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 6

Pages 745 through 874

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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
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
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APPEARANCES:	(As heretofore noted.)

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I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
106	Final Order in Case of Public Service Company of Oklahoma	783	789
20			788
21			790
22	MJH-1	808	
82	MJH-2	809	

PROCEEDINGS

(Transcript continues in sequence from Volume 5.)

BY MR. MOYLE:

Q Let me refer you to Page 116, Bates-stamped number, I think on this document. There is some big bold number at the bottom. If you would go to Page 116. And just so the record is clear, would you read the title of the Page 116 that you are referring to?

A Rate case history, southeast list sorted by date.

Q Okay. And if I am reading this correctly, it looks like there has only been five ROEs decided by southeastern utility commission since 2007, correct?

A Oh, you are looking at the bottom of the list. I'm not following what you are saying.

Q Yes. I sorted it by date. I was trying to get some realtime information about what regulators in the southeast have done.

A That's correct.

Q And you were here for the testimony about the southeast may be a little more something to look at because all the southeastern states experience hurricanes, correct?

A Yes. I don't think these states are as vulnerable to hurricanes as that statement, but --

Q Could you, with that calculator, add up the five ROEs that have been authorized since 2007 in the southeastern United

States and tell me what the average is?

A Let me recalculate that. It's not my calculator and I think I hit the wrong button. (Pause.) I'm sorry, I wasn't able to clear the calculator. I apologize.

Q That's all right. We can do it the old-fashioned way.

A I was going to say, if you give me the number I think I can probably accept it.

Q My calculation was 10.58.

A That sounds like it would be right.

Q And you would agree, assuming my calculation was right, that that would be another approach, another tool to use in considering ROE?

A That would be a tool that represents allowed returns. If I may comment on those five cases?

Q Well, we are trying to move it along, and your counsel will have a chance to ask you on redirect if you care to give comments.

I'd like to move on to another area if I could, Mr. Chair.

A Certainly.

Q Ms. Abbott was just here, and you have expertise in economics and the market, correct?

A Yes.

Q Okay. And that includes debt markets as well as equity markets, correct?

A I think I have less expertise than Ms. Abbott in the debt markets.

Q Well, let me see if you can help me with something. I thought I understood some of her testimony to be essentially -- and Commissioner Skop zeroed in on this -- essentially if you have an A rating that's better than a BBB, and she was saying you have access to capital as an A that you might not have as a B, correct?

A That is a generally accepted principle, yes.

Q And I think she said access was shut down once since she can recall. Isn't it true when the credit markets were closed, if you refer to Mr. Gillette's Exhibit Number 2 for that couple of week period in September, that the credit markets were closed to everyone including companies with A ratings as well as companies with BBB?

A That was my understanding.

Q So the idea that just because you have an A means you got automatic access to capital doesn't necessarily stand true if you consider what happened in September of 2008, correct?

A Yes. That's defining access in a very, very stringent way.

Q A few more questions. This ROE is something that I am learning about, but if I understand what you are trying to do, you are trying to peg an appropriate return that a company will then be able to charge its ratepayers for in rates, correct?

A Well, I am looking at it, I think, from a different perspective. I am looking -- and you have mentioned Bluefield. I think I am looking at it more the language of Hope, the Hope Natural Gas case, which I think is trying to determine what return is necessary to attract capital for a particular investment.

Q But in terms of making that judgment, you are informed by current market conditions, correct?

A Absolutely.

Q And current market conditions are a key driver in that judgment, correct?

A Yes.

Q The last time Tampa Electric was in for a full-blown rate case was approximately 17 years ago, correct?

A That is what I understand, yes, sir.

Q Mr. Gillette, I think, referred to the craziness of the market. Ms. Abbott talked about the volatility of the market. You would agree the market right now is not exactly stable, correct?

A The market is very volatile now and very unpredictable. And as I heard Ms. Abbott state, it is recovering much more slowly than we would like to see it recover.

Q Wouldn't it make sense to you rather than asking this Commission to come in, and given the volatility of the markets and trying to make an informed judgment about what the ROE should be, that you consider maybe another approach, either deferring a decision on ROE, or considering pegging an ROE to some type of an index that adjusts? Would either of those make any sense to you?

A I guess, I think you are saying two things, and I want to think about both of those rather carefully, I think. Talking about pegging it to something, I'm not sure what you would peg it to unless you peg it to some kind of another market rate, such as a BAA bond rate, for example. I think that that might work for a brief period of time. In my observation of most of those kinds of determinations at some point run off one side of the road or the other. They become unworkable. For a period of time it might work. Now, I can't remember what your first proposal was.

Q The first one was given the volatility and that the volatility drives things, wouldn't it make some sense maybe to defer a decision until the markets have calmed down, maybe make a decision on the ROE at a later point in time?

A I don't quite understand how you would do that. If the company has to raise capital for its capital expenditures program, it has to raise funds for that purpose, I don't know how you can defer it for a long period of time. And there is the question of the current investors and trying to maintain investment in the facility.

Q But they don't have to raise capital until November, correct?

A I understand they are planning to raise capital next fall.

Q Am I looking at this improperly, that if I was a utility that it would make sense to come in and argue for as high of an ROE as I could, because given the fact that you don't come in for a rate case very often, you try to get it as high as you can, and then you can earn underneath it. I mean, in Tampa Electric's case it was 17 years, so that, you know, that's really a key driver in a ratemaking process?

A I have been involved in proceedings a number of times in which companies have come in for requests that are lower than I think the current market is and that they thought the current market was, and for the simple reason they had something else that they were really interested in. They are concerned about getting a plant into rate base, for example. They were involved in some kind of a contract decision. They might actually be acquiring some properties or something, and there is something that in their business judgment was a higher priority than return. And, therefore, they could come in for a lower request than what I thought was appropriate and that they would openly admit that they thought was lower than the current market.

Q But you don't think Tampa Electric Company is coming in with a below-market request, do you?

A I think Tampa Electric is coming in with a request which I recommended and I think it is an appropriate market request in today's market.

Q A couple of more questions on this idea of pegging an ROE to something that floats. Are you aware that that is something that California does?

A I'm not aware of what California has done currently.

Q You know, given the importance of the market and the market conditions in establishing an ROE, do you have a belief that the economic stimulus package which has been announced by our new president, Mr. Obama, is likely to have a positive impact on markets?

A Undoubtedly it will have a positive impact on markets. I think when you say stimulus package, I think you are talking about the fiscal side of the package that is being introduced by the House?

Q Yes, sir.

A I think that is what you are talking about, because the Federal Reserve has been very active for the last almost 10 or 12 months.

MR. MOYLE: Mr. Chair, if I could just have a quick minute.

CHAIRMAN CARTER: You may.

(Pause.)

BY MR. MOYLE:

Q You answered -- just a couple more questions, Mr. Murry, and I appreciate your time and your travels all the way from Oklahoma to be with us. You had said you thought that Wall Street had a conflict of interest in response to a question from Ms. Christensen. Wouldn't you also think that rating agencies, given the fact that a majority of their income derives from companies that they regulate, also could appear to have a conflict of interest?

A I have never felt that, and that response has nothing to do with my previous testimony in this case. I felt the rating agencies because the institutional investors rely on their judgment, really tried very hard to give their best estimate of what they thought the ratings were. Because their recommendation would deteriorate if it was not -- if they didn't maintain credibility.

Q Are you aware that some rating agencies are currently under investigation?

A I am aware that they are, and I'm not aware of the details of what it is about.

Q And it is a little bit of a finer point, but given that you may not view that there is a conflict of interest, you would agree that someone could have that perception that there might be a conflict?

A I certainly would agree with that, yes.

MR. MOYLE: I have nothing further.

CHAIRMAN CARTER: Thank you, Mr. Moyle.

Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good morning, Doctor Murry.

A Good morning.

Q I think as a predicate we can agree that it is the Florida Public Service Commission's job in this case to assign a rate of return on equity specifically for Tampa Electric Company, the regulated utility, correct?

A Yes.

Q Thank you. In response -- this may have been a response to Mr. Moyle or to Ms. Bradley, I believe you testified that you believe you have recommended a return on equity lower than other witnesses in other cases. Is that what you said?

A He asked me if I ever had and I said I'm sure that I had.

Q Can you name such a case?

A I was trying to reflect on that at the moment, and I can't name a case at this point.

Q Am I correct that your testimonial experience regarding rates of return on equity has been limited to testifying on behalf of utility companies?

A That is not correct.

Q Okay. Have you testified for Public Service Commission staffs?

A I have testified in the past for the staff of the Missouri Public Service Commission. That was a number of years ago. As my resume shows, I was at the staff of the Federal Power Commission, and, of course, I testified on behalf of the Federal Power Commission. I have testified on behalf of some industrial customers on several occasions. I have testified on behalf of some cooperative groups.

Q You mentioned you testified on behalf of industrial customers on ROE.

A Excuse me?

Q You mentioned your testimony on behalf of industrial consumers. Was that on return on equity?

A Yes.

Q Thank you. Will you agree that the provision of regulated monopoly electricity service is a low-risk business service?

A Well, I think the answer is that that is a common view, and it is certainly lower risk than some other enterprises. But it varies by company, as I'm sure you know.

Q Would you agree that Tampa Electric Company has an excellent business risk profile?

A Excellent is a term and it's a relative term. I think Tampa Electric has a very -- it seems to be a very favorable business risk profile, as I understand it. But when you read the financial information about Tampa Electric there is concern about environmental requirements and concern about the capital expenditure programs. They have many of the problems that are typical in the utility business today, and there is -- I mean, I think it is being well handled the best I can tell, but clearly Tampa Electric by being a compact system has a hurricane exposure that one wouldn't find for a lot of utilities.

Q Have you reviewed Ms. Abbott's testimony in this case?

A I did review it, yes.

Q Are you aware that Standard and Poor characterizes Tampa Electric's business risk profile as excellent?

A I saw that that was their reference.

Q Do you disagree with that?

A No. I say it is a relative term, and I'm not sure exactly what they are comparing it to.

Q So when Standard and Poor's makes a publication that a particular company has an excellent business risk, you don't know what that means?

A I accept her testimony that that is Standard and Poor's opinion.

Q Will you agree that TECO Energy's nonregulated business operations, such as its coal mining operation and its Guatemala operations are riskier than the provision of regulated monopoly electric service in Florida?

A I believe that is probably the case.

Q Would you agree that including the low risk electric operation in Florida with higher risk mining operations and overseas operations would imply that investors would seek and expect a rate of return higher for the overall company, TECO Energy in this case, than for Tampa Electric were it evaluated on its own?

A If I understood the question correctly, the answer would be yes. I think I followed it.

Q Thank you. Leaving aside our differences of opinion over the reasonableness of your selected comparable group and the adjustments you made in your ROE analyses, would you agree that the range of results shown by your models is reasonable?

A Would you rephrase just the last phrase, please?

Q Will you agree that the range of results, ROE results shown by your models is reasonable?

A If you define reasonable as what I would have expected under the circumstance, the answer, I guess, is yes. They didn't seem to come out of bounds of what I would have anticipated.

Q Well, let me ask a follow-up question. Would you agree that a utility regulatory authority, the Florida Public Service Commission in this case, could assign a rate of return on equity for Tampa Electric Company within the range of results shown by your models? Would that be reasonable for this Commission to do?

A I think the results from the calculations that I determined were so broad that one could almost pick -- could almost avoid picking a number within that range.

Q My question was could the Florida Public Service Commission make a reasonable decision to use a return on equity within the ranges of results shown by your models for Tampa Electric Company in this case? If you could answer yes or no, and then explain your answer, that would be great.

A Maybe you need to explain to me what range you are talking about so I know what we are talking about.

Q Well, you have got a bunch of exhibits at the back of your direct testimony.

A Maybe I could refer you to Schedule 22.

Q Yes. Yes, let's use that range. You have got three different models in the comparable group with lows and highs. The lowest low is 10.05 percent for the comparable group, the highest high is 13.27 percent.

A Yes.

Q Let me ask that question. Could the Florida Public Service Commission reasonably decide to use an ROE for setting Tampa Electric's rates in this case between those two values as shown by your models?

A I would say that a number outside of that range is not reflective of current market conditions.

Q Mr. Chairman and Doctor Murry, I apologize, but I was distracted. I think you said a number outside that range would not be reasonable. Is that fair?

A Well, I said it would not reflect current market conditions, and if reasonable is representative of current market conditions, that is correct.

Q Okay. If I could ask you to look at your Document 15 of your exhibit which is on numbered Page 86 of your prefiled testimony. Do I interpret this table correctly as showing that your DCF results using the 52-week period for the comparable group shows an average of 9.14 percent on the low end and an average of 10.21 percent on the high end?

A That is what it shows in that calculation.

Q Would it be unreasonable for the Florida Public Service Commission to use a rate of return on equity for Tampa Electric Company in this case between those two values, i.e., between 9.14 percent and 10.21 percent?

A In today's market it is judgment it would be, yes, sir. I'm sorry, did you say reasonable or unreasonable?

Q I did say reasonable.

A You said would it be reasonable?

Q Yes, that was the question.

A I'm sorry, no, it would not be reasonable. I misinterpreted your question.

Q In response to some questions by Ms. Bradley, you indicated that you generally focus on cost of capital and what the cost of capital is and not on consumers. Is that a fair characterization of your prior testimony?

A My task was to estimate the current cost of capital in this proceeding.

Q Is it your testimony without qualification that Tampa Electric would not be able to raise needed equity or debt capital if the Commission set a return on equity for Tampa Electric in this case of 9.75 percent?

A It has been my experience that a Commission could set a return almost at any level provided there were other provisions in the rate order that would give the company the cash flow that Ms. Abbott was talking about this morning. And so the 9.75 number becomes very much a relative number. It is not the current cost of capital. Quite the contrary. It would be very low in today's market. It would be barely above the cost of debt.

Q Now, it is fair to say that that is your opinion, correct?

A I guess, yes.

Q In your testimony you have testified that Tampa Electric requires a cushion sort of adder to its ROE. Is that a fair characterization?

A No, it is not.

Q Okay. Well, what does your testimony about the cushion mean, then?

A You asked me about that, or someone asked me about that in my deposition and I thought we explained it. I tried to explain in some detail in my testimony that one of the problems which I mentioned earlier with the DCF is it calculates the marginal cost of capital, not the average cost of capital. So it means that on the average you wouldn't expect it to be high enough in marginal conditions to meet the required cost of capital. And I pointed out there are a number of mechanisms, such as flotation cost adjustments, pressure adjustments, market-to-book ratio adjustments that I have observed in many jurisdictions utility commissions follow to provide somewhat of an adjustment to make the allowed return more viable based on a DCF calculation. And I think I used the term cushion in my testimony, and I think that is what you are focusing on. I said that there is a recognition, it is not an adder, it is a recognition that if you go to the low end of the DCF calculation mechanically you are almost guaranteeing the company will not earn its return.

Q And trying to put that together with the previous response, it is your testimony that is because of the difference between the marginal cost of capital and the average cost of capital, or because of issuance costs, or what?

A It is because of the nature of the DCF methodology is what it is.

Q You do agree that the risk free rate on capital is the proper rate to use as -- the proxy for the risk free rate is the interest rate on a 30-year treasury bond, correct?

A I think we talked about that in my deposition, as well, and I think I pointed out that the risk free rate is probably an unfortunate misnomer that got in the literature decades ago, because there is no such thing as a risk free rate.

I think the most common rate used in a CAPM as the base benchmark rate, which is called the risk free rate, is the 20 or 30-year bond. I think I used the 20-year bond for a variety of reasons, and that is very commonly used in the CAPM. In today's market it is far from risk free because the federal government is so active in the treasury market.

Q Well, what we say down here in walking around language, the 20 or 30-year T-bond rate is usually referred to in this business as the risk free rate, correct?

A In CAPM, filling in that number, it's typically a 20 or 30-year treasury bond.

Q And you used a premium of 7,100 basis points on top of that in your CAPM analysis, correct?

A I used a risk premium of 71 basis points, yes.

Q 7100 basis.

A 7100, yes, sir.

MR. WRIGHT: That's all the questions I have, Mr. Chairman.

Thank you, Doctor Murry.

CHAIRMAN CARTER: Thank you, Mr. Wright.

Mr. Twomey.

MR. TWOMEY: I don't have any questions, Mr. Chairman.

COMMISSIONER ARGENZIANO: I do.

CHAIRMAN CARTER: Commissioner Argenziano, you're recognized.

COMMISSIONER ARGENZIANO: Thank you. They say you are the guy I need to ask the questions to.

THE WITNESS: I heard that.

COMMISSIONER ARGENZIANO: And I guess I'm trying to really figure out how all of these models work, and in my mind as I look over them, and maybe you can help me understand it a little better, it just seemed as I was asking Ms. Abbott earlier, that when I looked at the different models, and I guess the CAPM had these four subjectively, I guess, qualitative variables that was the expected return on capital assets, sensitively to asset returns, expected return of the market, and risk premium combined. And while each of them may be subject to a mathematical notation, it seemed that neither of them avoided or eliminated the subjective input. And it made me wonder how you can really rely on something that is so subjective, and that is why I'm trying to figure out the differences between CAPM and DCF. It seemed to be the same thing. Three subjectively determined input sources which were variables; cash flow to discount, expected growth, and discount rate. And looking at that I think the same comment I had on the CAPM. And then looked at risk premium, which risk premium exclusively seemed to have the benefit of a certain honesty as I was saying before which was, I guess, simple, but invoking the risk premium seemed to permit reliance on the identifiable zero risk rate, the U.S. Treasury Bills averaged over an identified period. And it seemed to put one variable, the factor, which to multiply the risk free rate in play.

So looking at the three of those, it seemed to me that I wasn't sure how you really could be confident in the, I guess, subjective two models versus the one that seemed to be more factually based, or pretty much simple rather than so complicated. And I said the other day that Einstein had an admonition that everything should be as simple as it is, but not simpler. And I guess that is the way I am looking at it. And maybe you could shed some light on that observation that I have.

THE WITNESS: Well, if I understand your comments, I think you are very much on point in current markets, because the information used -- and I don't want to get into more detail here than you want, but in the current market circumstances leaves something to be desired at least let us say in the DCF and the CAPM model. And more so now than when I did my direct testimony back in June because of the way the market has moved.

With regard to the CAPM, and I think I'm on point in your answer, with regard to the CAPM, the problem is often in determining what the so-called risk free rate is, or what to use as a benchmark rate. Now, I do two CAPM analyses. In one I don't use governments because the government bonds are likely to be so influenced by Federal Reserve policy by being active in the market. And that on a go-forward basis is going to be more important than it is now. Because to finance this large fiscal package, this $825 billion, or whatever the number finally becomes, there is an argument currently within the Federal Reserve among their technical people, and it is now leaking out, there is an argument as to how the Federal Reserve will help finance it. And one concern, or one proposal is literally that the Federal Reserve would buy the bonds that are being issued by the Federal Reserve.

Now, we did that during World War II and they called it pegging the interest rate, and what it does is create huge amounts of liquidity, because essentially it even runs faster than the Treasury Department running the printing presses. And so there are obviously some longer term concerns. I don't want to get off too far in that. But if that happens, calling 20 year and 30-year Treasury Bonds as a risk free rate certainly makes no sense whatsoever. And you couldn't use it as a benchmark to do what you have to do to set a return on equity, because it would be pegged totally to Federal Reserve policy.

But that is going forward. The other problem with the CAPM is the beta calculation. The beta calculation is nothing more -- let's look at it from the standpoint of the theory of the CAPM is looking at it as an investor. And if you are an investor you can buy the stock as part of your portfolio, and if this stock is too risky for your taste, you can essentially buy other stocks that offset that and diversify. But some of that risk means the stock is not going to operate with the market. Some of that risk is nondiversifiable. And so that is what the CAPM is trying to capture.

So that beta number is nothing more than how this market -- this price of this stock moves over time relative to the overall market. Statistically it's just a regression coefficient. So if you have a beta of .8, it means that if the market goes up by 10 percent you should expect your stock to go up 8 percent. But if it goes down by 10 percent, your stock should only go gown by 8 percent. That is what the beta means.

COMMISSIONER ARGENZIANO: But beta has no predictive value.

THE WITNESS: That's the problem. That is why you are right on point. The beta represents what has historically occurred for this particular stock, and my quarrel with the CAPM and with the beta, and there is literature on this, is that that is a single dimension measure of risk. It is only market volatility, and obviously there are other kinds of risk. You could have companies with very high betas and tomorrow they go bankrupt. And that has literally happened.

COMMISSIONER ARGENZIANO: Okay. But if it has predictive value, how would that affect the CAPM? I'm trying to --

THE WITNESS: Well, in normal times, you can say that represents what you are likely to expect for the future. And so if we are talking about setting rates in this case for a period of three years or so, or looking that far in the future, a beta that is stable is likely to help predict what that rate should be.

COMMISSIONER ARGENZIANO: Okay. Wouldn't the history of the stock or a stock as represented by its periodic market derived value be a more accurate indicator of risk acceptance out of the beta?

THE WITNESS: I'm sorry, I didn't understand the question.

COMMISSIONER ARGENZIANO: I guess in trying to figure this out, and I'm not sure I've got it thought out properly yet, but if that is true, isn't the history of a stock as represented by its market derived value, or its periodic market derived value be a more accurate indicator of risk acceptance by an investor rather than beta?

THE WITNESS: Well, they are two different pieces of information, and so I'm not saying it is -- I think you are wrong to say it is more reliable, and I think at some points in times it would be more reliable and other points in time it might not be more reliable.

At this particular junction where we are, the debt market for a BAA corporate bond is running over 8 percent, 8 to 9 percent. And that means common equities have to be an equity risk premium higher than that.

COMMISSIONER ARGENZIANO: All right. And bear with me --

THE WITNESS: And I think that was the point you were making earlier.

COMMISSIONER ARGENZIANO: Yes. What impact should the market movement, I guess, altogether have on TECO or any other regulated utility on their ROE?

THE WITNESS: Oh, the market movement overall?

COMMISSIONER ARGENZIANO: As a total, uh-huh.

THE WITNESS: Well, if market prices -- let's look at it this way. If the market prices drop by 25 percent as they have over this last year --

COMMISSIONER ARGENZIANO: Uh-huh.

THE WITNESS: -- from a simple supply and demand relationship that means there is not as much demand for those particular securities, and people who have those securities are liquidating and they are driving down the price.

COMMISSIONER ARGENZIANO: If there were a drop of 25 or 40 percent reduction in the stock value, wouldn't that -- totally overall, wouldn't that equally be reflected in the utility's ROE?

THE WITNESS: Yes, absolutely. And that will show up directly in the DCF.

COMMISSIONER ARGENZIANO: In the DCF.

THE WITNESS: Because the market price is one of the variables in the DCF.

COMMISSIONER ARGENZIANO: Okay. I think maybe two other questions, maybe three. And I think we may have gotten this, but it is penetrating. If beta is a significant consideration and no risk T-bills are at, let's say, 3 percent, how should that translate into impact on a no or a minimum risk utility, how is that?

THE WITNESS: How is the beta, is that the question?

COMMISSIONER ARGENZIANO: Yes.

THE WITNESS: Well, there is literature on this, and I can't answer the question precisely, but a stock -- there is statistical literature that shows that a stock that has a beta less than one, that the CAPM will undervalue that stock. And conversely, a stock with a beta greater than one, the market is going to have a beta of one, so a stock with a beta greater than one, the CAPM analysis will overvalue that.

It is very hard to know what that adjustment is. But why that is relevant for utilities is that utilities should have betas less than one, because they don't move as rapidly as the market. They don't go up as rapidly, they don't down as rapidly, and that's pretty reliable.

COMMISSIONER ARGENZIANO: But still subjective, isn't it?

THE WITNESS: Well, that is empirical. That is measurable how the stocks move relative to the market.

COMMISSIONER ARGENZIANO: I mean the beta factor.

THE WITNESS: Oh. No, the beta is a statistical calculation. I mean, it's not a subjective number. It is a calculable statistically derived number.

COMMISSIONER ARGENZIANO: That is where I'm having a hard time.

THE WITNESS: Well, if you think in terms of the market going up by 10 percent, of stock going up by 8 percent, they are going to track through time up and down, and statistically you can determine that relationship. And that is what a beta is, it is a statistical determination of that relationship.

COMMISSIONER ARGENZIANO: Okay. And how significant should the consideration of a risk factor be in establishing an ROE, do you think?

THE WITNESS: I think it should be very significant.

COMMISSIONER ARGENZIANO: One other thing. I think before you had mentioned that there were some other companies with lower risks than TECO, or utilities similar or larger. I'm trying to think of some to be honest with you that may not be government regulated. Are there any?

THE WITNESS: That are less risky than --

COMMISSIONER ARGENZIANO: Yes.

THE WITNESS: Well, I think I heard you ask some questions last week about the cost-recovery formula and how that affects risk. I think you have to look at utilities regulated different from other companies and there is a pro and a con. Their returns are more predictable, and not so much in recent years, but earlier they were viewed as income securities because retired people would buy them for the dividend returns.

COMMISSIONER ARGENZIANO: Sure.

THE WITNESS: But then the energy markets especially got more volatile and unpredictable and things occurred and people started looking at utility stocks differently.

COMMISSIONER ARGENZIANO: But at the same time --

THE WITNESS: I'm sorry. And so there is a stability mechanism that is clearly involved in the cost-recovery. I can remember when many states didn't have fuel cost-recoveries even, but obviously there are good reasons for doing that. That is beneficial. But think of it on the other side. As an investor if you look at it a utility can't raise its rates, either. If something is happening to it, it can't adjust its rates upward as rapidly in case of inflation because it doesn't have everything covered in cost-recovery, only pieces of it. And interestingly enough on the down side, utilities rates are set and fuel costs are going down now and those flow through to customers. And so that is not a benefit. If you were in a competitive industry and you saw your costs go down your profits would go up. Utilities don't get that benefit, either.

So investors look at regulated industries differently. They have a different set of risks, and there is risks they don't have, and I think you just have to look at both sides of that issue.

COMMISSIONER ARGENZIANO: I agree with that, except that if you look at it as an investor, I think the big difference is there are guarantees in investments on a utility where there are no guarantees on a nonregulated entity, such as the recoveries. There are guaranteed recoveries. Some may be slower or longer to get to, but they are eventually going to get a guaranteed pretty much more than half of their costs. And I guess that is the consideration I look at. So it is really, I guess, in the eye of the beholder and what an investor is really looking for.

If I were an investor, and what it seems to me when I look at people who are investing in utility stocks, they are the ones -- and I have asked some to be honest with you, they are looking for security, more security and a more stable regulatory -- I mean, it is a regulated entity that has a government guarantee of a return. And even with hurricanes, as you mentioned before, there is a lot to be recovered. I mean, we can point to Louisiana and say that is a case where it went bust. There is nothing to recover. Everybody is gone, but that's just one in a million, I guess.

THE WITNESS: I just want to say that when you look at a broad perspective, though -- I mean, you are using the word guarantee, and it makes me a little comfortable, because some companies I have worked for or observed, they get an allowed return and they never make their allowed return for a practice variety of reasons. And so in that sense it is not a guarantee.

COMMISSIONER ARGENZIANO: Well, I guess if I owned a different company, the Argenziano Fruit Stand Company, I don't know, I guess the way I would say guarantee is that there is nobody who would guarantee me that I am going to make any profit.

THE WITNESS: No, I mean -- I wasn't trying to quibble on that point. I'm just trying to say it is not that assured.

COMMISSIONER ARGENZIANO: But it is pretty darn close. Thank you. I appreciate it.

THE WITNESS: Sure.

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Good afternoon, Mr. Murry.

THE WITNESS: Good afternoon.

COMMISSIONER SKOP: I have to check the time to make sure it was afternoon. But just to follow up on a few points of your testimony. I think that you mentioned that with respect to what consideration should be given to the risk free rate, or what benchmark should be used, that the Federal Treasuries are not a good measure of the risk free rate to the extent that they may be artificially depressed by Federal Reserve policy and actions, is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: And with respect to the beta that factors very prominently in the CAPM analysis, would it be correct to say that historically, subject to studies that have been done on correlation of variation analysis that betas for utilities are somewhat stable to the extent that they don't move all over the place like a technology stock would?

THE WITNESS: Yes. If a utility beta is not, say, between 65 and 80, you want to try to verify why it is not.

COMMISSIONER SKOP: Okay. And I think that you also mentioned that ratemaking is not an exact science, and that both the CAPM and discounted flow models are just merely tools that should be used along with regulatory discretion in ratemaking to determine what an appropriate ROE would be. Would that be correct?

THE WITNESS: Absolutely.

COMMISSIONER SKOP: Okay. And I guess given the current market volatility, interest rates, and inflationary measures that may result in coming out of a recession, what would be the merits of taking a long-term approach to ratemaking based on sound regulatory policy versus a near-term approach in terms of looking at what the markets are doing now?

And I guess what I'm trying to get at is that under the current prevailing market conditions, should one model, being the CAPM or the discounted cash flow be given weight over another model in terms of where we are at in the driving factors that factor into those calculations?

THE WITNESS: I think when you said where we are at you are talking about the current conditions?

COMMISSIONER SKOP: The market turmoil that we are experiencing now.

THE WITNESS: At this point in time, I would assign a little more weight, I think, to a CAPM calculation because it is more stable. I think they both have some frailties and they both tell you something.

COMMISSIONER SKOP: And I do appreciate in your prefiled testimony you giving the pro and con on that. I thought that was very instructive.

And just one final question with respect to appropriate ROE, and I wanted to get your opinion on this to the extent that, I guess, the prior witness had indicated you would be the subject matter expert to give an opinion. But I guess one witness in this case will testify that the appropriate ROE should be 7-1/2 percent, and I was wondering in your professional opinion what regulatory signal would a 400 basis point reduction by this Commission send to the capital markets?

THE WITNESS: Well, a 7-1/2 percent return on equity is out of bounds in current markets if you use as a benchmark what the debt markets are bringing.

COMMISSIONER SKOP: And such an action, regulatory action by the Commission, I guess some testimony is focused on RRA credit support, and I know that Mr. Shipman (phonetic) from Standard and Poor's has just recently come out with a credit support showing Florida as one of the best ranked regulatory states. But would such action cause a flight of capital to more attractive investments?

THE WITNESS: I think it would be publicly recognized in the financial community and, yes, it would.

COMMISSIONER SKOP: And such action might result in a credit downgrade ultimately causing consumers more money in the long run?

THE WITNESS: I don't know at what point --

MR. MOYLE: I'm going to object. It calls for speculation, but I guess the other point I wanted to make, Mr. Chairman, was that I understand this witness we are doing his direct and this is rebuttal testimony. And I had some questions on this very same point, but I thought we were going to defer them until later on.

COMMISSIONER SKOP: I will withdraw the question, but I do think it is well within my right as a Commissioner to ask any question I deem appropriate. Again, he is a recognized expert, and I do value his professional opinion in terms of my decision-making process.

Thank you, Mr. Chairman.

CHAIRMAN CARTER: Thank you. Mr. Moyle, there is no -- I'm not going to recognize you for an objection. A Commissioner does have the discretion to ask questions on issues that come before us, and Commissioner Skop is within his right to do that. And we will just move on from there, okay.

Commissioners, I'm going to go to -- before I go to staff, Commissioner Argenziano.

COMMISSIONER ARGENZIANO: I'm sorry, Mr. Chair. I hate to do this, because I am thinking about things and I need to go back. Commissioner Skop had said -- and I think you agreed that beta is stable. And I am having a really hard time with beta and the CAPM approach. And I understand that it has been used, and it seems to me that it is subject to mathematical notations, but, like I said before, it does not avoid the subjective input. And I think it rearranges the position by which it is input, and I think it could even expand the number of subjective inputs. Does that make sense?

THE WITNESS: I think.

COMMISSIONER ARGENZIANO: So I'm having a hard time understanding how beta is so certain, or it is not just a subjective input that could be -- I guess I feel like it is unsupported reliance on something where I look at -- and I know it is not mentioned here much at all, the risk premium, and this is why I'm trying to discuss this, because I am kind of straight forward. I like to see things as they are and how they make sense to me. And risk premium seems to rely on the certainty versus the beta, which can be manipulated. And I just -- I am not -- I guess I don't feel strongly, Mr. Chairman, at this point about how beta is so certain. I guess maybe that is just my opinion, and I didn't know if you could add anything to that to make me feel any different. I'm not sure you can, but I am going to try.

THE WITNESS: I will try. You are making me want to go to the board and start drawing graphs.

CHAIRMAN CARTER: Let's not do that, please.

(Laughter.)

THE WITNESS: And I don't want to bore you with that. But think in terms of price, a price series of a stock and the price series of the market. And if you think in terms of the relationship between those two time series, the beta is sort of the average relationship. It is a statistically determined empirically derived number based on this time series.

Now, there is some subjectivity that goes into that calculation. You can choose your length of your time series, for example, and that beta will change, obviously, depending on the time series you choose. But it's a calculation. You know, it is statistically empirically determined, and so in that sense it is not subjective.

And even in choosing different time periods, you are not going to find a lot of fluctuation in the resulting calculation. And so when I said the beta -- it is more stable, I was referring to -- and that is my experience in using it different ways. The results of the CAPM are not going to fluctuate around nearly as much as the DCF, for example, as another tool. It is going to be -- sometimes I think it is too high, sometimes I think it is too low, and that doesn't mean it doesn't have problems, but it is likely to be long-term a relatively stable calculation.

COMMISSIONER ARGENZIANO: I guess I think of the black swan factor when I am not certain, and looking at recent, you know, long-term capital management debacle that we have looked at, but I appreciate your answers. Thank you.

CHAIRMAN CARTER: Commissioners, I'm going to go to staff and then I will come back to the bench just in case you have any further questions.

Staff, you're recognized.

MR. YOUNG: Thank you, sir.

CROSS EXAMINATION

BY MR. YOUNG:

Q Doctor Murry, you have recommended a return on equity of 12 percent for the purpose of this proceeding, correct?

A Yes.

Q Are you familiar with the Public Service Company of Oklahoma?

A Yes.

Q In fact, Doctor Murry, you recently testified in a rate proceeding on behalf of the Public Service Company of Oklahoma before the Corporation Commission of Oklahoma, which is the OCC, correct?

A That is correct.

Q Do you recall the return on equity you recommended the OCC authorize for the Public Service Company of Oklahoma?

A Are you asking do I recall, I recommended or --

Q Do you recall what you recommended?

A I think it was a range, as I recall, from 11-1/2 to 12.

Q Eleven-and-a-half to 12?

A I think that's right.

Q Do you know the authorized return on equity the Oklahoma Commission approved for the Public Service Company of Oklahoma?

A I believe they approved 10-1/2, I think. I'm doing that by recollection.

MR. YOUNG: Mr. Chairman, I would like to have an exhibit that Mr. Prestwood is handing out be marked for identification purposes as Number 106.

CHAIRMAN CARTER: Title?

MR. YOUNG: And I will give a short title as Final Order in Case of Public Service Company of Oklahoma.

CHAIRMAN CARTER: Thank you. You may proceed.

(Exhibit Number 106 marked for identification.)

BY MR. YOUNG:

Q Doctor Murry, have you seen this order before?

A I don't think I ever saw the order, no, sir.

Q Okay. But you just stated you gave testimony in this proceeding, correct?

A Yes.

Q Can I ask you to have a moment to review this order. I am going to ask you specifically -- although you haven't seen the order, can you please review it. I am going to ask based on some of the testimony you gave in this proceeding.

MR. BEASLEY: Could we ask if there is a page number that you might want to refer to.

MR. YOUNG: Yes. If you can turn to Page 45 of the order.

CHAIRMAN CARTER: One second, please. Commissioner, you had a question?

COMMISSIONER SKOP: Mr. Chair, I was just going to add that I am glad that our Commission orders aren't are in 12 point fonts.

CHAIRMAN CARTER: I would need a magnifying glass for these. You're right, Commissioner. You may proceed.

BY MR. YOUNG:

Q Doctor Murry, I am going to ask you turn first to Page 45 just to get a date, and then I'm going to ask you to turn to Page 11.

A Did you say Page 45?

Q Just for the date.

A Oh.

Q Would you agree that this order was issued on January 14th, 2009?

A Oh, yes.

Q Now, can you please turn to Page 11 of the order. Are you there, sir?

A Yes.

Q Okay. Looking in the first paragraph, the second sentence, it says Doctor Murry for PSO. Are you the same Doctor Murry for PSO?

A Yes.

Q Okay. And now I would like for you to turn -- or looking at the third paragraph on this page, sir?

A Yes.

Q If I can have you read aloud the third paragraph of this page.

A "Although only PSO argued that the Commission should give consideration to the current financial markets determining an appropriate ROE for PSO, the Commission recognizes the uncertainty of economic markets for at least the near future may have a negative impact on the expectations of investors. The Commission desires that PSO be able to raise the capital it needs to maintain its infrastructure in a safe and reliable manner and implement the demand-side management programs recommended by the Commission. The Commission believes that an authorized ROE of 10.5 percent will allow the company the opportunity to quickly begin implementing the capital projects necessary to accomplish these goals."

Q Thank you, sir.

So, Doctor Murry, you would agree that the Oklahoma Commission believed even with the recognition of the uncertainty in the economic markets that an authorized ROE of 10.5 percent was reasonable to allow the Public Service Company of Oklahoma the opportunity to fund its capital expenditure programs?

A That is what the statement says, but let me also point out in the first paragraph that staff recommended a return in this case of 10.75 to 11.18 percent, and that included averaging in some outdated market information.

Q Okay. In the table at the bottom of the page -- are you there?

A Yes.

Q Okay. You would agree that the Oklahoma Commission also approved an equity ratio of 44.1 percent for purposes of determining the utility's overall cost of capital?

A Yes.

MR. YOUNG: Thank you.

No further questions.

CHAIRMAN CARTER: Thank you.

Commissioners.

MR. BEASLEY: I just have one redirect.

CHAIRMAN CARTER: You're recognized.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Doctor Murry, could you describe the context of the five southeastern utility ROE decisions since January 2007 that Mr. Moyle asked you about?

A Yes. I put that aside. Can you give me that page reference again?

Q Page 116.

A Oh, it's 116. I have it. Yes, I was going to respond out of those five cases, two of those I was party to, and that is the Arkansas Oklahoma Gas and Electric case, which shows a return of 10 percent, and the South Carolina Electric and Gas which shows a return of 11 percent allowed, and those are both cases that I was in, and I should add that we subscribe to RRA, and we do use it for research and a variety of things. But this is an example of the problems in using RRA for allowed returns. In both of those instances, those cases were settled and those are stipulated agreements. They were not litigated. I did not testify live, and there were other issues in those cases, in each case that were relatively more important apparently than ROE because it was not litigated.

MR. BEASLEY: Thank you.

We have no further redirect and we would like to move exhibits.

CHAIRMAN CARTER: One second. Let me come back to the bench.

Commissioner Skop, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Mr. Murry, real quick with respect to the five southeastern decisions on Page 116, and I know that you mentioned in your clarification that there were some unique circumstances that are not presented here that reflect why returns were authorized in the manner in which they were. But would you generally agree that the difference in the spread between the requested return on equity and those authorized by the respective commissions in those five decisions was anywhere from less than 250 basis points between what was requested and what was authorized?

THE WITNESS: Yes.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Anything further from the bench? Okay. Let's deal with exhibits.

MR. BEASLEY: We would like to move Exhibit 20.

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

(Exhibit Number 20 admitted into the record.)

CHAIRMAN CARTER: Staff, you're recognized.

MR. YOUNG: Staff would like to moved Exhibit Number 106.

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

(Exhibit Number 106 admitted into the record.)

CHAIRMAN CARTER: Thank you. The witness may be excused.

Commissioners, for planning purposes, we are going to press on, but we will stop at 1:15 for lunch, and we'll go from 11:15 to 2:30 for lunch. And just for the parties, be back in at 2:30, because we are going to hit the ground running.

So you may excused. Call your next witness.

MR. MOYLE: Mr. Chairman, we have been going since 9:30, could we take fives minutes for a biological break?

CHAIRMAN CARTER: You're not up yet. Go ahead.

(Laughter.)

COMMISSIONER ARGENZIANO: I agree.

CHAIRMAN CARTER: You guys need a biological break? What's up with that? Okay. We're on recess for five minutes. We'll come back at twenty of.

(Recess.)

CHAIRMAN CARTER: We are back on the record and you may proceed.

MR. BEASLEY: Mr. Chairman, our next witness, Ms. Lorraine Cifuentes has been excused from the proceeding. I would simply like to ask that her prepared direct testimony be inserted into the record as though read.

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

MR. BEASLEY: And it was accompanied by an exhibit, LLC-1, marked Hearing Exhibit Number 21. I would like to move that exhibit into the record.

CHAIRMAN CARTER: Any objections?

Without objection, show it done.

(Exhibit Number 21 admitted into the record.)

CHAIRMAN CARTER: You may proceed.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

LORRAINE L. CIFUENTES

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

A. My name is Lorraine L. Cifuentes. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Load Research and Forecasting in the Regulatory Affairs Department.

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

A. In 1986, I received a Bachelor of Science degree in Management Information Systems from the University of South Florida. In 1992, I received a Masters of Business Administration degree from the University of Tampa. In October 1987, I joined Tampa Electric as a Generation Planning Technician and I have held various positions within the areas of Generation Planning, Load Forecasting and Load Research. In October 2002, I was promoted to

Manager, Load Research and Forecasting. My present responsibilities include the management of Tampa Electric's customer, peak demand and energy sales forecasts as well as management of Tampa Electric's load research program and other related activities.

Q. What is the purpose of your direct testimony?

A. My direct testimony describes Tampa Electric's customer, demand and energy forecasting process, describes the methodologies and assumptions, and presents the forecasts used in Tampa Electric's budget that support its request for a base rate increase. Additionally, I demonstrate how these forecasts are appropriate and reasonable.

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

A. Yes, I am sponsoring Exhibit No. ____ (LLC-1) consisting of 10 documents, prepared under my direction and supervision. These consist of:

Document No. 1	List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By Lorraine L. Cifuentes
Document No. 2	Customer Forecast

Document No. 3	Economic Assumptions Average Annual Growth Rate
Document No. 4	Real Price Of Electricity
Document No. 5	Per-Customer Energy Consumption
Document No. 6	Retail Energy Sales
Document No. 7	Per-Customer Peak Demand
Document No. 8	Peak Demand
Document No. 9	Firm Peak Demand
Document No. 10	Load Factor

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

A. Yes. I sponsor or co-sponsor the MFRs shown in Document No. 1 of my Exhibit No. ____ (LLC-1).

Q. What is Tampa Electric's existing and forecasted customer base?

A. Tampa Electric's current customer base and forecasted growth is shown in Document No. 2 of my exhibit. In 2007, Tampa Electric's customer base was 666,354 and is projected to grow at an average annual rate of 2.1 percent over the next 10 years. The company expects to have 679,941 customers in 2009.

Q. By how much has Tampa Electric's customer base increased since 1992, the year of Tampa Electric's last rate case filing?

A. Since 1992, the number of customers Tampa Electric serves has increased by almost 200,000 or 42 percent. Peak energy demands have also increased significantly. Summer peak demand has increased by approximately 1,350 MW or 50 percent, while summer firm peak demands have increased even further, by 1,480 MW or 62 percent.

Q. How is Tampa Electric's inflation assumption, which is used in its operations and maintenance ("O&M") budget, developed?

A. Tampa Electric uses the Consumer Price Index ("CPI") projections provided by Moody's Economy.com, a leading provider of economic forecasting services, in developing its inflation forecast for budgeting purposes. CPI is the most widely utilized indicator of changes in the price of goods and services. MFR Schedules C-33 and C-40 provide historical and projected annual percent changes in CPI. The projected values were used as a guide in the development of the 2009 projected test year O&M budget.

TAMPA ELECTRIC'S FORECASTING PROCESS

Q. Please describe Tampa Electric's load forecasting process.

A. Tampa Electric uses econometric models and statistically adjusted engineering ("SAE") models, which are integrated to develop projections of customer growth, energy consumption and peak demands. The econometric models measure past relationships between economic variables, such as population, employment and customer growth. The SAE models incorporate end-use trends into an econometric model and are used for projecting average per-customer consumption. Tampa Electric has consistently used these models for generation planning purposes and the modeling results have been submitted to the Florida Public Service Commission for review and approval in past regulatory proceedings and in the Ten-Year Site Plan approval process. The models have proven to be accurate within plus or minus three percent. MFR Schedule F-5 provides a more detailed description of the forecasting process.

Q. What assumptions were used in the base case analysis of customer growth?

A. The primary economic drivers for the customer forecast are state population estimates, service area households and Hillsborough County employment. The state population forecast is the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research ("BEBR") and Moody's Economy.com provide population projections for Florida. The population forecast is based upon the projections of BEBR in the short-term and is a blend of BEBR and Economy.com for the long-term forecast. Service area households and Hillsborough County employment assumptions are used to estimate non-residential customer growth because they are proven indicators of such growth. An increase in the number of households results in a need for additional services, restaurants and retail establishments. Projections of employment in the construction sector are a good indicator of expected trends in local construction activity. Similarly, commercial and industrial employment growth is a good indicator of the level of activity to expect in their respective sectors. Economy.com provides projections of Hillsborough County households and employment by major sectors. The 10-year historical and forecasted average annual growth rates for these economic indicators are shown in Document No. 3 of my exhibit.

Q. What assumptions were used in the base case analysis of energy sales growth?

A. Customer growth and per-customer consumption growth are the primary drivers for growth in energy sales. The average per-customer consumption for each revenue class is based on SAE models with three components. The first component includes assumptions of the long-term saturation and efficiency trends in end-use equipment. The second component captures changes in economic conditions, such as real household income, persons per household and the price of electricity, and how these factors affect a residential customer's consumption level. A complete list of the critical economic assumptions used in developing these forecasts is shown in Document No. 3 of my exhibit. The third component captures the seasonality of energy consumption. Heating and cooling degree-day assumptions allocate the appropriate monthly weather impacts and are based on weather patterns over the past 20 years. MFR Schedule F-07 provides a description and the historical and projected values of each assumption used in the development of the 2009 test year retail energy sales.

Q. What assumptions were used in the base case analysis of peak demand growth?

A. Peak demand growth is affected by long-term appliance trends, economic conditions and weather conditions. The end-use and economic conditions are integrated into the peak demand model from the energy sales forecast. The weather variables are heating and cooling degree-days at the time of the peak and for the 24-hour period of the peak day. Weather variables provide the seasonality to the monthly peaks.

Q. Does Tampa Electric assess the reasonableness of these base assumptions?

A. Yes. The base case economic assumptions have been evaluated based on a comparison of the data series' historical average annual growth rates to the projected average annual growth rates for the forecast period. In addition, economic forecasts are compared to alternate sources and evaluated for consistent trends. Economy.com's projections for Florida employment by major sectors and Florida real household income are compared to the projections of the Office of Economic and Demographic Research of the Florida Legislature. The projected trends for Florida were consistent between the two sources; therefore, it is reasonable to conclude that Economy.com's Hillsborough County projections were also reasonable.

Q. Were the forecasts for population growth also evaluated for reasonableness?

A. Yes. Economy.com and BEBR's population forecasts were compared and evaluated for consistency. A blend of the two sources was used and provides a reasonable population projection for the state of Florida.

Q. Why are population projections at the state level preferred over the Hillsborough County or service area level?

A. State level population projections are preferred over county level projections for several reasons. Tampa Electric's forecasting models show a very high correlation between Florida population and residential customer growth. In addition, Hillsborough County represents approximately 85 percent of Tampa Electric's service area but portions of Polk, Pasco, and Pinellas counties are also served. Historical and projected population growth rates are similar for Florida and

Hillsborough County; therefore, Florida population is a reasonable explanatory variable to use in Tampa Electric's customer models.

Q. Was the price of electricity included in your energy sales models?

A. Yes. The price of electricity was included in each per-customer consumption model. Document No. 4 of my exhibit includes the real or inflation-free price of electricity by class. The price variable was primarily used to capture long-term impacts of the real price of electricity. The recent increases in the real price of electricity have resulted in reduced growth in residential sales in the short-term and increased growth as the price moderates. In order to eliminate recent abnormal swings in prices, a smoothed trend of the real price of electricity was used in the residential model. Energy sales for the remaining sectors were not as sensitive to the changes in the real price of electricity.

Q. Historically, what has been the accuracy of the company's retail energy sales forecasts?

A. Over the past 10 years, the average accuracy of the retail energy sales forecasts, excluding the phosphate sector, which is volatile year over year, is 1.1 percent.

Q. Have Tampa Electric's forecasting models and assumptions used in developing the customer, demand and energy forecasts been reviewed for reasonableness?

A. Yes. Itron Corporation is an industry leader that provides utility forecasting software and methodologies to more than 160 utilities and energy companies. Itron has reviewed Tampa Electric's forecasting models and the assumptions used to develop the customer, demand and energy forecasts. Itron Corporation concluded that the forecast models were theoretically sound with excellent model statistics and modeling errors were reasonable and consistent with other utilities.

TAMPA ELECTRIC'S FORECASTED GROWTH

Q. What is Tampa Electric's customer growth forecast?

A. Tampa Electric is projecting an annual average increase of 15,730 new customers over the next 10 years (2008-2017). This average annual increase of 2.1 percent is slightly lower than the average annual growth rate of 2.6

percent during the past 10 years (1998-2007), as reflected in Document No. 2 of my exhibit.

Q. What is Tampa Electric's energy sales forecast?

A. Retail energy sales are expected to increase at an average annual rate of 2.0 percent. The primary driver behind the increase in the energy sales forecast is the average annual increase in customers of 2.1 percent. In addition, per-customer consumption is expected to remain relatively flat at an average annual rate of -0.1 percent, as shown in Document No. 5 of my exhibit. Combining the growth in customers and per-customer consumption results in the average annual rate of 2.0 percent. When energy sales to the phosphate sector are excluded, retail energy sales are expected to increase at an average annual rate of 2.1 percent. Historical and forecasted energy sales are shown in Document No. 6 of my exhibit.

Q. What is the primary driver behind the average annual per-customer consumption growth rate of -0.1 percent?

A. The lower growth rate for per-customer consumption is driven by updated economic and appliance efficiency trend assumptions and the addition of Tampa Electric's new conservation programs approved in 2007.

Q. Do higher energy prices have an energy conservation effect?

A. Yes. Tampa Electric has seen a correlation between recent increases in energy costs and a resulting reduction in consumption levels. However, while the reduced consumption results in decreased energy sales, peak demand growth is still occurring due to the lower price-elasticity of peak demand.

Q. Did you consider the housing slowdown in your growth analysis?

A. Yes. The recent downturn in housing is reflected in the population estimates used in the customer growth models. The current slowdown in customer growth is stronger and will last longer than previously expected. Tampa Electric does not expect housing growth to revert back to normal levels until 2010 and perhaps later.

Q. What is Tampa Electric's peak demand forecast for 2008 through 2017?

A. Summer and winter peak usage per-customer is projected to remain relatively flat over the next 10 years, which is consistent with recent historical growth rates as well as per-customer energy consumption. Document No. 7 of my exhibit shows historical and forecasted peak usage per-customer for summer and winter peaks. The annual growth in customers and in per-customer demand results in an average annual growth rate of 2.0 percent for the winter peak and a 2.1 percent growth rate for the summer peak. As shown in Document No. 8 of my exhibit, peak demand for the summer of 2008 is forecasted to be 4,144 MW, increasing to 4,983 MW in 2017, an average increase of 93 MW per year. The forecasted 2008 winter peak is 4,275 MW, increasing to 5,129 MW in 2017, an average increase of 95 MW per year. The summer and winter peak demands projected for the 2009 test year are 4,206 MW and 4,345 MW, respectively. Summer and winter firm peak demands, which have been reduced by curtailable load such as load management and interruptible loads, are shown in Document No. 9 of my exhibit.

Q. Are conservation and demand-side management ("DSM") impacts accounted for in the energy sales and peak demand forecasts?

A. Yes. Tampa Electric forecasts demand and energy reductions for each conservation and DSM program, which are aggregated to represent the total cumulative savings. The total incremental savings adjust the energy sales and peak demand forecasts each year.

Q. Are Tampa Electric's forecasts of customers, energy sales and demand appropriate and reasonable?

A. Yes. The results have been compared to trend analyses and annual multi-regression sales models. The average annual growth rates for per-customer demand and energy usage are compared with each other for consistency and compared to historical growth rates. Summer and winter load factors are reviewed to ensure proper integration of the peak and energy models. The results show that the load factors are reasonable compared to historical years. Load factors have dropped slightly due to the loss of phosphate load. The load factors are shown in Document No. 10 of my exhibit. In addition, Itron Corporation has reviewed the company's forecasts results and concluded that they are consistent with the economic outlook and with historical usage trends.

Q. Please summarize your direct testimony.

A. The purpose of my direct testimony is to present Tampa Electric's customer, peak demand and energy sales forecasts and the methodologies and assumptions used to arrive at the projections for the 2009 test year. Tampa Electric's 2007 customer base was 666,354 and is projected to grow at an average annual rate of 2.1 percent over the next 10 years. Per-customer demand and energy consumption is expected to remain relatively flat over the next 10 years. Combining the growth in customers and per-customer consumption, retail energy sales are expected to increase at an average annual rate of 2.0 percent over the next 10 years. These forecasts are based on proven methodologies using appropriate and reasonable assumptions. The forecasting models described in my direct testimony have consistently been used by Tampa Electric for generation planning purposes and the results have been submitted to the Commission for review and approval in past regulatory proceedings and in the Ten-Year Site Plan approval process.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MR. HART: Mr. Chairman, Tampa Electric Company calls Mark J. Hornick.

MARK J. HORNICK

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

DIRECT EXAMINATION

BY MR. HART:

Q Would you please state your name and business address, please?

A Yes. My name is Mark J. Hornick. My business address is 702 North Franklin Street, Tampa, Florida.

Q Mr. Hornick, did you prepare and cause to be filed in this proceeding prepared direct testimony consisting of 28 pages?

A Yes, I did.

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

A The only change to my direct testimony is that when we filed the docket my position was listed as General Manager of Polk and Phillips Power Station. Since then I have had a change of role. My current title is Director of Engineering and Construction.

Q And attached to your direct testimony, did you include a composite exhibit premarked as Exhibit MJH-1 and Hearing Exhibit Number 22 consisting of five documents?

A Yes, sir, I did.

MR. BEASLEY: Mr. Chairman, we would ask that Mr. Hornick's composite exhibit premarked as Exhibit MJH-1 be formally identified for the record as Hearing Exhibit Number 22.

CHAIRMAN CARTER: For the record, show it done.

(Exhibit Number 22 marked for identification.)

BY MR. HART:

Q Mr. Hornick, do you have any changes to Exhibit 22?

A Yes, I do. One change. Subject to the filing, we discovered there was an incorrect graph and that was revised on Document Number 5, and it was filed with the Commission on October 3rd, 2008.

MR. HART: Mr. Chairman, I would request that the revised document be substituted for Number 5 in the prefiled testimony.

CHAIRMAN CARTER: Have all the parties received a copy of it?

MR. HART: Yes.

CHAIRMAN CARTER: Okay. Show it done.

BY MR. HART:

Q Mr. Hornick, did you prepare and cause to be filed in this proceeding prepared rebuttal testimony consisting of 17 pages?

A Yes, I did.

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

A No, there are not.

Q Attached to your rebuttal testimony, did you include a composite exhibit premarked as Exhibit MJH-2 and Hearing Exhibit Number 82 consisting of one document?

A Yes, sir.

MR. HART: Mr. Chairman, we would ask that Mr. Hornick's exhibit premarked as MJH-2 be formally identified for the record at this time as Hearing Exhibit Number 82.

CHAIRMAN CARTER: You want to do the rebuttal testimony? The rebuttal testimony of the witness will be inserted into the record as though read, and the exhibits will be noted for the record, just for the record.

You may proceed.

(Exhibit Number 82 marked for identification.)

MR. HART: We had identified both of them. I don't believe that the direct testimony has been identified into the record yet.

CHAIRMAN CARTER: I thought I had done that.

MR. HART: Okay.

CHAIRMAN CARTER: You said if he had any changes to it if you asked him the same questions. He said his only changes were on his position. He got a promotion, or a demotion, or a lateral.

THE WITNESS: A lateral.

MR. HART: I apologize for the confusion, but for the record, both the direct and the prefiled have been admitted into the record.

CHAIRMAN CARTER: Just for the record, just out of an abundance of caution and clarity, both the prefiled rebuttal and direct testimony of the witness will be inserted into the record as though read. And the exhibits for the witness have been identified for the record. You may proceed.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK J. HORNICK

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

A. My name is Mark J. Hornick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of General Manager - Polk and Phillips Power Stations.

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

A. I received a Bachelor of Science Degree in Mechanical Engineering in 1981 from the University of South Florida. I am a registered professional engineer in the state of Florida. I began my career with Tampa Electric in 1981 as an Engineer Associate in the Production Department. I have held a number of engineering and management positions at Tampa Electric's power generating stations. From 1991 to 1998, I was a manager at Big Bend Power Station with various responsibilities including serving as Manager of Operations from 1995 to 1998. In July 1998, I was promoted to Director, Fuels where I was responsible for managing Tampa Electric's fuel procurement and transportation activities.

In March 2000, I was promoted to my current role of General Manager, Polk and Phillips Power Stations. I am responsible for the overall operations of these two generating facilities. I have broad experience in the engineering and operations of power generation equipment including Integrated Gasification Combined Cycle ("IGCC") technology. I have served on the Electric Power Research Institute's "IGCC Experts Panel". I am currently the Chairman of the Gasifier Users Association, an international group of users and potential users of gasification technology.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports the company's budgeted construction capital and operations and maintenance ("O&M") expenses related to generation facilities included in the 2009 test year and the company's generation expansion plan. I show that the amounts budgeted for these items are reasonable and prudent. My direct testimony discusses the resource planning process used by Tampa Electric and the capital expenditures that are needed for generation expansion and continued operations of existing units. I also discuss the O&M activities and resources needed for continued operations of the company's generating assets. Finally, my direct testimony discusses the variance between the O&M benchmark and the test year for production.

Q. Have you prepared an exhibit for presentation in this proceeding?

A. Yes, Exhibit No. _____ (MJH-1) entitled "Exhibit of Mark J. Hornick" was prepared under my direction and supervision. It consists of the following five documents:

Document No. 1	List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By Mark J. Hornick
Document No. 2	2009 Production Construction Budget
Document No. 3	2009 Production O&M Budget
Document No. 4	Total System Equivalent Availability Factor
Document No. 5	Total System Heat Rate

CHANGES TO GENERATING SYSTEMS

Q. Please describe the significant changes to the Tampa Electric generating system since the last rate case proceeding in 1992.

A. There have been several significant changes to the Tampa Electric generating system since 1992. In 2007, the company served a retail winter peak load of 4,123 megawatts ("MW") compared to 2,771 MW served in 1992, an increase of approximately 50 percent or 1,350 MW. To meet this growing demand, the company added new generation to its system beginning in 1996 at the Polk Power Station. Polk Unit 1 has been named the cleanest coal-fired power plant in North America, and the world leader in producing electricity from environmentally friendly, coal-derived synthesis gas. Polk Unit 1 is a 255 MW (net winter capability) coal and distillate oil fueled unit utilizing IGCC technology. Its combined cycle technology increases efficiency because it reuses exhaust heat to produce more electricity. Sulfur is removed from the gas prior to combustion. Polk Units 2 and 3 are 184 MW (net winter capability) dual fuel (natural gas and distillate oil) simple cycle combustion turbine ("CT") generating units that began commercial operation in 2000. Polk Units 4 and 5 are 184 MW (net winter capability) natural gas fired simple cycle CTs that began operation in 2007.

As the result of environmental agreements Tampa Electric made with the U.S. Environmental Protection Agency ("EPA") and Florida's Department of Environmental Protection ("FDEP") in late 1999 and 2000, the six coal fired units at Gannon Station totaling a nominal 1,200 MW were removed from service in 2003. The existing steam turbine generators from Gannon Units 5 and 6 were integrated into two new natural gas combined cycle units. The exhaust heat from three new CTs is used to generate steam to power the existing Gannon 5 steam turbine. This three-on-one configuration makes up Bayside Unit 1, which was put into service in April 2003. The exhaust heat from four new CTs is used to generate steam to power the existing Gannon Unit 6 steam turbine. This four-on-one configuration makes up Bayside Unit 2, which began operation in January 2004. These new highly efficient and reliable units comprise the H. L. Culbreath Bayside Power Station, a nominal 1,650 MW natural gas fired facility.

The changes at Bayside Power Station have resulted in significant reductions in sulfur dioxide ("SO_2"), nitrogen oxide ("NO_x"), particulate matter, mercury and carbon dioxide ("CO_2") emissions. Besides the significant emission reductions, the repowering was the most cost effective alternative based on 1) the need to satisfy customer demand for reliable electricity at reasonable costs; 2) the ability to use existing substation and transmission facilities; 3) the availability of natural gas supplied from existing and then-proposed natural gas pipelines in the area; and, 4) the opportunity to reuse existing plant equipment.

The five oil-fired units at Hookers Point Station, totaling 220 MW, which were originally constructed in the 1940's and 1950's, were retired from service in 2002. The 12 MW oil and gas fired unit at the Dinner Lake Station was also retired from service in 2006.

Significant environmental retrofit projects have been completed at the Big Bend Power Station. Flue gas desulphurization ("FGD" or "scrubbers") equipment was added to Big Bend Units 1, 2 and 3. The scrubbers remove more than 95 percent of SO_2 from the four Big Bend units. Selective catalytic reduction ("SCR") equipment was added to Big Bend Units 3 and 4 and will be added to Big Bend Units 1 and 2 by 2010.

Q. Please describe the benefits of the environmental retrofit projects and environmental agreements with EPA and FDEP that have been undertaken since the last rate case in 1992.

A. Tampa Electric is now one of the cleanest utilities in the nation using coal and with no nuclear generation. This is the result of an industry-leading 10-year, $1.2 billion environmental improvement program that is currently in its final stages of implementation. As a result, by 2010, system wide NO_x emissions will be reduced by approximately 90 percent below 1998 levels. This significant reduction is possible due to the repowering of the Gannon Station to the natural gas fired Bayside Power Station and the installation of SCR systems on all four Big Bend units.

By 2010, system wide emissions of SO_2 will be reduced by approximately 90 percent below 1998 levels. This significant reduction was the result of several projects. In 1995, through the innovative efforts of Tampa Electric, a project was completed to integrate the flue gas from Big Bend Unit 3 with the exiting FGD system on Big Bend Unit 4. This provided the required level of sulfur removal at a very low cost. In 1999, an innovative single tower FGD system was completed to treat the flue gas from Big Bend Units 1 and 2, which also provided sulfur removal at a low cost. The scrubbers in service at Big Bend Power Station remove more than 95 percent of the SO_2 emissions from the flue gas streams. Sulfur emission reductions also resulted from the repowering of the Gannon Station to the natural gas fired Bayside Power Station.

By 2010, system wide emissions of mercury and particulate matter will both be reduced by approximately 72 percent from 1998 levels. These reductions are possible due to the combination of FGD and SCR system installations on the Big Bend units and the repowering of Gannon Station.

In addition to the reductions in regulated emissions listed above, since 1998, system-wide emissions of CO_2 have been reduced by over 20 percent bringing emissions below 1990 levels.

PLANNING PROCESS

Q. What process does Tampa Electric use to determine the need for additional generation facilities?

A. Tampa Electric uses an Integrated Resource Planning ("IRP") process. The IRP process determines the timing, type and amount of additional resources required to maintain system reliability in a cost-effective manner. The process considers expected growth in customer demand, existing and future demand side management ("DSM"), and renewable/supply-side resources needed to meet reliability requirements.

Q. Please describe the reliability criteria that Tampa Electric utilizes to determine the need for additional resources.

A. Tampa Electric utilizes a 20 percent planning reserve margin reliability criteria, as required by the Florida Public Service Commission ("FPSC" or "Commission") in Order No. PSC-99-2507-S-EU issued in December 1999. The total system firm peak is determined by including all firm wholesale agreements and excluding non-firm customer demand from the total system demand. Non-firm demand includes all interruptible service customers and DSM load reduction programs. Customers participating in these voluntary programs help defer the need for additional supply-side resources by reducing peak demands.

Q. How does the company plan and manage its generation projects?

A. The company utilizes long range planning tools to determine its future capital projects and generation plant additions. In very simplistic terms, once a need for future generating capacity is identified, a project team is assigned to begin project evaluations. The priorities in the evaluation process include the need to determine feasible alternatives, costs, schedules and participants in the project. After a specific project is identified as being the most cost-effective alternative, it must be approved by the company's management and Board of Directors. Once approved, the project team executes the project to design the plant, obtain permits, procure the equipment, construct, start-up and commission the plant until it achieves commercial operation. Throughout this process, the project is managed to meet the cost, schedule and performance goals.

Another phase of long range planning is the development of a five-year construction budget, which identifies other near term projects required to provide reliable service. The capital projects in the five-year plan include maintenance projects to replace existing plant equipment that will affect the generating unit reliability, capacity or efficiency. It also includes additions of new equipment to meet new environmental requirements.

The plan is modified as new information is obtained. Each year the company must determine its capital plan for the following year. Information regarding the generating unit availability, operating conditions, new regulations and environmental needs are reviewed and considered for inclusion in the capital plan. Some projects are not discretionary but instead are required due to environmental or safety considerations, new regulations, etc. Other projects are prioritized based upon their relative benefits. Through a review process, the projects are selected for inclusion in the next year's budget. Similarly to how new generation projects are managed, these projects are also initiated and executed by a project team. Each project goes though an estimating and approval process to ensure its benefit and need. These projects are monitored for cost, schedule and desired performance throughout the process until they are completed and in service.

CONSTRUCTION PROGRAM AND CAPITAL BUDGET

Q. What are Tampa Electric's major generation construction requirements through 2009?

A. The company's forecasted capital additions and retirements are listed in MFR Schedule B-11. Tampa Electric's 2008 Ten Year Site Plan indicates the need for additional peaking capacity in the near term. Projects are underway to add five simple cycle CTs in 2009. These generating units will be aero-derivative CTs ("Aero CTs"), each with a nominal capacity of 60 MW. The term aero-derivative indicates that this technology was originally developed for aircraft engines. The Aero CTs provide good efficiency with net operating heat rates of 10,641 Btu/kWh (higher heating value), have low emissions and have quick start capability enabling the unit to start up and achieve off line to full load in 10 minutes. These machines offer a more economic option for meeting the company's operating reserve requirements than by spinning reserve, which requires keeping large units running. The use of quick start CTs in lieu of spinning reserve benefits customers by allowing the in-service generating units to operate at higher average outputs, which improves efficiency and reduces heat rate.

One 60 MW Aero CT, Big Bend CT Unit 4, will be placed in service in September 2009 at the Big Bend Power Station and will have the capability to use either natural gas or distillate oil as a fuel source. The electrical power required to start this unit is relatively small and can be provided by an on-site engine driven generator. The output of Big Bend CT Unit 4 may be used to provide power directly to the electric grid and provide the power required to start additional generating units at Big Bend Power Station. The Florida Reliability Coordinating Council defines the ability to energize portions of a blacked out region utilizing resources independent of an energized connection as "black start capability". This black start capability could allow for faster restoration of electric service to customers following events such as hurricanes that may cause widespread damage to the electric grid. The existing 10 MW Big Bend CT Unit 1, which provides black start capability, is at the end of its useful life and will be retired after Big Bend CT Unit 4 is placed into service in 2009.

Four 60 MW Aero natural gas fired CTs will be located at Bayside Power Station and will be designated Bayside Units 3, 4, 5 and 6. As with the Big Bend CT Unit 4, Bayside Units 3 through 6 can be started without requiring an energized connection from the electric grid by using on-site generators. This will provide black start capability at the Bayside Power Station. Two of the Bayside Aero CTs will be connected to the 69 kV system to allow power from these units to start the other Bayside units without an energized connection from the grid external to the station.

Bayside Units 5 and 6 will be placed in service in May 2009. Big Bend CT Unit 4 and Bayside Units 3 and 4 will be placed in service in September 2009. These five generating units will provide needed generating capacity and operating flexibility with a high level of efficiency and environmental performance.

Q. What other major generation-related capital projects are planned for 2009?

A. There are two major, non-expansion projects planned for 2009: the continuation of Big Bend Power Station's SCR installations and the construction of rail facilities at Big Bend Power Station to accommodate solid fuel transportation.

Q. Please describe the Big Bend SCR installation project.

A. The EPA and FDEP agreements require that Big Bend Power Station achieve certain NO_x emission reductions by 2010. The company determined that the most cost-effective solution was the installation of SCRs on all four units. SCR technology was installed on Unit 4 in 2007; SCR for Unit 3 was placed in service during summer 2008; and Unit 2 and Unit 1 SCRs are scheduled to be placed in service in May 2009 and May 2010, respectively. The total cost for installation is expected to be $330 million, which will be recovered through the Environmental Cost Recovery Clause in accordance with past Commission orders.

Q. Please describe the rail facilities construction at Big Bend Power Station.

A. In 2007, Tampa Electric issued a request for proposal for solid fuel transportation to replace its existing contract that will expire on December 31, 2008. Based upon final contract negotiations, the company has contracted for bimodal transportation: water and rail. Bimodal transportation will afford the company more options to procure coal from additional sources resulting in customer benefits. Since there are no rail facilities for unloading coal at Big Bend Power Station, they must be constructed in 2008 and 2009 for deliveries to begin by January 1, 2010. Construction for this project is expected to begin in late 2008. The company expects to spend a total of $45,000,000 with $15,900,000 and $29,127,000 being invested in 2008 and 2009, respectively.

Q. What is Tampa Electric's construction capital budget for production facilities in 2009?

A. As shown on Document No. 2 of my exhibit, the construction capital budget for production facilities totals $369,593,000 for 2009. This includes $165,603,000 for recurring, non-expansion projects, $54,723,000 for the Big Bend SCR project and $29,127,000 of the total project cost of $45,000,000 for the rail facilities at Big Bend Power Station. The five Aero CTs are budgeted at $114,058,000 in 2009 of the $236,588,000 total project cost. The 2009 budget also includes $6,082,000 for transmission expansion associated with the addition of a natural gas combined cycle unit at Polk Power Station by 2013. Tampa Electric witness Jeffrey S. Chronister explains the company's proposed treatment of the Aero CTs and rail facilities in his direct testimony.

PRODUCTION O&M EXPENSES

Q. What is Tampa Electric's production O&M and non-recoverable fuel expense budgeted for 2009?

A. As shown on Document No. 3 of my exhibit, Tampa Electric's total production expense (excluding Environmental Cost Recovery Clause expense) budgeted in 2009 is $154,292,000. One item worth mentioning is the roughly $6.9 million the company plans to spend on channel dredging in 2009. Every five years, the channel adjacent to Big Bend Power Station must be dredged to allow vessels to deliver solid fuel to the plant efficiently. As discussed by witness Chronister, the company has made a pro forma adjustment to amortize the expense over five years.

Q. How does this compare with the FPSC O&M benchmark?

A. As described by witness Chronister in his direct testimony, the company's total 2009 O&M costs are expected to be under the benchmark by $7,693,000. This is despite the many challenges the company has faced since the last time O&M levels were reviewed by this Commission and it demonstrates cost control efforts have been able to offset increasing cost pressure over time. Witness Chronister notes that the company expects its 2009 budgeted expense for production to be below the benchmark. Specifically, the adjusted test year total production O&M per company books in 2009 is $142,429,000. The adjusted test year total production O&M benchmark in 1991 is $150,122,000. The production O&M benchmark calculation is shown in MFR Schedule C-37.

Q. How has the company managed to stay below the O&M benchmark for 2009 production expenses?

A. Tampa Electric is focused on controlling costs and ensuring that O&M dollars are spent in a prudent fashion. Generating technology is selected based on overall project economics that includes the expense needed for operations and maintenance. Recent generation additions such as the Bayside and Polk units have lower O&M expense than coal-fired units.

Q. Over the years, what are the major factors that have contributed to increase O&M needed to maintain Tampa Electric's fleet of generating units?

A. There are several factors contributing to increase production O&M expenses over time. The cost of materials, supplies and labor have all escalated significantly since the company's last rate proceeding and, in many cases, dramatically in recent years. For example, the cost of iron and steel has increased 88 percent and industrial chemicals have increased 85 percent over the past five years. Qualified construction labor has become more difficult to secure and labor costs are increasing. Labor costs have increased 31 percent from January 2003 to February 2008.

Changes in generating equipment technology and associated maintenance and outage costs have impacted O&M expenses as well. The additions of environmental control equipment to the generating units along with other environmental requirements have also increased the costs of O&M.

Q. Please define planned outages versus other types of outages.

A. Planned outages, as the name suggests, are defined as those outage periods that are anticipated and planned for well in advance of the actual outage period (typically at least one year in advance). Forced outages, on the other hand, are not planned and scheduled in advance of the outage period and can be the result of an in service failure or imminent failure of some generating unit component. In addition, forced outages are typically short in duration and have greatly reduced scope of work versus planned outages. Maintenance conducted during planned outages consists of large tasks that are performed infrequently and have a long duration. Typical examples are steam turbine inspections and repairs, replacement of large heat transfer surfaces in the boiler, and refurbishment of large motors and pumps. The maintenance performed during these outages is required to ensure the safe and reliable operation of the generating units.

Q. What is the impact of planned outages on Tampa Electric's generating units in the test year?

A. The 2009 planned unit maintenance durations are shown for each unit in MFR Schedule F-8 page 10 of 21. There are 13 generating units with planned maintenance outages scheduled in 2009. A total of 54 planned outage weeks are scheduled across the 13 units. The planned outage schedule varies from year to year based on the maintenance requirements of each generating unit and the need for adequate generating capacity in service to meet demand throughout the year. The planned maintenance forecasted for 2009 is typical of the past and expected future planned outage requirements.

Q. What has been the reliability of Tampa Electric's generating units over time?

A. The overall generating unit equivalent availability factor ("EAF") has increased from approximately 75 percent in 1997 to the 80 percent range now. This improvement was due in large part to the installation of new, highly reliable units at the Polk and Bayside Power Stations. Document No. 4 of my exhibit shows the total system EAF from 1997 to 2007.

Q. What has been the efficiency of Tampa Electric's generating units over time?

A. The heat rate of Tampa Electric's units has improved from approximately 10,500 Btu/kWh in 1997 to approximately 9,500 Btu/kWh. Document No. 6 of my exhibit shows the total system heat rate from 1997 to 2007.

Q. How do the maintenance needs of newer generation using CT technology compare with those of a conventional steam unit?

A. CT technology, when used in simple cycle or in combined cycle applications, provides a high level of performance and low emissions but has unique maintenance challenges. CTs operate at very high firing temperatures, which results in high efficiency, but also places high stress and thermal fatigue on the turbine components. Turbine suppliers have prescribed maintenance intervals for most key components in the machines that are dictated by the amount of use each turbine experiences. Maintenance of turbines in peaking service is typically dictated by the number of accumulated starts. Maintenance of turbines in intermediate or base load service is typically dictated by the number of accumulated operating hours. Each turbine must have the recommended maintenance performed at the intervals prescribed by the equipment manufacturer to ensure safe and reliable service.

Gas turbine components such as turbine blades, nozzles and combustion hardware are highly engineered with specialized designs and often are only available from the original equipment supplier or in some limited cases, a few aftermarket suppliers. Parts availability, particularly on new model machines can be very limited and if not managed properly, can have a detrimental impact on turbine reliability and availability.

Q. How has Tampa Electric addressed the maintenance needs of its CTs?

A. The CTs used by Tampa Electric at Polk and Bayside Power Stations are General Electric ("GE") 7F frames and they have a high level of performance and low emissions. The availability of parts and technical support services for these machines is very limited; therefore, Tampa Electric entered into contractual services agreements ("CSAs") with GE to perform ongoing maintenance of these turbines. Under these agreements, GE is responsible for supplying maintenance services and parts necessary to perform all planned and unplanned maintenance on the covered units in order to keep them in good working condition and in an effort to maintain availability and reliability while operating in a cost-effective and safe manner.

Q. What are the benefits of using CSAs for the ongoing maintenance needs of Tampa Electric's CTs?

A. Under CSAs, the availability of spare parts is improved and the inventory requirements for these parts are reduced. The risks of cost increases due to reduced maintenance interval requirements, parts life risk and fallout from inspection are borne by GE. Unplanned maintenance expense and the management of maintenance services including subcontracting qualified craft labor and providing technical support are also GE's responsibility. Maintenance costs are levelized and escalation rates are pre-negotiated.

Q. Are contractual services agreements an accepted industry practice for the maintenance of CTs?

A. Yes. It is a common practice for CT operators to enter into CSAs with the original equipment supplier. According to GE, 504 of the 590 operating 7F class CTs in North America are covered by CSAs. In the southern region of the United States, 307 of the 334 units are covered by CSAs.

Q. Has Tampa Electric taken other measures to control generation O&M costs over this same period?

A. Yes. Tampa Electric has taken a number of steps to ensure that its team members are safe, productive and focused on the right priorities while managing costs. Some of the key measures are in the areas of safety, staffing and productivity, and operating goals and priorities.

Tampa Electric emphasizes safety over all other considerations. Considerable effort has been placed on safety improvements across the entire company, including in Energy Supply, which implemented programs to deal with hazard elimination and personal safety behavior improvement. The company investigates safety incidents and near miss events to determine the root cause and appropriate corrective actions. The company observes team members while performing tasks to reinforce positive safety behaviors and coach them on opportunities to improve. These efforts have reduced the Occupational Safety and Health Administration recordable injury rates, which represents the annual number of recordable incidents per 100 employees, in the Energy Supply area from 3.80 in 2003 to 1.43 in 2007, which is a 68 percent reduction.

Staffing levels in Energy Supply have been reduced from over 1,000 in 1991 to an estimated 807 in 2009. This reduction took place during a period when net generation increased by nearly 1,000 MW and was accomplished through efficiency improvements and by the installation of less O&M intensive generating technologies such as the conversion from Gannon Station's coal-fired generation to Bayside Power Station's gas-fired generation. Front line craftsmen are trained and encouraged to perform tasks outside of traditional boundaries safely. In cooperation with the collective bargaining unit at the Big Bend and Bayside Power Stations, team members now perform maintenance and operation tasks as needs dictate without barriers from prior strict work rules. A pay-for-skills system encourages team members to learn and apply key skills in addition to their primary maintenance craft at the Polk and Phillips Power Stations. For example, a team member who has a core skill in mechanical maintenance may learn certain skills traditionally limited to electricians. When a task involves both mechanical and electrical work elements, one team member is able to complete the work, which improves overall workforce efficiency and productivity and allows for reduced staffing levels.

Tampa Electric ensures team members' priorities are aligned with business goals by setting business goals at the company level, which are in turn supported by goals at the department and business unit level. Team members can receive incentive pay known as Success Sharing if certain goals are met. Progress on goal achievement is regularly reviewed with team members. All of these actions have contributed to the company's ability to control costs while still providing reliable service to customers.

Q. Please summarize your direct testimony.

A. Tampa Electric serves a retail peak load of 4,123 MW compared to almost 2,800 MW served in 1992. To meet this growing demand, the company added new generation to the system beginning in 1996 at the Polk Power Station. The company has also made significant investments in environmental projects including the repowering from coal to natural gas at Bayside Power Station and the installation of scrubbers and SCRs at Big Bend Power Station. The production capital construction and O&M expenses projected for 2009 are reasonable, prudent and below the FPSC O&M benchmark. The budgets were developed and include expenditures that will improve heat rate, prevent forced outages and help ensure the availability of efficient, reasonably priced generation for customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

MARK J. HORNICK

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

A. My name is Mark J. Hornick. 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 and Construction.

Q. Are you the same Mark J. Hornick 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 errors and shortcomings in the prepared direct testimony of Mr. Helmuth W. Schultz III and Mr. Hugh Larkin, Jr. CPA, testifying on behalf of the Citizens of the State of Florida, and Mr. Jeffry Pollock, testifying on behalf of the Florida Industrial Power Users' Group ("FIPUG"). Mr. Larkin reaches incorrect conclusions about the company's dredging expense, combustion turbines, and rail facilities. Messrs. Schultz and Pollock reach incorrect conclusions about the company's scheduled outages and overall generation maintenance plans and associated expenses.

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

A. Yes I have. My Rebuttal Exhibit No.___ (MJH-2) consists of one document, "Total Planned Outages - All Plants", which was prepared by me or under my direction and supervision.

BIG BEND CHANNEL DREDGING

Q. Is the dredging of the Big Bend shipping channel in 2009 necessary and appropriate?

A. Yes. The delivery of solid fuel to Big Bend Station is currently performed using waterborne vessels. The shipping channels near the station accumulate sediment over time, which eventually impedes the vessels' ability to navigate when fully loaded. Tampa Electric's experience has shown that dredging needs to occur about every five years. The dock area and channels were dredged in 1992, 1997 and again in 2002. Without dredging in 2009, vessels will need to be "light loaded" to reduce their required draft to navigate the channel. The light loading of vessels will result in transportation inefficiencies and increased fuel costs in the form of financial penalties for waterborne fuel transportation. Furthermore, Tampa Electric has a contractual obligation with United Maritime Group to maintain the Big Bend channels to accommodate vessels to a draft of 33 feet.

Dredging of the inlet canal is also needed in 2009 due to silt and sediment accumulation at the circulating water pump inlets. This accumulation reduces unit efficiency, thereby increasing fuel costs, and causes additional maintenance expense.

Q. On page 30 of his direct testimony, Mr. Larkin argues that the company's estimated dredging costs for 2009 are too high compared with past years' expenses. What is the basis for the company's cost estimate for dredging in 2009?

A. The company's estimate is based on a realistic view of the dredging projects needed in 2009. The company's cost estimate for dredging is $6.9 million, which consists of $5.5 million for the shipping channel dredging, $1 million for the inlet canal dredging, $200,000 for the terminal dock area dredging and $200,000 for required aids to navigation maintenance.

There are several reasons for the higher costs than in prior years. In previous years' dredging projects, the spoil material removed from the channel was conveyed to disposal areas adjacent to the Big Bend Station. This has been efficient and low in cost. With each successive dredge, the available storage at adjacent disposal areas has been depleted. The disposal areas are currently about 80 percent full and there is not enough capacity to store the volume of dredge material that will be removed in 2009. The additional cost of expanding an existing disposal area or paying for off-site spoil disposal was included in the 2009 budgeted amount. Also, the estimate from the dredging contractor to perform the work has increased significantly since 2002. All of these factors are reflected in the $6.9 million estimate for the dredging project.

Q. How did Tampa Electric estimate the 2009 cost for dredging?

A. The company estimated the quantity of material to be dredged in the shipping and inlet channels based upon preliminary hydrographic surveys and past dredging experience and then obtained estimates for this work from a local dredge/marine contractor. The company compiled estimates for other costs that accompany dredging including dike integrity testing, surveys, and other costs based upon the company's last dredging project. Because the adjacent disposal areas cannot handle additional dredge material, an additional cost was added to the estimate either to increase the dikes on one of the local disposal areas or to account for offsite disposal. Finally, since there are currently two users of the channel, many of the costs are expected to be shared between Tampa Electric and the Mosaic Company. Only the company's portion of dredging costs is reflected in the 2009 projections.

Q. How do you respond to Mr. Larkin's argument that according to the company's five year dredging cycle, dredging should have occurred in 2007 and therefore, it is not needed in 2009?

A. While the company's experience has been that the Big Bend channels need to be dredged every five years, it is not a hard and fast rule. In 2007 as the company evaluated the need to dredge, it made the determination that since it was not incurring "light loading" penalties from its waterborne carrier, it could wait for a year or two before incurring dredging expense. The last dredging was completed in late 2002 and the company expects to begin work in early 2009 so the interval will be just over six years. Certainly Mr. Larkin would not suggest that Tampa Electric should have gone ahead and incurred almost $7 million of dredging expense in 2007, just because five years had lapsed since the last dredging project. To suggest that because the company deferred dredging beyond 2007 so there is not a need to dredge in 2009 is illogical. As with most decisions that the company must make, Tampa Electric manages its overall business needs and available resources to ensure it is providing the best service at reasonable rates. This decision to delay dredging until 2009 was no different.

Dredging the Big Bend channels in 2009 is necessary and the company has reasonably estimated its share of dredging expense at $6.9 million. After this project is completed, the company will continue to monitor the condition of the channel. It will most likely not need to be dredged for another five years.

ANNUALIZATION OF COMBUSTION TURBINES

Q. In Mr. Larkin's direct testimony regarding the addition of the combustion turbines ("CTs") in May and September of 2009, he concludes that "if, in fact, these combustion turbines are necessary and used and useful, the Company must be projecting additional sales so that the utilization of the combustion turbines is a necessary addition to the Company's generation." Please comment on his conclusion.

A. The CT peaking unit additions in 2009 are primarily needed to ensure the reliability and operating efficiency of the system, not to increase the sales of electricity. These peaking units, as the description suggests, will serve the demand of customers at peak periods of time. They will replace the existing CTs at Big Bend Station and provide additional peaking capacity. The energy sales from these machines will be relatively small and have been included in the test year projections for energy production.

Q. What other benefits will the five CTs provide?

A. As described in my direct testimony, in addition to meeting peak demand, the 2009 CTs will provide black start and quick start capability. The quick start capability (capability to go from off line to full load in 10 minutes) meets the operating reserve requirement criteria with machines that are off line but ready to start at a moments notice. Without this capability, the generating units that are in service would need to be operated at less than maximum capacity to insure that they can increase output to meet the reserve requirement. This is known as "spinning reserve".

Q. Please address Mr. Larkin's assertion on page 18 that "there are cost savings which the Company did not reflect in the annualization of these units."

A. He is incorrect and it appears he misunderstood my statement that "these machines offer a more economic option for meeting the company's operating reserve requirements than by spinning reserve, which requires keeping large units running." The benefits come to customers primarily by way of fuel savings, which are not the subject of this proceeding. These fuel savings are made possible by enabling the company to operate its generating units in a more efficient manner. There are no significant O&M savings to capture in 2009 projections as Mr. Larkin suggests.

ANNUALIZATION OF BIG BEND STATION RAIL FACILITIES

Q. Mr. Larkin's direct testimony regarding the Big Bend Station rail facilities concludes, "Reduced fuel costs will stimulate additional sales and thus, provide a return on the Company's investment." Do you agree with his conclusion?

A. No I do not. The Big Bend Station rail facilities are needed to cost effectively and reliably transport solid fuel by rail as described in Tampa Electric witness Joann Wehle's rebuttal testimony. The reduction in fuel costs would have very little, if any, impact on the sales of energy. The facilities are not being constructed to enhance electric sales; they are being constructed to help ensure the lowest delivered cost for coal and petroleum coke.

Q. Will the rail facilities include a train loading structure, a more costly option, as Mr. Larkin describes in his direct testimony?

A. No. The rail facilities are being designed and built to only unload solid fuel from rail cars. An option to add train loading equipment was depicted on one of the general arrangement drawings; however, this option is not being pursued and there are no costs for rail loading included in the company's 2009 estimated costs for this project.

GENERATING UNIT OUTAGES AND MAINTENANCE EXPENSES

Q. Are there other shortcomings in Mr. Pollock's analysis related to generation outages and maintenance expenses?

A. Yes. His testimony and analysis contains several factual errors. He simply averages scheduled outage expenses for 2003 through 2009 and concludes this amount represents future maintenance expenses. The calculation is flawed in many respects and it in no way reflects the company's expected costs for generation maintenance.

Q. Please describe in more detail Mr. Pollock's errors.

A. Mr. Pollock's analysis contains three errors. First, he ignores my direct testimony where I describe several significant factors that have contributed to increased production O&M expenses including 1) the cost of materials and supplies have increased dramatically in recent years, 2) qualified construction labor has been expensive and difficult to secure, and 3) the increased costs associated with operating environmental control equipment on the generating units along with other environmental requirements. Mr. Pollock's analysis does not adjust historical expenses for known escalations.

Second, his simple averaging approach focuses only on planned outage expense and ignores forced outage and routine (non-outage) maintenance expense. To only focus on one aspect of overall generation maintenance expense is not appropriate.

Third, his analysis concludes that the total number of planned outage weeks in the test year is not representative of a normal year based on historical comparisons. While the 2009 planned outage weeks are slightly higher than other years, they are reasonable given Tampa Electric's existing and future generating fleet maintenance needs.

Q. The first flaw you identified is easily understandable. Please explain Mr. Pollock's second flaw in more detail.

A. Not only does Mr. Pollock calculate his proposed outage expense using a simple arithmetic average of planned outage expenses from 2003 through 2009 while completely ignoring escalation, he also fails to recognize the relationship between planned outage expense, forced outage expense and routine (non-outage) maintenance expense. During years with lower than average planned outages, there will generally be higher levels of forced outage and non-outage maintenance expense simply because the units are operating more and there are more opportunities for in-service failures and routine non-outage needs. Conversely, forced outage or non-outage expenses are not incurred when a unit is out of service during a planned outage. It is not appropriate to single out and reduce one category of maintenance expense without evaluating overall maintenance impacts.

Q. Please describe Mr. Pollock's third flaw in his analysis and recommended disallowance.

A. Mr. Pollock's testimony contains several factual errors. On page 8, lines 16 and 17, Mr. Pollock states, "Overall plant outages would increase from 43 weeks in 2008 to 54 weeks in 2009." The total planned outage weeks budgeted for 2008 are 48.5 weeks, not 43 weeks. He repeats this error on page 9, line 14 and in his exhibit JP-1 on page

2 of 2. This error leads to an incorrect conclusion that the planned outage weeks in 2009 are much higher than in 2008.

On page of 8, lines 21 and 22 of Mr. Pollock's testimony, he incorrectly states, "The last time two major Big Bend outages occurred in the same years was in 2006 when Units 1 and 3 were both down for major inspection outages." In fact, there were two major Big Bend outages in 2007 when Big Bend Unit 4 had a major outage which included the tie-in work on the selective catalytic reduction ("SCR") equipment in the spring and Big Bend Unit 3 began its major outage in the fall with 6.15 weeks in 2007 and then into 2008.

Finally, in his exhibit JP-1 on page 2 of 2, Mr. Pollock shows the total planned outage weeks in 2004 as 28.9. The number of total planned outage weeks was actually 29.1 as provided in the company's response to FIPUG's First Set of Interrogatories No. 1.

Q. But isn't it true that the recent outages at Big Bend Station have been due to SCR installations and should not be considered normal and recurring types of outages?

A. It is true that since 2007 Tampa Electric has been and will continue installing SCRs on all four Big Bend units. This work will be complete in April 2010. However, while these units have been out of service for environmental equipment installation purposes, other routine maintenance has also been performed to optimize overall outage time on the company's most cost effective units. While SCR installations will not occur after 2010, other routine maintenance will continue annually.

Q. Mr. Pollock concludes that production O&M expense in the test year is overstated because it reflects an abnormal number of scheduled outages. Are the number of scheduled outages in the test year reasonable compared to the number of expected scheduled outages in future years?

A. Yes they are. The overall generation scheduled outages for the years 2008 through 2011 are shown in detail on Document No. 1 of my rebuttal exhibit. It shows that the number of outage weeks per year will range from 45 to 54 weeks and will average 48.4 weeks. It is true that the planned outage duration for 2009 is greater than that for 2008, 2010 and 2011 but it is not unreasonable.

While Mr. Pollock focuses specifically on Big Bend

Station, the company's projected generation outages are driven not only by planned outages at Big Bend Station but also by planned outages at Bayside and Polk Power stations. Bayside Station Units 1 and 2 are scheduled for major planned outages in 2011 and 2012. At Polk Power Station, Polk Unit 1 is scheduled for a major outage in 2012. The four CT's at Polk Power Station are also scheduled for outages over the next several years. Finally there will be scheduled outage requirements for the five new CT's following their installation in 2009.

Q. To summarize, do you agree with Mr. Pollock's analysis and conclusions recommending that Tampa Electric recover only $12.2 million for planned outages rather than the company's projected $20.2 million?

A. No. His analysis is flawed and incomplete. Overall, the test year's scheduled outage O&M expenses of $20.2 million are reasonable and prudent for inclusion.

Q. Did you find any errors in Mr. Schultz's testimony as it relates to generation outages and production costs?

A. Yes I did. Mr. Schultz performed an analysis of generation maintenance expense using historical expenses from 2003 through 2009 for the three generation maintenance accounts 511, 512 and 513 and compared these to the budgeted test year expenses to determine reasonableness. Unlike Mr. Pollock, he did index historical expenses to account for escalation using published indices. However, when he compared historical data with the company's 2009 projected expenses, he did not recognize that Account 511 was abnormally high due to the Big Bend channel dredging expense. As I described above, the company expects to incur a $6.9 million expense for dredging and the entire amount was included in Account 511 for 2009. Since channel dredging typically occurs every five years, the company subsequently made a pro forma adjustment to remove $5.5 million of the $6.9 million to reach an annual amount of $1.4 million. Therefore, the effective 2009 total generation maintenance expense (the total of Accounts 511, 512 and 513) is $63.631 million, not $69.151 million as shown on his exhibit. Once this correction is made, Mr. Schultz's allowable expenses of $60.671 million should be compared to the adjusted expense total of $63.631 million. Mr. Schultz's own methodology (which the company disagrees with) would only result in a recommended disallowance of $2.96 million, which is less than five percent of company's projected generation maintenance expenses included in the 2009 test year. The company based its projected expense on better known information and it is appropriate, even when compared to the historical averaging method used by Mr. Schultz.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony points out errors and shortcomings in the testimonies of Messrs. Schultz, Larkin, and Pollock. Their assumptions and calculations had several errors that led them to incorrect conclusions about the Big Bend Station rail facilities, the five CTs scheduled to go in service in May and September 2009, and generation outage schedules and expenses for 2009. None of their recommended adjustments are appropriate.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BY MR. HART:

Q Mr. Hornick, please summarize your direct and rebuttal testimony.

A I will be glad to.

Good afternoon, Commissioners. My direct testimony supports the company's activity related to power generating facilities in the 2009 test year and the company's generation, investment, and expansion plan.

Tampa Electric's generating fleet has undergone substantial changes since the last rate case proceeding in 1992. We have increased the generating capacity of our system by 25 percent from approximately 3,600 megawatts in 1993 to 4,500 megawatts in 2008. The aging oil-fired units at Hookers Point Station have been decommissioned and the coal-fired Gannon Station has been repowered to the natural gas combined cycle Bayside Power Station. We have also constructed the Polk Power Station consisting of Polk Unit 1, which has been rated the cleanest coal-fired power plant in North America, and four simple-cycle combustion turbines to serve our customers' peaking needs. These changes have improved the reliability and efficiency of our generating mix and have given us a more diversified fuel mix.

The environmental profile of our generating fleet has improved dramatically since the last rate case proceeding. The major additions of environmental control equipment at Big Bend, the repowering of coal-fired Gannon to gas-fired Bayside, and the addition of clean generation at Polk have greatly reduced system emissions. These changes represent significant benefits to our customers and our community.

The company plans to install five aero-derivative simple cycle combustion turbines in 2009, each with a nominal capacity of 60 megawatts. These units will help ensure that there is an adequate generating reserve margin during peak periods and provide other customer operating benefits. They have rapid start capability, meaning they can come from off-line to full load in less than ten minutes. They also provide black start capability, meaning that they can self-start in the event of loss of power on the electric grid.

The flexibility provided by these new units will allow us to operate the entire generating system more efficiently. This will result in savings for our customers with greater system reliability.

Tampa Electric also continues to be focused on prudent spending and cost control. The company's budgeted generation-related O&M spending for 2009 is $7.7 million below the Commission's benchmark level. The budgeted expenses represent prudent activities to ensure safe reliable operations of the generating units to meet the needs of our customers in the future.

Finally, my rebuttal testimony points out errors and shortcomings in the intervenor testimonies concerning the Big Bend rail facility, the combustion turbine additions, and generating unit outage and maintenance expense for 2009. The intervenors' assumptions and calculations included several errors that led them to incorrect conclusions. None of the recommended adjustments are appropriate and they should not be adopted by the Commission.

This concludes my summary.

CHAIRMAN CARTER: Thank you.

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

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

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Good afternoon, Mr. Hornick. Let me direct you to Page 12 of your direct testimony. On Page 12, you talk about the five new CTs that Tampa Electric is planning to have come on-line. And starting at Line 18 through Line 21, isn't it correct your testimony says, "These machines offer a more economic option for meeting the company's operating reserve requirements than by spinning reserves which requires keeping large units running."

A Yes, that's correct. That's what it says.

Q Now, if the large units are no longer running to meet spinning reserve requirements, there would be costs or savings related to fuel, isn't that correct?

A Yes, there would be fuel cost savings. Probably to state it more clearly, the large units would still be running, but they would be running -- when they have to meet spinning reserve requirements, they would run at less than their maximum output such that they could be ready to increase output should the need for operating reserves be called upon.

With the new aero-derivative turbines, they can actually meet that criteria even off-line. The fact that they can start and come to full load in less than 15 minutes, actually less than ten minutes, the reserve requirement is 15, allows us to satisfy that criteria. With that in place, we can operate the larger units at a higher net output, which is also a more efficient operating place for them to run. That will save fuel costs and reduce fuel expense for our customers.

Q Let me turn to dredging costs.

Mr. Hornick, wasn't it correct that you were asked to produce in OPC's Production of Documents Request Number 100 a bid that the company received for dredging costs in 2009?

A I believe that was the request, yes.

Q And in response to the Request for Production of Documents, the company stated that it provided all documentation regarding bids that the company received for dredging for costs for 2009. Is that correct?

A Yes. I believe there were some 300 pages of invoices that were provided under that production of documents.

Q On Page 4 of your direct testimony, Line 20 -- excuse me, I think that's rebuttal testimony. You stated that also the estimate from the dredging contractor to perform the work has increased significantly since 2002. Wouldn't it be correct that in response to the Production of Document Request Number 100 you did not provide any bid documentation regarding dredging contractors for 2009?

A Yes, that is correct. The wording of the request was such that it asked for a -- I'm trying to remember the exact wording -- a bid for the 2009 dredging. The document that we used as a basis of our estimate was a cost proposal that was provided in December of 2006, if I remember correctly, and I believe we provided that as a late-filed exhibit subsequent to my deposition.

Q So it would be correct to say that the company does not have any competitive bids showing the costs for dredging for 2009?

A That's correct. We do not have bids that have been solicited and received in 2009 for that work.

Q Okay. And it would be also correct to say that the company has not actually solicited for competitive bids for the 2009 dredging costs.

A That is correct. At this point in the project we have not solicited bids. We have been working the engineering, have been going out for permits, so we haven't gotten to that stage in the process yet.

Q So you would agree, Mr. Hornick, that the Company's amount of 6.9 million for the dredging costs in 2009 was calculated by either yourself or somebody under your direction at Tampa Electric?

A Yes.

Q And would it also be correct that the basis of the 5.5 million for the shipping channel dredging costs which you show on Page 4, Line 4 of your rebuttal testimony, is a calculation that you or either someone else under your supervision made?

A Yes, that is true. It is a calculation that we made. It was based on information that we had. However, it was based on the cost per yard of dredging that was obtained in late 2006. Also part of that calculation is the amount of material that must be removed to dredge the channel to the required depth, and we had performed or had performed for us hydrographic surveys that estimated the amount of cubic yards of material that would need to be removed. So those two elements went into the $5.5 million cost estimate. In addition to that, there was an allowance made for disposal of spoil material that made up an additional part of that $5.5 million.

Q Okay. Referring to the one million dollar for inlet channel dredging costs which you state on Line 4 and 5 of Page

4 of your rebuttal testimony, that is also a calculation you made, correct?

A Yes. Again, that's a calculation that we made. It was based on the cost estimate, the cost proposal that we got for the charge to remove a certain number of cubic yards, and it was also based on a hydrographic survey that estimated the number of yards present to be removed.

Q And, likewise, the $200,000 number for terminal docking area dredging, and the 200,000 for required aids to navigational maintenance is based on Tampa Electric's own calculated estimate rather than a competitive bid, correct?

A Yes, that is correct. The $200,000 for the terminal dock dredging area, once again, was based on that cost per yard and the estimate of the number of yards present. The $200,000 for maintenance for required navigation was based on our internal folks, their assessment of the needs to repair the facilities. That estimate was developed by those folks.

Q Mr. Hornick, you indicated that the disposal area at the Big Bend plant is 80 percent full, is that correct?

A Yes. We actually have two disposal areas that were created when the station was built for the purpose of disposing of spoils from channel dredging. Those two areas over time have become more and more used up, and at this point they are about 80 percent full to their capacity.

Q And would it be correct that the company did not have an outside study conducted to determine that the Big Bend disposal area is 80 percent full?

A I'm not sure that's totally correct. In terms of a study, I don't believe we commissioned a study to ascertain that, but we did provide and contract for, I believe, it was aerial survey techniques that would allow us to accurately assess the volume, the original volume and the used volume in those areas. So we did have assistance from outside companies in that calculation.

Q But, essentially, the determination was made by the company that the disposal area was 80 percent full, is that correct?

A Based on the -- yes, that's correct, but it was based on the aerial survey and assessment of the actual amount of material in those disposal areas.

Q Now, isn't it correct that the 2002 dredging costs included the cost of an engineering firm that evaluated the spoils area and the existing dyke and outlet structure evaluation at Big Bend station?

A I'm not familiar with that specific charge. It doesn't sound unreasonable, but I don't have direct knowledge of it.

Q Okay. Has the company used the Big Bend disposal area for dredging purposes since 1970?

A Yes, we have.

Q And would it be correct that the company has utilized the Big Bend disposal area for approximately 32 years?

A Yes. I'm trying to remember the dates. Big Bend Unit 1 went into service in 1970. I can't recall the first time that the channel was dredged at that point. But, yes, we have used those disposal areas for spoil disposal since the station was built.

Q Okay. If the company dredges the channel every five years, that would mean the company has disposed of material in that area approximately 6.5 times. Would that be correct?

A Roughly. That sounds right subject to check. I don't have the total history in front of me, but, yes, our practice and experience has been about every five years those channels need to be dredged.

Q Okay. And just some back-of-the-envelope calculation, if the landfill is 80 percent full and it has been used approximately 6.5 times in the last 32 years, wouldn't it be correct that each dredging disposal filled the landfill approximately 12.5 percent?

A The mathematics of that appear to be correct. However, we have on one of the disposal areas periodically removed some of the spoils from there. So it's a little more complicated calculation than you suggest, because there has been material removed over time, a fairly small portion.

Q Okay. Well, based on the 80 percent remainder usage, if the landfill still has 20 percent capacity for disposal of sediment, why would it be necessary to incur additional costs for disposal of silt and sediment if there is still adequate capacity remaining?

A It has to do with the way hydraulic dredging is performed. You contract with a company that goes out in the channel, they use a large pipe that syphons or suctions the spoiled material from the bottom. That is then pumped to a disposal area. That disposal area is going to receive not only the spoil material, but the water that goes along with that process, and you have got to have adequate storage in the disposal area not only for the solid material, but for the water and a sufficient resonance time to allow that spoiled material to settle out. The clean water then transits across the spoil over a weir and is recirculated back to the bay.

So, the calculation -- typically what we assume is to perform dredging, and to use a disposal area you actually need about three times the storage volume of the solid material to be able to effectively use that dredge area for hydraulic dredging, allowing for that water and the settling time.

Q Have you provided a calculation of the estimated sediment for 2009?

A I'm trying to recall if we have provided it in the hearing. Certainly we have an estimate. It is a little over 300,000 cubic yards. I'm not sure if that has been requested as part of the discovery in this proceeding. I don't believe it has. I don't think it was requested.

Q Is that 300,000 cubic feet for the total dredge or just for a portion of it?

A No, that would be the total spoil volume for the entire dredge activity. The number I have in front of me here is 304,000 cubic yards. That would include the shipping channel, the turning basin, and the dock areas.

Q And some of those areas are shared with IMC?

A It is actually shared -- the company is Mosaic currently.

Q Mosaic, excuse me. The last time the company had the channel dredged was in the year 2002, correct?

A Yes, that's correct.

Q And in your direct testimony you state that dredging occurs every five years, therefore, based on your testimony, your original testimony, the next dredging cycle would have been 2007, correct?

A Yes. As my testimony indicated, our typical expectation is that approximately every five years that channel needs to be dredged. We do evaluate that as the time nears. In the case in 2007, as we evaluated the hydrographic surveys which told us what the bottom looked like, and also spoke and got input from the transportation provider as to how the vessels were able to transit through the system, we made the decision that that was a deferable project. So it's a five year rough number. But each time that activity comes up we do make an evaluation as to is it prudent to do it now or can it be deferred.

Q So 2007 was the last formal hydrographic --

CHAIRMAN CARTER: Ms. Christensen, would you yield for a moment, please?

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chair.

Just a quick question on that. And I know nothing about dredging, so I appreciate the education on this issue. But I was just wondering in light of the storms that Florida has incurred in terms of the hurricanes, and storm surge, and related issues like that, does that impact the need to dredge sooner rather than later, or if you could just elaborate on that, I would appreciate it.

THE WITNESS: Yes, Commissioner, it does absolutely. The storm activity, the wave action particularly deep below the surface, these channels are roughly 34 feet deep, and the areas surrounding them are quite a bit shallower, so heavy wave action, a series of storms will definitely impact the frequency of the necessity to dredge more or less frequently, as will the barge traffic actually.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Thank you. If the landfill that you have used is filled, where will the spoil go now? And let me ask you to take a step back. Are you permitted by DEP to do the dredging?

THE WITNESS: The entity that provides the permitting -- I'm not sure. I think the DEP is involved, but I believe there is another entity that is required to get a permit from.

COMMISSIONER ARGENZIANO: Probably the water management district or EPA?

THE WITNESS: The Army Corps of Engineers is involved, the Tampa Port Authority is involved, there's other entities involved.

COMMISSIONER ARGENZIANO: So the permits then, are they for simple soils or are they considered hazardous?

THE WITNESS: The permits are actually for the dredging activity.

COMMISSIONER ARGENZIANO: I know. And when you remove soil you have to deposit it in a certain area, and I'm trying to figure out where your deposits have to go. If they are considered simple soil it is an area that is probably not as costly. If it is considered a hazardous -- not hazardous meaning sometimes there is oil or whatever that is determined by the regulating entity it costs more to -- I'm trying to figure what your costs are. How your soil or your spoils are being, I guess, specified as and where they will be placed.

THE WITNESS: Yes, Commissioner. The spoiled material is a mixture of sand, silt, and clays that are naturally occurring on the bay bottom. They are not classified as a hazardous waste, but they also are not suitable for many purposes such as fill where you might have a residential area that you may need to be filled. Because of the clay content, it is really not suitable for that.

Similarly, for landfills, the ability to use as a daily (phonetic) cover is also limited because of the clay content of those materials. So it limits the locations which can be disposed of, but it is not classified as a hazardous waste and it would be much for expensive if that was the case.

COMMISSIONER ARGENZIANO: Right. But do you know where the spoils would have to be taken to, the spoil would have to be taken to?

THE WITNESS: We have looked into that. I think we have bids or indications of pricing from three landfills. One of them I'm familiar with is in Okeechobee. I believe it is a Class 1 landfill.

COMMISSIONER ARGENZIANO: Okay. Thank you.

CHAIRMAN CARTER: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you.

I think Ms. Christensen asked you about this point, but in your direct testimony you state that the five CTs will offer a more economic option for meeting the reserve requirements, improving efficiency, and reducing heat rate. And in the position statement TECO states that the units will not be revenue producing or growth related, and the position of the intervenors is exactly the opposite. Could you speak to that point?

THE WITNESS: Yes. The primary reason that the CTs are being installed is for reliability for reserve margin purposes. When we looked at the need on our system in 2007, late 2007 when this decision was made, there was a clear need for all five units to sequence in and allow the 20 percent reserve margin that's a Commission specified number. So that is their primary purpose.

I believe our estimate of operation for those units in the early years is something around 300 hours per year, so they will be used -- which is about 4 percent of the time. They will be used, you know, for peaking purposes. And the amount of total energy that they will provide to our system is between 2/10ths and 4/10ths of one percent of the total energy. So the amount of energy they will serve is relatively small. Their primary function is peak demand to make sure there is reliability on the system.

That being said, you also asked about the other operating benefits. That's where we can derive fuel savings by operating our entire fleet more efficiently because of the nature of these machines being quick start and multiple starts per day. They fill in the gaps in our operating portfolio very nicely.

COMMISSIONER EDGAR: Thank you.

CHAIRMAN CARTER: Ms. Christensen, you may proceed.

MS. CHRISTENSEN: Okay.

BY MS. CHRISTENSEN:

Q Let me just follow up on Commissioner Edgar's question. My recollection from your deposition is that if all five CTs were brought on-line that would bring an additional about 170 megawatts of power available for customer use.

A Yes, that's correct. As we discussed in my deposition, each one of these machines has a nominal capacity of 60 megawatts, so the total there is 300 megawatts. But there are three combustion turbines at the Big Bend station that are old and have reached the end of their useful life and are being decommissioned, so the net capacity addition considering the new CTs and the retired CTs is approximately 170 megawatts.

Q Okay. And you would agree with Mr. Black's earlier testimony that you all are reevaluating whether or not all five CTs will be brought on in 2009, is that correct?

A Yes, I heard Mr. Black state that.

Q And is that also your testimony here today?

A I'm not familiar with the discussions about deferral.

In my position as Director of Engineering and Construction, we are moving forward with all five CTs. I believe Mr. Black said that there was consideration of deferral in the broad context of our business, but I'm not aware of any specific discussion or direction to change our position in moving forward with those five CTs.

Q Okay. But if a determination were made to defer some of the CTs, that would be a direction that your department would follow?

A Yes, it would.

Q Okay. Now, let me redirect you back to the dredging issues. In 2007, was that the last formal hydrographic survey the company had performed?

A No, I don't believe it was. I believe we have had subsequent hydrographic surveys. I don't remember the date specifically. I believe it was in 2008.

Q Okay. Now, related to --

CHAIRMAN CARTER: Ms. Christensen, are you about to go to another area? Because we are within two minutes. If you are about to go to a new line, this would be a good breaking point.

MS. CHRISTENSEN: I have a few more questions along this line, but it shouldn't be that much longer, and then I will be going to a new subject area.

CHAIRMAN CARTER: Well, I am kind of being a stickler for time because I want us to make sure that we get everything done that we need to do. And we are like one minute away from the break that I offered you guys for lunch from 1:15 to 2:30.

MS. CHRISTENSEN: Well, I can tell you I won't be done in one minute.

CHAIRMAN CARTER: Okay, good. Since you won't be done in one minute, we will do this. We will be on lunch and we will reconvene at 2:30.

We're on recess.

(Lunch recess.)

(Transcript continues in sequence with Volume 7.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

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

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

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

DATED THIS 28th day of January, 2009.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732