity factor of those units?

A. It will have -- the capacity factor.

Q. Well, let's start with the availability factor. What's it going to do to the availability factor?

A. Okay. The availability factor. Certainly with more planned outage time, you will have more time for the units spent unavailable during that. However, there will be an offsetting impact. The forced outage time for those units will decrease such that the overall reliability we feel will be improved based on a more frequent major outage schedule.

Major outages, just to clarify a little bit, can run different lengths. Which classify a major as a four-week outage, four-week duration or greater. Depending on the critical path job, you could have a four-week major outage or potentially an eight-week major outage, depending on what we call the critical path scope, the longest duration job within that duration.

**Q.** What is the average forced outage rate on your Big Bend units?

**A.** Just bear with me a second.

I don't have the breakdown on forced outage rate for the Big Bend units. The overall availability, it varies by units. It's in the high 60, 70 percent range, by memory, subject to check.

**Q.** The overall availability factor?

**A.** Equivalent availability factor, yes. It varies by year. Of course, currently, with these longer SCR outages, that's impacting it to some extent as well.

**Q.** Just in ballpark terms, is the forced outage rate for those units higher than 3 or 4 percent?

**A.** Yes.

**Q.** I think you mentioned in some prior responses that you're in the middle of an extended outage at Big Bend 2. Did I get that right?

**A.** Yes, that's correct.

**Q.** And it started in November of 2008?

**A.** Yes.

**Q.** And you also testified that you recently hit a new high winter peak last week, I think, or the week before?

**A.** Yes. Last week, Wednesday -- Thursday morning.

**Q.** I'm just curious why you all are scheduling outages of your major base load units during the time that you're likely to encounter winter peak. Why is that?

**A.** It's because of the requirement for these SCR installations. We really -- we've got to sequence four units in, long duration outages over a four-year interval, so that's the primary driver there.

**Q.** And when did you enter into the settlement agreement that required you to install the SCR equipment on these plants?

**A.** It was several years ago, 1999, 2000, somewhere -- I'm really not sure.

**Q.** Thank you. That's consistent with my recollection.

I just have one more question for you. You testify in your testimony regarding the representation as fact that Tampa Electric's production O&M has not exceeded the Florida Public Service Commission's O&M benchmark; is that correct?

**A.** That's correct.

**Q.** And my question for you really just goes to the meaning of the benchmark. Will you agree that the benchmark is simply an initial evaluative tool and that it's not -- that if you don't exceed it, that doesn't mean that you don't have to prove up anything else about the prudency of your costs? Is that a fair characterization?

**A.** It's my understanding that the benchmark comparison is one method, Commission-approved method that provides an indication as to the prudency of expense. And I'm not -- regulatory affairs is not my area of expertise, and I'm not sure I could offer an opinion beyond that.

MR. WRIGHT: Thank you very much. Thank you, Mr. Chairman. Thank you, Mr. Hornick.

CHAIRMAN CARTER: Thank you, Mr. Wright. Mr. Twomey.

MR. TWOMEY: I don't have any questions of this witness.

CHAIRMAN CARTER: Thank you, Mr. Twomey. Commissioners, I'm going to go to staff. Staff, you're recognized.

MR. YOUNG: No questions.

CHAIRMAN CARTER: Okay. Back to the bench. Anything further?

Okay. Let's go to redirect.

MR. HART: No, Mr. Chairman, we don't have any redirect, but we would move Exhibits Number 22 and 82 into the record.

CHAIRMAN CARTER: Exhibit Number 22 and 82, are there any objections? Without objection, show it done.

(Exhibits 22 and 82 were admitted into the record.)

CHAIRMAN CARTER: Anything further for this witness?

MR. HART: May Mr. Hornick be excused?

CHAIRMAN CARTER: You may be excused. Call your next witness.

MR. BEASLEY: We call Ms. Wehle.

CHAIRMAN CARTER: I beg your pardon? Ms. Wehle?

MR. BEASLEY: W-e-h-l-e.

CHAIRMAN CARTER: Thank you.

MR. BEASLEY: Ms. Wehle, have you previously been sworn in this proceeding?

THE WITNESS: No, I have not.

CHAIRMAN CARTER: Ms. Wehle, would you please stand and raise your right hand.

(Witness sworn.)

CHAIRMAN CARTER: Please be seated. You may proceed.

Thereupon,

JOANN T. WEHLE

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

DIRECT EXAMINATION

BY MR. BEASLEY:

**Q.** Ms. Wehle, would you please state your name, your business address, and your position with Tampa Electric Company?

**A.** Yes. My name is Joann Wehle. I am the director of wholesale marketing and fuels for Tampa Electric Company. My business address is 702 North Franklin Street, Tampa, Florida.

**Q.** Ms. Wehle, did you prepare and submit in this proceeding a document entitled "Direct Testimony of Joann T. Wehle"?

**A.** Yes, I did.

**Q.** Do you have any corrections to make to that document?

**A.** No, I do not.

**Q.** If I were to ask you the questions contained in your prepared direct testimony, would your answers be the same?

**A.** Yes, they would.

MR. BEASLEY: Mr. Chairman, I would ask that Ms. Wehle's direct testimony be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony of the witness 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**

**JOANN T. WEHLE**

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

**A.** My name is Joann T. Wehle. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Wholesale Marketing & Fuels.

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

**A.** I received a Bachelor of Business Administration Degree in Accounting in 1985 from St. Mary's College, Notre Dame, Indiana. I am a Certified Public Accountant in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services; subsequently, I rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

**Q.** What is the purpose of your direct testimony?

**A.** My direct testimony describes Tampa Electric's fuel inventory planning process and the factors that influence the reliable supply and delivery of coal, oil and natural gas. Fuel inventory planning is used to determine the proposed fuel inventory working capital levels included in the rate base in this proceeding.

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

**A.** Yes, Exhibit No. ___ (JTW-1), entitled "Exhibit of Joann T. Wehle", was prepared under my direction and supervision. It consists of the following documents:

| | | |
|---|---|---|
| Document No. | 1 | List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By Joann T. Wehle |
| Document No. | 2 | 2009 Proposed Coal Inventory |
| Document No. | 3 | Coal Inventory Levels 2003-2007 |

Document No. 4 2009 Proposed Fuel Inventory

**Q.** What is the objective of Tampa Electric's fuel inventory planning process?

**A.** The company seeks to maintain the level of fuel inventory necessary to minimize the risk of service interruptions due to fuel depletion or the lack of environmentally acceptable fuels. This means that the company's overall planning process must recognize factors that affect inventory levels, such as fuel supply uncertainty, fuel delivery disruption, fuel burn variation and extraordinary events.

Tampa Electric's fuel inventory planning process is driven by the understanding that depleting fuel inventory to unreasonably low levels is costly and unacceptable. The company believes that the cost of carrying sufficient levels of fuel is much less expensive than making emergency purchases of fuel at a premium price, buying replacement power or interrupting electrical service to customers due to the lack of supply of fuel. By recognizing the multitude of issues that may interrupt fuel supply at a power plant, Tampa Electric uses diverse supply sources, redundant delivery methods and sufficient storage sites within its system.

**Q.** What types of fuel does Tampa Electric use?

**A.** Tampa Electric uses coal and pet coke ("coal"), natural gas, light oil and heavy oil for generation fuels. In 2007, energy generated by Tampa Electric was fueled by about 56 percent coal, 44 percent natural gas and less than one percent fuel oil. The company's annual coal requirement is a burn of approximately five million tons and the annual natural gas requirements are about 60 million MMBTUs. A relatively small amount of heavy (#6) oil and light (#2) oil is used to meet peak load and backup requirements.

**Q.** What fuel inventories are components of your overall system-wide fuel inventory?

**A.** Tampa Electric considers coal, natural gas and oil to be components of its overall system-wide inventory. For coal, inventory includes all coal that the company owns and has in its control. This includes coal that is stored on-site at the power plants, stored off-site, and en route. The natural gas amount included in inventory is the amount owned by Tampa Electric and stored in underground storage caverns or stored in interstate pipelines. For oil, only that which is stored on-site is included in inventory because oil is not under Tampa Electric's ownership or control until it reaches the plant site.

**Q.** Please explain Tampa Electric's fuel inventory planning process.

**A.** Tampa Electric's overall system-wide inventory planning process relies on projected burns, forecasted purchase arrangements and delivery lead times to convert the target days of inventory into the required tons, MMBTUs or barrels of inventory. As circumstances and projections change, Tampa Electric updates projections for future periods to assure it maintains reliable inventory levels. It is important to recognize that appropriate inventory levels vary from one type of fuel to another and are not necessarily the same for all utilities.

**COAL INVENTORY**

**Q.** What system-wide coal inventory levels are included in the company's inventory planning process?

**A.** Tampa Electric's coal inventory levels are included at "target" levels. Tampa Electric's overall system-wide coal inventory target level is 98 days projected burn (95 days supply under normal circumstances plus 3 days supply for test-burn). This is consistent with the 98 days projected burn approved in the company's last rate case. While the number of days of burn is the same, the overall tonnage of coal is actually less due to re-powering Gannon Power Station from coal to natural gas, and renaming it, H. L. Culbreath Bayside Power Station.

**Q.** Please describe the company's experience in maintaining coal inventory.

**A.** The company has over 50 years of experience in fuel supply management, including coal and other fuel sources. Over this time, the coal supply inventory levels have been impacted by adverse weather conditions including floods, hurricanes, water route blockages, coal and railroad industry strikes, burn variations and transportation provider equipment breakdowns. The company has established its coal inventory planning process to reflect the impact of these and other factors. These factors are monitored continually because running out of fuel or exceeding environmental limitations due to the lack of environmentally useable coal types is not acceptable.

**Q.** What major factors influence the level of coal inventory Tampa Electric proposes to maintain in 2009?

**A.** There are a number of considerations that influence Tampa Electric's proposed 2009 coal inventory level. These factors can best be discussed under three major categories of inventory planning: 1) coal supply and transportation uncertainty 2) coal burn variability and 3) other risk factors.

**Q.** What are some examples of supply and transportation disruptions that contribute to or cause coal inventory uncertainty?

**A.** Tampa Electric's plants are located approximately 1,000 miles from the Illinois Basin where the vast majority of its coal is mined. Force majeure events and safety issues can halt coal production or interrupt transportation. Diminished supplier performance can also cause a supply disruption or reduction on contract and spot purchases.

The river and rail transportation systems used to deliver coal are subject to supply disruptions. Tampa Electric faces the possibility of river closings associated with the repair of lock mechanisms. These river locks raise and lower the barges for proper navigation through the Mississippi and Ohio River systems. Almost every year the river systems have high and/or low water conditions due to excessive drought or rainy conditions. Fog, ice and transportation equipment breakdowns can delay or interrupt transportation on the river system as well.

Likewise, the Gulf transportation system can be affected by fog, hurricanes and equipment breakdowns. Gulf Coast hurricanes such as Hurricane Katrina that impact the mouth of the Mississippi can significantly disrupt coal and all other energy commodity deliveries.

The rail transportation system can be affected by congestion, maintenance down time, rail blockings, flooding and equipment breakdowns resulting in slower turn times, the time it takes a train to return to the coal mine for its next shipment and fewer annual deliveries.

**Q.** How can these coal supply and transportation disruptions affect Tampa Electric's inventory?

**A.** Up to 50 percent of Tampa Electric's coal inventory at any given time is off-site or in-transit. As a result, up to half of the inventory is subject to the risk of being delayed due to many factors, which can affect coal availability. The availability of Tampa Electric's coal supply and consequently the level of inventory the company must have on hand must reflect these types of coal supply uncertainties.

**Q.** What is meant by coal burn variability?

**A.** Coal burn variability refers to the difference between a planned and actual coal burn. One reason for having coal inventories is to ensure against periods of unexpectedly high coal burn requirements. Typically, coal suppliers and transporters require relatively level production and delivery schedules to offer their lowest pricing. However, the coal units' consumption actually varies daily and monthly depending on weather, performance, fuel type and outages.

**Q.** Why is the recognition of coal burn variability important for Tampa Electric in its planning process?

**A.** The importance relates to reliability. The amount of burn variability in the overall inventory planning process depends on how quickly and how completely the company's means of coal delivery can respond to unexpected fuel requirements at the plants. As I previously stated, the company's power plants are located approximately 1,000 miles away from their coal supply sources; therefore, the company's coal inventory planning process must ensure that higher than expected fuel consumption can be accommodated.

**Q.** What is meant by other risk factors affecting coal inventory planning?

**A.** Other risk factors are those unidentified low probability but high consequence events that prudent fuel inventory management must take into consideration because they could significantly affect fuel levels. These events can result in major disruptions to coal supplies by affecting suppliers, the transportation system and even fuel requirements.

**Q.** What are some examples of these other risk factors?

**A.** These other risk factors include events of severe weather such as hurricanes, transportation route shut downs or legislative and regulatory changes affecting fuel use.

Given the risks associated with hurricane activity and the problems one Gulf hurricane can cause, maintaining a 98 day coal inventory level is very reasonable. For example, due to Hurricanes Katrina and Rita in 2005 coal inventory levels were depleted to less than 20 days at Big Bend Power Station in the months following the hurricanes because of the extended interruption of transportation. These same events caused a shutdown of gas supply due to the evacuation of and damage to gas production platforms in the Gulf of Mexico. As a result, limited gas supply due to infrastructure and transportation facility damage can create a higher demand for coal.

Catastrophic events like damage to the Sunshine Skyway Bridge in the 1980's blocked the channel and prevented coal deliveries for an extended period. Vessels can and have sunk in the Port of Tampa channels, blocking deliveries.

In addition, the events of September 11, 2001 complicated and delayed the transportation of coal due to heightened security in ports.

There is an additional risk that multiple supply disruption events can occur in rapid succession and compound the effects of these individual risks. The prospect of running out of fuel is not an option; therefore, it is essential to have an adequate cushion to avoid such an event.

**Q.** Please summarize Tampa Electric's proposed 2009 coal inventory.

**A.** The overall anticipated quantities of coal in inventory by station for 2009 are reflected in Document No. 2 of my exhibit. This chart includes coal stored on-site at the power plants, stored off-site and in-transit. The inventory levels are consistent with the targets in the company's inventory planning process, which reflects the company's projected needs.

**Q.** What is the proposed average coal inventory level for 2009?

**A.** The proposed 13-month average coal inventory value for 2009 is $83,819,000 and is equivalent to 94 days burn under normal circumstances at an approximate 13,000 daily tonnage burn rate. This tonnage does not include any test burn supply because the company will be continuing its installation of the final selective catalytic reduction equipment at Big Bend Power Station and will not perform test burns until the installation is complete. This proposed level is slightly less than but consistent with the 98 days coal burn total (95 day supply under normal circumstances plus three days supply for test burn) established in the company's last full rate case. A 94 day coal inventory is conservative because of the circumstances and risks I have described. A 94 day coal inventory is the absolute minimum given that a 98 day coal inventory target is appropriate.

**Q.** How does the proposed coal inventory level compare to Tampa Electric's historical coal inventory levels?

**A.** It compares favorably with the company's actual coal inventory levels over the past five years. Tampa Electric's actual coal inventories have averaged 1.21 million tons. Extraordinary events such as the 2004 and 2005 hurricanes and significant river lock outages in

2006 brought the overall inventory levels down by several days on average. In the past two years, inventory of coal for Tampa Electric represented an average of 97 days. Document No. 3 of my exhibit details the historic coal inventory levels for 2003 through 2007.

**Q.** Aside from the Commission Order issued in the company's last base rate proceeding, how does the proposed coal inventory level compare to other Commission precedent?

**A.** Order No. 12645, issued in Docket No. 830001-EU, addresses Fuel Inventory Policies. In this Order, staff proposed a "generic" fuel inventory policy to be applied in a rate case if a utility fails to fully justify its inventory level. The proposed generic fuel inventory policy for coal was 90 days projected burn plus base coal volumes. Tampa Electric has fully justified its request for 98 days of coal inventory and the level requested is slightly higher than but consistent with the 90 day fuel inventory policy.

**NATURAL GAS INVENTORY**

**Q.** Please describe the company's experience in maintaining natural gas inventory.

**A.** Tampa Electric's oldest natural gas fired unit, Polk Unit 2, is a combustion turbine that became operational in 1998. Since that time, Tampa Electric has added three more combustion turbines and re-powered Gannon Station as natural gas combined cycle Bayside Units 1 and 2. Bayside Units 1 and 2 became operational in 2003 and 2004, respectively. Tampa Electric has continually enhanced its natural gas supply portfolio since 1998 including adding underground natural gas storage capacity beginning in 2005.

**Q.** What is Tampa Electric's inventory planning process for natural gas?

**A.** The company's supply plan for natural gas is to maintain a portfolio of natural gas supply arrangements that have various delivery points, volume flexibility and term lengths. These natural gas supply arrangements are conducted through industry standard contracts with creditworthy parties. This process allows for reliability of supply, operational flexibility and lower overall cost.

Besides having secure supply arrangements, underground natural gas storage is a valuable component of maintaining reliable service for customers. Natural gas storage is used primarily to address unexpected swings in gas supply needs due to forced outages of units and weather changes, and to "smooth" gas supplies over weekends and holidays when consumption levels may change dramatically. Tampa Electric also maintains nearly full contracted storage levels during times of greatest uncertainty. For instance, Tampa Electric fills storage before the start of each hurricane season since supply availability may be at risk during the same period that gas consumption is at its maximum. Similarly, Tampa Electric keeps natural gas storage nearly full during major plant outages and extreme cold periods since gas consumption has the greatest uncertainty during those periods.

**Q.** What natural gas storage does Tampa Electric have?

**A.** Tampa Electric currently has a contract with Bay Gas Storage for up to 850,000 MMBTU of storage capacity and expects to increase its total storage to 1,250,000 MMBTU with the completion of Bay Gas Storage Cavern in the summer of 2009. The 1,250,000 MMBTU of storage capacity provides Tampa Electric with approximately six summer days of gas supply. The volume of natural gas in storage in 2009 is projected to average about 545,000 MMBTU of gas in storage with a 13-month average value of $4,495,000.

**OIL INVENTORY**

**Q.** What is the company's oil inventory planning process?

**A.** Although less than one percent of the company's generation comes from its oil-fired units, this generation is critical for peak demand periods. Therefore, the company is concerned with maintaining proper levels of oil inventory. The minimum desired level for both light and heavy oil at each plant is an adequate supply determined to be necessary to maintain the reliability of the company's generation system during maximum demand conditions.

**Q.** Do the criteria for oil inventory levels differ from those applicable to coal inventory?

**A.** Yes. While the normal generation dispatch procedure provides for priority generation by coal, the oil-fired generating units must have adequate supplies of oil, not only for expected use, but also to allow for their continued use in the event of unscheduled outages of major coal-fired units, limitations of natural gas supply, and/or higher than expected loads. This contingency consideration dictates that greater quantities of oil be maintained in inventory than normally would be maintained on a purely projected burn basis. The No. 2 oil is also necessary for boiler ignition of the coal-fired units.

**Q.** What is the goal of Tampa Electric's inventory planning process for heavy oil?

**A.** The company's heavy oil inventory planning process is to maintain, at a minimum, the level of oil necessary to provide peaking reliability in its generating system. The company projects to average 9,203 barrels of heavy oil in inventory in 2009, with an average value of $780,000.

**Q.** What is Tampa Electric's inventory plan for light oil?

**A.** The company's light oil inventory plan is to maintain, at a minimum, the level of oil necessary to provide peaking reliability in its generating system. The company has included 77,068 barrels of light oil in inventory for 2009, which equates to a 13-month average of $9,312,000.

**TOTAL FUEL INVENTORY**

**Q.** What is the total amount of fuel inventory that Tampa Electric proposes to be included in working capital for 2009?

**A.** The 2009 13-month average total fuel inventory included in working capital is $98,406,000 as shown on Document No. 4 of my exhibit.

**Q.** Please summarize your direct testimony.

**A.** Tampa Electric generates energy for customer use from a diversified portfolio of coal, oil and natural gas fired units. The company utilizes a dynamic fuel inventory plan that takes into account fuel supply and transportation uncertainty, fuel burn variability, and other risk factors, to provide a consistent level of system protection and reliability. Inventory levels take into account the types of fuel maintained and burned to meet plant requirements at the lowest possible cost to customers.

Tampa Electric's 2009 total proposed fuel inventory of

$98,406,000 is an appropriate value for the fuel inventory component of working capital. This level of inventory provides for continued reliable service at a cost that is less than the consequences of not having enough fuel to meet the customer needs. Finally, this inventory level is consistent with the company's inventory planning process and actual historic inventory levels.

**Q.** Does this conclude your direct testimony?

**A.** Yes, it does.

BY MR. BEASLEY:

**Q.** Ms. Wehle, did you prepare the document, the exhibit entitled -- or identified as JTW-1 and marked Hearing Exhibit Number 23 that accompanies your prepared direct testimony?

**A.** Yes, I did.

**Q.** Do you have any corrections or changes to make to that exhibit?

**A.** No, I do not.

**Q.** Did you also prepare and submit in this proceeding a nine-page document entitled "Rebuttal Testimony of Joann T. Wehle"?

**A.** Yes, I did.

**Q.** Do you have any corrections to make to that testimony?

**A.** No, I do not.

**Q.** If I were to ask you the questions contained in that testimony, would your answers be the same?

**A.** Yes, they would.

MR. BEASLEY: I would ask that Ms. Wehle's rebuttal testimony be inserted into the record as though read.

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

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 080317-EI**
**FILED: 12/17/08**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**REBUTTAL TESTIMONY**

**OF**

**JOANN T. WEHLE**

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

**A.** My name is Joann T. Wehle. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Wholesale Marketing & Fuels.

**Q.** Are you the same Joann T. Wehle 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 serious errors and shortcomings in the prepared direct testimony of witness Hugh Larkin, Jr. testifying on behalf of the Citizens of the State of Florida related to the appropriateness of rail facilities at Big Bend

Station and fuel inventory valuation.

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

**A.** Yes, I have. My Rebuttal Exhibit No.__ (JTW-2) was prepared under my direction and supervision. It consists of the following two documents:

| | |
|---|---|
| Document No. 1 | Excerpt from Order PSC-04-0999-FOF-EI in Docket No. 031033-EI |
| Document No. 2 | Hill & Associates, Inc. Rail Feasibility Study - Executive Summary |

**Q.** Please summarize the key concerns and disagreements you have regarding the substance of Mr. Larkin's testimony.

**A.** My key concerns and disagreements are that:

- Mr. Larkin makes several false assumptions about the company's planned rail facilities at Big Bend Station which result in an unwarranted adjustment to Tampa Electric's revenue requirement.

- Mr. Larkin arbitrarily reduces the fuel stock value component of the company's working capital request to reflect perceived fuel price reductions. Mr. Larkin based his unwarranted adjustment on the assumption that the values Tampa Electric uses are inflated when they are not.

**RAIL FACILITIES**

**Q.** In reference to the rail facilities at Big Bend Station, Mr. Larkin denotes that a solicitation for coal and solid fuel transportation was conducted. Can you please elaborate on the requirements of this solicitation?

**A.** Yes. As part of Order PSC-04-0999-FOF-EI issued on October 12, 2004 in Docket No. 031033-EI ("the Order"), the Florida Public Service Commission ("Commission"), among other things, outlined requirements for the company's next competitive bidding process in connection with solid fuel transportation. This competitive bidding process occurred in 2007 and 2008. The pertinent portion of the Order is included as Document No. 1 of my rebuttal exhibit.

Another requirement of the Order was that Tampa Electric was to conduct a study on the feasibility for bimodal transportation. The company hired Hill & Associates to conduct the study in 2005 and the executive summary of the study is included as Document No. 2 of my rebuttal exhibit. The complete study was made available to Office of Public Counsel, Staff and all other parties in 2005.

**Q.** Did Tampa Electric comply with all of the requirements of the Order and what were the results of this competitive bidding process?

**A.** Yes. The Commission recently made its determination in Docket 080001-EI ("Fuel Docket") that the company had conducted a competitive solicitation process as required by the Order. As a result of the process, the company awarded solid fuel transportation contracts to three bidders: United Maritime Group, AEP Memco, and CSX Transportation ("CSX").

**Q.** Please provide more information about the rail feasibility study that was required by the Order.

**A.** A rail feasibility study was conducted by Hill & Associates in 2005, and Tampa Electric filed it with the commission. The study was a comprehensive review of all possible coal sources that meet the company's quality specifications and the associated costs of delivering those coals by rail or by water to Tampa Electric's generating stations. The conclusion of the study was that there are certain coals that are more cost effective when delivered via rail. The company's recent competitive bid solicitation supported these same conclusions.

**Q.** What benefits did the company determine exist from a rail provider?

**A.** Tampa Electric determined that bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitive, overall delivered cost, 2) the flexibility to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

**Q.** Did the Commission agree that there are company and customer benefits by contracting with CSX?

**A.** Yes, it did. In the Fuel Docket, the Commission determined that the company had performed a competitive procurement process with a beneficial outcome for its customers.

REDACTED

Q. In order to begin taking delivery of solid fuels at Big Bend Station, what infrastructure is required?

A. As described in the direct testimony of Tampa Electric witness Mark Hornick, the company is required to construct rail facilities. The facilities must be built and tested in 2009 to begin taking delivery by January 1, 2010. These facilities will benefit customers for, at a minimum, the five-year term of the contract.

Q. Mr. Larkin states in his testimony on page 21 that the rail carrier stands to benefit from the movement of additional coal and it would be appropriate for it to absorb some of the needed facility costs, which is common practice. Please comment on this statement.

A. I understand that railroads have absorbed costs or contributed financially to the construction of rail facilities but I am not aware of how often this arrangement has occurred with railroads. In Tampa Electric's contract with CSX, there is a provision for a per ton refund in consideration for the construction of the rail facilities [redacted]. Tampa Electric proposes that it use the refund to first offset the capital costs associated with the facilities that are in excess of those granted in base rates with any remainder being credited to customers through the fuel and purchase power cost recovery clause.

**FUEL INVENTORY VALUATION**

**Q.** What adjustment to the company's fuel inventory value does Mr. Larkin recommend in his direct testimony and why?

**A.** On page 35 of his testimony, Mr. Larkin reduces the fuel stock value 10 percent or $9.493 million. His reasoning is that the 10 percent reduction reflects current reductions "which might have occurred in coal, oil and gas prices" (emphasis added).

**Q.** Is this adjustment appropriate?

**A.** No it is not. His proposed adjustment is based on a baseless and arbitrary assumption and he admits it. Mr. Larkin states on page 35, lines 21 through 23 that "The adjustment I have made does not accurately reflect an estimate of the decline in fuel prices because I do not have all necessary information available to me." Clearly he is not in a position to make such an adjustment.

**Q.** Are the values for fuel inventory represented in your direct testimony still appropriate?

**A.** Yes, they are. The company utilized fuel pricing from the spring of 2008, which is still representative of projected fuel prices.

**Q.** How do the fuel prices included in your direct testimony compare to the company's 2009 fuel filings approved in the Fuel Docket?

**A.** The estimated 2009 fuel prices I use in this proceeding are actually lower for coal inventory than the updated projections approved in the Fuel Docket. Coal represents approximately 85 percent of the total value of fuel inventory as shown in Document No. 4 of Exhibit No.__ (JTW-1) of my direct testimony. The values of the other commodities, natural gas, and fuel oil, which represent the remaining 15 percent of fuel inventory, are in line with the fuel pricing approved in the Fuel Docket. Using Mr. Larkin's methodology of "re-pricing fuel stock inventory to accurately reflect the current price of fuel", one could easily justify an increase, not a decrease, in the overall value of fuel stock. Therefore, the fuel prices used in the company's inventory valuation are conservative and appropriate for this proceeding.

**SUMMARY OF REBUTTAL TESTIMONY**

**Q.** Please summarize your rebuttal testimony.

**A.** Tampa Electric conducted both a comprehensive feasibility study on bimodal transportation and a solid fuel competitive bidding process for the delivery of coal in accordance with the Order. The bid process and the resulting transportation contracts supported the feasibility study's conclusions that adding coal delivered by rail to the company's portfolio will enhance the company's solid fuel transportation network for the benefit of customers. Therefore, the facilities are the result of Commission direction and constructing the Big Bend Station rail facilities is appropriate and necessary. In addition, the company's fuel inventory is valued appropriately.

**Q.** Does this conclude your rebuttal testimony?

**A.** Yes, it does.

BY MR. BEASLEY:

**Q.** Ms. Wehle, did you prepare the exhibit that accompanies your rebuttal testimony that has been identified as Exhibit JTW-2 and marked for identification as Hearing Exhibit Number 83?

**A.** Yes, I did.

**Q.** Would you please summarize for us your direct and rebuttal testimonies?

**A.** Thank you. Good afternoon, Commissioners. My direct testimony describes Tampa Electric's fuel inventory planning process, including the factors that influence the reliable supply and delivery of solid fuel, which is comprised of coal and petroleum coke and oil and natural gas.

Based on these factors, I recommend the Commission include the value of 98 days' burn of solid fuel, together with the value of smaller inventories of other fuel types in working capital.

The company maintains its fuel inventory in order to minimize the risk of service interruptions due to fuel supply depletion or fuel delivery interruptions. Tampa Electric's fuel inventory planning process relies on a variety of inputs, projected burns, forecasted purchase arrangements, and delivery lead times, especially for coal, since the source of that fuel is approximately 1,000 miles away from our power stations.

Our plan reflects the factors that might drive inventory to unreasonably low levels, such as changes in maintenance schedules, excess burn at the power plants, adverse weather conditions like floods and hurricanes, water route blockages, transportation provider equipment breakdowns, and unexpected force majeure events like mining disruptions and transportation congestion.

The company believes that investing in a sufficient level of fuel inventory is much less costly overall than the alternatives, and those are making emergency purchases of fuel at premium prices, buying replacement power that is more expensive, or worst of all, interrupting our customers' electrical service.

The company has over 50 years of experience in fuels management, and we recognize the need for appropriate inventory levels to maintain reliable electric service to our customers. Based on this experience, Tampa Electric seeks a coal inventory target level of 98 days of projected burn. This is consistent with the 98 days' projected burn in the company's last rate case. While the numbers of days of burn is the same, the overall tonnage of coal is approximately one-third less due to the repowering of the Gannon Power Station from coal to natural gas and renaming it the

Bayside Power Station.

The company also requests the inclusion of the value of its natural gas, light oil, and heavy oil in storage in the company's inventory calculation. Each of these fuel types is burned in our power plants to provide base load, intermediate, and peaking reliability to the company's generating assets. Overall, the company generates energy for its customers from a diversified portfolio of coal, natural gas, and oil-fired units. The company's 2009 total proposed fuel inventory levels are necessary for it to be able to continue providing reliable service to our customers.

My rebuttal testimony addresses serious shortcomings in the direct testimony of OPC's witness Hugh Larkin, Jr. Specifically, my rebuttal testimony addresses the comprehensive rail feasibility and transportation request for proposal processes which were completed by the company consistent with the requirements set out in Commission Order Number PSC-04-0999-FOF-EI. The results of these two processes support the company's decision to construct the rail facilities at Big Bend Station.

Lastly, my rebuttal testimony addresses Mr. Larkin's arbitrary and unnecessary reduction in fuel prices. The pricing utilized in the fuel inventory evaluation of this proceeding is conservative and appropriate.

This concludes the summary of my direct and rebuttal testimonies.

MR. BEASLEY: We would submit Ms. Wehle for cross-examination.

COMMISSIONER EDGAR: Thank you. Are there questions from OPC for this witness?

MR. REHWINKEL: Yes, Madam Chairman.

CROSS-EXAMINATION

BY MR. REHWINKEL:

**Q.** Good afternoon, Ms. Wehle. My name is Charles Rehwinkel on behalf of the Public Counsel's Office.

**A.** Good afternoon.

**Q.** You've stated that you testify in rebuttal to Mr. Larkin about the need for and the proposed treatment of the Big Bend rail facility; is that correct?

**A.** That is correct.

**Q.** Ms. Wehle, you are a certified public accountant, a CPA?

**A.** Yes, I am.

**Q.** And for a while, you've testified you were the director of audit services for Tampa Electric?

**A.** That is correct.

**Q.** And in that role, did you oversee audits that reviewed plant in service balances, among other things?

**A.** No, I did not.

**Q.** You did not. Ms. Wehle, you were involved, were you not, in the be negotiation of the fuel transportation contract with CSX; is that right?

**A.** Yes, I was.

**Q.** And in fact, you signed the contract as a witness on October 1, 2008?

**A.** That is correct.

**Q.** And in fact, in the contract, you are designated as the person within Tampa Electric Company to receive notices for the company, at least your job title is; is that correct?

**A.** That's correct. As part of my position, the director of wholesale marketing and fuels would receive notices in relation to the contract itself.

**Q.** Okay. Isn't it true that this contract calls for the reimbursement of Tampa Electric for its construction costs for the rail facility at Big Bend Station, at least a significant amount of them?

**A.** That is true, yes.

**Q.** And that would be over the term of the contract; is that right?

**A.** The intervals within the contract actually specify that it could be reimbursed over the life of the contract, or it could be at varying intervals within the contract term.

**Q.** Thank you. Now, Tampa Electric originally projected the cost to construct this rail facility was about $46 million, and that amount was included as a pro forma adjustment to the minimum filing requirements in this case; is that right?

**A.** Yes, that is true.

**Q.** Now, is it also true that the proposed cost of this facility has increased to around $64 million or so? Is that right?

**A.** That is my understanding, yes.

**Q.** Is it also true that Tampa Electric is expending these capital costs in order to positively impact your fuel supply as to reliability, diversity, and price?

**A.** We are expending these capital costs in order to build the facility in order to receive benefits on the fuel equation, that is correct.

MR. REHWINKEL: Thank you. Madam Chairman, at this time, I would like to pass out a confidential exhibit. Actually, I want to pass out a folder, red folders with confidential documents in them. While they're being passed out, I would like to explain what documents are in them. There are three separate documents. Two of them are excerpts from documents that are already included in the record, and I've included these excerpts just for the convenience, rather than wade through the stack of documents that are in there.

The first document is a confidential page 6 from Ms. Wehle's rebuttal testimony, and that has already been moved into the record. And there's also the fuel contract excerpts from the entire contract, which is in the record as a late-filed exhibit to Ms. Wehle's deposition. The third document is for cross-examination purposes, and it is a one-page letter dated December 17, 2007, from CSX to Tampa Electric Company.

I don't intend to offer any but possibly the last document into evidence. These are merely for cross-examination purposes at this time.

CHAIRMAN CARTER: Okay. So let's just do this, just out of a abundance of caution. For the last one, which is the entitled "Cross-Examination Exhibit," why don't we just plug a number in there, and if you decide at the end that you don't want to enter it, that will still be fine. Do you want to do that? Will that be better?

MR. REHWINKEL: Yes. Thank you, Mr. Chairman.

CHAIRMAN CARTER: Commissioners, that will be

Exhibit Number 107.

MS. HELTON: Mr. Chairman?

CHAIRMAN CARTER: Yes, ma'am. One second.

MS. HELTON: I just wanted to ask Mr. Rehwinkel a clarifying question. Is all the information in these document confidential, or is there only certain parts of it? I'm just trying to figure out what we should avoid talking about.

MR. REHWINKEL: I have discussed -- that's a good point. I have discussed these documents with counsel for Tampa Electric Company, and I intend -- each document, each of the three documents or excerpts from the documents contains information that is considered by the company to be confidential and/or is the subject of a pending confidentiality request and is thus covered. I intend to pursue cross-examination and only refer to confidential numbers that the company has indicated to me are confidential by reference rather than by expression on the record. Does that answer --

CHAIRMAN CARTER: Ms. Helton.

MS. HELTON: I think so. I guess I'm used to seeing certain information highlighted in yellow, and we know for sure that's the information that everyone has identified as being confidential, and I don't see any of that here. So I'm just working under the assumption that everything here is confidential, and we should act accordingly.

MR. REHWINKEL: I am proceeding on that basis and hope to -- that's why I'm not sure that I'm going to offer anything into evidence. And anything that's already in the record has already been so designated as confidential under the Commission's rules and orders.

CHAIRMAN CARTER: So if you want, I can just delete that space, 107, and we can use it for something else. All right? Since you're just using this primarily for cross-examination purposes anyway.

MR. REHWINKEL: That's correct. And it's really to -- you have these giant stacks behind you where the information is buried, and I'm trying to make it a little easier.

CHAIRMAN CARTER: Okay. Thank you. It's very much appreciated, by the way.

What we'll do, Commissioners, we'll just leave -- 107 will be blank, so we won't have a 107, because what Mr. Rehwinkel is doing primarily is just using this last portion just for cross-examination purposes.

You're recognized, sir.

MR. REHWINKEL: Thank you.

BY MR. REHWINKEL:

**Q.** Ms. Wehle, after all that, are you familiar with the documents that are contained in the red folder that you've been handed?

**A.** Yes, I am.

**Q.** Okay. Is it -- and I would ask you to refer to the document that is the CSX letter. It's dated December 17, 2007, from Michael C. Bullock to Karen Bramley.

**A.** Yes.

**Q.** Does Karen Bramley work in your chain of command?

**A.** Yes, she does.

**Q.** She reports to you?

**A.** Yes.

**Q.** Okay. And I think I've cleared this with counsel for Tampa Electric Company, but I would ask you, unless there's an objection from counsel, for you to read the third full paragraph in that letter.

CHAIRMAN CARTER: Is there any objection? Are you guys familiar with this -- he's talking about the last letter, the letter that says cross-examination, the two-pager, and attached to that is a letter from --

MR. BEASLEY: That's correct, sir. We're okay with her reading it.

CHAIRMAN CARTER: Okay. You may proceed.

**A.** Okay. "CSXT is also committed to reimbursing

TEC for the capital outlay required to serve the Big Bend Plant. This rail direct option will provide TEC with increased reliability in the event of unpredictable disruptions to the water delivery system."

**Q.** Thank you. And for clarification, TEC refers to Tampa Electric Company?

**A.** That is correct.

**Q.** And CSXT is CSX Transportation, the railroad company?

**A.** That is correct.

**Q.** Thank you. Is it fair to characterize the commitment that is represented in the paragraph you just read as an agreement by the railroad to make contributions in the form of transportation cost rebates as a way of substantially funding or offsetting the capital costs of the rail facility at Big Bend?

**A.** No, it is not fair to characterize it that way. The reimbursement amount is specifically for capital costs associated with the construction of the facility, and it is not a rebate.

**Q.** Okay. Thank you. Ms. Wehle, would you agree that CSX -- or is it your perception that CSX agreed to make this contribution or funding because they also benefit from a contract that has a minimum level of transportation services purchased in it?

**A.** I would agree that the capital contribution -- in order for us to do any business with CSX, they recognize the need for us to have an unloading facility at our station, so therefore, that's what the capital contributions are for, building that unloading facility and doing business with them in the future.

**Q.** Thank you. Now, CSX has not agreed to cover the entire $64 million cost of the facility; is that correct?

**A.** That number is confidential, sir.

**Q.** Are you saying -- the $64 million is not confidential; correct?

**A.** That is correct.

**Q.** Okay. And is it confidential as to whether they've agreed to cover the entire cost of that?

**A.** That is correct, it is confidential.

**Q.** Okay. Can you please refer to the confidential version of your testimony on page 6, line 23?

**A.** Yes.

**Q.** And that document is also contained in the red folder. Therein, the confidential information is the amount that CSX is willing to contribute to cover the cost of that facility over the term of the contract; is that correct?

**A.** That is correct.

**Q.** Okay. In order to receive the maximum amount of funding that CSX is willing under the contract to make, is Tampa Electric Company required to configure the rail facility in a certain way?

**A.** Yes, that is true. Part of the initial design was -- when we had started talking about this, there was a certain amount that was going to be contributed for a single loop design, and the amount was increased when we started talking about a double loop design in order to accommodate traffic at our Big Bend facility for our trains.

**Q.** Okay. Would you agree that there is an increment above the amount that's included in the MFRs, i.e., the $46 million, that will not be covered by the contribution from CSX over the life of the contract?

**A.** I'm trying to see if I don't reveal confidential information. Can you repeat your question? I'll see if I can answer that.

**Q.** Let's do this. In your rebuttal testimony at page 6 -- and let's just refer to the nonconfidential version of it -- at the bottom of page 6 on lines 23 through 25, continuing on to page -- line 3 of page 7.

**A.** Yes.

**Q.** The implication there is that there is an excess.

**A.** There could be an excess.

**Q.** Okay. And if there is such an excess, that it would be treated the way your testimony describes; is that right?

**A.** That's right. And basically what we're saying there is that if there is an excess over and above, the difference between what we have now determined to be the cost associated with the construction of the facilities, the 64 million, versus what we included in our base rate filing, which was the 46, so that delta of about $20 million, if we received a refund of, for instance, let's say, 25 million, what we are proposing is that the first 20 million would go to the company to offset the additional capital costs over and above what we had included and hopefully we'll receive in base rates from this Commission, and any excess above that, in my example, potentially 5 million, would be credited through the fuel clause directly back to customers as incurred.

**Q.** Okay. I would like to ask you about some provisions in the contract. And within the red folder, there are excerpts from the contract, and I'll just use that document. This document is numbered several different ways. What I would like to do is just refer to the actual contract page numbers that are at the very bottom --

**A.** That would be helpful.

**Q.** -- above the Bates stamp numbers.

**A.** Okay. That would be helpful.

**Q.** Okay. On page 21, which is the second page of this excerpt from the contract, under Article 11, this paragraph describes certain minimum -- this article. Let me rephrase that. This article states certain minimum and maximum tonnages to be purchased under the contract; is that correct?

**A.** That is correct.

**Q.** Now, what's confidential in this article are the actual minimum numbers and maximum numbers of net tons; is that correct?

**A.** Yes, sir.

**Q.** So if one were to calculate the minimum tonnage in the first year, you would take the first number on page 22 of the contract excerpt in the second line there and multiply that by a number on the next page of the exhibit, which is page 25 of the contract. And it is the first number. It's about two-thirds of way down there. It's a dollar amount per ton; is that correct?

**A.** Yes, that is correct.

Q. And that number would be the minimum contract purchase by Tampa Electric Company. That would be the -- let me step back. That is the amount of the capital contribution that would be made in the first year if you bought the minimum tonnage, if you multiplied that number times the minimum tonnage number on page 21; is that correct?

A. That is correct.

Q. If you were to calculate the maximum tonnage number, you would use again the second net ton number on page 22 and multiply that by the first dollar per net ton figure on page 25 of the contract; is that correct?

A. Correct, for the first year.

Q. For the first contract year.

A. That is correct.

Q. And in the contract, I don't have it in this exhibit, but would you agree, subject to check, that in the contract, the first contract year is on a calendar year basis?

A. Yes, it is.

Q. Okay. Now, to calculate -- and the term of this contract is for how many years?

A. It is for five years.

Q. Okay. And for years 2 through 5, to calculate the amount of the capital contribution, if you will, from CSX to Tampa Electric Company, you would use the second dollar figure on page 25, the second per net ton dollar figure; is that correct?

**A.** That is correct.

**Q.** Times whatever tonnage is purchased?

**A.** That is correct.

**Q.** And do the minimum tonnages apply for the second through the fifth year?

**A.** They do.

**Q.** As well as the maximum tonnage?

**A.** Yes.

**Q.** Okay. So on page 25 of the contract, towards the bottom of that page, again, we see the number that is also used in your testimony, the number that is confidential, is that correct, the total -- the maximum amount of capital contribution from CSX?

**A.** Yes.

**Q.** And the way the contract is phrased, it's the lesser of that number or how much you actually spend on the rail facility; is that correct?

**A.** That is correct.

**Q.** Okay. Based on what you know today, does it seem like that there will not be a number less than the maximum that you would expect to receive?

**A.** Again, I think I'm treading on confidential information, and I think it would at least reveal --

**Q.** Okay.

**A.** I think that everyone here can make that determination from the information that we've provided so far.

**Q.** Fair enough. On page 27 of the contract, and again using the excerpt document, Section 13.2 is the procedure under the contract for Tampa Electric Company to receive capital contributions once you've made certain amounts of purchases for services under the contract; is that right?

**A.** That is correct.

**Q.** And you can do that once every six months; is that correct?

**A.** Once every six months in the first year of the contract, and I believe each subsequent contract year thereafter.

**Q.** Okay. So the first year, you can do it twice, and then in years 2 through 5, it's annually?

**A.** Correct.

**Q.** And then after those six annual trigger periods, there's another 75 days or so before you could expect payment; is that right?

**A.** I believe that it's within 45 days of the request is when we would receive payment.

**Q.** But you have to wait 30 days beyond the end of the six- or the twelve-month period to ask, and then it's 45 days beyond that?

**A.** I believe it's after the completion of the contract year, which, in essence, you would -- you know, it's within the realm that it would be days after the end of the contract year.

**Q.** Okay. Now, in Section 14.1 on page 27, the service commencement date of the contract can be postponed if the facility is not completed to the satisfaction of CSX; is that correct?

**A.** This section states that it's substantially completed construction of the facilities, yes, to carrier's reasonable satisfaction. And really, what we're getting at there is, we are partnering with CSX on this. And from the standpoint of making sure that they understand what these facilities are going to be, we brought them in meetings with our construction folks. We want to make sure that they agree with what we're doing and that they're going to be safe and reliable as they bring trains onto our property. And that's really the reason why we have that reasonable satisfaction criteria in the contract.

**Q.** If for some reason you delayed the completion of the rail facility, the contract, the commencement date of the contract would be postponed for the same amount of time, would it not, and you would start the five-year period of the contract once the facility was complete; is that correct?

**A.** That is correct. And the reason why we added that into this contract is because we knew it was a good deal for our ratepayers, and we didn't want a delay to hamper our efforts with CSX, and have this contract work to the benefit of our ratepayers. And the delays that we would only anticipate would be anything that would be beyond our reasonable control, such as any kind of permit delays or the like.

**Q.** Or hurricanes or bad weather?

**A.** Well, certainly.

**Q.** And you have actually until September of 2011 to finish that facility and still maintain the benefit of the other provisions of the contract, including the five-year term and the capital contribution; is that correct?

**A.** That is correct. However, again, the reason why we added that in here was for reasons beyond our control. We don't anticipate that there would be delays for the construction of the facilities. This contract was negotiated before we even got started really with the permitting process, so it was sort of built in there to make sure that we can continue doing business with CSX.

**Q.** When would you anticipate ordering the first trainload of coal to be delivered at this facility?

**A.** We anticipate that we would like to take two test shipments in the month of December of 2009.

**Q.** Okay. But you haven't ordered coal for those shipments?

**A.** Well, actually, we have coal under contract that is currently going through our waterborne transportation system, but it can easily be converted over to our rail system, and that particular contract would be the one that would convert over to complete rail once the facility is up and running.

**Q.** But the company is not obligated at this point in time to take delivery via train?

**A.** Actually, they take the trains to the river, so instead of taking a train to the river, they would take the train directly to our plant facility.

**Q.** But you're not obligated to take coal via train to this facility at this point?

**A.** No, we are not, but it is at our election.

**Q.** Right. You stated in your rebuttal testimony that the contributions that CSX has committed to make to offset the construction costs of this facility would be applied first to the amount that the shareholders would bear over and above what's included in the -- the 46 million that's included in this case; is that right?

**A.** It would be the amount above those granted in base rates; that is correct.

**Q.** Okay. And then the remainder of whatever -- well, let me ask you this. How long would it take for you to accumulate enough contribution from CSX to offset that amount?

**A.** It could possibly take us one year.

**Q.** Could it take as long as two years?

**A.** It certainly could.

**Q.** Isn't it true that in the Capital -- what's it called? In the Capital Leadership Team document that it was estimated it could take as long as two years?

**A.** Again, it's all based on rail deliveries on a per ton basis, so it certainly could.

**Q.** Okay. And then after that, is it possible that it could take into the year 2012 before the amount above what the shareholders would receive as an offset would be used to apply to reduce fuel expense in the fuel docket?

**A.** Again, that would be based on your hypothetical of it taking two years. We don't anticipate that it would take two years, but clearly, if it did take two years, it could roll into that same time period.

Q. Okay. So essentially, what Tampa Electric Company is requesting in this case is full rate base recovery of the cost of the facility, while not including for rate setting purposes in this case the substantial capital cost offsets in the form of contributions from CSX; is that correct?

A. I don't understand your question.

Q. You're proposing in this case that the full $46 million of revenue requirements be included.

A. That is correct.

Q. For rate setting purposes. But you're not proposing that in this case for purposes of setting base rates that any of the CSX capital contributions be considered; is that correct?

A. That is correct, because our estimate at this point is higher, 64 million. And again, our proposal is that we would use the difference to offset that additional capital cost, and then any excess over and above that would flow back to the customers through the fuel clause.

Q. In your role as a CPA and as past director of audit services, are you familiar with the concept of contribution in aid of construction?

A. I understand that it exists. I have never really done any work associated with that.

Q. Do you know whether a contribution in aid of construction is recorded in the books of account to offset the plant?

A. I do not know.

Q. Okay. You would agree, though, that the capital contributions from CSX are not discounts related to transportation or other O&M expenses; is that right?

A. That is correct.

MR. REHWINKEL: Mr. Chairman, if you could give me one second, I think I can wrap this up.

CHAIRMAN CARTER: Yes, sir.

MR. REHWINKEL: Thank you.

(Pause.)

MR. REHWINKEL: Mr. Chairman, that is all the cross-examination I have of this witness. At this time, if it would be appropriate, I can collect the red folders so we can --

CHAIRMAN CARTER: It would be appropriate.

MR. REHWINKEL: Thank you. Thank you, Ms. Wehle.

CHAIRMAN CARTER: We'll give you a moment to collect those, and then after that we'll recognize Ms. Bradley.

(Pause.)

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

MS. BRADLEY: No questions.

CHAIRMAN CARTER: Thank you. Mr. Moyle, you're recognized.

MR. MOYLE: Thank you. I have just a few questions.

CROSS-EXAMINATION

BY MR. MOYLE:

**Q.** I wanted, if I could, to follow up on just a couple of questions that my colleague, Mr. Rehwinkel, was asking. Typically when you're coming in requesting rates, don't you come in and request rates that will cover your capital expenditures?

**A.** That is correct. At the time that we were putting together -- again, this is my understanding. The $46 million that we have requested in rates was our initial estimate of the facilities. Since then, to my knowledge, additional refinement of those estimates has been done, and the costs have increased.

**Q.** Okay. From the big picture, a lot of these things we talked about, it could be O&M in Big Bend, and after the rate case, then things can go up or can go down, is that correct, in terms of expenses?

**A.** Certainly they can. I wish you would have asked these questions of Mr. Hornick. He would have a much better understanding of exactly why the costs are where they are. However, I do know that the estimates have been refined and that several contracts have been entered into with different parties for material and labor and so forth, so I think that these are good estimates now.

**Q.** So you made a filing at 46 -- and I'm going to be respectful of the confidential stuff, but you've answered, I think, that 46 is what your filing was, and your estimates now are 64. Is that roughly it?

**A.** That is correct.

**Q.** And I can talk about those numbers; correct?

**A.** Yes, sir.

**Q.** And have you drilled down into that 64 number in great detail?

**A.** Again, I'm really not the appropriate witness for that. Those are construction activities. I do know that there were several changes again to the loop design and things like that that added additional cost to the whole construction of that facility. However, I'm not the person that really could answer those questions.

**Q.** What in your mind is the difference between a rebate and a refund?

A. When I think of rebate, I think of rates, and when I think of refund, I think of something -- for example, in this particular instance, a refund is moneys that are to be used for a specific purpose. A rebate to me is just -- it can be used for whatever purpose the recipient would choose.

Q. Okay. And in this case, just so I'm clear, you're characterizing it as a refund that would then be provided that would be used to assist in the capital outlay project of constructing the rail facility; correct?

A. That's correct.

Q. So let's just -- for the purposes of my question, let's just say the contribution amount to be made by CSX is a thousand dollars. Okay?

A. Okay.

Q. All right. So if CSX is going to kick in a thousand dollars toward the capital expenditure, how would that thousand dollars be treated if you're already getting $46 million back from the ratepayers? You know, let's assume that the project came in at 46. How would that thousand dollars be treated? You wouldn't double recover it, would it? You wouldn't get it from the ratepayers and then also get it from CSX?

A. Well, again, with your hypothetical example, if we were to receive and be granted $46 million in base rates and the capital costs were 64 million, that thousand dollars would go towards the first thousand dollars above the 46 million that we received, in reimbursement to the company for those additional costs.

**Q.** But just for the purposes of understanding this, let's say that it didn't go over budget. Let's just say that it came in right at budget and you got 46 million from the customers. As you understand it, how would that thousand dollars be handled?

**A.** It would go through the -- again, in our proposal, it would through the fuel and purchased power cost recovery clause, so it would still go back to customers. It would go back in the time frame at which the refund is received.

**Q.** So essentially, you're asking that the delta between the 46 million, whatever the ultimate costs end up being, that any moneys that you receive as a result of a refund go to the company before they would go to customers, to the consumers; correct?

**A.** That is correct.

**Q.** Okay. I have one other line of inquiry. Part of this rail facility is to give you additional supply channels, diversify your supply channels, because previously all you had was a waterborne route; correct?

**A.** That is correct.

**Q.** And this rail facility will give you, in a sense, two pathways to bring coal to your generation units?

**A.** That is correct.

**Q.** Now, you said that your last rate case was 17 years ago, and you had a 98-day supply of inventory 17 years ago; is that correct?

**A.** That was what was granted in our last rate case, was a 98-day supply of coal inventory in our working capital calculations.

**Q.** Okay. Wouldn't it seem now that you have another alternative path to provide coal that you might not need as much inventory on hand, because you have two diverse supply streams as compared to one?

**A.** Actually, no. And I think we covered this in my deposition. At the time when we requested -- in our last rate proceeding, we actually had rail at our other Gannon Power Station, which was coal-fired at the time. Now it's natural gas-fired. That's my point number one.

And then secondly, as I pointed out in my deposition, it's not as simple as just switching from waterborne over to rail. There are several complicating factors, such as, you know, if there were an interruption in the water system, everybody would try to be going over to the rail system. It could be very congested.

The other thing to keep in mind is, as we have waterborne deliveries, they're delivered in anywhere from 20,000 to 35, 36,000-ton increments at our power station. A rail -- a complete train is only about 11,500 tons included, so you have a disconnect there.

And so, you know, we have looked at this in the past. We've operated under a 98-day supply planning process, and we feel like it's still prudent in order to do that.

**Q.** Well, was it prudent 17 years ago when you asked for it and it was granted by the Commission, in your view?

**A.** Yes.

**Q.** Okay. And you're asking for the same equivalent today; correct?

**A.** That is correct.

**Q.** But it's also true that your generation, the amount of power that you supply by coal since the last rate case has reduced by approximately one-third; correct?

**A.** That is correct. However, it is our base load unit, so we feel that there is no reason to have less than a 98-day supply. It is a lesser amount of tons, but it's still on a relative basis to our coal-burning facilities.

MR. MOYLE: That's all I have.

CHAIRMAN CARTER: Thank you, Mr. Moyle. Mr. Wright.

MR. WRIGHT: No questions, Mr. Chairman. Thank you.

CHAIRMAN CARTER: Thank you, Mr. Wright. Mr. Twomey.

MR. TWOMEY: No questions, Mr. Chair.

CHAIRMAN CARTER: Thank you. Commissioners, I'll go to the staff unless -- Staff, you're recognized.

MR. YOUNG: No questions.

CHAIRMAN CARTER: Commissioners, before I go back to redirect. Redirect.

MR. BEASLEY: Sir, we have no redirect. I would like to move the admission of Exhibits 23 and 83.

CHAIRMAN CARTER: Okay. Let's see here. Exhibit Number -- let me turn my page here. Number 23, any objections? Without objection, show it done. And also Number 83. Let me get to the right page here. Any objections? Without objection, show it done.

(Exhibits 23 and 83 were admitted into the record.)

CHAIRMAN CARTER: This witness may be excused.

Call your next witness.

MR. HART: Tampa Electric Company calls Regan B. Haines.

CHAIRMAN CARTER: Turn your mike on there.

MR. HART: Yes. Tampa Electric Company calls Regan B. Haines.

CHAIRMAN CARTER: One more time for the record.

MR. HART: Tampa Electric Company calls Regan B. Haines.

CHAIRMAN CARTER: Thank you. You may proceed.

Thereupon,

REGAN B. HAINES

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

DIRECT EXAMINATION

BY MR. HART:

**Q.** Please state your name and business address.

**A.** My name is Regan B. Haines, and my business address is 702 North Franklin Street, Tampa, Florida.

**Q.** Did you prepare and cause to be filed in this proceeding prepared direct testimony consisting of 54 pages?

**A.** Yes, I did.

**Q.** And attached to our direct testimony, did you include a composite exhibit premarked as Exhibit RBH-1 and Hearing Exhibit Number 24, consisting of seven documents?

**A.** Yes, I did.

MR. HART: Mr. Chairman, we would ask that Mr. Haines' composite exhibit be formally identified for the record as Exhibit Number 24.

CHAIRMAN CARTER: Let's do this. Let's do the prefiled testimony first. Let's do that first before we identify for the record.

BY MR. HART:

**Q.** Are there any changes or corrections to your prepared direct testimony?

**A.** No, there's not.

**Q.** If I were to ask you the questions contained in your prepared direct testimony, would your answers be the same?

**A.** Yes, they would.

CHAIRMAN CARTER: Okay. The prefiled testimony of the witness will be entered into the record as though read. You may proceed.

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

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**REGAN B. HAINES**

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

**A.** My name is Regan B. Haines. My business address is 2200 East Sligh Avenue, Tampa, Florida 33610. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Engineering in the Energy Delivery Department.

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

**A.** I graduated from Clemson University in June 1989 with a Bachelor of Science degree in Electrical Engineering and again in December 1990 with a Master of Science degree in Electrical Engineering specializing in Power Systems Engineering. I have been employed at Tampa Electric since 1998. My career has included various positions in the areas of Transmission and Distribution System Planning and Engineering within the Energy Delivery

Department. In my current position, I am responsible for directing all activities associated with the designing, engineering, performance analysis, joint use and various construction services for the electric transmission and distribution systems from the generator to the customer's meter.

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

**A.** Yes. I have testified before the Commission in Docket No. 070297-EI concerning the impact of extreme weather events on the state's transmission and distribution ("T&D") infrastructure and the company's storm hardening efforts.

**Q.** What is the purpose of your direct testimony?

**A.** My direct testimony supports Tampa Electric's T&D related capital and operations and maintenance ("O&M") expenses of $218,945,000 and $76,256,000, respectively, for the 2009 test year. These amounts include the costs of implementing Tampa Electric's Storm Hardening Plan approved by this Commission in Order No. PSC-07-1020-FOF-EI, issued December 28, 2007. I will also discuss

T&D operations, system reliability and Tampa Electric's plan for continued cost-effective service to its customers. I will describe the increased federal regulatory challenges the company is facing and recommend a mechanism to recover required transmission additions. Finally, I will discuss and support the company's T&D O&M benchmark comparisons.

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

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

| | | |
|---|---|---|
| Document No. | 1 | List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By Regan B. Haines |
| Document No. | 2 | Transmission And Distribution Material, Equipment and Fuel Percentage Price Increases Since 1999 |
| Document No. | 3 | Transmission And Distribution Capital Investment For 2009 |
| Document No. | 4 | Transmission And Distribution Related O&M Budget For 2009 |

Document No. 5 2007 SAIDI Comparison From Southern Company Benchmark Consortium Study

Document No. 6 Florida Investor Owned Utility Historical SAIDI Comparison (Distribution Only)

Document No. 7 Storm Hardening Activity 2009 Projection

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

**A.** Yes. I am sponsoring or co-sponsoring the MFRs listed in Document No. 1 of my Exhibit No. ___ (RBH-1).

**Q.** Describe Tampa Electric's T&D system.

**A.** Tampa Electric's service area covers approximately 2,000 square miles in West Central Florida, including all of Hillsborough County and portions of Polk, Pasco and Pinellas counties. Tampa Electric's transmission system consists of approximately 1,300 miles of overhead facilities, 26,000 poles and 15 miles of underground facilities. The company's distribution system consists of approximately 6,100 miles of overhead lines, 300,000 poles and 7,900 miles of underground lines. Tampa

Electric's transmission and distribution systems are connected through 220 substations throughout its service territory.

**COST OVERVIEW**

**Q.** Please describe the expenditures you will be discussing in your direct testimony.

**A.** The expenditures I will be addressing are T&D related O&M expenses and capital investment. I will describe why these expenditures are required and how Tampa Electric is efficiently balancing short-term maintenance and long-term capital investment in an effort to provide the most cost-effective reliable power to its customers.

**Q.** What are the main drivers of capital and O&M spending?

**A.** The need for capital additions as well as O&M expenses are driven by a number of factors. One of the primary drivers is customer growth, which includes the addition of new customers as well as the increased demand requirements from existing customers. Tampa Electric has experienced significant customer growth over the last 16 years and continued growth is projected at a 2.1 percent annual average over the next 10 years. Tampa

Electric's customer base has increased 44 percent since 1991 to 666,354 customers in 2007 and is forecasted to be 679,941 customers by the end of 2009. This growth has occurred within all customer classes. Existing customers also continue to add appliances, televisions, computers, and expand the size of their residences and businesses, which increases demand. This load growth and increase in demand increases the utilization of the T&D system and eventually forces the expansion of the system. As the system increases in size, increased expenditures are required to ensure the safe and effective operation of the system. This increase in demand requires both capital expansion of the T&D system and increases in O&M expenses as well.

A second driver, which is normal and expected by all utilities, is capital and O&M expenses associated with the aging of infrastructure. Florida's population grew by approximately 4.8 million from 1960 to 1980. The number of Tampa Electric customers grew by approximately 168,000 during this time. A significant amount of electric infrastructure was installed to support this increasing population. As a result, some of the infrastructure is now 30 to 50 years old. As the system ages, increased expenditures, both capital and O&M, are required to replace aging infrastructure while providing safe and reliable service to the company's customers.

A third driver, which I discuss later in my testimony affecting both capital and O&M expenses is increases in material and equipment costs as illustrated in my Exhibit No. ___ (RBH-1), Document No. 2. Since 1992, general inflation has increased by 48 percent; steel by 72 percent and concrete by 73 percent.

Two additional drivers for O&M expenses are related to weather and regulatory compliance. The weather, which can vary from year-to-year, creates outages and system outage restoration activities. O&M expenses projected for the test year have been based on a normalized weather year.

Regulatory rules and related compliance costs have increased since 1991. The Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC") both have increased reliability and compliance requirements. The Florida Public Service Commission's storm hardening requirements have also had an impact.

Finally, maintenance spending is required for the company to inspect its growing T&D system on a prudent basis and to correct conditions found during these maintenance inspections before they become detrimental to the system and create operational or safety issues. The company has increased its maintenance activities in order to comply with all requirements of the recent Commission orders related to storm hardening which are further outlined later in my direct testimony.

**Q.** Please provide an overview of Tampa Electric's T&D related capital and O&M expenditures proposed in this proceeding.

**A.** Tampa Electric forecasts that it will invest $218,945,000 in T&D related capital and incur $76,256,000 in T&D related O&M expenses in 2009. The Energy Delivery business unit at Tampa Electric is primarily responsible for the T&D related capital expenditures and O&M expenses illustrated in Document Nos. 3 and 4 of my exhibit. The 2009 Energy Delivery capital budget includes the following initiatives: system expansion of transmission, substation and distribution facilities to support customer growth and generation expansion; storm hardening initiatives;

substation circuit breaker replacements; relocations to support road improvements; Automated Meter Reading ("AMR") meter additions; an Energy Management System ("EMS") upgrade project; and outdoor lighting additions.

The 2009 budgeted T&D related O&M costs include those activities required for system operation and restoration; meter reading; vegetation management; inspection programs; and the ongoing maintenance of equipment and computer systems. All projected budgets have taken into account efficiencies and productivity gains the company has achieved through technology and process improvements, which are mentioned later in my direct testimony. These capital investments and O&M expenses are necessary to provide electrical service in a cost-effective, safe and reliable manner while at the same time meeting FERC, NERC, and FPSC requirements.

**RELIABILITY**

**Q.** Please provide an overview of the company's reliability initiatives.

**A.** Tampa Electric focuses on multiple initiatives to cost-effectively maintain and enhance customer service and reliability. First, activities are targeted that will prevent or limit the number of outages experienced by customers and then the company work to reduce the amount of outage time experienced.

The two largest reliability programs the company employs are vegetation management and wood pole inspections. These two initiatives provide the largest benefit for preventing outages before they occur. Additionally, the company performs inspections and repairs to improve T&D circuit reliability, which include circuit thermovision evaluations to detect potential problem areas, condition-based substation maintenance to maintain equipment prior to ineffective operation or failure, underground cable testing to predict failure and pad-mounted transformer inspections and repairs.

Another measure taken by the company to maintain reliable service is through system capacity evaluations. These studies consider the forecasted peak loading demands of customers and identify potential problem areas within the system. This provides the company's engineers with the information needed to develop the most cost-effective alternatives for system expansion.

As a result of these initiatives, Tampa Electric's reliability performance is consistently in the top quartile among utilities according to annual Edison Electric Institute and Southern Company Consortium benchmark reports; see Document No. 5 of my exhibit.

**Q.** Please describe the primary indices used by the company to monitor system reliability performance.

**A.** Tampa Electric reviews multiple system reliability indices, but primarily monitors System Average Interruption Duration Index ("SAIDI") and Momentary Average Interruption Event Frequency Index ("MAIFIe"). SAIDI is generally considered a key reflection of operating performance. It indicates the total minutes of interruption time the average customer experiences in a year. SAIDI is calculated by dividing total customer minutes of interruption by total customers served. A significant factor having a direct influence on this index is the severity of the storm season.

MAIFIe defines the average number of times an average customer experiences a momentary interruption event. The MAIFIe index is calculated by dividing the total number of customer momentary interruption events by the total number of customers served. Tampa Electric annually sets reliability goals for both SAIDI and MAIFIe.

**Q.** Please describe your system reliability performance.

**A.** Since 2005, Tampa Electric has reduced its SAIDI by almost 10 percent, from 84 minutes to 77 minutes. Document No. 6 of my exhibit shows Tampa Electric's performance relative to the other investor-owned utilities in Florida since 1999. With the exception of the hurricane years of 2004 and 2005, Tampa Electric has consistently had the top or second best SAIDI performance in the state.

**Q.** What are some additional initiatives that the company has undertaken to improve overall reliability performance?

**A.** The company has recently made significant improvements to its overall system reliability through various reliability initiatives that will provide benefits in the coming years. This improved performance is a result of a continued focus on first preventing an outage from occurring and then minimizing outage times when they do occur.

For example, the company tracks the performance of distribution circuits that may require performance improvement and has developed a process for the identification and completion of corrective improvements. In 2007, 10 circuits were targeted which resulted in a 42 percent improvement in SAIDI performance for those circuits. Thirty-eight distribution circuits have been identified for this program in 2008.

MAIFIe is also another key measure of system reliability. The identification and elimination of line faults that generate momentary interruptions continues to be a priority and focus of improving distribution reliability for the company because these could eventually lead to lengthier outages in the future. Vegetation management is a major driver for momentary outages. Tampa Electric is transitioning to a three-year tree trim cycle in an effort to minimize these momentary outages.

Another major driver of momentary outages is lightning. Tampa Electric's service territory is located in "Lightning Alley", which has the heaviest concentration of annual lightning strikes in the United States

("U.S.") according to NASA. Replacement of failed lightning arrestors helps minimize lightning's impact. During the company's annual mock storm exercise each spring, team members take the opportunity during circuit patrols to identify lightning arrestors that need replacing.

The company has also pursued reductions to the duration of outages through the development and implementation of process efficiencies and the leveraging of technology. With the implementation of electronic relays on the transmission system, the location of the fault causing the outage is identified to the Energy System Operator ("ESO"). This allows the ESO to isolate the damaged area quickly using remotely controlled pole top switches and return most, if not all, customers back to service even before field team members arrive on site. The ESO also directs the transmission line patrolmen to the problem area to identify what repair will need to be made.

In 2007, the company implemented a distribution circuit restoration project that focused on reducing the duration of feeder outages. This was accomplished through realigning resources available to respond to an outage, isolating the damaged area, restoring service to as many customers as possible prior to repairing the damage, and then installing fault identification devices. This project is further described later in my direct testimony.

All of these initiatives not only help improve system reliability, but they ultimately save costs, which are reflected in all cost projections.

**PLANNING PROCESS**

**Q.** Please explain Tampa Electric's approach to planning for expansion of the T&D systems.

**A.** The objective of Tampa Electric's Energy Delivery System Planning Department is to plan well ahead of customers' needs in order to provide timely, cost-effective and reliable electrical service. Tampa Electric's 10-year demand and energy forecasts, produced by the company's Load Forecasting Department, along with various electrical characteristics are utilized to analyze the future needs of Tampa Electric's T&D system. The planning process identifies when new transmission, substation and/or distribution facilities will be needed to meet customer requirements.

Using the company's forecasted system load, a review of circuit loading, distribution transformer loading and distribution reactive power loading is performed on an annual basis for the next five-year period. Future potential thermal overloads and/or abnormal voltage conditions are also identified. Once it has been determined that additional distribution capacity is required in an area, various alternative projects are created and evaluated for meeting the estimated system growth. Cost estimates are produced for each alternative and the alternatives are then evaluated based on the impact to reliability, voltage, capacity, economics and constructability. Based on these criteria, the most cost-effective viable solution is chosen to accommodate the projected system growth on the distribution system.

The planning criteria for transmission system additions are based on NERC, Florida Reliability Coordinating Council ("FRCC") and other applicable standards. The NERC reliability standards specify transmission system scenarios to be evaluated and the levels of system performance to be attained. The company conducts an annual transmission assessment of the effects of forecasted future load growth over a 10-year period on the transmission system, the need to serve new load areas and/or large new customers, future interconnections with neighboring utilities, integration of new generation facilities and firm contractual transmission service obligations. The changes in system performance due to these factors are simulated and analyzed for the present and future years to identify existing and future system limitations. Alternative solutions to these limitations are then developed, analyzed, and screened based on electrical performance. Viable alternatives are compared for their relative merits with respect to reliability, voltage, capacity, economics and constructability. Transmission facility additions such as a new transmission line are implemented as a result of this process.

As these plans are evaluated, the company also considers the need to acquire land for future substation sites and power line rights-of-way. Growth in general and specific patterns are reviewed to ensure substation sites and power line rights-of-way can be acquired in a timely manner to install the facilities necessary for reliable service. Given the increased efforts presently necessary to acquire land for substations and rights-of-way, it is extremely important to identify and secure the needed rights early before growth makes it very difficult, expensive or impossible. Accordingly, Tampa Electric has acquired property held for future use, which is identified in MFR Schedule B-15, and requests that this property be included in rate base. This investment is both reasonable and prudent.

**Q.** How do the company's T&D expansion plans become actual projects?

**A.** Using the results of the planning process, a five-year construction plan and budget are developed which identify the near term projects required to provide reliable service. These plans are also incorporated into the FRCC's planning process, which is described later in my direct testimony.

**CAPITAL INVESTMENT**

**Q.** What are Tampa Electric's T&D capital investment plans during 2009?

**A.** Tampa Electric plans to invest $218,945,000 in T&D related capital in 2009. The company's forecasted T&D capital plans are listed and described in Document No. 3 of my exhibit. This T&D capital investment is required to provide reliable service to customers. In general, these expenditures include capital projects such as substation and switching station construction and upgrades, road widening projects, storm hardening projects, new lighting systems and new T&D circuit construction. Additional capital investments will be made to leverage technology including automated meter reading and various computer software projects.

**Q.** How have the company's T&D assets grown from 1991 until 2007?

**A.** The book value of the company's T&D assets in 1991 was $635,774,000. The book value has grown to $1,486,323,000 primarily due to the increase in the number of customers the company serves. The company added over 200,000 customers from 1992 to 2007. The increase in the number of customers has been a primary driver in load growth, which has driven the increase in capital investment.

**Q.** Are there other reasons driving the need for capital investment besides load growth?

**A.** Yes. In addition to customer load growth, there is also considerable capital investment required to maintain the reliability of service provided to Tampa Electric's current and future customers. Technology is one area of capital investment used to maintain reliability. Some examples are its outage management system ("OMS"), digital protective relays and fault indicators. Another area of capital investment for reliability is the program necessary to upgrade older equipment.

**Q.** Please explain the company's need to replace aging infrastructure and to perform system upgrades.

**A.** Most T&D equipment has a 30-year useful life. Tampa Electric installed a significant amount of T&D infrastructure to support the 168,000 customers that were added from 1960 to 1980. This infrastructure is approaching or is at the end of its useful life, which typically results in increased failures and higher maintenance costs. In order to replace these aging assets prior to failure and to upgrade the system in specific areas to maintain or, in some cases, improve existing reliability levels, capital investments are required.

Tampa Electric plans to target the following system upgrades specifically: various storm hardening improvements to the company's overhead and underground systems; pole replacements; transmission structure inspections and repairs; lightning protection improvements; replacement of obsolete oil-type circuit breakers; replacement of electromechanical meters and substation relays with electronic versions; and physical and cyber security enhancements mandated by the FERC and the NERC. As Tampa Electric's system continues to age and customer growth continues to increase, additional requirements are placed on the system making it imperative that the company keep pace with the service levels that customers expect.

**Q.** Are there other drivers to the increased cost of capital investment?

**A.** Yes. Material costs, which have increased at an astounding rate, are another key driver in the company's increased capital spending over the last few years. These high material costs are expected to continue in the future. For example, the price the company must pay for 69/13 kV substation transformers has increased by over 160 percent since 1999. Document No. 2 of my exhibit lists the percentage price increases for typical

T&D equipment experienced in the ten-year period from 1999 to 2008. The significant increases are largely attributable to the infrastructure growth occurring in developing countries causing competition for raw materials.

**OPERATIONS AND MAINTENANCE EXPENSE**

**Q.** Please describe what is included in operations expenses.

**A.** Operations expenses are typically those required to carry out the day-to-day activities associated with operating the T&D system and all activities required to support providing electric service to customers. These include expenses associated with meter reading, meter installations, locating underground facilities, dispatching field team members in response to customer requests, responding to and restoring the system following outages, and switching and re-configuring the company's T&D systems to ensure reliable operations.

**Q.** Please explain the main drivers for the company's T&D related operations expenses.

**A.** As mentioned earlier in my direct testimony, the two main drivers are load growth and weather related outages. The company has experienced significant load growth since its last rate case and projects continued growth in demand for the foreseeable future. This continued increase in demand impacts Energy Delivery's activities such as meter reading, meter disconnect and re-connect, and new meter connection activities. Weather related outage activity also has a direct impact on operations expenses associated with restoration activities.

**Q.** What is included in the T&D related maintenance expenses?

**A.** Maintenance expenses include activities performed to keep assets in serviceable condition, maintain safety requirements, avert premature failures and manage vegetation growth. They also include activities, which correct or repair non-operable or unsafe conditions on the system as identified through an inspection program or as a result of a storm or other event.

**Q.** What will be the result of the proposed maintenance spending?

**A.** During the 2009 test year, Tampa Electric will be increasing maintenance and tree trimming expenditures above current levels and will complete full implementation of inspection and maintenance programs in order to comply with FPSC requirements. The expected result will be improved reliability and service to customers on both a day-to-day basis and following a major storm event. Increasing the level of maintenance and focusing on key programs will enable the company to maintain the reliability standards historically provided to its customers. Tampa Electric's inspection and maintenance programs include: a three-year tree trimming and vegetation management cycle, an eight-year wooden pole inspection cycle, a six-year transmission structure inspection cycle, annual substation inspections, condition based substation preventative maintenance, downtown network inspections and underground system inspections.

**Q.** Please describe Tampa Electric's vegetation management program and explain why the program's costs are increasing.

**A.** Tampa Electric is increasing its vegetation management program to establish and maintain a three-year distribution system trimming cycle in order to comply with the Commission's requirements for storm hardening. Tampa Electric's vegetation management program provides a balanced and phased approach toward a three-year tree trim cycle plan to reach the company's desired objectives. The objectives are to improve the quality of line clearance while increasing system reliability. Tampa Electric began ramping up its vegetation management program at the end of 2005, with an emphasis on critical trimming needed in areas identified by the company's reliability based methodology. The company continues its progress toward a three-year tree trim cycle plan and anticipates reaching its goal by 2010.

To ensure the company is implementing the most cost-effective program, Tampa Electric's System Reliability and Line Clearance Departments take into consideration many factors in developing the annual plan, such as multi-year circuit performance data, last trim date and circuit priorities. Various improvements made throughout 2007 resulted in a 15 percent increase in total miles trimmed during 2007 with only a 12 percent increase over 2006 spending.

The proposed 2009 budget for this program is $16,073,000. This is the spending level, plus inflation, that will be maintained going forward. Tampa Electric will continue to review system reliability and all pertinent field and customer information along with its annual trimming plan in order to manage its overall vegetation management program effectively.

**Q.** Are there other cost drivers for the increased vegetation management costs?

**A.** Yes. While increased activity is a major driver for cost increases, per unit costs for vegetation management have also grown at a faster pace than inflation. This is primarily due to the competition for resources and increasing contractor rates mainly caused by escalating fuel costs.

**O&M BENCHMARK COMPARISON**

**Q.** Have you made a comparison of Tampa Electric's test year T&D O&M budget to the Commission's benchmark?

**A.** Yes. The comparison for transmission and distribution O&M expenses is shown in MFR Schedule C-37. It demonstrates that the projected T&D O&M expenses for the test year are below the O&M benchmark by $1,064,000. Transmission is $1,721,000 below the benchmark and distribution is $657,000 above.

**Q.** Why is distribution for 2009 above the O&M benchmark?

**A.** The 1991 base year included a four-year distribution tree trim cycle, while the 2009 test year includes a three-year distribution tree trim cycle. As I mentioned above, in order to comply with the Commission's storm hardening requirements, the company is transitioning to a three-year tree trim cycle to improve reliability during normal weather conditions as well as major storm events such as hurricanes.

**Q.** Why is the overall 2009 Transmission & Distribution O&M budget below the Commission's benchmark?

**A.** As I describe above, Tampa Electric's Energy Delivery team has taken a number of steps to ensure that spending is done in a prudent manner. The company has implemented a number of practices and programs that have improved the overall efficiency and effectiveness of operating and maintaining the T&D system while maintaining SAIDI performance in the first quartile as explained in the "Operational Efficiency and Effectiveness" section of my testimony and shown in

Document No. 6 of my exhibit.

**OPERATIONAL EFFICIENCY AND EFFECTIVENESS**

**Q.** What steps has the company taken to manage the company's T&D related capital and O&M expenditures effectively?

**A.** Tampa Electric's management team has taken a number of steps to ensure that a focus is placed on the right priorities, the proposed budgets are reasonable, and all expenditures are occurring in a wise manner. The company has implemented a number of practices to improve safety and the effectiveness of its workforce, and to create an environment for continuous improvement. These practices have favorably impacted performance in diverse areas of the business including: outage response, workforce utilization, inventory, project management, system protection and meter reading. Significant improvements have also been made to the company's distribution construction standards.

**Outage Response**

A new OMS was implemented in November 2001. The benefits of this system include a predictive point of outage typically resulting in decreased outage time; increased usage of the interactive voice response system

("IVR") including estimated outage duration and automatic call back when service is restored; and centralized outage information for customer service professionals and field personnel.

**Workforce Utilization**

In 2003, Tampa Electric hired a consultant to review the planning and scheduling of Energy Delivery's maintenance and construction work. They recommended that the planning and scheduling of work be centralized to give a global view of all resources and work. They also recommended that all work should be planned and scheduled except for true emergency work. This would reduce overall costs and improve on-time service dates due to the efficiencies gained with the process. Beginning in 2004, a new process was implemented and included developing a four-week schedule and releasing work two weeks ahead of time if all resources were available. Emergency work took a priority, but all non-emergency work was scheduled. Key process indicators were developed to evaluate ongoing area performance. In addition to improved customer service, this process change has resulted in many efficiency gains and avoided costs.

**Inventory**

In May 2003, an initiative was implemented to centralize all major material at one main storeroom and distribute material to the outlying storerooms as needed for scheduled work. A small level of maintenance stock was maintained at each of the outlying storerooms. This change has reduced the amount of duplicate material stored at each service area and resulted in a reduction of inventory levels and an improved inventory turnover ratio. While this initiative has benefited customers by reducing inventory costs, it has not impacted the company's ability to provide excellent customer service.

**Project Management**

A project management organization was formed in November 2006 to manage large T&D construction projects. This group manages projects from the cost-estimating phase to project completion. The purpose was to improve the execution and overall management of large project work following the identification of project scope. In 2007, this change resulted in the completion of seven out of nine projects within 10 percent of the cost estimate and meeting the in-service date. The seven projects totaled $8,329,500 and the final costs came within $347,370 of the total project cost estimates. The two projects that did not meet the 10 percent criteria totaled approximately $1,826,200 and the final cost came within $146,039 of the total project cost estimates.

**System Protection**

The main purpose of a protective relay is to sense abnormal conditions on the electric system and then operate the appropriate switching devices to isolate the problem to provide protection to the remainder of the electrical system. In 1998, Tampa Electric purchased its first fully integrated distribution electronic relay. Since that time, the company has installed over 1,400 electronic relays across 48 percent of its T&D system. The benefits of these relays are decreased costs, increased flexibility in system protection, decreased outage times through fault location, reduced maintenance, improved testing cycle time, and a self-monitoring feature that alarms when the relay is not functioning properly. These features have resulted in decreased costs and improved reliability for the company's T&D system.

**Automated Meter Reading**

In 2003, Tampa Electric initiated an AMR project, which is the application of electronic and communication technology to enable the reading of electric meters remotely. This technology has helped to increase operational efficiencies and to reduce exposure to issues surrounding safety and meters that are hard to access. The 2008 strategy includes the deployment of AMR meters in those areas where high cost reads and the hard to access meters overlap to generate the highest return on investment.

Once an area has been completely saturated with residential AMR meters, there are significant cost benefits. In the areas of Dade City, Plant City and Fish Hawk Ranch in Lithia, there has been a complete conversion of the residential meters to AMR and the cost to read a meter has been reduced from approximately 45 cents per read to 15 cents per read. In general, time needed to read meters in these three areas declined by approximately 58 percent. AMR also lowers the quantity of estimated meter reads. Estimated meter reads averaged 6.7 percent in 2005 but have remained below one percent for the past two years.

The company plans to convert 55,000 residential meters to AMR meters each year at an estimated cost of three million dollars per year. Tampa Electric ended 2007 with 73 meter readers and it is projected that 63 meter readers will be required at the end of 2009. The company has factored in all productivity improvements gained from this initiative into its cost projections.

**Construction Standards**

Tampa Electric has made many significant improvements to its construction standards since its last rate case. Some of the major enhancements include: 1) standardized overhead triangular construction to minimize life cycle costs; 2) added new class three wood poles to inventory to reduce use of class two poles; 3) converted porcelain horizontal line post insulators to polymer; 4) changed standard arrestor to flying lightning arrestor style on terminal poles; 5) implemented fiberglass guy strains; 6) changed 1/0 stranded cable to solid cable; 7) implemented shorter 1000 MCM reel length; 8) standardized overhead conductor sizes, eliminated 4/0 AL ALCSR; 9) implemented UG jacketed cable; 10) implemented strand filled (Moisture Block) underground cable; 11) eliminated radial (Live Front) pad-mounted transformers; 12) implemented new overhead transformer design with aluminum windings; 13) changed mild steel switchgear enclosures to stainless steel; and 14) changed mild steel single phase transformer enclosure to stainless steel hybrid. These changes have helped manage rising material costs and provided reliability benefits to the system.

**Other Process Improvements**

Circuit Restoration Initiative - In 2007, Tampa Electric embarked on a mission to reduce SAIDI by reducing distribution circuit outage time. A cross-functional team was put together to investigate the cause and nature of customer outages with a goal of improving reliability. The team discovered that 40 to 50 percent of yearly SAIDI was attributed to entire circuit outages. The result was a project called the Circuit Restoration Initiative. Accordingly, Tampa Electric implemented new guidelines for responding to circuit outages. For example, a guideline was established to have a minimum of two responders for each circuit outage. With the idea of working smarter not faster, two responders are able to patrol and locate problems in half the time. A philosophy of "switch before fix" was also implemented. Upon locating the problem, the first responder initially looks for ways to isolate the problem with switching; this energizes as many customers as possible with alternate feeds, before attempting to make repairs. Although this is not a new concept, with disciplined application, this subtle change has reduced the number of customers impacted while repairs are made.

The company also installed 700 strobe fault indicators on pre-selected circuits. These devices are attached to overhead main feeders at strategic locations. They flash when they sense fault current and the feeder is de-energized. This helps the first responder to quickly locate and isolate the cause of the outage. The company targeted circuits with historically the most problems as well as circuits with sections of lines that are difficult to access.

Preliminary results for the circuit restoration initiative have been outstanding. In 2006, circuit outages experienced were restored with an average restoration time of 48 minutes. In 2007, the average circuit outage restoration time dropped to 38 minutes. With the improvements made, the company was able to reduce the average circuit outage time by 20 percent. The company expects this initiative to play a significant role in reducing SAIDI.

Quicker Crew Call Outs - In 2004, Customer Service replaced the IVR system that provides telephone response for the customer contact center. As part of the IVR replacement, the "outbound dialer" functionality was included in the scope in order to allow for faster, automated call out of crews for restoration work.

Super Crews - This concept was introduced in 2005 to add a more flexible type of crew that could perform both restoration work as well as distribution maintenance work and has provided better resource scheduling flexibility.

Mock Storm Exercise/Faulty Equipment Identification - During the company's annual mock storm exercise each spring, the participants take the opportunity during circuit patrols to identify lightning arrestors and capacitor banks that need repair. The replacement of lightning arrestors and certain capacitor banks will improve reliability. Through this effort, the company not only practices its storm response procedures, but it also identifies equipment needing repair.

Lastly, the company implemented the use of text messaging and emails to alert key team members when a circuit is de-energized. This was accomplished by integrating the EMS and Supervisory Control and Data

Acquisition ("SCADA") systems with the company's email software. Immediately after a circuit outage, the system sends an alert via text message or email to selected local supervisors and managers. This creates an "all hands on deck, firefighter's mentality", to help facilitate a focused and timely response.

**Q.** How does Energy Delivery ensure operations and maintenance is performed in a timely, efficient and effective manner, and that funds are spent appropriately?

**A.** Energy Delivery verifies the status of achieving its goals through budgeting, planning and tracking systems and internal business control processes. The company monitors and measures performance through work management, system planning, project scheduling and asset tracking tools in several ways. For example, the key performance indicators are used to report on the performance of distribution, transmission and substation work. Another example is the further delineation of the O&M and capital budgets through the use of an activity-based costing tool, which tracks activities for both production units and costs per unit. Energy Delivery also tracks system performance for outage analysis and input for maintenance and capital spending decisions. Additionally, the company prioritizes the numerous capital projects considered each year and utilizes Primavera software for planning and scheduling many complex capital projects. Finally, Energy Delivery has implemented new financial processes and systems to prioritize, track and monitor spending against its business plans. All of these systems and processes, and the team members that support, develop and use this information, allow Energy Delivery to perform work efficiently and effectively. These activities are aimed at providing quality service to customers at the lowest long-term cost, consistent with meeting the service standards that customers want and deserve.

**STORM HARDENING ACTIVITIES**

**Q.** Please summarize Tampa Electric's storm hardening activities.

**A.** Tampa Electric's storm hardening activities, which include the company's Pole Inspection Program, Ten-Point Storm Preparedness Plan and Storm Hardening Plan, are a multi-pronged approach to enhance the reliability of the T&D facilities.

**Pole Inspection Program**

To implement Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, Tampa Electric expects to conduct approximately 38,900 distribution and 3,700 transmission wooden pole inspections in 2009 and all inspection related O&M spending is estimated to be $1,610,000 in 2009. Capital replacement and upgrades will cost an estimated $14,789,000 for the same period. This is representative of the pole inspections and replacement the company expects on an annual basis.

**Ten-Point Storm Preparedness Plan**

Implementation of the Commission's storm preparedness plan in Docket No. 060198-EI, required by Order No. PSC-06-0351-PAA-EI issued April 25, 2006 and approved by Order No. PSC-06-0781-PAA-EI issued on September 19, 2006, will cost an estimated $18,834,000, $17,645,000 in O&M and $1,189,000 in capital, during the 2009 test year. One of the most significant expenses is the implementation of the three-year tree trimming cycle required by the initiative of the Storm Preparedness Plan.

**Storm Hardening Plan**

Tampa Electric's storm hardening plan was developed in response to Commission Order No. PSC-07-0043-FOF-EU, issued on January 16, 2007, in Docket No. 060172-EU. The Commission has recognized that Tampa Electric's storm hardening plan provides a reasonable, measured approach to storm hardening. The objective of the company's storm hardening plan is to improve system reliability and resiliency during and after extreme weather events. The total storm hardening activities cost projections for the test year, including the previously discussed Pole Inspection Program, the Ten-Point Storm Preparedness Plan is $36,450,000, $19,255,000 in O&M and $17,195,000 in capital, and they are detailed in Document No. 7 of my exhibit.

**REGIONAL TRANSMISSION PLANNING**

**Q.** Has Tampa Electric experienced increased federal regulation of transmission reliability since its last rate proceeding?

**A.** Yes. In the mid-to-late 1990s, FERC began focusing on initiatives that helped enhance wholesale markets and ensure open access to transmission. In its Order 2000, FERC strongly supported the development of regional transmission organizations ("RTO") and encouraged utilities to divest ownership or control of their transmission assets. Tampa Electric, along with the other peninsular Florida investor-owned utilities worked for years on developing GridFlorida.

**Q.** How has transmission planning in Florida changed over the past few years?

**A.** A key element of FERC's Order 2000 was the requirement for regional transmission planning and although GridFlorida never materialized, regional transmission planning has remained a priority for Florida. In Order PSC-06-0388-FOF-EI ("GridFlorida Order") from Docket No. 020233-EI, the FPSC determined it would monitor the peninsular Florida utilities and stakeholders' efforts as they continued to find ways to enhance wholesale market opportunities. In its GridFlorida Order, the FPSC stated:

> "Even though we are allowing the Applicants to withdraw the petition, the underlying impetus for examining the feasibility of an RTO still remains a valid concern for the state. Florida would still benefit from laying additional basic framework for wholesale competition, and efficiencies may be gained by making modifications to the current market structure.

Over the past four years, Florida's peninsular utilities and this Commission have conducted a close examination of the current wholesale market and identified several areas where efficiencies may be gained in a cost-effective manner. One of these is already underway at the utilities' initiative, and there are two more that the utilities are investigating. The initiative that is underway is the FRCC Transmission Planning Process."

**Q.** Please describe the FRCC's transmission planning process.

**A.** The FRCC has developed a regional "top down" approach to peninsular Florida transmission planning. Prior to its development, transmission planning was primarily performed and studied individually by electric utilities. The individual utility plans would then be aggregated and reviewed by the FRCC for compliance with NERC's planning standards but it was never conducted on a holistic, regional perspective. Since the GridFlorida Order, FRCC has been working on a more comprehensive regional planning model.

The FRCC planning process is intended to develop a regional transmission plan to meet the existing and future requirements of all customers, users, providers, owners and operators of the transmission system in a coordinated, open and transparent transmission-planning environment. The planning process begins with the consolidation of the long-term transmission plans of all transmission owners and providers in the FRCC region. It is a requirement that the long-term transmission plans incorporate the integration of new firm resources as well as other firm commitments. This includes all 69 kV and above transmission facilities. A detailed evaluation and analysis of plans is conducted by utility working groups in concert with the FRCC staff and managed by the FRCC Planning Committee. The evaluations and analysis provide the basis for possible recommended changes to individual system plans that, if implemented, would result in a more reliable and robust transmission system for the FRCC region.

**Q.** Did the Energy Policy Act of 2005 ("the Act") have an impact on regional planning and reliability?

**A.** Yes. A significant change due to the Act that impacted the regional planning process was the development of an electric reliability organization ("ERO") with FERC oversight. The Act made compliance with reliability standards approved by FERC mandatory and enforceable, subject to civil penalties. In 2006, NERC was certified by FERC as the ERO for the U.S. The Act also authorized delegation of compliance, monitoring, and enforcement of reliability standards to regional entities such as the FRCC and, in 2007, FERC approved this delegation between NERC and the FRCC. The FRCC is responsible for regulating mandatory planning standards.

**Q.** What other changes have occurred that affect the regional planning process?

**A.** Another change that has occurred has resulted in revisions to the FERC Open Access Transmission Tariff ("OATT"). Following the Act, FERC initiated a rulemaking to implement revisions to the OATT to correct perceived shortcomings to FERC's previous orders. This rulemaking process culminated in the issuance of FERC's Order 890 in December 2007, which was the latest step in the evolution of allowing non-transmission owners fair access to transmission service. Order 890 was developed to provide greater specificity to reduce opportunities for undue discrimination. It also established a set of rules to make the planning and use of the nation's transmission system more open and transparent. In particular, Order 890 required the development of a cost allocation methodology for regional transmission expansion. In response, the FRCC developed a regional transmission cost allocation methodology.

**Q.** Please describe the FRCC cost allocation methodology.

**A.** A key element in FRCC's cost allocation methodology is that it addresses third-party impacts on transmission facilities; that is, when generation installed on a transmission owner's system overloads facilities on another transmission owner's system. The remedy could require expansion of another transmission owner's system. Third-party impacts have occurred periodically in Florida and have become more pronounced over time, especially since the peninsular Florida system is highly integrated, where changes on one system affect multiple systems.

The FRCC cost allocation methodology divides the peninsular Florida system into cost sharing zones. There are two south zones, one central zone, and three north zones. The protocol is triggered when a third-party impact occurs, an affected owner has requested application of the cost sharing methodology and the third-party impact has been confirmed by the FRCC. For example, assume that a transmission owner's system is in the central zone and the costs for expansion of his system will be shared by the load in the central zone and by the incremental generation in any zone that contributes to the overloading of his system. Under the FRCC methodology, the cost allocation methodology would allocate half of the costs to the load in the central Florida zone and half to the incremental generation that contributes to the third-party impact. While this example has been made simple for illustrative purposes, third-party impacts can be much more complex in terms of identifying costs and benefits. The FRCC methodology represents a framework describing criteria, principles and dispute resolution to guide cost sharing negotiations amongst the parties.

**Q.** Does Tampa Electric's projected 2009 transmission expenditures include projects that will be submitted for FRCC review?

**A.** Yes. For 2009, the company has included $68,101,000 in its budget for 230 kV transmission projects. However, given the regional planning process and the dynamic nature of generation and transmission needs for the next five years, it is virtually impossible to predict Tampa Electric's share of expected expenditures accurately. As Florida and the U.S. refine energy policy relative to greenhouse gas legislation, alternative technologies and fuel sources, generation technologies and requirements will be refined accordingly. Even over the past year, clean coal technology has taken a backseat to nuclear and renewable sources. Along with the uncertainty of energy policy, the cost of transmission construction has dramatically increased over the past few years. During the years 2000 through 2002, it cost approximately $700,000 to construct a mile of transmission line. Today that cost could be three times as much due to the higher labor, land acquisition and raw material costs.

**Q.** In this proceeding, what are you recommending for future transmission expenditures as it relates to cost recovery?

**A.** Given the need for additional transmission in Florida and the uncertainty associated with future expenditures, I recommend the Commission approve a Transmission Base Rate Adjustment ("TBRA"). The TBRA would allow Tampa

Electric to timely recover its transmission costs associated with those 230 kV and above transmission projects submitted for FRCC review. As I stated above, the company has included $68,101,000 in its 2009 test year budget for such projects, but it is very likely that future expenditures could be even more significant. A TBRA will allow the company to recover its required transmission related expenditures as they are incurred rather than through base rates. In his direct testimony, Tampa Electric witness Jeffrey S. Chronister describes the mechanism in further detail.

**LAKE AGNES - CANE ISLAND TAP 230 kV LINE**

**Q.** Please describe the Lake Agnes - Cane Island Tap 230 kV line.

**A.** The Lake Agnes - Cane Island Tap 230 kV line is made up of two transmission circuits: Lake Agnes - Osceola 230 kV circuit and four miles of the Osceola - Cane Island 230 kV circuit. Tampa Electric owns 25 percent interest in the Lake Agnes - Cane Island Tap 230 kV line. The line is 25.4 miles and connects the Lake Agnes and Osceola substations and includes four miles of transmission line east from the Osceola substation to the tap for the Cane Island substation.

**Q.** Is the line in Tampa Electric's retail rate base?

**A.** No. During Docket No. 950379-EI, Order No. PSC-97-0436-FOF-EI, issued on April 17, 1997, the Commission said:

> "It appears that TECO purchased 25 percent of the line primarily to ensure the ability to make wholesale sales to entities such as the Reedy Creek Improvement District ("RCID"). Based on the information available at this time, the company finds that the entire investment shall be assigned to the wholesale jurisdiction."

**Q.** Are there any reasons this ruling should be reviewed again?

**A.** Yes. The Lake Agnes - Osceola 230 kV circuit was upgraded in 2008 to meet NERC reliability standards for the bulk electric grid. The Osceola - Cane Island 230 kV circuit is planned to be upgraded in 2010.

**Q.** Explain the importance of the bulk electric grid to the retail ratepayers.

**A.** Tampa Electric is interconnected to other utilities via the bulk electric grid. Given the breadth of the Eastern Interconnection from Florida to Canada, west to the Mississippi River, disturbance impacts are minimized due to the solidarity of the grid. The redundancy of transmission grid provides alternate paths for power to flow when there are planned and unplanned outages on the bulk electric grid. Tampa Electric's retail customers also benefit because of its participation in a reserve sharing group ("RSG"). NERC standards require that an entity have enough generation available within 15 minutes to replace the loss of its largest resource. Because of the interconnection, Tampa Electric participates in a RSG that limits the amount of resources that Tampa Electric must maintain to meet this NERC standard. This benefits retail customers from both a cost and a reliability perspective.

**Q.** Has the Lake Agnes - Cane Island Tap 230 kV line been impacted by the NERC planning standards?

**A.** Yes. In June 2005, a FRCC transmission assessment of the Central Florida region studied the planned generation additions in the Polk County region and their impact on the I-4 corridor transmission based on NERC planning standards. A Florida Central Coordinated

Restudy of the area was completed June 2006 with the recommendation to upgrade the Lake Agnes - Osceola circuit by June 2008 and the Osceola - Cane Island circuit by June 2011.

**Q.** Has the Lake Agnes - Osceola upgrade been completed and at what cost?

**A.** Yes. The upgrade went in service April 24, 2008 at a cost to Tampa Electric of $3,268,000. The Osceola - Cane Island upgrade is expected to cost approximately $900,000. The upgrades and improvements were made to maintain the reliability of the bulk electric grid, which benefits the company's retail customers.

**SUMMARY**

**Q.** Please summarize your direct testimony.

**A.** Tampa Electric forecasts that it will invest $218,945,000 in T&D related capital and incur $76,256,000 in T&D related O&M expenses in 2009. The Energy Delivery capital budget includes system expansion of transmission, substation and distribution facilities to support customer growth and generation expansion, storm hardening initiatives, substation circuit breaker replacements, AMR meter additions and an EMS upgrade project. The 2009 O&M budget includes those activities required for system operations and restoration, meter reading, vegetation management, inspection programs, and the maintenance of equipment and computer systems. These capital investments and O&M expenses are necessary to preserve the company's reliable electric service and to meet the Commission's requirements for storm hardening.

To ensure that the T&D system is reliable, Tampa Electric maintains the necessary capacity and reserves on the system, ensures the quality of the power is acceptable, limits outages from occurring and minimizes the outage time when they occur. The company has recently made significant improvements to its overall system reliability through various reliability initiatives that will also provide benefits in the coming years. Since 2005, Tampa Electric has reduced its SAIDI by almost 10 percent, from 84 minutes to 77 minutes. This improved performance is a result of a concentrated focus on first preventing an outage and then minimizing outage times when they do occur.

To efficiently and effectively manage costs, Tampa

Electric's management team has implemented a number of practices to improve safety, the effectiveness of its workforce, and generally to promote an environment for continuous improvement. These practices have favorably impacted performance in diverse areas of the business: outage response, workforce utilization, inventory, project management, system protection, and meter reading. Significant improvements have also been made to the company's construction standards.

At the same time, the company has experienced additional federal and state regulatory requirements. Tampa Electric, along with the other transmission owners in Florida, expects to invest significantly in the transmission system. Because of the significance of the expenditures and the unpredictable nature of regional cost allocations, a TBRA will serve as an appropriate cost recovery mechanism for future transmission investments.

Overall, Tampa Electric has been able to maintain its system reliability performance and position within the first quartile of comparable peer utilities while remaining below the Commission's O&M benchmark. This represents an appropriate balance between the quality service that customers expect and reasonable costs.

**Q.** Does this conclude your testimony?

**A.** Yes, it does.

MR. HART: Mr. Chairman, we would ask that the exhibit that we had just identified be marked as Hearing Exhibit Number 24.

CHAIRMAN CARTER: For identification purpose only.

MR. HART: Yes.

CHAIRMAN CARTER: Show it done. You may proceed.

(Exhibit Number 24 was identified for the record.)

BY MR. HART:

Q. Mr. Haines, did you also prepare and cause to be filed in this proceeding prepared rebuttal testimony consisting of 22 pages?

A. Yes, I did.

Q. Are there any changes or corrections to your prepared rebuttal testimony?

A. No, there's not.

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

A. Yes, they would.

Q. Attached to your rebuttal testimony, did you included a composite exhibit premarked as RBH-2 and Hearing Exhibit Number 84, consisting of two documents?

A. Yes.

MR. HART: Mr. Chairman, we would ask that Mr. Haines' composite exhibit be formally identified for the record as Hearing Exhibit Number 84.

CHAIRMAN CARTER: Let's do this first. Let's adopt the prefiled rebuttal testimony of the witness into the record as though read. And for the record, the prefiled exhibit will be identified for the record. You may proceed.

(Exhibit Number 84 was identified for the record.)

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**REBUTTAL TESTIMONY**

**OF**

**REGAN B. HAINES**

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

**A.** My name is Regan B. Haines. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Engineering in the Energy Delivery Department.

**Q.** Are you the same Regan B. Haines that filed Direct Testimony in this proceeding?

**A.** Yes, I am.

**Q.** What is the purpose of your rebuttal testimony in this proceeding?

**A.** The purpose of my rebuttal testimony is to address serious errors and shortcomings in opposition to certain aspects of Tampa Electric's Petition for an Increase in

Base Rates made by Helmuth W. Shultz, III and Hugh Larkin, Jr., both on behalf of the Office of Public Counsel ("OPC") and by Jeffry Pollock on behalf of The Florida Industrial Power Users Group ("FIPUG") in testimony filed on November 26, 2008.

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

**A.** Yes, I have. My Rebuttal Exhibit No.__ (RBH-2) consists of the following two documents, which were prepared by me or under my direction and supervision:

Document No. 1 2009 Substation Preventive Maintenance

Document No. 2 2002 through 2008 SAIDI Goals and Performance

**Q.** Please summarize the key concerns and disagreements you have regarding the substance of witness Shultz's testimony.

**A.** Mr. Shultz's testimony, at pages 21 through 27, narrowly objects to four aspects of Tampa Electric's proposed transmission and distribution maintenance programs for 1) tree trimming, 2) pole inspections, 3) transmission inspections, and 4) substation preventative maintenance.

He also reaches incorrect conclusions about reliability incentive compensation targets. The recommendations proposed by Mr. Shultz are based on inaccurate information and, therefore, his recommended adjustments to Tampa Electric's base rate increase are incorrect and inappropriate.

**TREE TRIMMING**

**Q.** What is your response to Mr. Shultz's objection to Tampa Electric's proposed tree trimming expenditures?

**A.** Although I have numerous issues with Mr. Schultz's objections to the company's tree trimming practices and projected expenses, he is correct in his assessment on page 21 of his direct testimony that the transmission request is reasonable. However, throughout his testimony, Mr. Shultz fails to recognize and discuss the reasons that Tampa Electric has committed to meet its Commission-required three-year distribution tree trim cycle by 2010. As stated in my direct testimony, "Tampa Electric is increasing its vegetation management program to establish and maintain a three-year distribution system trimming cycle in order to comply with the Commission's requirements for storm hardening." Tampa Electric's commitment and this requirement is the result of many workshops and due diligence by this Commission on the benefits of tree trimming as it relates to storm hardening and reducing outages and improving restoration following a major storm event. Tampa Electric has testified previously on its experiences with hurricanes and the damage that trees cause. The company believes and agrees with the Commission that investing in additional tree trimming activity now should reduce the number of outages and possibly reduce overall restoration costs following a major storm event.

**Q.** Did Mr. Schultz fairly represent the funding levels for tree trimming approved in the company's last base rate proceeding 16 years ago?

**A.** No. While Tampa Electric did request funding for a two-year tree trim cycle in its last base rate proceeding in 1992, the Commission actually approved funding to support a four-year cycle. Since that time, there have been years when the company was able to trim more than 25 percent of its system (equal to a four-year cycle) and some years when the company trimmed less. Many factors are considered and weighed each year such as the circuits requiring trimming and other maintenance programs. Since the company's last rate proceeding, the impacts of increased hurricane activity have been a major focal point for this Commission and the need for increased tree trimming has been debated and reestablished.

**Q.** *Do you agree with Mr. Schultz assessment that the costs for distribution tree trimming are excessive?*

**A.** No I do not. In my direct testimony, I partially attribute increased contractor rates to escalated fuel costs but I also state, "per unit costs for vegetation management have also grown at a faster pace than inflation. This is primarily due to the competition for resources as all electric utilities are responding to this Commission's policies requiring more aggressive tree trimming activity as well as increasing contractor rates mainly caused by escalating fuel costs." My point is that contractor rates have increased at a greater rate than CPI due to increased demand for these resources and increased fuel costs. The company based its 2009 projected expenditures on known contract rates along with other reasonable cost estimates.

**Q.** *Do you agree with Mr. Schultz's statement on page 22 that the company "does not know how many miles on the system actually requires trimming per year"?*

A. No. That is an outrageous allegation. Of course the company knows how many miles are in its system and what needs to be trimmed. Mr. Shultz's recommendation that the company receive approval for funding only 1,530 miles per year is equally incorrect. Not only is the logic he uses to calculate the miles flawed, but such an adjustment would place the company on a four-year tree trim cycle which conflicts with this Commission's storm hardening order.

Q. Please describe the company's plan in more detail and be more specific as to how Mr. Schultz's recommendation contradicts it.

A. Tampa Electric's vegetation management program includes trimming approximately one-third of its distribution system or 2,040 circuit miles each year on average. Mr. Shultz states that the company trimming all 6,121 miles of overhead distribution lines is not required because trees do not exist along all the miles. While this is true, this is not how the company has historically tracked or reported miles trimmed to the Commission. Tree conditions can change from year to year due to different tree species growth rates, amount of rain, and tree removals and additions. Because of these factors, the company physically inspects every mile of its system regardless of whether it trims trees every three years. The number of miles trimmed each year by the company and reported to the Commission reflects the total miles inspected and/or trimmed which includes some miles that have no vegetation. Therefore, Mr. Shultz's suggestion that the actual miles requiring trimming and associated costs should be adjusted is inaccurate and inconsistent with how the company reports miles trimmed. The $7,897 cost per mile figure that Mr. Shultz references is a total cost which includes both circuit miles with and without trees. To translate that cost to only those circuit miles with trees would result in a significantly higher cost per mile.

**Q.** Based on recent experience, do you have any reason to believe that the company's estimated costs for 2009 are not reasonable?

**A.** No. In 2007, the company spent approximately $10.3 million and trimmed roughly 22 percent of its distribution system. Applying a four percent contractor increase each year, the company would need $11.2 million to trim 22 percent. Given recent experience with costs, it is very reasonable to expect that $16 million will be required to trim approximately 33 percent of the distribution system by 2010. In 2009, the company plans to ramp up the additional tree trim resources needed to trim 29 percent of the distribution system. The company supports this Commission's policies with respect to a three-year trim cycle and believes it creates the right balance to minimize the number of outages following a major storm event.

**POLE AND TRANSMISSION STRUCTURE INSPECTIONS**

**Q.** What is your response to Mr. Shultz's objection to the company's proposed pole inspection program?

**A.** As with tree trimming, Mr. Schultz completely ignores Commission directives. Tampa Electric's pole inspection plan was filed and approved by the Commission in Order No. PSC-06-0778-PAA-EU issued on September 18, 2006. The proposed budget for the 2009 pole inspection program is appropriate and necessary to meet the Commission's requirements.

Mr. Shultz's attempt to reduce the company's request by using 2007 per unit cost information to project 2009 cost requirements is flawed for several reasons. First, the $30.63 average cost per pole inspection in 2007 used by

Mr. Shultz does not include the comprehensive pole loading analysis the company is required to do for all joint use poles, which was included in the company's 2009 pole inspection budget. Secondly, the contractor used by the company to perform this work has escalated its rates at a greater rate than the index referenced by Mr. Shultz. Finally, the 40,750 poles to be inspected each year include both distribution and transmission poles which have different rates. Thus far in 2008, the company has experienced a rate of $33.03 per distribution pole inspection. Once a four percent contractor price increase is factored in, the projected 2009 cost per distribution pole inspection will increase to $34.35. When this is applied to the 37,500 distribution poles to be inspected annually (one-eighth of the system), the proposed budget is $1,288,170. Finally, when the budgeted $147,844 for transmission pole inspections and $95,892 for comprehensive loading analysis are included, the total 2009 budget is reasonable. The company's estimate is based on actual rates rather than the arbitrarily adjusted rates used by Mr. Schultz. He is simply asking the Commission to ignore reality.

**Q.** What is your response to Mr. Shultz's objection to the company's proposed transmission structure inspection program?

A. Once again, Mr. Schultz ignores this Commission's orders. Transmission structure inspections and repair is another element of the Commission's storm hardening requirements. The company's transmission structure inspection program was filed and approved by the Commission as part of its Ten Point Storm Hardening Plan, in Order No. PSC-06-0144-PAA-EI issued December 28, 2007 in Docket No. 070927-EI.

Because transmission structure inspection activities have increased for all utilities in the state, the costs for these inspections have increased significantly since 2005. The new inspection requirements were first put into place in 2007 and now include infrared and above-ground type inspections which were not performed in all of the years that Mr. Shultz utilized in his cost averaging. The costs of infrared and above-ground inspections have increased by 33 percent and 28 percent, respectively, since 2005.

The company's 2009 budget also includes $29,000 for lattice tower inspections, something that has not been performed recently but is now required for the foreseeable future given the aging infrastructure.

Finally, while the transmission structure inspections have been occurring since the Commission's storm hardening rules were first established, all of the identified repairs as a result of the inspections must now be made. The company expects that it will need $300,000 annually to make these repairs.

**Q.** Based on recent experience, do you have any reason to believe that the company's estimated costs for 2009 for pole and transmission structure inspections are not reasonable?

**A.** No, I do not. These estimated costs remain reasonable and should be used in establishing the company's revenue requirements in this proceeding.

**SUBSTATION PREVENTIVE MAINTENANCE**

**Q.** What is your response to Mr. Shultz's objection to the company's proposed substation preventive maintenance program?

**A.** There are several elements of Mr. Shultz's testimony related to substation maintenance that are misleading. First, the 2007 costs he references are not representative of all activities that are needed in 2009.

Two thousand seven was not a typical year for circuit breaker maintenance; therefore, it is misleading to use it to project 2009 costs. For example, there were 23 fewer circuit breakers that needed to be maintained than in 2009 at an additional cost of $28,000. There were also changes made for classifying oil test costs from corrective maintenance to preventative maintenance late in 2007 that creates an *apples and oranges* comparison. This change amounts to an additional $17,000 needed in 2009. Finally, the contractor costs for North American Electric Reliability Corporation ("NERC") required relay testing have increased at a higher rate than CPI and also at a higher rate than was experienced in 2007, resulting in additional costs of $80,000 in 2009. Given the extensiveness of NERC's relay standards and the lessons learned from testing, Tampa Electric plans to test all of its relays. The yearly additional cost is $429,000 which includes two additional relay testers that have been included in headcount numbers.

Finally for 2008 and 2009, the substation condition-based preventative maintenance included annual substation inspection costs, but the 2003 through 2007 historical costs did not. For comparison purposes, 2009 condition-based preventative substation maintenance should be

$1,979,010 as shown in Document No. 1 of my rebuttal exhibit.

**Q.** Based on recent experience, do you have any reason to believe that the company's estimated costs for 2009 for substation preventive maintenance are not reasonable?

**A.** No. In fact, based on the company's experience in 2008, the costs are most likely understated.

**SAIDI INCENTIVE COMPENSATION TARGETS**

**Q.** Do you agree with Mr. Shultz's claims that the company's SAIDI incentive compensation goal targets are set such that employees are not required to improve their performance?

**A.** No, I do not. Mr. Shultz's assertion that the company sets its SAIDI reliability goal in such a manner that employees are not required to improve their performance or the service provided to our customers shows a lack of appreciation and understanding of electric operations. While Tampa Electric witness Dianne Merrill addresses incentive compensation in her rebuttal testimony, I will provide more detail on how the goal is set and elements that can have a significant impact on actual achievement.

Document No. 2 of my rebuttal exhibit illustrates the company's SAIDI goals and actual performance since 2002. The company's SAIDI performance varies significantly from year to year and there are numerous drivers as shown in Document No. 2. Certainly the severity of storm season has an impact and this does not just include hurricanes. The Tampa Bay area is the lightning capital of the world and summer storms can significantly impact SAIDI. For example, in 2003 outage totals increased over 2002 totals by 369 outages (three percent) due to extensive severe weather.

Operational changes and system enhancements can greatly impact reliability results. For example in late 2001, the company migrated to a new outage management system ("OMS") that featured enhanced measuring capabilities over the previous OMS system. These capabilities generally included the ability to more accurately capture customer outages and related outage times. System enhancements also allowed for step-restoration to be captured, which matches the correct number of customers to associated restoration times. Therefore, 2002 represented the first full year using the new OMS system and the company attributes an increase in SAIDI from 2001 to 2002 and 2003 to the new system enhancements. In addition, the company conducted training for the Trouble Department that year which improved their knowledge and use of the new system. Even with these impacts in actual results, the company continued to set aggressive SAIDI goals through 2005 when the impact of the OMS to SAIDI was fully realized.

**Q.** Do you agree with Mr. Shultz's insinuation that the company sets its goals so that they can easily be met and that employees are not encouraged to improve?

**A.** Absolutely not. Document No. 2 of my rebuttal exhibit illustrates that the company has only met its SAIDI goal twice since 2002. The company's objective is to set goals that can be accomplished, but are a stretch to do so. The fact that the goals were set at a level which was only met twice since 2002 demonstrates how high the bar has been set to encourage improvement.

Operational improvements are constantly encouraged at Tampa Electric. As I highlighted in my direct testimony, the company has accomplished top quartile performance compared to peer utilities since 2002 because of several recently implemented programs designed to improve system reliability. Mr. Schultz is completely wrong to conclude that goals are set so that they can be easily met and employees are not encouraged to improve.

**TRANSMISSION BASE RATE ADJUSTMENT**

**Q.** Please summarize the key concerns and disagreements you have regarding the substance of witness Larkin's testimony concerning the company's proposed Transmission Base Rate Adjustment ("TBRA") clause.

**A.** There are two primary areas where I disagree with Mr. Larkin's testimony. First the Federal Energy Regulatory Commission ("FERC"), NERC, and the Florida Reliability Coordinating Council ("FRCC") significantly impact Tampa Electric's transmission construction planning and costs. Second, the appropriateness of a TBRA is consistent with that of other cost adjustment clauses.

**Q.** Please explain how the FERC, NERC, and FRCC can have a direct impact on Tampa Electric's transmission construction costs.

**A.** The FERC, NERC and FRCC's impact on the company's transmission planning and associated costs have significantly changed in recent years. NERC's reliability standards dictate the planning and operating criteria for the transmission system that all utilities must meet. The criteria can and does have a direct impact on what transmission gets constructed and when it is required.

Under the Energy Policy Act of 2005, the FERC has the right to mandate reliability standards and enforce them in multiple ways including by assessing civil penalties for non-compliance. In 2007, the FERC approved the delegation of compliance, monitoring, and enforcement of reliability standards for Florida from the NERC to the FRCC. Given this, transmission projects identified and required to meet these reliability standards must be constructed and they must be completed in a proper timeframe to meet the NERC criteria. This is analogous to a government mandate. There is no flexibility with meeting these reliability standards. In addition, the Commission looks to the FRCC to provide input on the reliability of the transmission grid in Florida and recent history shows their support of projects recommended by the FRCC.

**Q.** Are there any other impacts from the FERC, NERC, or FRCC that make transmission construction costs difficult to anticipate?

A. Yes. While at one time transmission planning and construction was as Mr. Pollock describes on page 75 of his testimony, "as a member of the FRCC and the party responsible for constructing new facilities, TECO has some control over the [sic] both the timing and cost", and as Mr. Larkin describes on page 10 of his testimony that "The facilities which are constructed on the Tampa Electric system are fully under the control of the Company and the Florida Public Service Commission", the process has changed and clearly Messrs. Pollock and Larkin have not been updated. While Florida never adopted a regional transmission organization with a cost allocation methodology for the sharing of regional transmission costs, the FRCC did develop a cost allocation methodology in response to FERC Order 890 in December 2007. This methodology is a settlement structure that parties agree to use when there are third party impacts resulting in the construction of new transmission facilities. Under the methodology, costs are allocated among multiple entities who contribute to the need for the third party facilities and who benefit from their construction. While this methodology is meant to allow for a fair allocation of costs based on who is causing the impact, the allocation of these costs will be an involved process among multiple parties and it will be very difficult to predict each party's share or cost responsibility.

Another unpredictable aspect for planning and constructing transmission facilities is the FERC transmission tariff mandate that a transmission provider build transmission needed for generator interconnection requests for firm transmission service. As existing transmission capacity has been consumed over the last few years with these requests for generator interconnection and firm transmission service, new requests are requiring the construction of new transmission facilities. These requests are not predictable in nature but the construction of the facilities requested is necessary to maintain safe and reliable electric service in peninsular Florida.

**Q.** Please comment on Mr. Pollock's statement, on page 76 of his testimony, that "transmission plant additions will be offset to some degree by the growth in revenues stemming from growing electricity sales."

**A.** Mr. Pollock is incorrect. While there could be some peripheral benefits, the primary benefits come by way of reliability and possibly lower fuel costs from off-system purchases and sales.

**Q.** How is the TBRA similar to other cost recovery clauses?

**A.** I am not an expert on cost recovery clauses and Tampa Electric witness Jeffrey Chronister will address this issue in more detail in his rebuttal testimony. However, Mr. Pollock argues that "costs that are subject to recovery outside of a general rate case should be "material, volatile, and beyond the utility's control" and that transmission investment does not meet these criteria. I disagree. Given the authority of FERC to mandate reliability standards and enforce them with civil penalties, transmission investment can be "beyond the utility's control". Transmission investment can be volatile given third party impacts and the FRCC cost allocation methodology as stated above.

**Q.** After reading the intervenors' testimony, are you still convinced that a TBRA is a necessary mechanism?

**A.** Yes I am. The TBRA will result in lower costs by facilitating a coordinated and cost-effective means of planning and constructing transmission for the entire FRCC region. Moreover, this will result in improved reliability and lower fuel costs by enhancing generation dispatch for the entire region.

**SUMMARY OF REBUTTAL TESTIMONY**

**Q.** Please summarize your rebuttal testimony.

**A.** There are several areas of the intervenors' testimony regarding tree trimming and system maintenance and the company's proposed TBRA clause that I address. Mr. Shultz's claim that the proposed tree trimming, pole inspection, and transmission structure maintenance expenses are excessive is not based on accurate information. These three elements of Tampa Electric's storm hardening plan have been reviewed and approved by this Commission and are critical to improving the company's performance following a major storm event. These activities are necessary, prudent and in compliance with the Commission's storm hardening requirements. The costs are based on recent performance and established contractor prices. Mr. Shultz's statements about preventative substation maintenance are inaccurate and the proposed amounts are prudent and will allow Tampa Electric to perform the appropriate levels of relay testing and breaker maintenance to meet NERC relay standards.

In addition, Messrs. Larkin and Pollock have not fairly represented the challenges facing Tampa Electric, the state of Florida, and the country when it comes to the electric transmission grid and the new requirements established by the FERC, NERC, and FRCC. The proposed TBRA clause will allow the company to timely recover its transmission costs associated with 230 kV and above transmission projects submitted for FRCC review. Given the authority of FERC to mandate reliability standards and enforce them with civil penalties, transmission investment can be "beyond the utility's control." Transmission investment can be volatile given unforeseen third party impacts and the FRCC's cost allocation methodology. For these reasons, I believe the TBRA structure is an efficient and effective approach to addressing these new challenges.

**Q.** Does this conclude your rebuttal testimony?

**A.** Yes, it does.

BY MR. HART:

Q. Would you please summarize your direct and rebuttal testimony?

A. Yes. Good afternoon, Commissioners. The purpose of my direct testimony is to summarize Tampa Electric's transmission and distribution related capital and O&M expenses for the 2009 test year. I have also filed rebuttal testimony which addresses the shortcomings in testimony filed on behalf of the OPC and FIPUG regarding the company's tree trimming, pole inspection, transmission structure, and substation maintenance plans, as well as the company's reliability goals and proposed transmission base rate adjustment clause.

Since the company's last rate case 16 years ago, significant changes have occurred that have impacted the transmission and distribution side of Tampa Electric's business. While increasing our customer base by 200,000 customers has certainly had an effect, some of the other factors that have affected the way we plan, engineer, construct, and operate our delivery system include the following:

Increased hurricane activity has impacted the state more than ever before, causing a heightened focus to hardening our delivery system infrastructure.

The security and reliability of the nation's transmission grid has and will continue to require more transmission expansion in our service territory over the next five to ten years than we have experienced over the last 20 years.

And material and equipment costs have significantly outpaced inflation, putting upward pressure on our costs. Tampa Electric forecasts that it will invest almost $219 million in capital and $76 million in O&M for transmission and distribution in 2009. While the company's transmission and distribution related capital and O&M expenses have increased over the years, we have managed to remain below the Commission's O&M benchmark. The majority of the company's T&D related increases for 2009 are attributable to the construction of major high voltage transmission facilities needed to meet NERC standards and additional tree trimming and system maintenance expenses for hardening our system, as ordered by the Commission.

Overall, Tampa Electric has done well at maintaining its system reliability and has ranked within the first quartile of comparable utilities, while effectively managing its resources. However, the company is facing new challenges and requirements that necessitate additional investment in our T&D

infrastructure.

Tampa Electric has proposed a transmission base rate adjustment clause to allow for timely recovery of its transmission costs associated with the expected increase in 230 kV and above transmission projects that are required by the FRCC regional transmission planning process to meet NERC standards. This clause is appropriate and necessary given the changes in how regional transmission planning is performed and how associated costs are allocated to peninsular Florida utilities. The company's proposed T&D capital and O&M budgets for 2009 represent an appropriate balance to provide safe and reliable service that will benefit our customers at a reasonable price.

This concludes my summary.

MR. HART: Mr. Haines is tendered for cross-examination.

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

MS. CHRISTENSEN: Thank you.

CROSS-EXAMINATION

BY MS. CHRISTENSEN:

**Q.** Good morning, Mr. Haines.

**A.** Good morning, or good afternoon. I'm following your lead.

CHAIRMAN CARTER: It's Groundhog Day.

MS. CHRISTENSEN: Excuse me. I hope not.

BY MS. CHRISTENSEN:

**Q.** Mr. Haines, let me -- I'm going to ask you a few questions about Tampa's tree trimming and its cycle. Is it correct that there are 6,121 distribution miles in Tampa Electric's system?

**A.** That is correct.

**Q.** Okay. And how many miles actually required trimming to be performed?

**A.** Well, that number is our overhead distribution miles. And in order to comply with the three-year tree trim cycle, we would be trimming roughly 2,040 miles every year on average.

**Q.** Okay. Of those 2,040 miles, do you know how many of those miles actually required trimming versus covered miles?

**A.** Well, as I stated in my rebuttal testimony, that can change from year to year, as trees grows, as trees are planted, as trees are removed. So what we do is, we send out crews out, and they patrol every circuit, every mile of every circuit, and cut what is needed to be trimmed in order to meet our specifications.

**Q.** Okay. So the answer to the question would be that you don't possess or have the data or a method of identifying the total system miles that do not require trimming or maintenance because vegetation is in the right-of-ways or does not exist?

**A.** I guess the answer to the question is, it changes every year, so we patrol the circuits that are designated for trimming and trim what's needed. It's hard to say at any given time what's required for trimming without actually physically going out there and looking at the circuits.

**Q.** Okay. In response to interrogatory number 109, where it was asked -- where the company was asked a question regarding how many of the system's miles actually required tree trimming, the company responded with the statement that the company does not possess the requested data or have a method of identifying the total system miles that do not require trimming or maintenance because vegetation is in the right-of-way or does not exist. Does that sound correct to you?

**A.** That sounds correct, yes.

**Q.** Now, is it the company's goal to be on a three-year tree trimming cycle?

**A.** That's correct.

**Q.** And it would be correct that the cycle would be based on the system miles and not actual miles that require trimming?

**A.** That's correct. That's typically how we have reported miles that are trimmed each year and I believe how the other utilities in the state report trimmed miles each year.

**Q.** Okay. And I think you had said this earlier, but I want to confirm that 2,040 is the system miles that would be ideally trimmed in a year.

**A.** That is a third of our overall overhead distribution system miles, yes.

**Q.** And is it correct that the company in response to the Commission's storm hardening initiative determined that it would be on a three-year tree trimming cycle?

**A.** Yes. We are transitioning to a three-year tree trim cycle.

**Q.** Okay. Now, in 2006, would you agree that 1,108 miles were trimmed?

**A.** Are you referring to an interrogatory response?

**Q.** Would referring to interrogatory response number 67 help refresh your recollection, or if you have it there?

**A.** That number sounds familiar. I just don't have the exact number committed to memory.

**Q.** I'm specifically referring to number 67.

**A.** If that's what we responded in our interrogatory, then that should be accurate.

**Q.** I'm going to be asking a few more questions, though. If it would help, I can give you a copy.

**A.** Which number? I have a copy.

**Q.** Sixty-seven.

**A.** Okay.

**Q.** Okay. And I think we agreed that the number of miles that were trimmed in 2006 was 1,108 miles; correct?

**A.** That's correct.

**Q.** Okay. And that's approximately 18 percent of your system?

**A.** If you've done the math, that sounds about right.

**Q.** And in 2007, Tampa Electric trimmed 1,307 miles; correct?

**A.** That's correct.

**Q.** And that would be approximately 21 percent of the total system miles?

**A.** That's correct.

**Q.** Okay. And is it correct that Tampa Electric budgeted for 1,141 miles to be trimmed in 2008?

**A.** Could you repeat that number?

**Q.** 1,141.

**A.** That sounds correct.

**Q.** Okay. And that would have been about 18 percent of Tampa Electric's total system miles?

**A.** Correct.

**Q.** Okay. Now, would it be also correct to say while Tampa Electric was working on a plan to achieve a three-year trim cycle, it budgeted in 2008 a decrease in the number of miles to be trimmed?

**A.** What actually happened was -- no. In 2007, at the end of the year, we trimmed additional miles. We had additional contractors on-site and went ahead and accelerated some of the 2008 trimming into the last part of 2007.

**Q.** Looking at Tampa Electric's budgeted number for 2009, is it correct that Tampa Electric budgeted for 1,753 miles to be trimmed?

**A.** That's correct.

**Q.** And that would be approximately 28.6 percent of the system; correct?

**A.** Yes.

**Q.** Now, let me refer you to page 7 of your rebuttal testimony.

**A.** Okay.

**Q.** Starting at line 24, the sentence that begins with, "Given recent experience with costs, it is very reasonable to expect that 16 million will be required to trim approximately 33 percent of the distribution system by 2010." Now, is it correct that the company is requesting $16,073,444 to trim 29 percent of its system miles in 2009?

**A.** That is correct.

**Q.** Now, Mr. Haines, the Commission approved recovery for a four-year trim cycle that the company proposed in the last rate case; is that not correct?

**A.** Yes.

**Q.** And in 2002, again referring to interrogatory number 67, Tampa Electric trimmed 1,326 miles; correct?

**A.** Yes.

**Q.** And that's approximately 21 percent of your system miles?

**A.** Yes.

**Q.** And in 2003, Tampa Electric trimmed only 786 miles; correct?

**A.** That is correct.

**Q.** And that would be approximately 12 percent of the system miles?

**A.** That is correct. And again, the four-year cycle is on average over a period of time. You try to trim your entire system over a four-year period, so it's going to fluctuate. It's not going to be exactly 25 percent on a four-year cycle every year.

**Q.** Okay. Well, let me ask you, in 2004, Tampa Electric trimmed 941 miles; correct?

**A.** That is correct.

**Q.** And that's approximately 15 percent of your system?

**A.** That is correct.

**Q.** And in 2005, Tampa Electric trimmed 1,064 miles; correct?

**A.** That is correct. But I would also point back on that same interrogatory response to the years 1998, '99 and 2000, where we were trimming above the 25 percent. So again, you have to look at a period of time and look at the average cycle that you're trimming your system.

**Q.** And for 2005, would you agree that that was only 17 percent of the system?

**A.** I haven't done the math, but I'm going to -- yes.

**Q.** Okay. And you would agree in the years that we just discussed, 2002 through 2005, Tampa Electric did not trim the equivalent of 25 percent of the system miles?

**A.** That is correct.

Q. Okay. And you would also agree that since the company maintained a less than four-year cycle, that the costs would be higher to return to a four-year or less cycle than it would have been if the company had maintained the four-year cycle to begin with that was approved in the last rate case?

A. Could you repeat that question?

Q. Certainly. Essentially, would you agree that the company, had it maintained the four-year cycle which was approved in the last rate case, it would have been less costly to maintain that four-year cycle or less if the company had all along maintained the four-year cycle which was approved?

A. I would agree, but at the same time, I would point to 2004, when we were impacted by three hurricanes. There was a significant amount of tree trimming that was performed following those hurricanes that we would get benefit from that you won't see in these numbers, because this reflects more the day-to-day type trimming that our crews do.

Q. Okay. Would you agree that there's no quantifiable benefit reflected in the 2009 O&M expense as a result of the increase in the trimming proposed?

A. The proposed trimming is to do 1,753 miles for 16 million, which is what -- based on the current rates we're seeing on a per mile basis is what it's going to take to trim 1,753 miles. Moving forward, we think we can get additional miles done for the same cost, taking into account -- I think what your point is is that when you start to trim, if you stay on top of that cycle, you're going to have more cost-effective trimming. It's not going to cost you as much in the long run. So that is factored into our costs, as far as if you look at 16 million to trim 1,753 miles, which is not a three-year cycle, but for those same costs, we believe we can manage a three-year cycle moving forward.

**Q.** Okay. But I'm not sure you did answer my question, which was that there were no quantifiable benefits reflected in the 2009 O&M expenses as a result of the increased trimming that you proposed; is that correct?

**A.** I'm not sure if I follow your question. Could you maybe rephrase it?

**Q.** You haven't shown any reductions in O&M expenses related to this increased tree trimming in the 2009 projected test year; correct?

**A.** Such as?

**Q.** Such as reduced -- others types of reduced maintenance.

**A.** We covered this a little bit in our deposition. Tree trimming is a maintenance expense. It's a maintenance activity. So I'm not sure what other maintenance activities would be decreased due to additional tree trimming, because other maintenance activities are replacing aged equipment or equipment that has failed. So tree trimming is going to have -- not have a whole lot of impact on those types of expenses.

**Q.** Okay.

**A.** It's more reducing outages and reducing impacts following a hurricane and improving restoration times following a hurricane, is what the objective is.

**Q.** Okay. Do you agree that storms cause outages each year, not necessarily just hurricanes, but other types of storms?

**A.** Yes.

**Q.** Okay. And would you agree that if there's an increase in trimming, there should be some benefit in the cost reductions for those types of outages as well?

**A.** For restoration, I agree, yes.

**Q.** Would you agree that the contracts for trimming are on a time and equipment basis?

**A.** Yes, they are.

**Q.** Okay. And is it true that the contracts are subject to an adjustment if the fuel costs change?

**A.** Yes. If the cost swings more than plus or minus 5 percent of the negotiated range, then there's a true-up in our current contracts either way to take into account those fuel cost swings.

**Q.** Okay. And let me refer you to interrogatory response number 83. Do you have that in front of you?

**A.** Yes. Okay.

**Q.** Okay. Now, referring to that interrogatory response, would you agree that the cost per overhead mile for 2008 for planned trimming is $7,200?

**A.** Yes, it is.

**Q.** Okay. And would you also agree, referring to that exhibit, that the cost per overhead mile for the 2009 planned trimming jumps to $8,200?

**A.** Yes, it does. There are several factors as to why that is occurring, including increased contractor costs, because there's more competition for these tree trimming resources in the state. The cost for that service has outpaced inflation, and that's factored into that, as well as the circuits that we have targeted to be trimmed in 2009 are harder to trim circuits. That is, a lot of the overhead facilities are in rear lots behind our customers' homes, and they're more difficult to get to, and therefore, it takes longer to trim those types of circuits. So all that's factored into that cost per mile projection.

Q. Okay. Would you agree that that represents an increase of approximately 14 percent in one year?

A. That sounds about right, yes.

Q. Okay. Now, let me switch subjects a little bit to pole inspections. The company has not quantified any cost savings in 2009 for maintenance associated with the increase in pole inspections; is that correct?

A. We have not recognized any quantifiable savings with pole inspections. Pole inspections are going to lead to additional costs as you identify poles that need to be replaced. And based on the failure rates that we're seeing, that's what we used to project the capital costs associated with pole replacements. And again, this is centered around the eight-year pole inspection cycle that was passed by this Commission during the hurricane hardening activities and workshops that we had.

Q. Okay. Now, in your rebuttal testimony, you took exception to Mr. Schultz's pole inspection adjustment; is that correct?

A. That is correct.

Q. Okay. And one exception was that you noted on page 8 of your rebuttal his use of the $30.63 2007 average cost per inspection; correct?

**A.** That is correct.

**Q.** If you'll refer yourself to Mr. Schultz's Schedule C-7.

**A.** Okay.

**Q.** Now, it was Schedule C-7 that you were referring to in your rebuttal testimony; is that correct?

**A.** That is correct.

**Q.** Now, do you have a copy of interrogatory -- Tampa Electric's response to interrogatory number 68 in front of you?

**A.** Yes, I do.

**Q.** Okay. In looking at Tampa Electric's response to interrogatory number 68, wouldn't you agree that it's the source for the average rate used by Mr. Schultz?

**A.** For the years 2007 and prior, this is his source.

**Q.** Okay.

**A.** There's different types of activities in the numbers prior to 2007 and the numbers in 2008 that he's comparing to.

**Q.** Okay. Well, let me ask you some additional questions regarding interrogatory number 68. The average inspection cost developed by Mr. Schultz reflects both the transmission and distribution inspections; correct?

**A.** He has combined those two, yes, he has.

**Q.** And you also stated in your rebuttal testimony on page 9 that the 40,750 pole count used by Mr. Schultz in his calculation includes both transmission and distribution poles; is that correct?

**A.** That's correct. There's approximately 37,500 distribution poles that we're inspecting and then another over 3,000 transmission poles that we inspect each year in order to meet the eight-year requirement, and those poles -- the cost to inspect those poles are at two different rates.

**Q.** Now, you would agree that Mr. Schultz made his adjustment by comparing his calculated amount to the 2009 budgeted amount of $1,573,778?

**A.** That's correct.

**Q.** And looking at Tampa Electric's response to interrogatory number 71, if you have that in front of you --

**A.** Okay.

**Q.** Isn't it correct that the projected 2009 cost is 1,573,778?

**A.** It is. But if you look under that section titled "Eight-year Pole Inspection Cycle Program," the last line item is comprehensive loading analysis for approximately $96,000 a year. The $1.573 million number that you referenced is the total cost for the program. The numbers that Mr. Schultz is using are the costs for just the pole inspections.

**Q.** But you would agree that that $1,573,778 includes both transmission and distribution pole inspection; correct?

**A.** Yes. It includes that plus the comprehensive loading analysis. So that last piece, comprehensive loading analysis, is the activity that we're doing since the storm hardening requirements to analyze how loaded our poles are, to make sure they're not overloaded, which would cause a failure if we get impacted by a high wind event. That is a new activity that is not included in the numbers Mr. Schultz used to compare to for 2007 and prior.

**Q.** But you would agree his recommended adjustment is based on Tampa Electric's response, the 40,750 poles per year on an eight-year cycle; correct?

**A.** It is, but the rate that he's calculating to suggest it would be an appropriate rate is not an accurate calculation.

**Q.** Let me move on to page 10 of your rebuttal testimony. You state that the new requirements were put in place in 2007 --

**A.** I'm sorry. One second, please. Page 10?

**Q.** Page 10, uh-huh. I have to find it myself.

Regarding the transmission structure inspection program, you state that the new requirements were put in place in 2007 and were not included in all the years that Mr. Schultz utilized in his cost averaging; is that correct?

**A.** That is correct.

**Q.** So it was your contention that Mr. Schultz ignored the Commission orders because he was basing his adjustment on averages that did not include the new requirements that were put in place in 2007?

**A.** Yes. The issue with how Mr. Schultz calculated his expense number for 2009 is using previous numbers that did not include certain activities that we're required to do since the hardening initiative, as well as the costs for those services now have increased and outpaced inflation. And so the costs that we've reflected represent the activity that we need to do and represent our current contract prices that have already been negotiated and are accurate for the 2009 test year.

**Q.** Looking at Mr. Schultz's C-8 --

**A.** Okay.

**Q.** Specifically line 8, you would agree that that's Mr. Schultz's calculated estimated cost?

**A.** 323,927?

**Q.** Correct.

**A.** Yes.

**Q.** And looking at the notation on the side, would you agree that that refers to Tampa Electric's interrogatory response number 69, which is based on actual 2007 numbers?

**A.** It is 2007 numbers, yes.

**Q.** Okay. And would you agree that -- looking at the reference on Schedule C-8, that the basis for the schedule calculation is the actual 2007 numbers from POD 69?

**A.** The 302,195?

**Q.** Correct.

**A.** Yes.

**Q.** On page 11 of your rebuttal testimony, you state that inspections have been occurring, and now the company expects that they will need $300,000 annually to make repairs; is that correct?

**A.** That is correct. As we are inspecting more of the transmission system, we're obviously finding things that need to be repaired, and those things that are critical, on an emergency type basis, we're correcting those immediately.

But there are minor repairs such as woodpecker holes and downed guy repairs that need to be made, that are starting to accumulate, and we're developing a list of those repairs. That is new as far as we're identifying those things through the new inspection program, and so those costs to repair those types of items were not included in the 2007 or -- some in 2008, but not in 2007, and they are included in the 2009 test year. And that's approximately $300,000 that we've identified that's required to fix those minor type repairs on an annual basis moving forward, and I think that would explain the difference, the majority of the difference between the number that Mr. Schultz has calculated and what we've included in the budget.

**Q.** However, during your deposition, when you were asked why the information on the $300,000 was not included in the initial filing, you stated that the costs were in the initial filing; is that correct?

**A.** The costs are in the initial filing, and they're included in the -- I believe it's 600 and -- $642,773. Yes, they are included in that number.

**Q.** However, in your prefiled testimony, you don't discuss the $300,000 of repairs that are included in the company's projected costs for 2009; is that correct?

**A.** Yes. I don't think I specifically mentioned the $300,000 for those types of repairs.

**Q.** And looking at the company's response to interrogatory number 71, it would be also correct to say that the $300,000 was not specifically identified as repairs?

**A.** Well, no, I don't agree with that. I believe it is. If you look at the second line item under the six-year transmission structure inspection cycle program, that section is titled "Aboveground Inspection and Related O&M Repairs." The related O&M repairs is the 300,000 that we're referring to.

**Q.** But it's not specifically identified as a separate line item?

**A.** We combined the aboveground inspection and the related repairs in the 539,000, and 300,000 of that 539 is the repairs. We did not break it out separately.

**Q.** Okay. Now I want to turn your attention to substation preventative maintenance. Do you identify conditions based substation preventative maintenance as a program for reliability on page 24 of your prefiled testimony?

**A.** On page 24, we reference the costs associated -- well, not specifically, but we mention the activities of annual substation inspections, condition based substation preventative maintenance, downtown network inspections.

**Q.** Okay. Looking at that section of your testimony, isn't it correct that you don't provide any further detail on what condition based substation preventative maintenance is and what the cost is included in the 2009 filing?

**A.** In that section we do not. I would have to look.

**Q.** And in fact, nowhere else in the prefiled testimony, to your knowledge, do you provide any further detail regarding the condition based substation preventative maintenance; correct?

**A.** It's not broken out separately and identified as substation maintenance, but it is spread in the transmission and distribution maintenance activities that are highlighted in document number 4 of my exhibit.

**Q.** Well, let's go back to interrogatory number 71. You would agree that nowhere in the response does it provide the budgeted cost and the 2009 projected cost for condition based substation preventative maintenance; correct?

**A.** In interrogatory response 71?

**Q.** Correct.

**A.** Yes, it is, at the bottom. In the second section from the bottom, condition based substation preventative maintenance is broken out, distribution and

transmission. And for 2009, the total is $2,256,610.
Q. Okay. So that's the 2008 and 2009 budgeted and projected cost, respectively?
A. Yes.
Q. Now, looking at interrogatory response number 112, would you agree -- well, let me wait until you get there.
A. Give me one second. 112?
Q. Uh-huh.
A. For some reason, I don't have a copy of that response.
Q. Well, let me go ahead and just show you the copy that I have.
A. Okay.
Q. Does the response provide any information or explanation that would indicate that the 2003 through 2007 costs are not comparable to the 2008 and 2009 costs regarding the comparative information that was requested?
A. Well, it responds to the question, which is, provide information for 2003 through 2007. So the request did not ask us to compare to 2008 and 2009, the way I read it.
Q. Let me ask you, on page 12 of your rebuttal testimony, you indicate that Mr. Schultz has not

recognized an amount of $554,000; correct?

**A.** Which line item, or line number?

**Q.** I think it's referring to the cost -- the relay testing and the additional cost of 80,000 related to that as well.

**A.** Yes.

**Q.** Okay. Now, is it correct that these are new costs that you were describing for the first time in your rebuttal testimony?

**A.** I think it's fair to say it's the first time we've described in detail to that level what the breakdown of the substation preventative maintenance costs are.

**Q.** Okay. And on page 12, you identify an additional 429,000 for relay testing; is that correct?

**A.** That is correct.

**Q.** And you indicate that this is an annual cost; correct?

**A.** That is an annual cost moving forward, yes.

**Q.** Okay. Did you perform that testing, that level of testing in 2007?

**A.** No, we did not.

**Q.** Okay. In your deposition, did you state that Tampa Electric is proposing to restart this type of testing starting in 2009?

**A.** Yes, I did.

**Q.** And how long has it been since you performed this level of testing?

**A.** This testing is for 69 kV and 13 kV breakers, or relays, excuse me. And we used to test those, probably early 2000s. And as those relays are getting older, we believe that it's appropriate and time to start testing those relays again. It's more of an industry standard. I believe it's a few years since we've done the level of testing that we've included in our test year.

**Q.** Okay. Well, let me just make sure I understand. You would agree that you haven't done that level of testing since the early 2000s?

**A.** That's correct.

**Q.** Okay. Referring to incentive compensation targets on page 15 of your testimony --

**A.** Of my rebuttal?

**Q.** In your rebuttal testimony. You say the company's objective is to set goals that can be accomplished, but are a stretch to do so? Would you agree that's the testimony?

**A.** That's correct.

**Q.** Okay. And you would agree that goals must be set at a level that encourage improvement; correct?

**A.** That is correct.

**Q.** And you would also agree to improve, once a goal has been reached, the bar must be continually raised to increase improvement?

**A.** That's correct.

**Q.** Okay. Now, referring to the FRCC, would you agree that the --

CHAIRMAN CARTER: Ms. Christensen, before you go to your next -- hold your thought there for a moment. We're off the record.

(Short recess.)

(Transcript follows in sequence in Volume 8.)

## CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 875 through 1079 are a true and correct record of the aforesaid proceedings.

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

DATED THIS 28th day of January, 2008.

Mary Allen Neel

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