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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140025-EI

APPLICATION FOR RATE
INCREASE BY FLORIDA
PUBLIC UTILITIES COMPANY.
_________________________/

VOLUME 1
Pages 1 through 227

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: COMMISSIONER LISA POLAK EDGAR
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

TIME: Commenced at 1:03 p.m.
Concluded at 1:45 p.m.

DATE: Monday, September 15, 2014

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

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

APPEARANCES:

BETH KEATING, LILA A. JABER, and CHARLES A. GUYTON, ESQUIRES, Gunster Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1839, appearing on behalf of Florida Public Utilities Company.

J. R. KELLY, PUBLIC COUNSEL, and PATRICIA CHRISTENSEN, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32393-1400, appearing on behalf of the Citizens of the State of Florida.

SUZANNE BROWNLESS and MARTHA BARRERA, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1 - 72	(As identified on Comprehensive Exhibit List)	37	37

P R O C E E D I N G S

COMMISSIONER EDGAR: Okay. Good afternoon. I call this hearing to order. And I'd like to ask our staff to read the notice.

MS. BROWNLESS: Thank you. This is Docket Number 140025-EI, the application for a rate increase by Florida Public Utilities Company. The purpose of this hearing is to permit the parties to present testimony and exhibits relative to the application for Florida Public Utilities Company for approval of a rate increase and for such other purposes as the Commission may deem appropriate.

COMMISSIONER EDGAR: Thank you. And let's take appearances.

MS. KEATING: Good afternoon, Madam Chairman, Commissioners. I'm Beth Keating with the Gunster Law Firm here today on behalf of Florida Public Utilities. I'd also like to enter an appearance today for Lila Jaber and Charles Guyton.

COMMISSIONER EDGAR: Thank you.

MS. CHRISTENSEN: Good afternoon, Commissioners. Patty Christensen and along with J.R. Kelly, Public Counsel, on behalf of the citizens.

COMMISSIONER EDGAR: Thank you. And our staff.

MS. BROWNLESS: Yes, ma'am. I'm Suzanne Brownless, and with me is Martha Barrera on behalf of the staff of the Florida Public Service Commission.

COMMISSIONER EDGAR: Thank you.

MS. HELTON: And Mary Anne Helton, advisor to the Commission.

COMMISSIONER EDGAR: Thank you.

Okay. As I expect pretty much everybody here is aware, that we have held two customer service hearings in the territory as we prepared for this hearing date, and that as of, I believe, last week a proposed stipulation was submitted. So let me ask our staff to tee that up for us, please.

MS. BROWNLESS: Thank you. On August 29th, 2014, the parties filed a joint motion for approval of stipulation and settlement. Pursuant to Order Number PSC-14-0194-PCO-EI, a prehearing conference was held on September 4th. At that time the Prehearing Officer announced that the settlement agreement would be taken up today as the first order of business.

COMMISSIONER EDGAR: Thank you.

Ms. Keating, will you please give us an overview, and then, Ms. Christensen, I'll look to you.

MS. KEATING: Thank you, Madam Chair, Commissioners. At the outset, I'll note that I'm speaking on behalf of both parties to the stipulation and settlement, but again, as you noted, Ms. Christensen will have some additional remarks. And then if you'd like, I can walk through the specific points of the settlement.

Commissioners, we are very pleased to come before you today with this joint motion and settlement, and we're united in asking for your approval of this fair and reasonable resolution of this case.

As with any settlement, there's been give and take on both sides, and the result is a settlement that we both agree is fair to both sides and that we're committed to making work. The settlement fairly resolves critical issues in the case and avoids the additional time and expense of litigation. It also provides a means by which the company can address some of the concerns that were heard at the service hearings from customers.

In addition, it's important to note that a critical provision of the settlement, that the rates implementing the settlement will go into effect with the first billing cycle in November, about 45 days from now, which is a little longer than the Commission's standard policy of requiring at least 30 days between the Commission vote and implementation of new rates.

As the Commission has recognized time and again, public policy favors settlements over litigation. And to that end, OPC and FPUC have compromised on their respective positions and reached a resolution that's acceptable to both sides.

The settlement carries key benefits for FPUC's customers including rate stability for at least the next 25 months and the assurance that the company will continue its efforts to improve its system to increase reliability and safety of its service to customers. As such, we believe approval of this settlement is in the public interest.

Now we'd be remiss if we didn't express our appreciation to the Prehearing Officer as well as to staff for helping us to get to this point. Allowing us to maintain the status quo by staying discovery and deferral of a full prehearing conference allowed us to focus our efforts on coming to terms.

We also appreciate the further efforts that were made to lay the procedural groundwork that enabled us to bring the settlement to you today at the start of this hearing as well as the staff's efforts to work with the parties to make sure that you have sufficient information in the record to address this good document. All these efforts have been greatly appreciated and have facilitated moving the ball forward on the settlement without requiring the parties to continue to function in adversarial roles moving towards hearing.

Again, just speaking for FPUC specifically, we'd like to express our sincere appreciation to the OPC for working with us in the first instance to come to terms and then for working with us expeditiously to get those terms in paper -- on paper in a timely manner for your consideration. It wasn't a simple process, particularly given our litigation postures, but we think that's probably one of the best indicators that this settlement does truly strike a fair balance and, as such, we ask that it be approved. That's the end of my preliminary remarks and then if you want to come back.

COMMISSIONER EDGAR: Okay. Thank you, Ms. Keating.

Ms. Christensen.

MS. CHRISTENSEN: Good afternoon, Commissioners. Again on behalf of myself and Mr. Kelly, who is the Public Counsel, we want to say that this is a good settlement. Again, as my colleague said and I want to reiterate, there was give and take in the negotiation process. It resolves critical issues for rate base, cost of capital, net operating income, and resulting revenue requirement.

We believe that given that this was a negotiation and a negotiated process that the settlement as a whole is good and beneficial to the ratepayers of FPUC and that it is in the public interest and should be approved.

We would also like to reiterate FPUC's comments that we are very grateful for their participation in the settlement talks. They came to the table in good faith with great professionalism and worked with us, and we were able to, because of the productive time, come to what we believe is a very good result. And we also concur that this helps us avoid additional litigation cost, and we'd also like to thank the Prehearing Officer and staff for allowing us to kind of abate some of the proceedings once the stipulation and settlement had been filed and allowed us to kind of reduce some of those costs and to be able to concentrate on getting the information to the Commission staff for the Commissioners to be able to make your evaluation of the settlement.

And with that said, I would just reiterate and urge that the Commission approve the settlement. It is in the public interest. And I would turn it back over to my colleague Ms. Keating to go through an overview of the settlement terms.

COMMISSIONER EDGAR: Commissioners, would you like to have an overview? I know I've met with our staff and done it, I presume both of you have as well, and/or specific questions. This would be the time. Okay. Commissioner Balbis, do you have a preference?

COMMISSIONER BALBIS: Yes, Madam Chairman. I think for, just for the interest of the public I think just a quick overview of the terms of the settlement agreement would be helpful. I, of course, have read thoroughly and been briefed thoroughly on the agreement, but I think a quick overview, I think, would be helpful.

COMMISSIONER EDGAR: Okay. Ms. Keating.

MS. KEATING: Thank you, Madam Chair. Again, this is a balanced settlement. One of the key provisions is that it would go through December 2016, therefore assuring rate stability for at least that period of time.

But one of the things I wanted to point out is that it's structured very similarly to other settlements that you've addressed for other IOUs in recent years, so you'll hear some similarities, I think.

Specifically the key points of the settlement provide that FPUC will be entitled to increase its base rates, base rates and service charges to generate an additional $3,750,000 in annual revenues based on the projected test year September 2015 billing determinants. The rates designed to achieve this revenue increase are designed in accordance with the cost of service and rate design methodology set forth in the company's MFRs. The new rates would become effective with the first billing cycle of November 2014, and thereafter the rates and the agreement would again remain in effect through at least December 2016.

FPUC's authorized ROE would be within a range of 9.25 percent to 11.25 percent, with a midpoint of 10.25. FPUC's equity ratio and capital structure will be based on the actual capital structure recorded on its books and its pro rata share of its corporate parent, Chesapeake Utilities, capital structure for equity and debt. Customer deposits, investment tax credits, and deferred income taxes will be the balances recorded on FPUC's books.

FPUC is committed that it will not file for a base rate increase prior to December 2016 unless its ROE falls below the authorized range. Likewise, if the company's ROE exceeds the authorized range, OPC will have the right to seek a rate decrease for the company. FPUC will also use all reasonable and prudent efforts to continue implementing infrastructure projects consistent with those that are outlined in Attachment A to the agreement.

Now just to be clear, this is neither an exhaustive list nor a definitive list. Instead, the parties really intend this list to be demonstrative of the company's commitment to continue moving forward with facility upgrades and reliability improvements. The settlement also provides that the company will be allowed to implement its economic development rider, which will become effective along with the rates for the first billing cycle in November. The rider is very similar to other economic development riders that have been approved for other Florida IOUs, and it will enable the company to better facilitate economic development efforts in the communities that it serves.

The settlement also provides the company will continue to be allowed to seek recovery of costs through the regular cost recovery clauses, like the fuel clause and the conservation clause, as long as the costs that they're seeking aren't costs that were traditionally and historically recovered through the company's base rates. The company will also still be able to seek recovery of storm restoration costs arising from named storms. And, likewise, OPC will not be precluded from contesting the amount of those costs.

FPUC will also be allowed to amortize rate case expense over a five-year period, and it will also be allowed to establish a regulatory asset to address the income tax rate step-up that occurred when Chesapeake acquired the company. The amortization period for that tax asset will be 26 years, which represents the remaining life of the asset as of the date that Chesapeake actually acquired FPUC in 2009.

If the company incurs an item that would otherwise qualify as a regulatory asset or liability or if the company incurs or realizes any loss or gain on sale of property that's currently recovered through base rates, those amounts will be deferred until the next rate case. The parties have also agreed that the company can establish a general liability reserve that will be funded by FPUC at $25,000 a year until a cap of $250,000 is reached.

In addition, the settlement provides that the company will be entitled to establish another regulatory asset to address a one-time $250,000 general liability claim. Once established, that asset will be amortized at $50,000 a year over a five-year period. Upon expiration of the asset, that $50,000 amortization amount will be credited to the general liability reserve.

And finally, Commissioners, the company has agreed to suspend accrual to its storm reserve for two years. The amount of the accrual would then be used to accelerate tree trimming for both divisions as well as to fund a study on undergrounding for both divisions. This will facilitate the company being able to address some of the more specific concerns that we heard at the service hearings.

Commissioners, that concludes my overview of the settlement itself. And we just respectfully urge that you approve this balanced settlement in its entirety, resolving this case in a manner that best serves the public interest. Thank you.

MS. BARRERA: Thank you, Ms. Keating.

Commissioners, questions? Commissioner Brown.

COMMISSIONER BROWN: Thank you, Madam Chair. Well, I would, of course, like to commend the parties, as I said during the prehearing conference, for brining us a well-structured settlement agreement for our contemplation. I do believe that the settlement agreement does address citizens' concerns that we heard in Fernandina and Marianna. It helps the utility achieve the capital improvement measures that I believe is needed and is definitely in the public interest. As I said, I do believe it's well-structured, but I did have one clarification on an ambiguity that appears to be an ambiguity to me, so I just wanted to bring that to your attention. On page 10 of the settlement agreement, paragraph XIX(c) entitled New Rates, it says that, "The Parties agree that, after the Commission vote upon the Parties' Agreement, the remaining issues identified in Paragraph XVIII-Resolution of Issues, relating to Cost of Service and Rate Design should be decided by the Commission as expeditiously as possible in order to" -- blah, blah, blah.

The question is tariffs are attached to the settlement agreement as an exhibit which incorporate the cost of service, and it references the witnesses Mark Cutshaw and Buddy Shelley's prefiled testimony. So what other measures would be needed if we were to approve the settlement agreement today?

MS. KEATING: The settlement agreement addresses the key issues in the case, and we have supplied exhibits that reflect the rates that would comply with the settlement agreement. OPC has not taken a position on certain issues, but we think that with approval of the settlement you have the documents before you to resolve the case in its entirety today.

COMMISSIONER BROWN: And that's what I believed, that upon approval of the settlement agreement with the attachments and the tariffs, that would complete the case.

MS. KEATING: That is our understanding.

COMMISSIONER BROWN: Okay. Madam Chair, just a few questions, just general questions for clarification, for my own edification. But, like I said, I do believe -- I've spent some time looking at the settlement agreement and the prefiled testimony too and I've read the settlement agreement a few times. I think it's one of the best structured agreements I've seen during the past four years I've been in office.

That being said, I just want a couple of clarifications. Why the two-year abbreviated term? Is there a specific reason why there is a two-year term rather than four, per se?

MS. CHRISTENSEN: I believe the period was intended to be three years. Is that three years?

MS. KEATING: It's through the end --

COMMISSIONER BROWN: And please don't divulge confidential discussions. That's not --

MS. CHRISTENSEN: It's a three-year period and I think that was a part of the negotiation process. I don't think there's any particular magic number where it's, you know, versus three, versus four, versus something else. But I think for this company and this negotiation that is the term that worked best for all the parties involved.

COMMISSIONER BROWN: Well, with regard to the ROE and a two-year stay out, so to speak, either the utility or the Office of Public Counsel --

(Interruption.)

That was fun. Either the utility or the Office of Public Counsel can come in and seek a rate relief for an increase or a decrease below the authorized rate, ROE. Could you explain that two-year? I guess it's not a traditional stay out, or could you elaborate on that two-year period?

MS. CHRISTENSEN: It's our intention, and as I said before, I think it's actually three years when you go through the end of 2016 since we're implementing it in 2014, that was our intention. But it, you know, and I agree, yes, at least two full years.

Our intention is that during that time period that what would take place is that unless it either went below that threshold or above that range, they would stay out and they would not seek any rate increases during that time and we would not seek to bring them in for anything during that time, so long as we're operating within the terms of the agreement. And that's why there's other terms in here relating to storm damage and other kind of unusual events that might have caused them to come in early, but we've addressed those, I think, as individual terms of the conditions of the stipulation. So it's our intent to kind of allow this to function --

COMMISSIONER BROWN: As a stay out.

MS. CHRISTENSEN: -- as a stay out.

COMMISSIONER BROWN: Even though there's some safe harbor -- a lot of safe harbor provisions in my opinion.

Okay. My two favorite aspects of the settlement agreement, just for my fellow Commissioners, but I do have a question, are the benefit -- for the customers is the reliability and safety for the projects that were enumerated in Exhibit A, along with the acceleration of the company's tree trimming, and I like that studying of the underground facilities. So I commend the utility and the Office of Public Counsel for coming together with those. Those are great protections for the customers.

With regard to the projects listed though, my understanding is that the company will use all reasonable and prudent efforts to achieve those projects, but there's no mechanisms or measures in place to require the utility to complete those projects?

MS. KEATING: That's correct. This was intended to be a demonstrative exhibit only. But just so you know, those exhibits are in the company's capital budget right now. They are planned projects. But the idea is if another project comes up that is more critical, something breaks down, they have a severe storm on the east coast, that certainly those kinds of projects would take precedent over some of these.

COMMISSIONER BROWN: Excellent answer. Thank you. And then what does the company plan on doing with the results from the feasibility study on undergrounding the facilities?

MS. KEATING: Right now the approach for getting that information back to the customers is under discussion. It is likely that that will be delivered to the customer groups that specifically brought those issues up. The mechanism for precisely handling that has not yet been determined primarily because we're still in the early stages of determining how that study will be conducted and who will be conducting the study.

COMMISSIONER BROWN: That's great. That's what I wanted to hear.

Madam Chair, just two more questions.

COMMISSIONER EDGAR: Yes.

COMMISSIONER BROWN: The general liability reserve fund, can you elaborate the reason for the creation of this and why the company is at this point now seeking to self-insure? Is it because of that $250,000 general liability claim?

MS. KEATING: It's not solely because of that. I think the other divisions of the utility have similar reserves, and it just makes good, prudent business sense to establish a reserve for a utility of this size.

COMMISSIONER BROWN: Okay. Agreed. And with regard to replenishing that amount though, you have an annual $25,000 credit and then there's a measure in the agreement that provides that it will be replenished if it falls below the $250,000 during the term of the agreement. So does that mean that you -- it's in addition, that you can replenish it at any time if it falls below the 250? In addition to the $25,000 annual credit there can be additional credits towards it? I got a little confused by that provision, and it is section IX(iv).

MS. KEATING: Are you speaking in terms of the credit from the --

COMMISSIONER BROWN: It says, "In the event the cap is reached." So I would think the cap would be 250. "Should the reserve subsequently fall below the cap level, FPUC shall reinstitute the mandatory annual credit to the reserve in the full annual amount." Does that mean $25,000 additional?

MS. CHRISTENSEN: Our understanding from the Office of Public Counsel is that we set aside $25,000 a year annual credit to the reserve. And so long as it's not being used, it will continue to grow over the terms of the agreement for however long it lasts. I mean, we have -- essentially the stay out provision is a minimum term. But if they don't file, it continues or can continue on after that. So it would continue to grow.

What would happen is that would be the annual accrual until such time as it reached the cap level of $250,000, and they would no longer have to continue to accrue the amount to the general liability reserve.

However, if at any point they have a liability claim that they want to take against that reserve that would bring it below that $250,000 level, then they would reinstitute the annual accrual until it rebuilt to the 250.

COMMISSIONER BROWN: Okay.

MS. KEATING: To the amount.

COMMISSIONER BROWN: Okay. Got it. And finally -- thank you for that, Ms. Christensen. And then finally section -- the settlement talks about the rate case expense being amortized over five years, and traditionally we do four years. So that's nice. But I was wondering what that amount was, the final amount to date.

MS. KEATING: We don't have a final amount at this point because we're still in the rate case process, but at this point it would be approximately --

COMMISSIONER BROWN: At least how much that would be amortized over a five-year period, if you could ballpark.

MS. KEATING: About, ballpark, 975,000.

COMMISSIONER BROWN: Okay. Thank you very much.

COMMISSIONER EDGAR: Thank you. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Madam Chair.

I have a few questions for each of the parties, and I know, Ms. Keating, you're representing both, but I'd like to address both of you individually and just for a point of reference. I mean, how I started this process is once the settlement agreement was presented to me, I met with staff and the first thing I asked for, which we would have gone through in the hearing process, is looking at the last 12 months' earnings surveillance report just to see, you know, what the company is achieving. And that ranged everywhere from 3.98 percent to 7.21 percent, which is significantly lower than the allowed return. So that's one of the factors that indicate rate relief is necessary. So now we're at the point, well, how much is truly needed? And FPUC submitted testimony justifying, you know, a $5.8 million increase, and then OPC submitted testimony alternatively supporting just a $2 million increase. And the settlement agreement provides, you know, $2 million less than FPUC requested.

So my question for you, Ms. Keating, is how can -- because what we do is balance the needs of the utility versus those of consumers and all the parties. So how can we be assured that if by approving this settlement agreement that FPUC will have the revenues necessary to provide safe, reliable service?

MS. KEATING: We truly believe that the way this settlement is structured with the allowed revenue increase and the allowed ROE range that we can make the settlement work for the duration. There was a lot of give and take, as you can imagine, in the negotiation process. But ultimately we are comfortable with the settlement and believe that it can work through the end of December 2016.

COMMISSIONER BALBIS: Okay. Because even with the -- you know, there is a revenue reduction associated with the reduced ROE but there's also -- obviously the money has to come from somewhere. So you're comfortable that wherever those dollars come from it will not impact service?

MS. KEATING: We are, Commissioner.

COMMISSIONER BALBIS: Okay. And then for the Office of Public Counsel, Witness Ramas identified several areas that OPC was concerned with, you know, errors with some of their depreciation balances, CWIP provisions for the eCIS system, on down the line that I assume came up with a $2 million number. How did this settlement agreement alleviate those concerns?

MS. CHRISTENSEN: Commissioner, as with most settlements, we come with what we think is the best revenue requirement number that we can and address some specific terms. And we believe that through the testimony the company is aware of the issues that we have and concerns that we have with some of the corporate allocations, some of the projects that are still outstanding. And what we would intend to do is the next time they come in for a rate case is to use the testimony that we filed in this case, look at the settlement, and see what they're proposing in the next rate case, and see if they've addressed those issues to our satisfaction in the next rate case. They certainly are aware of where we have concerns. And some of those have yet to be realized, and so we'll have to wait to see how those play out in the future since we're talking projections. When we have actuals we'll take a look at where we, what our testimony was in this particular case and we'll look at it in the next case and see if some of those issues still carry forward.

However, we think, given the terms of the settlement and given the amount that we've agreed to in this case, we think that the company certainly has plenty of resources to do this in the most cost-effective and efficient manner that will benefit the ratepayers and provide them with the best service and to give them some economies of scale since Chesapeake has taken over. So we do believe that the company will continue to work in its efforts to improve its service to the customers.

COMMISSIONER BALBIS: And, again, with all settlement agreements, if the Commission approves it, we will not take a position on those individual issues and those still would be live for any subsequent rate proceeding. Is that your understanding?

MS. CHRISTENSEN: My -- yes. I mean, we would -- we're taking this as a whole and as a whole revenue requirement. And as I said, those would still be issues we'd be looking at at the next case. I'm not sure what issues would still remain. They may resolve themselves between now and then. We hope they would be. But they certainly wouldn't have a definitive answer one way or the other. So if there were still issues that we thought were -- needed to be raised in the next rate case, we would certainly file testimony and raise those for the Commission's consideration in the next rate case. But we believe they have been adequately resolved for this rate case.

COMMISSIONER BALBIS: Okay. Thank you. And then, Ms. Keating, back to what the required revenues or projected needs would be, we've recently had an electric rate case in the northwest area where they were incorrect in their projections of revenues and it required them to come back in.

So, you know, I've scrutinized what the company has projected for growth and other revenue needs, and then I also looked back in your MFR schedules where even as recently as 2013 the difference between your budgeted and your actual amounts in a lot of those items were significantly different. How can we be assured that what the company projects and what the settlement agreement will provide them is going to be adequate?

MS. KEATING: Thank you, Commissioner. I think one thing that should give you comfort is that this company is a new company. It is under the direction now of Chesapeake Utilities, which is a larger corporation. I think you're going, you're going to see a company that can function within this budget, that is going to continue to move forward with all the projects that it needs to implement to make sure that it improves service and reliability, and I think that you've got a company that's going to be able to stick to this settlement agreement for the duration and that is going to be able to work within essentially the budget for this time frame.

COMMISSIONER BALBIS: Okay. Thank you.

And, Madam Chair, I have some questions when it comes to the rate design issue. And I don't know if now is the appropriate time or is there going to be a separate discussion on that? I'm not quite sure. But I think if we approve or vote on the settlement, it addresses rates as well.

COMMISSIONER EDGAR: Yes, we will address rates. And if you have questions, you might as well go right ahead and jump right in.

COMMISSIONER BALBIS: Okay. Thank you. The follow-up on Commissioner Brown's comments on the two different service hearings or customer meetings that we had, there were fairly distinct discussions or comments. And in the northwest division there was, you know, several comments concerning reliability, which I think the company adequately addresses in these proposed projects, but there was also a lot of comments on overall cost of service and affordability, which brings us to the rate design. And I noticed that the base rates were consolidated but the fuel charges were not. And it's my understanding that the fuel charges for the northwest division include transmission components from Gulf Power. So the northwest division is paying for all of that, and then in the northeast division the transmission components are in base rates which are being consolidated throughout. How is the company going to deal with that discrepancy?

MS. KEATING: Well, in last year's fuel clause the company -- the Commission allowed the company to allocate a portion of those transmission costs from the northwest division to the northeast division as a temporary fix to try to address that inequity. This year in the fuel clause the company is asking that the fuel rates be consolidated as a more permanent fix to that inequity.

COMMISSIONER BALBIS: Okay. That's my concern, that the northwest division may be bearing an unfair burden of those costs from the northeast. So I know we can't really talk about that now, but at least we have some vehicle to address that in the future. And that resolves the only questions that I had as far as the rate design issue, Madam Chair.

COMMISSIONER EDGAR: Questions on any other issues at this time?

COMMISSIONER BALBIS: No.

COMMISSIONER EDGAR: Okay. I have two brief questions. The first is, is it accurate that the interim rates that are in place due to this rate case will remain into effect until the first billing cycle in November and that no refunds are appropriate under the terms of the settlement and stipulation if it is approved?

MS. KEATING: That's correct.

COMMISSIONER EDGAR: Okay. And, Ms. Keating, you touched on this in your overview, but I would like, if you can or someone with the company, to give us a little more information on the undergrounding feasibility study or studies that are addressed in the agreement. As has, as you pointed out, has been noted by my colleagues, we heard at the service hearings both a great love for trees and also some concerns about short-term outages due to vegetation and accompanying wildlife. Recognizing that the two service territories are somewhat different -- one being obviously Marianna, much more rural, and in Fernandina, much more compact and higher density -- how are you going to address this feasibility study issue and then what happens after that?

MS. KEATING: Well, Madam Chairman, we definitely heard all those concerns loud and clear. If I may, if it's appropriate, I'd like to introduce the President of the company, Jeff Householder, and he can tell you a little bit more about how they plan to approach the feasibility study.

COMMISSIONER EDGAR: Yes. Thank you.

MR. HOUSEHOLDER: Commissioners, it's relatively straightforward, at least our plan at this point. As Ms. Keating described, we're still in a process to try to figure out exactly what we're going to do.

Our intent is to re-form at some level the citizens group that the City of Fernandina Beach formed a couple of years ago to look at this issue. I don't know that we'll be officially part of the city's review mechanism, but it at least will get some of the same folks that showed up at the service hearing.

It's interesting because in our northwest division we have similar underground issues, especially in the City of Marianna and around Chipola College. So this is not an issue that's singularly of concern to folks in Fernandina Beach and not in Marianna. And so we intend to take our own internal engineering resources and do an initial evaluation of areas that we think are most likely to benefit from underground utility service, both on the transmission and the distribution side.

We will then retain a third-party consultant. It's our intention to use community input from both of our divisions as we identify that consultant so that they're on board with the individuals that we retain. We would ask that consulting group to take a look at the work that we've done internally to lend some validation and credibility to it obviously and to price it. And so we would understand both from a cost perspective and from a technical perspective what it would actually take to do some of the underground work that the citizens groups are asking us to do. I think we have a pretty good understanding on our side of the cost. We've looked at this a number of times in the past. It's not cheap, as you well know, and certainly we would be cognizant of the utilities undergrounding rule as we move forward in any aspect of this study.

So our intention then would be to bring the citizens groups together both in the northwest and northeast division. Certainly you have full transparency as they look at the reports that we develop internally and the reports that we would have from the third party, and then we'll see where that goes. We have a number of different ideas on how we might fund some of this work in the future, you know, as -- again, as you well know, this is not an inexpensive thing to proceed with.

COMMISSIONER EDGAR: Thank you. I, as I believe my colleagues have said, appreciate the initiative of the company and of course with the cooperation and coordination with OPC to continue to look at those issues. We certainly did hear, as did all of you, great interest. I also recognize, as you have, that there are many issues involved, not the least of, not all of, but engineering technology, aesthetic, and, of course, financial. And, as always, what we would be looking for as that process moves forward is that consumers are getting good value from the steps that are taken.

MR. HOUSEHOLDER: One final point that we continue to try to remind our customers about is that we're not the only folks with wires hanging on those poles. And so this is -- it's a multifaceted issue when you start talking about undergrounding electric service for the intention of aesthetic removal of the poles and wires.

COMMISSIONER EDGAR: And we generally recognize the value of co-location but also recognize that it does bring in other issues as well.

Commissioners, any other questions regarding the proposed stipulation and settlement? Okay. Then I believe the issue that is before us at this time is whether to approve the proposed stipulation and settlement. If a majority of us vote in favor to do that, then we will have some additional procedural steps probably to take today. If we do not want to approve the stipulation and settlement, then that would put us in the posture of continuing the hearing with steps to get us there tomorrow. So that's where we are.

Commissioner Brown.

COMMISSIONER BROWN: Madam Chair, I am prepared to make a motion.

COMMISSIONER EDGAR: You're recognized.

COMMISSIONER BROWN: All right. As I stated earlier, I think that this settlement agreement achieves a fair balance of competing interests that truly favor the public interest and I'm very supportive of it. With that, I would move that the joint motion of Florida

Public Utilities Company and OPC for approval of the stipulation and settlement agreement be granted and the settlement agreement filed on August 29th, 2014, be approved. And I further move that the tariffs reflecting the revenue requirements agreed to in the settlement agreement also be approved. And I know that we also have to enter into evidence after this motion several items, including the MFRs.

COMMISSIONER EDGAR: Yes. Thank you.

Commissioner Balbis.

COMMISSIONER BALBIS: Madam Chair, thank you. I would second that and would also like to make a few comments indicating why I support this settlement agreement.

As I indicated before, their earnings reports indicate that some rate relief is necessary. And with the Office of Public Counsel thoroughly reviewing all of the issues and providing justification for the increased revenue amount, I'm supportive.

But the other thing I look at is I listen to the concerns of the ratepayers. And from a reliability standpoint they've seen a significant improvement since the acquisition of Florida Public Utilities. And in going through the testimony they've seen, you know, 27 percent improvement in their L-Bar, in their SAIDI, in their CAIDI and their SAIFI, significant, over 10 percent on each one of those, some of them as high as 20 percent. So those are real quantifiable numbers, those are quantifiable improvements that customers realize from a reliability standpoint. And they have the provision of potentially undergrounding, which was the other issue we heard about.

And we also heard a question about is this another rate increase? And, Madam Chair, I believe you explained correctly that the Commission approved an interim rate increase in August, and this settlement agreement is a reduction from that amount. So I think that that is something that shows that -- how we thoroughly investigate these issues, and I'm fully supportive of it. I think it's in the best interest of all the parties, the utility and the customers.

COMMISSIONER EDGAR: Thank you, Commissioner Balbis.

Then at this point, all in favor of the motion, say aye.

(Vote taken.)

It is unanimous. Then with that, I will go ahead and cancel the prehearing conference that had been scheduled for tomorrow, September 16th, and obviously the following hearing dates that had been reserved.

And at this point then we need to take up the Comprehensive Exhibit List, which is marked as Exhibit 1. We will enter that into the record at this time. And then the following exhibits, which I believe are 2 through 72, are there any questions or concerns about that? No? No? Okay. Then Exhibits 2 through 72 are entered into the record at this time.

(Exhibits 1 through 72 marked for identification and admitted into evidence.)

To our staff, any other matters?

MS. BROWNLESS: Only one other matter, Commissioner, which is we would move the prefiled testimony into the record as though read.

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

Q. Please state your name, affiliation, and business address.

A. My name is Jeffry M. Householder. I am the President of Florida Public Utilities Company ("FPU" or "the Company"). My business address is 911 South 8th Street, Fernandina Beach, Florida 32034.

Q. Please summarize your professional experience and academic background.

A. I joined FPU in June 2010 in my current position. For ten years prior to joining FPU, I provided energy, regulatory affairs, and business development consulting services to natural gas utilities, natural gas marketing companies, propane gas retailers, government agencies, and industrial and commercial clients. In that capacity, I participated in numerous regulatory filings before the Florida Public Service Commission (Commission), including several rate proceedings. Prior to beginning my consulting business, I spent sixteen years in the gas and electric industry in the following positions: Vice President of Marketing and Sales for TECO Peoples Gas; Vice President of Regulatory Affairs and Gas Management for West Florida Natural Gas Company; Vice President of Marketing and Sales at City Gas Company; and Utility Administrative Officer for the City of Tallahassee Utilities. Early in my career, I was a Section Manager with the Florida Department of Community Affairs, responsible for administering the Florida Energy Code and related construction industry regulatory standards. I was also employed as an Energy Analyst in the Florida Governor's Energy Office. I received a Bachelor of Science Degree from Florida State University in 1978 with an interdisciplinary major in

Social Science (principally Economics and Business), and additional majors in Government and International Relations.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes. Over the years, I have filed testimony in numerous cases. For example, I filed testimony most recently in Chesapeake Utilities' 2009 rate case proceeding (Docket No. 090125-GU). I also filed testimony on Chesapeake's behalf in the company's 2000 rate case (Docket No. 000108-GU). In 2007, I filed testimony on behalf of both Sebring Gas System and St. Joe Natural Gas Company in the Conservation Cost Recovery Clause proceedings (Docket No. 070004-GU). I also submitted testimony on behalf of Sebring Gas System in its 2004 rate case (Docket No. 040270-GU) and on behalf of St. Joe Natural Gas Company in its 2000 rate case (Docket No. 001447-GU). I have participated in quite a few other cases before the Commission either through the filing of testimony or development of programs, tariffs, or cost studies submitted for Commission review.

Q. Are you sponsoring any Exhibits to your Testimony?

A. Yes. I am sponsoring one exhibit, JMH-1, which is a year-by-year comparison of a residential bill for a residential typical 1,000 kWh customer on each of FPU's electric division systems since FPU's last rate case.

Q. Are you familiar with the operations and management of FPU's electric distribution utility?

A. Yes. As President of the Company, I am responsible for the overall management and direction of the electric utility and take an active role in strategic planning and resource allocation. I am also engaged in project development and regulatory issues on a regular basis.

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

A. My primary purpose is to provide an overview of current FPU operations, describe the current state of our company, address the impact that the acquisition by Chesapeake Utilities Corporation has had on FPU and introduce the witnesses in this case. I will also highlight some unique aspects of our case, as well the critical factors that have necessitated our filing. We have delayed filing for a rate increase as long as possible, but have reached the point where further delay is not in the best interests of the Company's customers or its shareholders. We take seriously our obligations to provide reliable and responsive service to our customers and the rates we seek support the continuation of that service obligation. I will outline our efforts to control costs while at the same time implementing several initiatives to significantly improve system reliability and the services we offer our customers.

Q. Please provide an overview of the Company.

A. This year, Florida Public Utilities Company will celebrate its 90th year of operations. In late 2009, FPUC merged with Chesapeake Utilities Corporation (Chesapeake), headquartered in Dover, Delaware. Chesapeake has operated in Florida since the late 1980's, when it acquired Central Florida Gas Company and Plant City Gas. At present, Chesapeake's principal Florida operations include regulated electric and natural gas distribution utilities, an intrastate gas transmission company, a natural gas marketing company and a propane distribution company. FPU is organized as a wholly owned subsidiary of Chesapeake.

FPU provides electric distribution service in two discrete Florida geographic areas – several small communities and rural areas in Jackson, Calhoun and Liberty counties (FPU's Northwest Division); and on Amelia Island (FPU's Northeast Division). The service areas present distinct service and growth challenges. While growth has been limited throughout both service areas, the counties in our Northwest Division have experienced an especially difficult time during the recent economic downturn. According to US Census data, Jackson and Liberty county populations have declined over the past several years, while Calhoun saw a minimal .04% increase. The City of Fernandina Beach on Amelia Island grew 1.9% since 2010. Construction activity has been at a virtual standstill in both Divisions although there are some signs of limited improvement on Amelia Island, where the first new residential subdivision (40 homes) in several years is breaking ground. FPU has experienced a declining usage trend over the past several years, not unlike many electric utilities in the U.S., as consumers conserve during tight economic times. Both FPU Divisions are subject to storm damage and outages. The Northeast Division operations also are susceptible to higher than typical levels of corrosion damage given the coastal location and a greater percentage of underground service. FPU's electric operation is also unique among Florida regulated electric utilities in that it does not own generation assets and, therefore, relies entirely upon wholesale power purchases to serve its 31,087 customers.

Q. How has the merger with Chesapeake impacted FPU?

A. The merger has resulted in several substantive benefits for customers, employees and the communities we serve. FPU's inclusion into a larger corporate structure provides greater access to lower cost capital. As other witnesses will detail, this capital has been carefully deployed to replace and upgrade old and failing electric infrastructure and equipment, increase storm hardening investments and generally return the Company's distribution infrastructure to a reliable operating condition. In addition, a more sophisticated management approach to the business is evidenced through the formal and disciplined planning, budgeting, project review and performance measurement processes introduced by Chesapeake. Significantly expanded resources are also now available to FPU in the areas of system planning and development, IT, HR, Treasury and risk management, communications and accounting.

Q. Can you provide examples of Chesapeake's resources and management influence benefiting customers, employees and communities?

A. Yes. Let me start with the employees. While our customers are central to every action we take, in Chesapeake's view the best way to take care of customers is to make sure employees are treated fairly and are fully engaged in the business. There is overwhelming evidence in numerous management and business studies that satisfied employees are directly correlated to satisfied customers. Over the four years of Chesapeake's management, a number of employee related actions have been taken. We first addressed the basics – conducting market based competitive pay reviews, bringing benefit packages up to industry standards and improving physical work conditions through equipment replacement and facility upgrades. In the Northeast Division, for example, we were operating out of a 100-year-old warehouse without operable indoor plumbing. Earlier this year we moved our employees into a modern office warehouse facility – with bathrooms. We also instituted a company-wide performance based pay system. The system sets performance standards for each employee along with Florida and corporate based annual financial, safety and customer satisfaction standards. Each employee's annual merit pay increase opportunity is directly tied to individual performance. In addition, a portion of each employee's target compensation (including our union employees represented by a collective bargaining unit) is based on achievement of the annual financial, safety and customer satisfaction performance targets. Finally, our employees are heavily engaged in the planning and review processes that fundamentally run our business. We communicate expansively at all levels in the Company to ensure that all employees understand our goals and performance standards.

Q. How have the employee initiatives benefitted customers and communities?

A. One of the fundamental elements of Chesapeake's business philosophy is that it lives by a set of key values. Striving to conduct business in an "Honorable" manner, making a "Personal Connection" with customers and communities and "Relentlessly" working to find new and better solutions to support customer needs are among these values. Building on the Values, a Service Excellence process is in place to continuously review and improve service to customers. Service Excellence teams map our processes, critically review our systems, and evaluate our contact methods through the "lens of the customer". Through this effort, we have instituted four primary Service Standards to guide our customer contact processes by which we measure success.

The most important of these Service Standards is "Safety". We want each of our employees to go home every night to their families in the same condition as they started the day. Equally important to us is the safety of our customers. We believe that our investments in system reliability, storm hardening, increased training programs and upgraded equipment discussed by witnesses Shelley and Cutshaw play a major role in keeping our customers and community's safe.

Our next Service Standard is "WOW". We want to give our customers the opportunity to be impressed by our efforts every time they come in contact with FPU employees. Through a series of employee training and empowerment actions, process improvements, technology upgrades and performance measurement activities we have vastly increased customer satisfaction. One measure is the number of Commission received customer complaints. In 2008, there were 37 complaints received by the Commission; in 2013 there were 4. In addition, we actively survey customers to assess our performance. Among other measurement metrics, we calculate a monthly and annual Net Promoter Score – essentially quantifying how many customers would recommend FPU to friends or neighbors. Our scores have steadily improved over the past two years to a very solid overall level. We continue to seek opportunities to keep improving. Another important example of this Service Standard is our willingness to play an active role in supporting the communities we serve. FPU employees are involved in numerous local service and civic organizations, charitable events, local sports sponsorships, business groups and trade associations.

Our third Service Standard is "Presentation". We adopted this standard after studying the Disney Company service standards. It applies not only to keeping our workplaces, vehicles and uniforms presentable (and safe), but also to presenting customers, vendors and service partners with straight-forward and useful methods to contact us and transact business. To this end, we have redesigned web sites, expanded payment options, extended Contact Center hours, modified CSR authority levels to support one call issue resolution, conducted a variety of community forums to provide information and promote energy conservation and other programs, improved our building parking, entry and customer service facilities for bill inquiries and payment, and numerous other customer-centric improvements.

Our final standard is "Results Oriented". We want every action we take, every decision we make and every activity in which we participate to have a positive result. I have touched on a few of the results we are achieving in the above discussion. The other witnesses in the case will provide additional indications that our Results Orientation is making a difference for our customers.

Q. Is the Company planning to take steps to further improve its service to customers?

A. Yes. One of the key initiatives when I was hired was a move to engage customers and glean an understanding of what they expected from us as a utility and further as a community partner. We have devoted significant resources to talking directly to customers, surveying customers, setting up e-mail response capabilities and working through various social media to develop that understanding. Those activities continue today as part of our on-going effort to see through the "lens of the customer". As a result we have restructure policies and procedures, streamlined organizational structures and improved technology. This year, we implemented a new Outage Management System in conjunction with a new GIS/mapping system.

We are working to link the systems to FPU Contact Centers and provide better information to customer service personnel. Ultimately, we will have an automated system for customers to both report an outage and receive information about an outage. Other witnesses in this case will outline several additional customer service improvements on the horizon. New telephony equipment, better capabilities to enable customers to self-serve (mobile apps, enhanced website payment plans, Kiosk payment centers) and an improved voice response system to reduce call wait times are in the works. Of course, we continue to work on operational service reliability as our primary customer service initiative. As we present our case, FPU witnesses will describe many of the physical system improvements we have completed and the excellent reliability results achieved to date.

Q. Please provide an overview of FPU's case and the testimony that will be presented by the Company's witnesses.

A. The Company's case will be presented by several FPU and Chesapeake corporate witnesses as well as outside experts retained to address certain aspects of the filing. These witnesses will collectively demonstrate the Company's focus on providing safe, reliable and high quality service to customers and its decreased ability to do so under the Company's current financial condition. Our witnesses will provide detailed information showing that our costs are reasonable and prudent and are being incurred at a level that exceeds our revenues. We will further demonstrate that both our actual and projected returns are well below the current authorized level and any level where the Company could reasonably expect to attract capital and continue to provide quality service to customers. Finally, our witnesses will provide a rate design that appropriately allocates our cost to provide service and establishes customer rates that are just and reasonable.

Several Company witnesses will describe FPU's efforts to improve service to customers. Drane A. "Buddy" Shelley, Director of Electric Operations and Mark Cutshaw, Director of Business Planning and Engineering will, collectively, submit panel testimony that outlines the significant investments in reliability and facility improvements since the last rate filing and planned through the test year. Their panel testimony also addresses various operational budget issues, along with the Company's recent historic and future planned efforts to reduce wholesale electricity purchase costs. Mariana "Guilly" Perea, Chesapeake Director of Customer Care, will discuss the Company's commitment to becoming an industry-recognized customer service operation. Ms. Perea also provides an overview of the focused effort we have made to improve our customer service operations and the performance results to date. Aleida Socarras, FPU Director of Marketing and Sales, describes the proposed economic incentive program, including the tariff rate provisions we are filing.

Several FPU, Chesapeake corporate and outside experts will present testimony on the Company's financial condition and proposed rate relief. Robert Canfield, Vice President of Christensen and Associates, will describe the forecast methodologies used to develop the FPU billing determinants and inflation factor. Cheryl Martin, FPU's Director of Regulatory Affairs, will address the overall need for rate relief and sponsor the principal financial information that supports the proposed revenue requirement increase. Ms. Martin is specifically responsible for the information provided in the Minimum Filing Requirements (MFR) Schedules A, B, C, D, F and G. Matt Kim, Chesapeake's Vice President and Corporate Controller will describe the Company's capital structure, related cost of capital, income tax expense and various corporate cost allocations. Mr. Kim also provides supporting testimony for several related financial MFR schedules. Paul Moul, will discuss the Company's cost of common equity. Finally, Company witness Mark Cutshaw will describe the Company's Cost of Service analysis and rate design within the panel testimony offered by he and Buddy Shelley.

Q. What is the specific rate relief that FPU is requesting in its filing?

A. FPU is requesting a permanent increase in its electric rates and charges in the amount of $5,852,171. This increase equates to an overall 6.79% increase in total revenues.

Q. Is FPU requesting interim rate relief?

A. Yes. FPU also seeks an interim increase in its electric rates and charges in the amount of $2,433,314 based on deficiency in revenues for the historic year ended September 30, 2013.

Q. Why is it imperative that FPU receive rate relief at this time?

A. Simply stated, the rates approved in the Company's 2008 rate case are no longer adequate to support the costs to provide quality service to customers. The Company has made significant investments in the infrastructure improvements, equipment and facilities and maintenance necessary to operate a safe, reliable electric system. We have also invested in improvements to our Customer Care operation, upgraded our system planning capabilities and ensured that our employee compensation and benefits are competitive. We have made these improvements in the face of flat to declining customer usage and revenues, because we feel a strong obligation to meet the service and reliability expectations of our customers. The costs of providing service have continued to increase over the seven-year interim since the Company's last rate case while revenues have not kept pace. The resulting negative impact on our electric financial returns has been predictable. In spite of the cost savings measures FPU has implemented, we have now reached the point where, without rate relief, we will be forced to delay important future capital investments and reduce maintenance actions that are critical to system reliability and efficiency.

Q. What are some of the actions the Company has taken to control costs and defer the need for this rate case?

A. As other witnesses describe in greater detail, FPU has taken several steps to control costs. We have implemented a number of process and organizational modifications that have enable us to continue to provide safe, reliable service without adding additional operational positions in either Division. We restructured our union agreements to make it easier for employees to cross division lines and now frequently share internal resources between divisions. As a result we are able to provide better service and reduce overtime and outside contractor costs. Last year, we established a System Planning and Engineering Unit that provides services to all Florida operations (electric, natural gas and propane). As examples, large project engineering and permitting and administration of the GIS/mapping system used by electric and natural gas operations are handled by the System Planning Unit. As a result, we have been able to share costs and reduce expenses. We have also had success in reducing maintenance costs through our investments to increase reliability. The replacement of old, high maintenance equipment has greatly improved our reliability metrics and reduced maintenance requirements. In spite of these efforts, however, the Company's costs continue to rise and further efforts to reduce costs would likely be detrimental to the Company's service quality and reliability performance.

Cost management alone is not enough to return the system to a sound financial footing. The return on equity has dropped each year since the prior rate case in 2008. Since 2010 it has been dramatically below the bottom of the Commission authorized range. The "Great Recession" stopped growth in our service areas, consumers appropriately reacted to the economy as well as the increasing electric wholesale prices by conserving, our operating costs continued to increase, and FPU invested heavily in system improvements following the Chesapeake acquisition. We have delayed seeking rate relief as long as possible; however, we no longer have that option.

Q. What is FPU's projected return on equity for the test year if relief is not granted?

A. The projected return on equity for the test year if relief is not granted will be a negative 1.46% in the year ending September 30, 2015. The projected overall rate of return is expected to be 1.27% for this same period. A rate of return at this low level is not in the best interest of the Company's customers. We will clearly be well below the 11.25% cost of common equity demonstrated as reasonable for FPU by Mr. Moul, to say nothing of the expectations of the Company's shareholders who provide the capital required to support system integrity and service to our customers.

Q. You describe above the impact of the recent economic turndown. Does FPU play a role in the economic recovery and development of the communities you serve?

A. I believe we have an important role to play. We work closely with economic development teams in each of the areas we serve. It is clear that the ability to provide reliable, competitively priced electricity is one of the fundamental concerns of both individuals and corporations evaluating sites for residence or development. From a business perspective, economic growth brings additional customers and revenue. It also promotes the more efficient use of existing distribution resources. Ultimately, growth helps spread costs and minimize future rate increase pressures. Aleida Socarras will testify to FPU's current level of economic development support and describe our interest in expanding support for local and regional development efforts. We have watched with admiration the economic development actions of other Florida utilities in close proximity to our service areas (Gulf Power and Florida Power and Light). While our resources are more limited, it is appropriate that we support both regional and local efforts to grow the economies of the areas we serve.

In this filing, we are seeking approval of an Economic Development Rider. Ms. Socarras will provide greater detail on the Rider. It is our intent to promote additional economic development and job growth through certain rate discounts offered to businesses either relocating or expanding in FPU's service areas.

Q. FPU's request includes testimony that suggests that fuel rate relief for customers may be expected in the near term. Please explain.

A. As witnesses Cheryl Martin and Mark Cutshaw will explain in more detail in their testimony, the Company is very conscious of the economic environment within which we are making this request for an increase. While the revenue increase is paramount to our ability to continue to provide safe, reliable service to our customers, we do recognize that any rate increase can result in a hardship to customers. Over the past several years, we have diligently pursued other avenues by which we might achieve overall bill savings for customers. The most critical focus has been on reducing the cost of wholesale purchased power. FPU's base rates are among the lowest for Florida utilities. Our wholesale power costs have, however, been among the highest over the past five years. We have made significant progress in that area by negotiating an amendment to our existing purchase power agreement with Gulf Power and by entering into an agreement to purchase renewable power from the Rayonier Performance Fibers QF cogeneration plant on Amelia Island. We also make periodic as available power purchases from the Rock Tenn QF cogeneration plant also on Amelia Island. Each of these actions has produced significant savings for our customers. Other options are under consideration.

It is FPU's intent to file in May 2014 a proposed purchase power agreement to acquire power from Eight Flags Energy, LLC, a Chesapeake affiliate. Eight Flags is in the final stage of developing [redacted] The FERC certified QF would sell [redacted] The power purchases are anticipated to be significantly lower than FPU's current wholesale power purchase pricing. In addition, the [redacted]

[redacted] would enable [redacted] and purchase the additional power. [redacted]. The Eight Flags project is scheduled to be in-service in Q1 2016.

At present, FPU's base rates are consolidated, but the fuel rates are individually approved for each division. In the Commission's 2014 fuel docket, FPU will seek Commission approval to consolidate its fuel cost recovery across both FPU operating divisions, consistent with the Commission's direction in the 2013 Fuel and Purchased Power Cost Recovery docket. Such a consolidation will ensure that all FPU customers participate in the fuel cost reduction described above. As Mr. Cutshaw describes in his testimony, the [redacted] the base rate increase requested in this filing.

Given that the savings are not scheduled to begin until 2016, FPU will be seeking options, in its Fuel and Purchased Power Cost Recovery filing, to mitigate some of the base rate increase in 2015. Our intent is to reduce consumer fuel costs by deferring collection of a portion of our fuel costs until the 2016 savings are realized. An action of this type would allow the Company to recover the revenue requirement authorized by the Commission, while smoothing out any rate increase as much as possible.

Q. Does this conclude your direct testimony?

A. Yes.

Q. Please state your name, affiliation, business address, and summarize your academic background and professional experience.

A. My name is Cheryl Martin. I am the Director of Regulatory Affairs for Florida Public Utilities Company (FPU) including the Florida Division of Chesapeake Utilities (Central Florida Gas or CFG), Peninsula Pipeline, and Eight Flags Energy, LLC (Eight Flags). FPU has its administrative offices at 1641 Worthington Road, Suite 220, West Palm Beach, Florida 33409. I have been employed by FPU since 1985 and performed numerous accounting functions until I was promoted to Corporate Accounting Manager in 1995 with responsibilities for managing the Corporate Accounting Department including regulatory accounting (fuel, PGA, conservation, rate cases, surveillance reports, reporting), tax accounting, external reports, and special projects. In January 2002, I was promoted to the position of Controller where my responsibilities included those above with additional responsibilities in the purchasing and general accounting areas and Security and Exchange Commission (SEC) filings. I was promoted to my current position in August 2011. My current responsibilities include directing the regulatory affairs for the Company in Florida including regulatory analysis, and reporting and filings before the Florida Public Service Commission (FPSC) for FPU, FPU-Indiantown, FPU-Fort Meade, Central Florida Gas, and Peninsula Pipeline Company. I graduated from Florida State University in 1984 with a B.S. in Accounting. I am also a Certified Public Accountant in Florida.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes, on several occasions. Among the dockets in which I have participated most recently, I testified in the Company's 2007 rate case in Docket No. 070304-EI, as well as the 2003 rate case in Docket No. 030438-EI, the 1993 rate case in Docket No. 930400-EI, and our 1988 rate case in Docket No. 881056-EI. I also provided testimony in the 2008 rate case for our Natural Gas Division in Docket No. 080366-GU, as well as the 2004 Natural Gas rate case in Docket No. 040216-GU and the 1990 and 1994 rate cases, addressed in Dockets Nos. 900151-GU, and 940620-GU, respectively. I have also filed testimony on numerous occasions in the Fuel and Purchased Power Cost Recovery proceeding, as well as in the Conservation Cost Recovery clause dockets and the annual Purchased Gas Adjustment proceedings. In addition, I have also been involved in the development of other regulatory filings in Florida on behalf of FPU and other Chesapeake companies.

Q. Do you have any exhibits to which you will refer in your testimony?

A. Yes. A summary of those exhibits follows:

<u>Exhibit CMM-1</u> provides a list of the MFRs that were prepared under my supervision and direction.

<u>Exhibit CMM-2</u> provides the detail for the account and amortization of the Regulatory Asset-Pensions.

<u>Exhibit CMM-3</u> provides the detail for the account and amortization of the Regulatory Asset - Litigation Costs/Gulf Refund.

<u>Exhibit CMM-4</u> provides the detail for the account and amortization of the Regulatory Asset -Tax Step Up (A new regulatory asset requested in this proceeding).

<u>Exhibit CMM-5</u> provides the detail for the account and amortization of the Regulatory Liability –Tax Gain.

<u>Exhibit CMM-6</u> provides the detail for the account and amortization of the Regulatory Liability – Post Retirement Benefit.

<u>Exhibit CMM-7</u> provides the detail for the account and amortization of the Regulatory Asset – General Liability Claim and the related General Liability Reserve (A new regulatory asset and reserve being requested in this proceeding).

<u>Exhibit CMM-8</u> provides the Company's current and former Paid Time Off Policies.

Q. Are you sponsoring any MFRs in this case?

A. Yes. I am sponsoring the MFRs listed in Exhibit CMM-1. I have reviewed and support the analysis and schedules listed in this exhibit. To the best of my knowledge, these MFRs are true and correct.

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

A. I am providing the financial information that supports the proposed increase in revenue requirements for FPU, electric operations. I am specifically responsible for the information provided in the Minimum Filing Requirements (MFR) Schedules A, B, C, D, F and G, as indicated in Exhibit CMM-1. Supporting information and additional testimony for these schedules has also been provided by the Corporate Office of Chesapeake Utilities Corporation (CUC) under the direction of the Corporate Vice President, Matt Kim, as well as the Director of Electric Operations, Drane A. "Buddy" Shelley, and Director of Business

Planning and Engineering, Mark Cutshaw. The President of Florida Public Utilities Company, Jeffry Householder, has also included testimony in support of this proceeding. The Company's Director of Sales and Marketing, Aleida Socarras, our Director of Customer Care, Mariana "Guilly" Perea and our Cost of Capital and Billing Determinant experts, Paul Moul, and Robert Camfield, respectively, have likewise provided information that I have utilized in the development of these schedules. With regard to the MFR E Schedules, Mark Cutshaw is specifically responsible for the information provided therein.

Q. Why is FPU seeking a rate increase in its base rates at this time?

A. The last rate increase proceeding was initiated seven years ago and was based on a 2006 historic year and 2008 forecasted test year. Since that time, the Company has been acquired by Chesapeake Utilities Corporation, a transaction consummated in 2009. Prior to the merger, the Company did not have adequate capital resources to make necessary reliability improvements to the electric systems or facilities in its service territories. In stark contrast, as a new subsidiary of Chesapeake, the Company has undertaken significant reliability improvements to its electric system, and capital expenditures have increased since the last rate proceeding. Also as a result of the merger, the Company has experienced decreases in certain expenditures since its last rate proceeding due to specific measures taken by the Company to consolidate functions within the electric operations. Some of these costs savings measures have been offset by increases in costs including expanded safety measures, increased communication to our employees and customers, and enhanced customer care initiatives. Our projections indicate that we can expect many costs to continue to increase; and for the most part, these costs are beyond our control. The Company is committed to providing customers, reliable service and superior customer service, while also ensuring our employees are adequately trained, operate in a safe environment, and are adequately compensated with competitive pay and benefits. Another contributing factor is the inflationary impacts on new and replacement utility plant, as well as operating expenses. Cost increases continue to contribute to the declining rate of return. The Company believes the proposed September 2015 test year will accurately reflect the economic conditions in which the consolidated electric division will be operating during the first twelve months the new rates will be in effect, and as such, this period is appropriate for rate setting purposes. The Company has not been able to achieve its allowed rate of return in the last 3 years. It has therefore become necessary for the Company to seek a rate increase at this time to allow the Company the opportunity to earn a fair rate of return on its investment in utility plant and working capital. Earning a fair rate of return will enable the Company to continue providing a high quality of service and to maintain its financial integrity, which are in the best interest of its customers.

Revenue Requirement

Q. What is the revenue increase requested by FPU in this proceeding?

A. FPU is requesting a permanent increase in the electric rates and charges for its consolidated electric operations in the amount of $5,852,171 in order to cover the deficiencies in revenue for the projected test year ending September 30, 2015. In accordance with Rule 25-6.140, F.A.C., Test Year Notification, we have notified the FPSC that we have selected the twelve month period ending September 30, 2015 as the projected test year for our petition to increase our rates and charges. FPU is also requesting an interim increase in the electric rates and charges for its consolidated operations in the amount of $2,433,314 based on deficiency in revenues for the historic year ended September 30, 2013.

Q. How did you derive the projected revenue requirement for the September 30, 2015 test year?

A. The derivation of the revenue requirement and projected revenue deficiency is summarized on MFR Schedule A-1. In summary, the 2015 revenue requirement is determined by multiplying the projected test year rate base by the required rate of return to arrive at the operating income required. This required operating income is then compared to the projected year ended September 30, 2015 operating income, shown on MFR Schedule C-1 using our existing billing rates and charges and projected rate base and operating expenses. Any deficiency in operating income is then expanded using the revenue expansion factor to arrive at the additional revenue required to realize a fair rate of return on rate base. This required increase amounts to an additional $5,852,171 in annual electric rates and charges. The required rate of return is 7.18% as shown on Schedule D-1a. The projected rate base is $60,596,169 and is provided in MFR Schedule B-1.

Interim Revenue Requirement

Q. You are also requesting that the Commission grant interim relief. Why are you seeking Interim Rate Relief at this time?

A. FPU is seeking Interim Rate Relief because as of September 30, 2013 the

Company is not earning a sufficient return on its investment to allow shareholders the opportunity to earn a fair rate of return. Capital investments, including reliability improvements, have increased without significant offsetting customer growth. Expenses have increased, and the current trends in the housing markets, appliance efficiency, and overall economy have presented further pressures that negatively impact our earnings. For several years, the Company has been, and is, currently below the low point of our allowable return. Without rate relief, the Company is expected to continue to earn a return well below its allowable rate of return. If that continues, this will jeopardize our ability to provide sufficient, consistent reliable service to our customers. With the length of the rate case process, interim rates will mitigate our negative earnings posture through the pendency of the rate case and until final rates can be put in place.

Q. How did you derive the interim revenue requirement?

A. The derivation of the revenue requirement for interim relief is summarized in MFR Schedule G-1. In summary, the interim revenue requirement is determined by multiplying the historic year ended September 30, 2013 rate base by the required rate of return using the last authorized rate of return (low-point authorized common equity rate) to arrive at the operating income required. This required operating income is then compared to the actual year ended September 30, 2013 operating income. Any deficiency in operating income is then expanded using the revenue expansion factor to arrive at the additional revenue required on an interim basis until final rates can be reviewed and authorized. The required rate of return for interim purposes is shown on MFR Schedule G-19a. The interim rate base for the historic year ended September 30, 2013 is shown on MFR Schedule G-2.

We have made the appropriate net operating income (NOI) adjustments in this filing to reflect the findings in the Company's last rate case, including elimination of fuel and conservation costs and revenues; elimination of shared facilities with non-regulated operations, and interest synchronization. We have removed any item that belonged in a prior period, or was out of period, as appropriate in the historic year net operating income schedules, and consistent with Commission practice. See explanations in the NOI section of this testimony for additional details on those adjustments.

We are asking therefore that the Commission allow us to collect appropriate interim rates pending the effective date of the final order in this proceeding. We recognize that, in accordance with Section 366.071, F.S., any approved interim increase will be subject to refund with interest upon the outcome of these proceedings. We therefore request that the Commission allow the Company to secure the requested amount through corporate undertaking, in lieu of a bond. FPU, through its parent Chesapeake, has sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund as reflected by our financial statements, which are incorporated in the MFR Schedules F-1 and F-2.

Rate Base

Q. What is the amount of rate base included in the projected test year September 30, 2015, as a basis for determination of revenue requirement?

A. As set forth in MFR Schedule B-1, Rate Base for the projected test year is $60,596,169. The Rate Base is comprised of two main sections, Net Plant and Working Capital.

Q. What was the basis for projecting the Rate Base?

A. The Company did a detailed analysis and projection of capital projects, retirements, and other components for the projected years ending September 30, 2014, and September 30, 2015, to project Net Plant. The Company utilized experts in the division, including the Director of Electric Operations, Drane (Buddy) Shelley, and Director of Business Planning and Engineering, Mark Cutshaw, as well as input from other key employees to determine the projects, amounts and timing of items to be included in Net Plant projections. The Company has planned capital projects required by storm hardening, reliability, infrastructure replacement, and other key projects; all have been incorporated into these projections. Working Capital was projected using both trend factors applied to the historic year September 30, 2013 thirteen month average balances or year end balances as appropriate, and direct projections for certain balance sheet accounts that do not lend themselves to projections based on trend factors.

Q. What is the amount of FPUC's capital additions for the historic year ending September 30, 2013, and the capital budget for the two projected years

ending September 30, 2014 and 2015, respectively?

A. The capital additions for the twelve months ending September 2013 were \$6,936,887. The capital budget for periods ending September 30, 2014 and 2015 are \$6,706,924 and \$3,195,398 respectively.

Q. Please explain how the Capital Budget forecasts were developed for this rate proceeding?

A. For all utility plant accounts and construction work in progress (CWIP), actual account balances were used through February 2014. For the remainder of 2014 through September 2015, plant accounts were projected based on anticipated changes in timing, projects and amounts. The original internal 2014 FPUC capital budgets were developed during the latter half of the previous year, using detailed analysis of planned projects at the time of the budget development. Detailed analysis of this original plan was completed during the early part of 2014 by division directors and managers, and the capital forecasts were updated with known and planned changes.

Q. Why did the Company's Capital Budget forecast change from the internal budget used for financial reporting?

A. The budget that is currently used in financial reporting was prepared well before the rate proceeding was compiled. The Company used the internal budget forecasts for capital projections as a starting point for the forecast for this rate proceeding. It was updated with more timely information and expectations. A more thorough review of the capital projects was completed by key management personnel responsible for capital projects, including Drane "Buddy" Shelley and Mark Cutshaw. Their panel testimony includes more details regarding the projected capital projects for the two projected years reflected in this rate proceeding.

Q. Are the capital projects and related forecasts included in this rate proceeding the best estimate for what will be expected during the two projected years ending September 30, 2015?

A. Yes, the forecasts used in rate base for net plant are the most up to date estimates of what is expected and planned. The Company prepared detailed projections for expected projects and retirements, and the projections used in this rate proceeding reflect our best estimate for the plant that will be in service or under construction for the two projected years.

Q. Are the capital projects planned for the two projected years necessary?

A. Yes, as further explained in the panel testimony of our witnesses Mark Cutshaw and Buddy Shelley, the planned projects consist of replacing and/or upgrading aging/unreliable underground conductors, relay control schemes at substations, transmission circuit breakers, substation buss, wooden poles, distribution regulators/reclosures and the relocation of inaccessible distribution lines to roadways. The planned capital projects are necessary for system reliability, improvements and replacement.

Q. Is it appropriate to include the construction work in progress (CWIP) planned for the projected test year in rate base?

A. Yes, the Company should be allowed to earn a fair return on capital projects under construction. Costs associated with these projects are all prudently incurred and necessary, and therefore, should be included in rate base. Historically, the Commission has allowed construction work in progress to be included in rate base for FPU. These projects are not subject to the Allowance for Funds Used during Construction and accordingly, will not receive duplicate recovery on these projects while in construction. In its previous rate case in Docket 070304-EI, the Company had included, for full recovery in rate base, a transformer that was ordered during the historic year, 2006; but, it had not been delivered by December 2007. The Company proposed that, for the purposes of rate setting, it was appropriate that the full 13-month average remain in the 2008 average rate base and be allowed for recovery. The Company also received recovery for CWIP during the projected test year. The Commission agreed and accepted our proposal. If full recovery of CWIP had not been allowed, it would have accelerated the need for the Company to seek further rate relief sooner than otherwise necessary, thereby increasing the overall cost to the customers associated with rate case costs. With this filing, we also believe it is appropriate for the Commission to allow us to recover costs associated with ongoing construction; because, these projects are critical to maintaining and improving our system reliability and ability to meet our customers' needs.

Q. What was the basis for the trend factors used for certain working capital items?

A. MFR Schedule C-7 contains a listing of the projection factors used. The most commonly used trend factors include Inflation, Payroll Growth, Customer

Growth, and Inflation & Customer Growth. The payroll trend factor is based on historical data, the experience of the Company's Human Resources Director, and her best estimate of expected payroll increases for both 2014 and 2015. The factors for customer growth, unit (kWh) growth and revenues are based on detailed analysis and the results from revenue related projections used within this rate proceeding. The methodology used to determine the billing determinant and revenue factors as well as the inflation factors are explained in greater detail in the testimony of Robert Camfield.

Trend factors were used that were consistent with those used in expense projections and in our prior rate proceedings.

Q. How were the relative trend factors applied to working capital?

A. The Company reviewed each balance sheet item, and when appropriate utilized a trend factor applied to the thirteen month average balance when it was necessary to reflect fluctuations that occur due to payment timing and seasonality. Some accounts were trended using the balance that existed at year end, when those accounts do not fluctuate with payment timing and seasonality. This basis produced a better projection. The Company performed analysis of all working capital components; reviewed historical methodology used for these same components, reviewed expense items related to these components, and relied upon internal expertise to determine the most appropriate factor to project the working capital components. Customer growth was used in trending the balance sheet accounts where the transactions were directly or indirectly associated with billing determinants. Inflation was used to trend accounts directly impacted by anticipated cost of living increases. Payroll was used to trend all payroll related accounts. Some accounts utilized a combination of trend factors such as Account 1420-Accounts Receivable, when changes not only are impacted by customers, but also the inflationary impacts to costs.

Q. What items included in working capital were projected using a direct method and what is a summary of the basis for those projections?

A. Some working capital accounts were projected using a method outside of a pure trend. Several accounts were directly projected using historical data, known or expected changes, or separate detailed analysis. The details of these projections are summarized below:

Account 1240/1430-A/R Other Investments: The balance of this account does not typically fluctuate year to year or month to month and is not expected to change in the next two projected years. The historic year-end amount was used to project this account.

Account 1310-Cash: This account was projected using a combination of trend factor and direct estimate. Since this account is materially impacted by accounts receivables and fuel related purchases, the customer growth factor was applied to the historic September 2013 13-month average balance of Depository Cash to arrive at the projected 13-month average balances for September 2014 and September 2015, respectively. The individual months for the projected years were then trended based on the monthly balance fluctuations of the historic year to account for seasonality. Part of this account, Account 1312-General Disbursements – Cash, was forecast to remain at the normal level of outstanding checks to be funded by FPU's parent company, Chesapeake Utilities Corporation.

Account 1350-Petty Cash: The balance of this account does not historically fluctuate, nor is it expected to fluctuate in the two projected years. Accordingly, this account was projected to remain at $8,000 per month.

Account 1430-Miscellaneous Accounts Receivable: The monthly balance of this account does not typically fluctuate from year to year and is not expected to materially change in the two projected years. The historic amounts were used for the projection.

Account 1730-Unbilled Revenues: A detailed analysis and forecast of unbilled revenues was prepared by our witness Robert Camfield for the projected years. Management reviewed and supports this estimate, and accordingly, this was used to project the related working capital component.

Account 1823-Other Regulatory Assets Pension and Other Post-Retirement Benefits (OPRB): The projected years were computed by using the actual monthly balances from October 2013 through February 2014. We then adjusted each subsequent month's balance by the monthly amortization of $23,064, authorized by the Florida Public Service Commission to commence in November 2009, and to continue through the remaining life of the asset. The Company received authorization from the Commission by Order PSC-08-0134-PAA-PU to create a regulatory asset related to a valuation adjustment on pension and retiree medical expense in accordance with FASB 158 requirements that existed due to the merger between FPU and Chesapeake Utilities Corporation. Company witness Matt Kim provides additional details on the pension expense projection in his testimony. See Exhibit CMM-2 for details on the account and amortization amounts reflected in the MFR.

Account 1823-Other Regulatory Assets Tax Step-up: Since the merger, FPU's statutory rate increased to 35 percent. This increase in the federal statutory rate increased FPU's effective income tax rate to 38.575 percent from 37.63 percent. Since FPU had a net deferred tax liability associated with its plant assets at the time of the merger, this resulted in a deficiency in the deferred tax reserve. The South Georgia method is one of the methods of the tax normalization accounting, which allows utilities to amortize the deficiency over the remaining lives of the property that gave rise to the deficiency. The tax step-up currently in regulatory assets, including tax gross up is $248,666. See Exhibit CMM-4 for details on the amortization amounts reflected in the MFR.

Account 1823-Other Regulatory Assets Deferred Litigation: The Company requested deferral treatment for the NW litigation costs in 2012. The Commission granted the Company's request for this deferral by PSC Order No. 12-0600-PAA-EI and Order No. 13-0599-PAA-EI. This account reflects the actual amounts being amortized during the projected periods.

Specifically, in August 2012, FPU requested approval to establish a regulatory asset to defer the litigation expenses associated with ongoing litigation with the City of Marianna. The basis and reasons for that litigation are detailed in full in prior Commission Dockets Nos. 100459-EI, 110041-EI, 120227-EI, and 130233-EI. On November 5, 2012, the Commission approved our request and permitted the Company to amortize the accumulated litigation costs, $1,869,657, over a 5-year period beginning January 2013. In March 2013, FPU and the City of Marianna reached a settlement resolving the aforementioned litigation. With the litigation resolved, Gulf began charging the lower capacity payments based on the amendment to our purchased power agreement that was approved in Docket No. 110041-EI. Gulf also refunded to FPUC the difference between the higher capacity payments from the original agreement and the lower capacity payments set forth in the approved amendment.

On November 13, 2013, the Commission issued Order No. PSC-13-0599-PAA-EI, allowing FPUC to apply the refund of $1,766,624 to the regulatory asset and amortize the net remaining amount over the existing five year period. The Regulatory Asset – Litigation reflects the appropriate amount in accordance with the Commission Order. See Exhibit CMM-3 for the account and amortization amounts reflected in this rate proceeding.

<u>Account 1860-Deferred Rate Case:</u> The projection for this account was based on detailed estimates based on expected expenditures necessary to prepare this rate

proceeding. The total accumulated rate case expense was then amortized over five years. MFR Schedule C-10 and additional testimony contained within this document, includes more details on the rate case expense.

Account 228.1-Storm Reserve: The projected balance of this account was forecast to increase by monthly accruals of $10,135 over the historic year, and adjusted for estimated storm costs based on historical activity and inflationary impacts to expected costs. This amount is consistent with our prior rate proceedings, See Docket No. 070300-EI. Conditions related to storm activity has not materially changed from our last rate proceeding to warrant a change in the storm reserve at this time. The reserve, with current accruals, is sufficient to provide recovery for storm costs over the next five years.

Account 2282-Accrued Liability Insurance: This account was projected based on detailed analysis of historical activity, known claims, and to project the impacts from a requested general liability reserve. I will further address the requested General Liability expense and reserve in the NOI section of my testimony. Our witness Matt Kim also addresses details associated with this in his testimony. See Exhibit CMM-7 for the amortization reflected in this proceeding.

Account 2283-Accrued Pension & Post Retirement Medical, Account 2283-Accrued Pension & Post Retirement Medical Allocated and Account 2283-Accrued Retiree Fees, Claims & Contributions: These accounts were projected based on a detailed estimate provided by Matt Kim on expected Pension and Post retirement expenses. Matt Kim's testimony includes additional details surrounding the related expense accounts.

<u>Account 2370-Interest Accrued:</u> The Company currently accrues interest on its mortgage bond at $60,533 (allocated @ 24% to electric) per month and makes semiannual payments on the accumulated balance in May and November of each year. The Company projected the monthly balances in the test year to reflect this same historic year amount.

<u>Account 2410-Tax Collections Payable:</u> The balance of this account typically does not fluctuate from zero. Tax payments generally match monthly accruals. The Company appropriately projected this account to consistently maintain an expected zero balance.

<u>Account 2420-Misc. Current & Accrued Liabilities:</u> With very few exceptions, this account has maintained a zero balance throughout the historic year. The Company appropriately projected this account to consistently maintain an expected zero balance.

<u>Account 2520-Customer Advances For Construction</u>: This account contains contracts with customers with an expiration date. The forecast reflects the diminishing balance due to expected refunds at the contract expiration date, with no additional contracts projected.

Account 2540-Regulatory Liability: This account contains the actual amount of a deferred gain, and the associated amortized amount authorized by the Florida Public Service Commission in Order No. PSC-12-0574-PAA-PU, issued October 24, 2012. By that Order, FPU received approval to record a tax liability associated with vehicle depreciation as a regulatory liability and amortize that liability over a 34-month period beginning January 1, 2012, through October 31, 2014. See Exhibit CMM-5 for the account and amortization amounts reflected in this rate proceeding.

This account also contains an additional regulatory liability associated with a one-time gain FPU incurred due to a change made to the Company's Post-Retirement Benefits. The merger between FPU and CUC prompted a continued effort to conform the benefits offered to FPU's employees to those offered to CUC's employees. This change reduced FPU's obligation under the plan. By Commission Order No. PSC-13-0594-PAA-PU, FPU was allowed to recognize the one-time gain and amortize it also over the 34-month period beginning January 1, 2012 and ending October 31, 2014. See Exhibit CMM-6 for the account and the amortization amount reflected in this rate proceeding.

Q. Is working capital as projected appropriate for computing the projected test year rate base for the period ending September 30, 2015?

A. Yes, the working capital as projected is appropriate for inclusion into rate base for the period ending September 30, 2015. The Company performed analysis of working capital accounts, reviewed historical methodology used for these same components, and reviewed expense items related to these accounts to determine the most appropriate factor to use to project the working capital.

Q. Please elaborate with more information to understand what is included in Net Plant.

A. The Company has included costs of significant reliability improvements to the infrastructure of its electric operations made since the last rate proceeding or will be made during the projected test year and prior year. In addition, the Company was operating out of facilities in its Northeast (NE) division, which were not only inadequate in terms of space, but were also in need of substantial repairs. In particular, the warehouse was deteriorating and was not sufficient to allow the Company to properly serve our customers, as further discussed in the panel testimony of witnesses Cutshaw and Shelley. There was not sufficient space in the administrative building or the warehouse to sufficiently serve the customers in this area or provide employees with adequate working facilities. The Company therefore made a prudent decision to build a new facility, which included the warehouse complex. This facility was prudently constructed, is centrally located, allows for efficient communications between personnel, and is adequate to serve its customers. To be clear, the Company has removed the old warehouse from rate base for purposes of rate base determination.

The old administrative building located in the NE division is currently being used for Florida Common purposes, and associated costs are allocated among the Florida business units, because they share in the benefits of the Common services and functions. This building is allocated to the Florida business units based on the level of investment by Business Unit; electric receives 16.7% of this allocation. This percentage is a fair estimate for the benefit the electric utility receives from this facility, and as such, is allocated appropriately.

Details of these and specific larger projects embedded in the rate base projections have been included in the MFRs, as well as the testimony provided by witnesses Cutshaw and Shelley.

Q. What are the items that are included in net plant that have been allocated from Corporate to the Electric operating unit?

A. The eCIS plus is a corporate wide billing system project. This is an upgrade from the current billing system. eCIS plus is being allocated from the Company's Corporate CWIP to each business unit's CWIP, based on their respective number of customers. This project is expected to enhance the options available to customers as well as provide additional analysis to the Company. See Mariana Perea's testimony for more details regarding the improvements made to customer service including those anticipated in the near future.

Q. What are the items that are included in net plant that have been allocated from Florida Common to the Electric operating unit?

A. The Company determined that certain Plant Assets were categorized as Florida Common due to their shared utilizations between multiple regulated and/ or non-regulated utilities. These assets are detailed on Schedule B-8 under Common

Plant.

Q. What is the basis for the allocation from Common Plant to the Utility?

A. Many common plant accounts, with the exception of Computer Equipment and Software and the Florida Common office, were allocated based on the utility's share of non-Common, total consolidated plant (exclusive of Computer Equipment and Software). Common's Computer Equipment and Software accounts were allocated to the electric utility based on the utility's share of total consolidated customers. The Florida NE Common office was allocated based on net investments.

Q. How does the electric division benefit from these assets?

A. These assets are necessary to the electric division in the day-to-day operations of the utility, enabling the Company to effectively and efficiently function in a number of areas, ranging from internal communications to customer care to maintenance issues. They are essential to the electric division, and the overall Company, in the performance of its duties and service to its customers. Shared resources provide benefits to the electric customers through efficient utilization of assets.

Q. Please explain the item and nature for all adjustments included in rate base for the historic and projected years included in the MFR filing?

A. The Company has removed plant and its reserve for a portion of the assets used for non-utility operations, consistent with the treatment approved in Docket

070304-EI. The adjustment to net plant, for the historic test year, decreased rate base by $222,737. For the period ending September 30, 2014, rate base was decreased by $507,448, and for the period ending September 30, 2015, rate base was decreased by $407,936.

In our last rate case Order, Order PSC-08-0327-FOF-EI, the Commission eliminated fuel and conservation under-recoveries and employee receivables. An adjustment was made to rate base to remove the net under-recoveries, which were $227,971 in the historic year, $590,782 at September 30, 2014, and $250,042 for the projected year ending September 30, 2015. The projected amounts of fuel under and over recoveries were based on detailed analysis of the expected fuel cost recovery in the projected years.

In that same Order PSC-08-0327-FOF-EI, the Commission also eliminated Non-Utility (Employee) Receivables from working capital. Working capital was increased in the historic year because the employee receivable included in the actual 13-month average balance sheet at September 30, 2013 was a credit of $4,248.

The Commission likewise removed one-half of deferred rate case expenses. Consistent with the Commission's decision, we removed one-half of the projected deferred rate case expenses. The reduction to projected rate base was $148,077 in the September 30, 2014 test year and $346,028 in the September 30, 2015 test year. There was no adjustment necessary to the historic test year for this item since there was no rate case expense being amortized.

The historic test year included other adjustments to record amortization of regulatory assets and liabilities that were established by Commission Orders in 2012 and 2013. These adjustments were not necessary in the projected years because the assets and liabilities were forecast for the September 30, 2014 and 2015 years using the adjusted amounts. For instance, in the historic test year, a regulatory asset was established by Order No. PSC-12-0600-PAA-EI for recovery of litigation costs with the City of Marianna. The Commission later approved a settlement whereby the Company was allowed to substantially reduce that asset by the amount of proceeds of a refund from Gulf Power, as set forth in Order No. PSC-13-0599-PAA-EI. The 13-month average of the costs less the amount approved by the settlement and the approved amortization resulted in an average balance of $470,288. However, the actual net average balance recorded in working capital for this asset was $377,922. Therefore, an increase of $92,306 was made to rate base for 2013 to reflect the authorized amount and amortization in the Commission orders.

Commission Order PSC-13-0594-PAA-PU issued on November 4, 2013, established a regulatory liability for the one-time gain realized as a result of the change in its post retirement benefits and approved the Company to amortize the regulatory liability over a 34-month period beginning January 1, 2012 and ending October 31, 2014. For the thirteen month average as of September 30, 2013, the books reflected a balance of ($258,659). Based on this order, the balance should have been ($144,545). Therefore, rate base was increased by $114,114 for 2013 to reflect the Commission order.

The final adjustment was to properly reflect the regulatory liability - tax gain and related amortization established in Commission Order PSC-12-0574-PAA-PU. The 13-month average balance included in the historic test year working capital balance was ($416,777). The balances based on the Commission Order resulted in an average of ($519,927). Therefore, rate base was reduced by $103,150.

No other adjustments were made to rate base.

Revenues and Billing Determinants

Q. What was the method for determining the projected test year billing determinants?

A. The billing determinants and operating revenues have been projected using a test year ended September 30, 2015. To project operating revenues for 2015 the Company used current rates multiplied by the projected 2015 weather-normalized billing determinants (number of customers and usage). The Company also included the impact of the energy efficient appliances, economic conditions and projected base revenue increases on customer's consumption. Also, despite some customer growth in our Northeast (NE) division, the Northwest (NW) division continues to struggle with the economic downturn that the nation as a whole has endured over the last several years. The NW division is mostly rural, and does not have the same prospect for customer growth that our NE division anticipates; therefore, recovery has been slower. Robert Camfield further addresses this issue in his testimony. Additional information with regard to the billing determinant forecasts may also be found in Schedule F-5. Projected operating revenues for 2015 are shown on MFR Schedule C-5.

Q. Does the Company feel that the billing determinants and revenue forecast used in this MFR filing are appropriate for the two projected years?

A. Yes, the Company has reviewed the analysis, results and testimony provided by Robert Camfield. After careful consideration, FPU has concluded that the results are appropriate and fairly represent the revenues and billing determinants expected for the two projected years including the projected test year ending September 30, 2015.

<u>NOI and Operating Expenses</u>

Q. **Does the historic test year accurately reflect net operating income?**

A. Yes, the Company has included all adjustments to remove items that did not belong ("out of period") in the historic year, and accordingly the MFR Schedule C-1 for the period ending September 30, 2013 reflects the appropriate historic year net operating income. "Out of period" refers to adjustments on the Company's books in the historic year that belong in another period. Other adjustments were required to the historic year to remove items that do not belong to the electric divisions, or were required in past rate proceeding.

Q. Please explain the items and basis for any adjustments made to operating income for the historic year included in MFR Schedules C-2 and C-3.

A. Fuel and Conservation:

Consistent with the prior rate proceeding, the fuel and conservation revenues and expenses have been eliminated from both the historic and projected years. These items are handled in separate dockets outside of the base rate proceeding and are appropriate for review and approval within those separate proceedings.

Gross Receipts and Franchise tax:

Gross Receipts tax and Franchise tax revenue and expenses have also been eliminated from the historic and projected test years. Although they are not handled in separate dockets, it is appropriate to remove them. They are a direct pass-through for revenues and expenses and they are excluded from setting base rates.

Unbilled Revenues:

Unbilled revenues were decreased by $122,438 due to a correction made in December 2013 that impacted the period January 2012 through December 2013. The error involved the use of an improper input in the computation of unbilled revenues; but, the issue was subsequently corrected. This reduced amount reflects the portion of the adjustment made in December 2013 that belonged in the historic year ending September 30, 2013.

Marianna Litigation Expenses:

Adjustments were made to correct O&M and amortization expense associated with the Marianna litigation. This is relevant to litigation initiated on March 2, 2011, when the City of Marianna filed a complaint against FPU in the Circuit Court in Jackson County, Florida. Further details regarding this issue are also included in the panel testimony of witnesses Cutshaw and Shelley, as well as in the Commission Docket No. 100459-EI. In summary, the City of Marianna alleged that FPU breached its franchise agreement. The City of Marianna was seeking judgment allowing it to exercise its option under the franchise agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. Subsequently, FPU and the City of Marianna entered into a settlement agreement, which contemplated, among other items, the City of Marianna proceeding with a referendum on the purchase of FPU's facilities within the City of Marianna. On April 19, 2013, the referendum took place, and the citizens of the City of Marianna voted, by a wide margin, to reject the purchase of FPU's facilities by the City of Marianna. Total litigation expense associated with the City of Marianna was approximately $1,871,000. As previously noted in my testimony, In August 2012, the Company sought Commission approval to establish a regulatory asset to defer the litigation expenses associated with the ongoing litigation with the City of Marianna and amortize it over a five (5) year period beginning January 2013. Upon receiving approval for treatment as a regulatory asset and approval to offset these costs with the refund from Gulf Power Company, by Order No. PSC-12-0600-

PAA-EI and Order No. PSC-13-0599-PAA-EI, respectively, the Company reversed expenses from a prior period of $1,319,358 in the actual historic year ending September 30, 2013. Thus, the prior period expense reversal was eliminated from the historic year appropriately. Also, in January 2013, the Company began amortizing the regulatory asset pertaining to the Marianna litigation at $31,161 per month for a total of $280,449 in the historic year. Since the Commission allowed the refund from Gulf Power to offset the regulatory asset related to the Marianna litigation, the amortization should have been lower and recorded at just $15,455. The amortization expense was reduced by $264,994 to correct the historic year results to reflect the actual amortization authorized by the Commission. Exhibit CMM-3 details the regulatory asset and related amortization.

Pension and Post Retirement Benefit:

In December 2012, the Company adjusted on its books, pension and post-retirement benefit expense true-ups and cost capitalization for the years 2010 through 2012. Of these adjustments, only three months were relevant to the historic year, and the remaining months and years were adjusted out of this period. Adjustments to NOI are listed below:

Pension true-up and cost capitalization	$39,226
Post-retirement true-up	$76,134

Depreciation Expense:

The Company has removed depreciation expense of $10,768 for a portion of the assets used for non-utility operations from the historic year, which is also consistent with the treatment used in our 2007 rate case in Docket 070304-EI.

Transformer:

Expenses have been reduced by $46,610 for costs related to a transformer that should have been capitalized during the historic year period. This entry was subsequently corrected on the Company's books in December 2013.

Income Tax Gain:

Amortization expense has been adjusted to eliminate $246,285 for prior period amortization related to an income tax liability allocated to the electric operations. After an internal audit of FPU records, it was determined that an income tax liability that originated on the Company's books prior to its merger with Chesapeake Utilities Corporation was no longer collectable by the Internal Revenue Service. The tax liability related to depreciation on company vehicles and the tax liability had outlived the applicable statute of limitations set forth by IRS Code and as such was no longer deemed a tax-related liability, and therefore could be excluded from the deferred tax liability account. FPU sought and received approval from the Commission, by Order No. PSC-12-0574-PAA-PU, to record a tax liability associated with the vehicle depreciation as a regulatory liability and to amortize that liability over a thirty four-month period beginning January 2012 through October 2014. Upon approval by the Commission, the amortization gain true-up of this regulatory liability ($301,015) was recorded on the Company books in November 2012 for the period January 2012 – November 2012. However, only two months were relevant to the historic year, and the remaining months were adjusted out of this period.

Paid Time Off:

In 2013, Chesapeake Utilities Corporation also made a change to the Paid Time Off (PTO) Policy for employees in FPU to align them with the Company wide PTO policy. The old PTO policy that originated with FPU prior to the merger accumulated the subsequent years change in total vacation pay as a liability and expense. The policy, because of the way the liability was created, resulted in pre accrual of future vacation pay changes. If an employee left the company on January 1st of the current year, they were entitled to the entire current calendar year's PTO pay as a payout. Accordingly, GAAP required the Company to record any change in the overall future liability prior to the related actual PTO or the actual payout year. The change in pay or additional weeks was then booked as an additional liability in the year preceding the actual payout. The new policy requires employees to accrue PTO as they work during the calendar year. Now, whenever an employee leaves the Company, they are only entitled to a PTO payout for the amount of PTO they have accrued during the current calendar year. A one-time reversal of the total accumulated PTO liability on the books in the historic year period was booked in the 2013 calendar year. The accumulation of this liability occurred over the last several decades and as such, the one-time reversal that occurred during the historic year relates to prior period expenses and does not belong in the historic year. The historic year has been adjusted to eliminate the impact of this change for $141,687 on the electric division's books. My Exhibit CMM-8 sets forth the new and old PTO policies.

Post Retirement Benefits:

During 2012, CUC modified the benefits offered to its FPU employees under the post-retirement health and life plan. This caused a one-time gain on the Company's books. FPU sought permission from the Commission to establish a regulatory liability and amortize this liability over a thirty four month period beginning January 1, 2012 and ending October 31, 2014. In November 2013, the Commission approved this request by Order No. PSC-13-0594-PAA-PU. Since the authorized amortization was not reflected in the historic year, an adjustment of $91,291 was made to NOI so that the historic year accurately reflects this amortization.

Vehicle Depreciation:

The depreciation on vehicles was calculated at the incorrect rate for the historic year ending September 30, 2013. An adjustment was made to NOI for $41,739 for the difference in the actual calculation versus what was recorded on the Company's books for the historic year ending September 30, 2013. Because depreciation expense on vehicles is allocated to FERC accounts following the related payroll expense, this change is reflected in O&M instead of depreciation expense. This entry was subsequently corrected on the Company's books in March 2014.

PSC Assessment:

Taxes other than income (TOTI) expense for PSC Assessment was increased by, $2,120, to account for the difference between accruals and actual payments on the Company's books.

Adjustments - Income Tax Impact:

The effective income tax rate on the adjustments described above has been appropriately included as an additional adjustment to expense in the historic year ending September 30, 2013.

For reference, MFR Schedules C-2 and C-3 include a summary of these adjustments and amounts.

Q. **Have you calculated the appropriate adjustment in income taxes to reflect the synchronized interest expense related to the adjusted rate base?**

A. Yes. The NOI has been adjusted to reflect the tax effect of synchronizing interest expense to rate base. Consistent with prior Commission practice, the synchronized or calculated interest expense is computed by multiplying the jurisdictional adjusted rate base by the weighted cost of debt included in the cost of capital. This adjustment ensures that the calculated revenue requirement reflects the appropriate tax deduction for the interest component of the revenue requirement calculation.

Q. How did you project Operating and Maintenance (O&M) expenses for the projected test year ending September 30, 2015?

A. The expenses reflected in this filing were projected separately for the business unit and corporate costs allocated to the business unit.

O&M expenses for the corporate office of Chesapeake Utilities Corporation (CPK) allocated to the electric utility were projected by Matt Kim. Additional details regarding those projections and related allocations to the Business Unit are included in his testimony.

O&M expenses for the business unit were projected by the Florida office. Business unit expenses were projected using the historic year as a starting point, making all necessary adjustments as reflected in this rate proceeding for the historic year and either trending those forward with an appropriate trend factor, or directly projecting the expense using the expertise of internal managers or known items impacting certain expenses as a basis for the projection.

Final projected O&M amounts were reviewed by internal managers and analysts and were determined to be a good estimate for expected costs during the projected test year.

Q. **Please explain in more detail the basis for projecting the business unit expenses included in the MFR filing.**

A. The business unit O&M expenses for the historic year ending September 30, 2013, provide the basis for most of the business unit expense items in the projected test year ending September 30, 2015. Each FERC account was separated into its payroll and non-payroll components for the historic year. All historic adjustments were made to the payroll and non-payroll components to exclude "out of period" items or other items as reflected in the historic year adjustments described in this testimony and shown on MFR Schedule C-2.

Some historic year amounts were then adjusted to normalize the expenses for the purpose of trending historic year accounts to the projected years. Normalization adjustments only impacted the projected years' amounts and were not included for purposes of establishing the historic year expenses included in the NOI for the period ending September 30, 2013. To normalize, expenses were re-classified to their appropriate FERC account to reflect a more accurate expense projection by FERC. This was just a transfer between accounts and did not change the overall expense level.

Then the adjusted historic year expenses plus or minus the "normalization" amounts were multiplied by one of several trend factors. Trend factors have been applied that are appropriate for each account and consistent with prior rate proceedings.

Some historic year items that were trended did not reflect the annual amount expected; estimates have been adjusted for increases and decreases to the trended amounts (Over and Under), as shown on MFR Schedule C-7 page 9.

Some expense items have been projected based on direct cost estimates provided by our internal management. Examples of direct cost estimates would include: pension, general liability, economic development, rate case and tree trimming.

The application of trend factors, including over and under items plus the direct projections, produced reasonable and expected results in O&M amounts for the projected test year.

Q. Please explain the items and the basis for any normalization adjustments made to operating expenses for the purpose of trending O&M expenses for the projected test year?

A. Normalization adjustments were made to the historic year in order to arrive at the appropriate expense level by FERC account for projection purposes. We re-classed expenses recorded on the Company's books from corporate Administrative and General (A&G) to non-corporate/business unit Distribution and A&G to ensure they were properly classified and aligned by FERC. These adjustments had no impact to NOI. Below are descriptions of the normalization adjustments made to the historic year for purposes of trending projected year expenses:

- Payroll not classified to correct FERC-$351,834
- Electric General Managers payroll and other expenses-$102,398
- IT related costs-$54,567
- System Planning department-$34,350
- Facilities Expenses-$81,365
- Advertising expenses -$28,750

Q. Please explain the basis of the trend factors used to project O&M expenses for the projected test year.

A. MFR Schedule C-7 contains a listing of the projection factors used. The most commonly used trend factors include Inflation, Payroll Growth, Customer Growth, Inflation & Customer Growth, and Payroll Growth & Customer Growth. The payroll trend factor is based on historical data, the experience and expertise of the Company's Human Resources Director, and her best estimate of expected payroll increases for both 2014 and 2015. The factors for customer growth, unit (kWh) growth and revenues are based on detailed analysis and the results from revenue related projections used within this rate proceeding. The methodology used to determine the billing determinant and revenue factors as well as the inflation factors are explained in greater detail in the testimony of Robert Camfield.

Q. How did the Company determine the appropriate trend factor for each expense projection?

A. All expenses were divided into two components, payroll (if applicable) and non-payroll. The payroll expenses for each account used either the Payroll or Payroll and Customer growth trend factors. The payroll factor was used on payroll accounts, like 560-Supervision and Engineering and 920-A&G Salaries. All other payroll components used the Payroll and Customer growth factor because the Company expects payroll to increase by not only the expected rate of pay, but also the expected overall number of personnel, as more customers are added. Although it is not a direct correlation, personnel will fluctuate overall by the number of customers the Company serves. The non-payroll component was based on the type of expense and most appropriate trend factor for the account.

This is consistent with historically approved trend factors used in prior rate proceedings, and resulted in expected levels of expenses.

Q. Can you explain the basis for the projected expenses outside of those based on historical data trended to the projected test year?

A. Operation and Maintenance over and under adjustments, as well as direct projections, were made to certain accounts outside of trending historical data when management determined that a trend would not adequately reflect expected results. A detailed listing of the over and under adjustments as well as direct projections has been included in MFR Schedule C-7. The Company utilized internal experts to project certain expenses shown as Direct.

Q. Can you summarize the items that were projected on a Direct Basis?

A. The pension expense of $280,219 was projected by the corporate office of Chesapeake Utilities Corporation. All other employee benefit expenses were trended based on payroll and customer growth factor.

Corporate O&M expenses, including pension expense, are reflected as Direct and were projected by the corporate office of Chesapeake Utilities Corporation, which is further explained in the testimony of our witness Matt Kim.

The projected regulatory Commission expense (i.e., rate case expense) was based on specific forecasts from consultants, attorneys, and in-house review of appropriate, anticipated costs. FPU estimates the incremental expenses related to this rate case to be $770,721. The Company is requesting to recover these expenses at a rate of $154,144 per year over a five-year amortization period, which is consistent with the Commission's decision in previous FPU rate cases. NOI has been adjusted by $154,144 for the projected test year. Detailed specifics of these costs are explained later in this testimony and can be found on MFR Schedule C-10.

Depreciation & amortization expenses for the year ended September 30, 2015, are projected to be $3,704,295. The detailed projected plant and the applicable depreciation rates approved during the Company's last depreciation study per Order PSC-12-0065-PAA-EI were used as a basis for depreciation expense. Depreciation expense was adjusted for a portion of non-electric usage for the office structures in Fernandina Beach. The depreciation expenses are shown by plant sub-account on MFR Schedule B-9.

Amortization expense includes the remaining amortization of regulatory assets and liabilities approved by the Commission as well as those we are requesting within this rate proceeding; thus, amortization of the tax regulatory asset for the South Georgia-Tax Step Up (Federal tax rate change from 34% to 35%) and for the General Liability Claim are included. Matt Kim provides additional details on these new, requested regulatory tax assets in his testimony as well as additional details contained within this testimony. The amortization is listed below as well as on MFR Schedule C-19.

Regulatory Asset-Litigation	$ 20,607
Regulatory Liability-Pension	$ (7,608)
Regulatory Liability-Tax Gain	$(27,365)
South Georgia –Tax Step up	$ 13,584
Regulatory Asset-General Liability	$ 50,000

Total income taxes for the test year ended September 30, 2015 are projected using the projected taxable operating income less calculated interest expenses less deductions multiplied by the current state and federal tax rates. Timing differences were estimated by the corporate office of Chesapeake Utilities Corporation to determine the deferred tax amounts, as elaborated upon in Matt Kim's testimony. The difference between total income taxes and deferred taxes is current income taxes. These calculations are shown on MFR Schedules C-22 and C-23.

The 2015 projected investment tax credits are calculated from the Investment Tax Credit (ITC) amortization schedule for the electric utility division. There is no ITC amortization remaining for the projected test year and accordingly the projection is zero. Annual ITC balances and amortization details appear in schedule B-23.

Q. What was the basis for the storm reserve and expense included in the test year?

A. The Company has included a storm accrual expense of $10,135 a month, or

$121,620 a year for a total storm reserve of $2,900,000, which was initially approved in Commission Order PSC-08-0327-FOF-EI. The Company does not anticipate any requirements for an increase or decrease in the annual storm expense and perceives the reserve, with current accruals, is adequate to cover any future expected storms.

Q. What is the basis for the rate case expense included in the projected test year?

A. The Company has projected rate case expense based on specific forecasts including the cost to use consultants to assist in preparation and support of a rate case and the cost for representation and consultation by an attorney. The Company is not staffed at a level to allow for preparation of rate proceedings, MFRs or the additional rate case related work load required after the MFRs are filed. Internally, the work load has increased since our last electric rate case was filed without an offsetting increase in staff within the Company. We now require additional resources beyond the level required in our last electric rate case. Much of our accounting staff that had previously worked on the rate proceedings is no longer with the Company; thus, the overall experience level of staff members as it relates to this type of regulatory proceeding has declined as compared to our 2007 rate case. The Company does not have the expertise in all areas to help facilitate the preparation of a rate case; therefore, we hired the expertise and extra assistance to assist us with this process. The Company also had to utilize temporary accounting staff and consultants to assist in the extra rate case work beyond the normal work load of the regulatory department. MFR Schedule C-10 includes more details on these expenses. All costs expected to be incurred are prudent, and should be allowed for full recovery in this rate proceeding.

The Company included a 5-year amortization period for the Company's rate case expense. Use of the 5-year amortization period will allow the Company to spread the rate case expense over a slightly longer period of time, which will therefore reduce the impact on customers' bills. The Commission has allowed the Company to use a 5-year amortization period in the past. Specifically, in Order No. 22224, issued in Docket No. 881056-EI, on November 27, 1989, the Commission authorized the Company to use a 5-year amortization period for rate case expense. Therein, the Commission recognized that it is appropriate to amortize rate case expense over the period of time between rate case proceedings and then concluded that a 5-year period was appropriate for FPU. It is likewise reasonable to use a 5-year amortization period in this proceeding as well, in view of the fact that the time span between the Company's most recent prior rate case proceeding and this filing extends more than 6 years.

Q. What is the basis for the general liability expense and reserve included in the projected test year?

A. The Company has incurred a recent claim in its electric operations that is expected to reach the cap of the self-insurance portion of our general liability account. The Company is requesting that this claim be allowed as a regulatory asset and be amortized over five years beginning with the test year. In addition, the Company is requesting establishment of a self-insurance reserve, similar to the one already in place and approved by the Commission for FPUC Natural Gas, to cover future general liability claims, and is proposing to accrue $50,000 per year to cover large claims, and $20,000 of smaller claims on an annual basis for the basis of the self-insurance reserve. This expense has been reflected in O&M expenses as a direct projection. The worker's compensation and general liability components of this account have been projected by the corporate office and details regarding the current liability claim are reflected in the testimony of Matt Kim.

The self-insurance component of this account has been projected based on our claim history. Due to an increase in claims, we have projected an increase in the reserve of $250,000 over a five year period, effective October 2014, to amortize an existing claim and establish a reserve for future claims. We have included expenses of $120,000 in our projected test year, which accounts for some large claims in auto or general liability of $250,000 over five years, plus $20,000 per year for smaller claims.

Q. **What is basis for Economic Development expenses included in the projected test year?**

A. The Company has been involved and has participated in economic development activities in the areas it serves for many years. The Company is currently developing a more robust, detailed program to guide our economic development efforts, which involves new business assistance, community involvement, customer retention, education, and local chamber involvement. The Company's

Marketing Director expects that expenses will increase due to this enhanced program, as fully explained in the testimony of Company witness Aleida Socarras. The Company has directly projected economic development expenses of $50,000 less the prior expenses of $28,750. Therefore, we have adjusted the projected test year by $21,250 for our economic development efforts. In addition, the Company is requesting approval of a new economic tariff to promote new business in its electric operations. Both our panel witnesses Cutshaw and Shelley, as well as witness Socarras, provide additional details on the economic development costs and tariffs being proposed in this rate proceeding.

Q. Are there any other direct or over and under adjustments included in the projected test year and if so, what is the basis for this expense?

A. Yes. Over and under adjustments were made to the projected test year for operational costs for which the historic year was not reflective as a sole basis of future costs or savings. The reorganization of the Electric Operations with one Director overseeing the NW and NE Divisions resulted in savings of approximately $73,000 and this expense was removed. Tree trimming, pole attachment audits, industry association dues, legal and consulting as well as transportation depreciation were also adjusted to reflect a typical year. Due to new hires, organizational changes, or revised employee allocations made during the historic year, expenses were adjusted to reflect costs for a full year. Details of all of the Over and Under adjustments made to the historic year are provided on MFR Schedule C7.

Q. What was the basis for the projection of Taxes Other Than Income ("TOTI") included in the projected test year?

A. The TOTI taxes were projected using trend factors applied to historic year expenses as appropriate or most reflective of future expected expense levels. Payroll taxes were trended based on payroll and customer growth. The regulatory assessment fee, gross receipts tax and franchise fees were calculated based on projected revenues. Property taxes were increased by inflation and plant growth. These calculations are shown on MFR Schedule C-20.

Q. Does the Company feel that the expenses projected for the test year ending September 30, 2015 adequately reflect actual expected ongoing expenses?

A. Yes, the Company reviewed the results of its projections and concluded that the expenses projected reflect expected ongoing normal expenditures in the twelve month period ending September 30, 2015. The Company reviewed results and compared them to prior projections, historical results, known changes, and anticipated changes. To the best of our knowledge and based on our review, the expenses reflected in this rate proceeding are the most accurate and up-to-date expectations for ongoing expenses.

Q. What is the basis for the Corporate Expenses allocated to the Business unit included in the test year?

A. The Corporate expenses are directly projected by the corporate office of Chesapeake Utilities Corporation and are addressed in the testimony of Matt Kim.

Q. How does the company allocate costs for corporate charges across the different utility services?

A. Whenever it is possible and practical, corporate expenses are directly assigned to the business unit incurring such cost. Corporate expenses that cannot be directly assigned are allocated among Chesapeake Utilities Corporation's business units that receive benefit from such functions and services. Chesapeake Utilities Corporation utilizes various methodologies in allocation of costs, depending on the type of expense. These methodologies are designed to reflect the relative size and benefit of each business unit receiving the shared functions and services and may include consideration of direct payroll, profitability, adjusted gross plant, investment and customers, among others, in determining the allocation basis. While Chesapeake Utilities Corporation utilizes different methodologies depending upon the type of expense, it uses the consistent methodology among all of its business units in allocating the same type of expense. The allocation methodologies are described in greater detail in Matt Kim's testimony. Chesapeake Utilities Corporation reviews and updates the allocation basis at least annually at the beginning of each fiscal year.

Q. **How does the Company allocate costs for Business Unit charges?**

A. Business unit charges are directly assigned to the business unit incurring the cost when feasible. Some expenses incurred by the FPU management and employees are allocated among only the Florida business units, allocating to those specific business units receiving the shared functions and services. As such, FPU utilizes various methodologies in allocation of costs, depending on the type of expense.

These methodologies may include customers, time studies/managers expert opinion, plant, and investment, among others, in determining the allocation basis and are consistent with prior approved methods authorized in prior rate proceedings for FPU. FPU management reviews and updates the allocation basis at least annually at the beginning of each year or as material changes warrant. The allocation basis used distributes expenses to the appropriate specific business units.

Q. What is the reason for the increase to Administrative & General (A & G) expenses for the projected test year over and above the inflation and customer growth since the last rate proceeding?

A. There are several reasons for the increase to A & G expenses. First, in the projected 2015 test year, $66,156 of common depreciation expense was included in Account 921. In the benchmark year, those charges were included in Account 403-Depreciation expense. Also, the 2015 projected year included rent expense of $124,609 that was not included in the benchmark year. The increase in rent expense is offset by reductions to rate base, depreciation expense, and taxes other than income that would have been included if the West Palm Beach corporate office was not sold. Likewise, the 2015 projected year included an increase to administrative and general insurance expense of $120,000 to establish a general liability reserve and to amortize a 2014 claim over five years. This reserve is in lieu of purchased insurance and reduces the volatility associated with periodic claims. Technology cost also increased by approximately $350,000. The remaining increase relates to additional travel costs and expanded corporate functions and services not previously available to FPU. Travel costs have increased because of centralization of the Florida staff, additional training available to employees and increased focus in customer service and employee satisfaction, which require managers to travel to all locations within Florida. The transfer of certain A & G functions to the corporate office in Delaware for increased quality and efficiency has also necessitated additional travel. Since the merger with Chesapeake in 2009, FPU has benefited from certain corporate functions, such as corporate communications and business development, which were not previously available to FPU. Better company-wide training, communications and website contents provide our employees with information necessary to provide superior customer service and increase customer engagement for higher satisfaction. See Matt Kim's testimony for additional information on A&G expenses and the reason for the variance.

Q. What is the reason for the increase in customer related expenses?

A. Customer-related expenses increased due to new customer service initiatives which included more customer service personnel, better customer systems, and an increase in service monitoring and education. This is appropriate because these initiatives allow us to better serve our customers. All costs have been prudently incurred and directly benefit the customers we serve. The testimony of Mariana Perea provides details on the customer service initiatives.

Q. What is the reason for the increase in marketing expenses?

A. Marketing expenses increased because of an increase in community awareness and notification campaigns and events which were designed to increase customers' awareness of changes taking place and what they may expect. The campaign to explain Time-Of-Use rates is an example of the type of campaigns that occurred in the historic year to better educate the customers on how to reduce their bill. The projected test year included costs for similar types of campaigns in addition to informing customers of purchased power rate changes that occur each year.

Q. What was the reason for the decrease in total transmission and distribution expense in the projected test year compared to the prior rate proceeding benchmarked to the same period?

A. These costs decreased primarily because the overall reliability of these systems was significantly improved as a result of Chesapeake's system improvement initiatives. We also centralized certain operating functions, which further contributed to the efficiency of these systems. As a direct result of these system improvements, the Company was able to significantly reduce the costs in this area over the prior rate case in today's terms; most notably, maintenance costs are down compared to the benchmark period. Despite savings, some costs increased over the bench mark period due to other Company efforts aimed at upgrading the overall quality and efficiency of our electric operations. Some of these efforts produced increased costs in the short term, but are expected to lead to lower costs, and increased efficiencies, in the long term. Among these efforts, some of which are ongoing, is our effort to assess fuel supply alternatives that will lead to lower fuel and purchased power costs for the Company and its ratepayers. Another significant factor impacting cost increases has been the actual inflationary impact on goods and services, as further outlined below. Meter expenses and other reliability-related operating costs also increased over the bench mark period, because we upgraded meters and other similar equipment, which led to similar additional expenses. Moreover, the Company has invested time and effort on ongoing training, employee development, safety enhancements, and improved communication, thereby adding to the increase in some costs over the prior rate proceeding but resulting in better service to our customers. As a result, customers directly benefit through better service, more knowledgeable and trained personnel and a more reliable system.

Also, as noted, the actual impact of inflation on payroll and goods was higher than the CPI-U factor would indicate; thus, a portion of the variance is attributable to an artificially low expectation on the true inflationary impact on costs. Management continually strives to improve the efficiency and effectiveness of our electric system, and to provide superb customer support and service at a prudent and reasonable cost to our customers.

Q. Is the O&M Compound multiplier factor which includes customer growth and inflation, appropriate to use for analysis of cost increases since the last rate proceeding?

A. No, although the factor generally considers the impact on costs due to inflation and customer growth, the economic conditions that existed in a few of the years during the benchmark period are not appropriate for measuring the true cost of inflation on goods and services during the same period. There were several abnormal years in terms of inflation that impacted the CPI-U factor. Despite having a computed inflation factor based on CPI-U that was negative in year 2008 to 2009; actual cost increases experienced during that period did not see the same rate of change due to inflation. The economic downturn and CPI-U factor was impacted by an unusual housing market and high unemployment. The Company did not experience those same decreases in payroll or in the cost of materials and supplies purchased during the benchmark period. A portion of the variance in costs compared to the bench mark periods is attributable to actual cost increases not matching the inflation factor shown in the CPI-U factors.

Q. Have there been any new positions included in the projected test year over the historic year?

A. We did not include any new positions in the projected test year, but we did include adjustments (over and under) for the promotions of two Assistant Operations Managers to Operations Managers in February 2014 which resulted from the reorganization of the Electric Operations to establish one Director overseeing both the NW and NE Divisions.

Q. **Have there been any positions eliminated in the projected test year compared to the historic year?**

A. Yes, the Company removed a portion of one position that will be allocated to other business units in Florida due to a change in job responsibilities. The "over and above" adjustment removes the portion of the payroll and related benefits that does not belong in electric operations.

Q. Are the payroll expenses incurred by the Company fair, appropriate and reasonable and appropriate for recovery in this rate proceeding?

A. Yes, FPU strives to be an employer of choice. Our goal is to attract and retain top talent. Customers benefit from our ability to employ and retain this talent through their abilities to perform the work that directly benefits our customers as well as indirectly benefits through optimal work efficiency and performance. We participate in annual compensation surveys to compare our salary ranges with the industry. We strive to pay Job Market Value to ensure we are able to compete in attracting top talent. In assessing what Job Market Value is for employees, we review a variety of annual compensation studies including the AGA (American Gas Association) Study; Payscale, Compdata Survey and other industry related studies/benchmarks. The Company also prepares detailed compensation studies on a periodic basis. For 2014, we have hired outside consultants (THEaster and Associates) to conduct a company-wide salary survey and revise and update job descriptions. The current salary ranges that are in place were based on a detailed study that was completed in 2011, which has been updated annually to reflect inflationary payroll impacts to those same ranges. In addition to paying competitive base salaries, an Incentive Performance Plan rewards employees for reaching individual and Company annual goals. This portion of pay is considered as part of normal compensation and was considered in establishing the appropriate salary ranges for positions. Making a portion of "pay" part of an incentive plan based on achieving goals is effective in ensuring that our employees meet the highest of standards in performance.

Additionally, union contracts determine pay increases for our union employees. All contracts have been prudently and fairly negotiated; however, these do impact the total payroll and benefits the Company is required to compensate union employees.

Total compensation includes reasonable and standard benefits for our full time employees including:

- 401(k) Savings Plan that matches $1 for $1 up to 6% of base salary.
- Short Term Disability (At no cost to the employee, they receive 60% of pay for extended illnesses after 7 days through Cigna).
- Long Term Disability (At no cost to employee, they receive 60% of base pay for extended illnesses after 90 days through Cigna).
- PTO days ranging from 14 – 29 per year depending on years of service.
- 10 Sick Days per year accrued.
- Tuition Reimbursement.
- Medical and Dental Benefits. Company pays a portion of the premiums.

Payroll as projected is fair, reasonable and appropriate for purposes of determining projected year expenses.

Q. **Are the maintenance expense amounts included in the test year appropriate for the purposes of setting base rates?**

A. Yes, overall maintenance expense levels are appropriate as projected in the test year; however, some of the specific periodic projects and amounts in maintenance accounts may vary from year to year. The projected test year reflects ongoing expense levels necessary to operate its system in a reliable, safe, and properly maintained manner. The Company, when feasible, takes the approach of spreading out required periodic maintenance projects over a period of time. This approach does not unduly burden the customers or the Company resources; yet, maintains the system in a safe and efficient manner.

Q. Are the expenses reflected in the projected test year prudent and reasonable?

A. Our expenses are prudently incurred. We have only sought cost recovery of expenses necessary to provide consistent reliable service to our customers. To that end, FPU has effectively and efficiently managed and controlled costs. In fact, since the merger, the Company's efficiencies have resulted in reduction of certain costs in certain areas enabling us to expand provided services and benefits to customers thereby keeping rates stable for as long as possible.

Q. **Does the net operating income used in the rate proceeding projection equal the company's budget that is used for financial reporting and if not, why?**

A. No, the Company prepared the current internal net operating income budget for the projected calendar years 2014 and 2015 during the summer of 2013, while the rate proceeding projections were based on more current expectations. Although the Company considered the items in the internal budget for purposes of the projections for this rate proceeding, a historic actual expense forward projection was used for the business unit forecast. Actual expenses were adjusted for out of period items and normalized for re-classifications between FERC accounts. These normalized and adjusted expenses were trended when appropriate and adjusted to reflect known items over or under those projections. The corporate forecast was prepared using the budget as a starting point and adjusted as appropriate to reflect current expectations. Matt Kim's testimony includes more details regarding that forecast. In addition, the internal budget is not budgeted to the same level of FERC detail that was performed in this rate proceeding forecast.

Also, since the internal budget was prepared in the summer of 2013, it did not include certain expenses pertinent to this rate proceeding. The key differences between the internal budget prepared in the summer of 2013, compared to the updated forecast reflected in this rate proceeding are as follows:

Amortization associated with the regulatory asset-pension	$274,000
Rate case amortization	$154,000
Amortization of general liability regulatory asset	$ 50,000
Accrual of general liability expense (establishment of reserve)	$ 70,000

Revenues were projected for the rate proceeding on a much more detailed basis than the internal budget with more extensive analysis to determine the appropriate billing determinants. The revenues used in this rate proceeding are the best forecast for expected revenues in the projected test year. Robert Camfield's testimony includes additional information regarding these projections.

Q. Are the revenues and expenses as projected in the test year ending September 30, 2015 appropriate for rate setting purposes?

A. Yes, the revenues and expenses reflect the prudently incurred expenses and expected revenues at current rates for the projected test year. The projected test year revenues and expenses reflected in the MFR Schedule Cs are appropriate for rate setting purposes.

Cost of Capital

Q. Please explain the basis for the projections included in MFR, Schedules D to compute the overall rate of return.

A. The Corporate offices of Chesapeake Utilities Corporation provided projections of the Chesapeake Utilities Corporation's overall capital structure for the projected years ending September 30, 2014 and 2015 included in MFR Schedule D-1 for common equity, long term debt, short term debt, and deferred taxes. Witness Kim's testimony includes and explains the methodology used to project these cost of capital components. Schedule D-1b discusses the reason for the specific equity adjustment included in Schedule D-1 which will be also be discussed further testimony provided by Matt Kim and Paul Moul. Schedule D-4a details the long term debt by issuance for both FPU and Chesapeake. Schedule D-3 includes the test year and projected short term debt along with a narrative of Chesapeake's policies on short term financing. The Company policy on the timing of entrance into capital markets is outlined in Schedule D-8. Customer Deposits for FPU electric were projected based on the historical year-end balance at September 30, 2013 and applying the customer growth rate to those balances. The cost rate was based on the historical year average cost rate, applied to the projected balance of customer deposits. The interest rates for customer deposits are paid in accordance with the rules and regulations required. Schedule D-6 in the MFRs contains the forecast for customer deposits. Deferred taxes for FPU electric were projected based on separate projections of each timing difference. A detailed projection was made for deferred taxes based on the timing differences expected. Depreciation expense was computed for tax purposes based on the specific capital projections included in this filing as part of the deferred tax estimate. This projection of deferred taxes is discussed further in witness Kim's testimony. The Company hired an expert in Cost of Capital analyses, witness Paul Moul, to assist with developing the overall capital structure and cost rates utilized in our MFR D Schedules, and he has also provided additional supporting testimony regarding our cost of capital.

Q. Please discuss the long term debt schedule included in the filing.

A. Schedule D-4a is broken in to two segments, FPU's debt and Chesapeake's debt. FPU's debt was originally issued by FPU before the merger with Chesapeake and the FPU debt has only been allocated to the original FPU divisions. The remainder of Chesapeake corporate debt was allocated to the electric operations based on the pro-rated overall percentage of Chesapeake debt to equity less the directly assigned FPU debt. This methodology is discussed further in witnesses Matt Kim's and Paul Moul's testimonies.

Q. What is the capital structure of the Company?

A. As discussed in depth by witness Moul, the projected capital structure of the company consists of 46.45% equity, 28.2% long term debt, and 5.19% short term debt. The rest of the capital structure is composed of direct components of the electric division. The overall weighted average cost of capital for the projected test year is 7.18%.

Q. How do the ratios compare with other electric utilities?

A. The 7.18% weighted average cost rate is comparable to other utilities in the State of Florida. The Common Equity ratio is also comparable to other major electric utilities in the state of Florida. Witness Moul also provides additional explanation regarding the ratios and cost rates.

Q. Has the merger with Chesapeake had an impact on FPU's overall cost of debt?

A. Yes. For instance, the debt rate in the 2006 rate case was 8.03%. In the current projections for 2015, the Chesapeake debt rate is 4.89%. The overall weighted cost of capital has decreased from 8.18% in 2006 to 7.18% in the projected test year.

Q. Let's discuss the basis for your projections of the various capital components. Are there any capital components that you have excluded from this filing that were included in the last rate case?

A. Yes, the Company no longer has preferred stock, which amounted to $600,000 in 2006 and was .0049% of the capital structure.

Q. Please explain how the projected amounts for deferred taxes and income tax credits were derived?

A. Witness Kim's testimony discusses these components in more detail. In summary detailed projections were made for expected deferred taxes using expected timing differences including depreciation expense for tax purposes. ITC has been fully amortized, and is projected to be zero for the test year.

Q. How did you determine the amount reflected for customer deposits?

A. Average customer deposits for the historic year ended September 30, 2013 was trended by customer growth expected for the two projected years to estimate the customer deposits included in the capital structure.

Q. Is this consistent with the methodology approved by the Commission for FPU in the Company's 2007 rate case?

A. Yes, the Company used this same forecast basis for customer deposits in the prior rate case.

<u>Consolidated Fuel Rates and Impact to Fuel from Generation Project</u>

Q. Please explain the need to consolidate Fuel rates for 2015 and the relative fairness issue related to this base rate proceeding.

A. The Company has transmission assets embedded in its base rates for the Consolidated Electric Division, but similar assets to serve the customers located in the NW division are owned by Gulf Power Company and the related rates are passed on to our NW division thru the fuel rates charged to just those customers. The Company had originally requested the consolidation of its fuel rates for these divisions in conjunction with the consolidation of base rates in our prior proceedings; however, the Commission approved the consolidation of base rates but not fuel rates. Accordingly, the Company recently requested a special allocation in the Fuel Clause to deal with the transmission related costs, and the fairness of associated rates. The Commission approved this allocation in the 2014 fuel rates; but, required that the Company consider and address consolidation of fuel rates in the 2015 Fuel Clause. The Company may, consequently, request that the Commission allow the Company to consolidate its fuel rates in through the upcoming Fuel Clause for the calendar year 2015. In the mean time, the Commission approved the allocation methodology currently used for the fuel rates for 2014 which addresses the fairness issue and customers are being billed the appropriate fuel rates. While the Company intends to address fuel rate consolidation in the context of Docket No. 140001-EI, as directed by the Commission, the Company does offer an alternative approach that could be considered in this proceeding. This alternative would remove the subject transmission assets entirely from rate base now, and allow recovery of these assets, along with expenses and return on assets, through the Fuel Clause in a manner consistent with the approved allocation of transmission related expenses for 2014.

Q. The Company expects to realize savings to its customers from a Power Generation Project in its NE division. What is the estimated savings to customers as a result of this project?

A. The Company is taking a number of measures to mitigate cost pressures and improve electricity services to retail consumers in the Northeast and Northwest Division. These changes include both tactical and strategic actions. An example of strategic actions is our newly formed power generation subsidiary, Eight Flags Energy LLC (Eight Flags), in the Northeast Division. As discussed in Mark Cutshaw's testimony, Eight Flags is expected to begin with a [redacted]

[redacted] which will substantially reduce the costs of power paid by retail consumers.

Because of its inherent technical efficiency and proximity on the Amelia Island, the Eight Flags project will also result in improved reliability and reduced environmental emissions. As addressed in the panel testimony of witnesses Cutshaw and Shelley, Eight Flags Energy is expected to provide net benefits of [redacted], during the initial two years of operation, 2016 and 2017, respectively. Over its initial ten years of operation, 2016-2025, the Company's Eight Flags cogeneration plant is expected to provide a total of direct net benefits of [redacted], stated on a nominal and discounted basis respectively.

Q. Is there anything that the Company can suggest to help bridge the gap between the base rate increases expected in 2015 as a result of this base rate proceeding, and the fuel cost decrease expected to begin in 2016?

A. One option that the Company will explore is to seek Commission approval in the Fuel Clause proceeding to allow the Company to under recover fuel costs in 2015 in order to offset some of the base rate increase. The Company would then recover the under-recovery in fuel over a three-year period when savings are expected to be realized as a result of the new generation project. This will provide relief from rate shock to our customers, and phase in the increase and decrease associated with the base rate increase, and fuel cost decrease, respectively. In other words, to avoid potential rate shock of a requested 6.79% increase on total revenues for the requested base rate change in 2015, and the expected fuel cost decrease of [redacted] on total revenues for the fuel rate change in 2016 and beyond, the Company may request a phased-in approach to this fuel cost decrease, and offset some of the increase in the bridge year of 2015. Customers would have a "one year gap" of base revenue increase without corresponding decrease in fuel costs. This gap could be collected over a three year period thus reducing the volatility associated with changing overall rates to customers.

Q. Are there any changes to the fuel rates required or requested at the time of this rate proceeding?

A. Yes, but only as a result of the consolidation of Outdoor and Streetlight tariffs requested in this base rate proceeding, which, if approved, would necessitate that fuel rates for these rate classes be combined as well. The panel testimony of witnesses Cutshaw and Shelley includes additional details surrounding this change to fuel rates and a related exhibit which computes the new fuel rates associated with the new Lighting tariffs.

Summary

Q. Please summarize your testimony.

A. As is clearly demonstrated, the Company has been, and is, currently below the low point of our allowable return. Without rate relief, the Company is expected to continue to earn a return well below its allowable rate of return. If that continues, this will jeopardize our ability to provide sufficient, consistent reliable service to our customers.

FPU is requesting a permanent increase in the electric rates and charges in the amount of $5,852,171 in order to cover the deficiencies in revenues for the projected September 30, 2015 test year. This required revenue is based on a rate of return equal to 7.18% and a projected rate base of $60,596,169.

Florida Public Utilities Company is also requesting interim rate relief in the amount of $2,433,314 in annual electric rates and charges. Stated in percentage terms, we seek an interim increase in revenues equal to 14.91% on base rates and charges. The interim rate increase is based on a weighted average cost of capital equal to 6.37% and a September 30, 2013 year end rate base of $54,511,326.

Furthermore, the Company has appropriately, fairly, and prudently projected the September 30, 2015 test year Net Operating Income, Rate Base and Cost of Capital; and as such, it should be used as a basis to determine the revenue requirement.

Q. Does this conclude your testimony?

A. Yes.

Q. **Please state your name, affiliation, business address and summarize your professional experience and academic background.**

A. My name is P. Mark Cutshaw. I am the Director of System Planning and Engineering for Florida Public Utilities Company (FPU or Company). My business office address is 911 South 8th Street, Fernandina Beach, Florida 32034. I joined FPU in May 1991 as Division Manager in the Marianna (Northwest Florida) Division. In January 2006, I became the General Manager of our Northeast Florida Division, and in 2013, I moved into my current position of Director of System Planning and Engineering. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. Since joining FPU, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes. Most recently, I provided testimony in the Commission's Fuel and Purchased Power Cost Recovery Proceeding in 2013. I also testified in the Company's 2007 rate case in Docket No. 070304-EI as part of a panel with Don Myers. Likewise, I participated in the 2003 rate case filing (Docket No. 030438-EI), wherein the Commission authorized the

Company to consolidate the base rates of the Company's Northeast (Fernandina) and Northwest (Marianna) divisions. I have been involved with numerous other filings, audits and data requests before the FPSC, including filing testimony on several prior occasions in the Fuel and Purchased Power Cost Recovery proceeding, as well as the preparation and support of the Company's cost of service studies for the 1993 rate case (Docket 930400-EI) and presentation of the Company's storm hardening and hurricane preparedness activities.

Q. **Are you familiar with the operations and management of the Northeast and Northwest Florida divisions?**

A. Yes. Having worked directly in both divisions and now as the Director of System Planning and Engineering for the Company, I am very familiar with all aspects of the operations and management. I have also been responsible for collecting the information necessary to support this important part of our filing.

Q. **Please state your name, affiliation, business address and summarize your professional experience and academic background.**

A. My name is Drane A. (Buddy) Shelley. I am Director, Electric Operations for Florida Public Utilities Company (FPU). My business office address is 911 South 8th Street, Fernandina Beach, Florida 32034. I joined FPU in December, 2006 as Operations Manager in the Marianna (Northwest Florida) Division. In February, 2009, I was promoted to General Manager of the Northwest Florida Division, and in 2013, I moved into my current position of Director, Electric Operations. I graduated from Murray State University in 1976 with a B.S. in Electrical Engineering Technology and began my career with Big Rivers Electric

Company in May, 1976. I spent 15 years with Big Rivers Electric Company and held positions of increasing responsibility that involved substation, transmission, distribution and power plant electrical design, as well as operations and maintenance activities. After leaving Big Rivers, I worked 14 years for three (3) different Engineering Consultant Firms providing services to several Electric Utility Companies including IOU's, Municipals, and Cooperatives. Since joining FPU, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. No.

Q. Are you familiar with the operations and management of the Northeast and Northwest Florida divisions?

A. Yes. Having worked directly in both divisions and now as the Director, Electric Operations for the Company, I am very familiar with all aspects of the operations and management. I have also been responsible for collecting the information necessary to support this important part of our filing.

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

A. We will provide information in Section I relating to the important projects that our Company has implemented over the last four years in a successful effort to improve the reliability of our electric system. We will also explain the rationale behind these projects and support the appropriateness of the associated investment dollars and expenses to be included in new base rates. In that context, we will address our Pole Replacement Plan and our Storm Hardening Plan. We will also address in Section II several other capital projects undertaken by the Company in recent years but will focus on one particular critical project. These additional projects are designed to support customer growth, improve customer service and provide significant fuel savings for FPU's customers. We will discuss our new operations center in Section III and describe our purchase power partners in Section IV and explain how we are working to lower customer fuel clause expenses. In Sections V and VI, we will address the Company's proposed cost of service methodology, including certain changes that the Company is seeking in conjunction with this rate case filing; the Company's rate design methodology, including a proposed step rate increase, as well as the benefits of consolidation of the Company's fuel rates, which the Company intends to propose for further Commission consideration later this year in the context of the Commission's fuel cost recovery proceedings. Finally, in Section VII, we will describe some of the positive impacts that the acquisition by Chesapeake Utilities Corporation has had on the Company's ability to improve reliability, improve safety, and provide savings for customers.

Q. Do you have any exhibits to which you will refer in your testimony?

A. Yes. We have 9 exhibits. Exhibit MC/DS-1 is a list of the MFRs that we sponsor. Exhibit MC/DS-2 is a list of capital projects that relate to reliability improvement efforts. Exhibit MC/DS-3 is a copy of our 2013 Storm Hardening and Reliability Report. Exhibit MC/DS-4 is a compilation of metrics related to FPU electric system reliability. Exhibit MC/DS-5 is a list of on-going and projected capital projects. Exhibit MC/DS-6 is a compilation of safety statistics. Exhibit MC/DS-7 is a list of the proposed lighting rates to be included in this proceeding. Exhibit MC/DS-8 is the determination of the purchase power adjustment changes that will be required with the consolidation of the outdoor and street lighting rates. Finally, Exhibit MC/DS-9 will include information regarding the purchased power adjustment benefits that customers will receive based upon a proposed cogeneration project. We have reviewed and support the preparation of each of these exhibits.

Q. Are you sponsoring any MFRs in this case?

A. Yes. We are sponsoring the MFRs listed in Exhibit MC/DS-1. To the best of our knowledge, these MFRs are true and correct.

Q. Please describe who will be responsible for the different aspects of the testimony.

A. Yes. P. Mark Cutshaw will be the primary witness responsible for defending the majority of the testimony. Drane A. (Buddy) Shelley will provide additional support to the testimony with particular focus on the operations activities and construction work.

Q. Please describe FPU's distribution system and your service area.

A. The service area is divided into the Northeast and Northwest Florida Divisions with a total of just over 31,000 customers. The Northeast Florida Division is located in Nassau County with the service area being confined to Amelia Island. The Northwest Florida Division is located in portions of Jackson, Calhoun and Liberty Counties with the majority of the customer base being located in Jackson County.

Q. Would you describe FPUC's distribution system and service area for the two divisions as being similar?

A. No. The Northeast Florida division is located on Amelia Island with a total service territory of approximately 40 square miles. Customer density is very heavy with a similar mix of overhead and underground distribution facilities. The proximity to the beach and a large city helps stabilize the resort and vacation areas of the island while two large paper mills provide excellent job opportunities and additional stability to the area. While the economy did have an impact on this area the recovery seems to be making some progress.

The Northwest Florida division is located in a more rural, inland area with a total service territory of approximately 300 square miles. Customer density is relatively sparse, similar to what you would expect in a rural area, with the service provided predominantly by an overhead distribution system. The rural, more inland service territory with fewer industrial customers makes this area slightly more susceptible to economic downturns and is not showing the recovery being experienced in the Northeast Florida division.

Ia. CAPITAL PROJECTS RELATING TO RELIABILITY IMPROVEMENTS

Q. Please identify the various capital projects to which you have referred that relate to improving reliability on the FPU electric system.

A. The capital improvement projects relating to improving reliability can be categorized as follows: replacement of aging/unreliable underground conductors, replacement and upgrade of relay and control schemes at substations, replacement/upgrade of transmission circuit breakers at two substations, upgrade of a substation buss at one substation, replacement of wood distribution poles, relocation of distribution lines that had been inaccessible to roadways, replacement of insulators along a coastal highway, replacement/upgrade/addition of distribution voltage regulators/reclosers, and replacement of wood transmission poles with concrete poles. Since 2008, and through our projected test year, we have or will have spent in excess of $10,900,000 for reliability improvements.

A. Replacement of Aging/Unreliable Underground Conductors

Q. What did the projects to replace underground conductors entail?

A. In the Northeast Division there were a significant amount of underground conductors that had been installed in the 1970s. These conductors were aging poorly and needed to be replaced. The scope of these projects was to replace underground conductors on Amelia Island with a significant portion of the work being conducted on the south end of Amelia Island. The focus on the south end of the Island was due largely to construction activity that occurred in that area in the 1970's.

Q. What were the costs associated with these projects?

A. Over $4.6 million was spent through the end of 2013 with total projected costs through 2014 projected to reach over $5.0 million. Exhibit MC/DS-2 shows the projects and associated cost details.

Q. Why were these projects necessary?

A. The existing underground conductors were older technology conductors that were operated in a harsh environment, in areas where the groundwater was near the surface and the salt content was high. They had been installed directly in the ground with an exposed concentric neutral. The concentric neutral in many cases had deteriorated and there was pitting of the conductor insulation. The failure rates were extremely high, at one point occurring almost daily. Reliability was suffering and customers were being adversely impacted.

Q. What benefit has the Company seen as a result of these projects?

A. The Company has experienced a significant reduction in underground cable failures, which reduces outages, improves the reliability indicators and has a direct impact in the reduction in overtime work and associated expense. Details of this type of improvement are included in the Company's annual 2013 Storm Hardening and Reliability Report that was submitted March 1, 2014 a summary of which is included in Exhibit MC/DS-3.

Q. What benefits have customers seen as a result of these projects?

A. Customers have benefitted from improved reliability through reduced electric outages which had significant, unwanted impacts on the daily life of our customers. Exhibit MC/DS-4 shows the detail and trend of FPU reliability metrics.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. As previously indicated, the Company was experiencing very frequent outages in certain areas prior to these projects to replace underground conductors. There was no other way to effectively remedy the situation and further delay would have exacerbated the deteriorating situation. Replacement of the underground cable in these areas actually began around 2000 and was focused on small areas of replacement each year. The cable failures and resulting outages, however, quickly outpaced the rate of cable replacement, which was ultimately accelerated slightly in 2006. This replacement effort continued, but the outages nonetheless continued at an unacceptable level. After the merger, our new parent, Chesapeake Utilities recognized that more focus should be applied to improving reliability. As a result, the decision was made to further accelerate the cable replacement with a goal to complete the work in 2013. Although some work still remains, the majority of the work was completed by year end 2013, and the outage rate has decreased dramatically as a result.

B. Replacement and Upgrades of Relays and Control Schemes at Substations

Q. What did the projects to replace and upgrade relays and control schemes at substations entail?

A. These projects primarily involved replacing existing electromechanical relays with electronic digital relays in multiple substations.

Q. What were the costs associated with these projects?

A. The costs were approximately $430,000. The projects and costs are shown in Exhibit MC/DS-2.

Q. Why were these projects necessary?

A. The Northeast Florida division does not currently have a Supervisory Control and Data Acquisition (SCADA) System and must rely on manual control of the substations. In order to move towards the installation of a functioning SCADA system and to comply with certain North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council (FRCC) compliance standards, the project began the systematic replacement of electromechanical relays within the substations with electronic digital relays. The relays could be easily integrated into a SCADA system, could also be programmed to comply with NERC/FRCC compliance standards and have also proved to be much more reliable than previous relays.

Q. What benefit has the Company seen as a result of these projects?

A. In addition to compliance with NERC and FRCC requirements, the Company will see two areas of benefits. First, replacing the older technology allows for more reliable and more secure substation operation. But also very importantly, the new electronic digital relays afford the opportunity for more flexible control schemes and the ability to remotely control operations and obtain additional information regarding the status and operational history of the substation.

Q. What benefits have customers seen as a result of these projects?

A. These projects have contributed to the improvements in the Company's reliability measures as shown on Exhibit MC/DS-4 and will continue to provide improvement as SCADA system controls are added.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. These projects were necessary both for regulatory compliance and as an integral part of the Company's reliability improvement plan.

C. Replacement/Upgrade of Transmission Circuit Breakers at Two Substations

Q. What did the projects to replace transmission circuit breakers at the referenced two substations entail?

A. Both the Amelia Island Plantation Substation and the Step-down Substation housed 1970's vintage switchgear which was becoming a recurring source of maintenance issues, was an older technology and had reached the end of its useful life. These projects focused on the replacement of the circuit breakers in the substations with modern equipment and the necessary modifications to the buss configuration necessary to maximize the effectiveness of the installation.

Q. What were the costs associated with these projects?

A. The costs were approximately $300,000 at the Amelia Island Plantation Substation and $1.09 million at the Step-down Substation. The projects and costs are shown in Exhibit MC/DS-2.

Q. Why were these projects necessary?

A. As stated, this switchgear was old and deteriorating. In particular, with regard to the circuit breakers, the insulators were breaking down, and the hydraulic systems were wearing out which would eventually lead to breaker failures and slow systems operations. In addition, the configuration of the buss only marginally met NESC code clearance requirements and could have been dramatically impacted by wind borne debris during a hurricane.

Q. What benefit has the Company seen as a result of these projects?

A. The main benefit to the Company is to improve the overall reliability and safety of the electric system by replacing outdated equipment with new technology equipment. The newer equipment operates much more quickly and reliably and avoids the possibility of mis-operations or catastrophic failure.

Q. What benefits have customers seen as a result of these projects?

A. In general customers are benefitting from the overall improvements to reliability on the FPU system. In particular, if one of these older breakers had failed while in service, there would be the high likelihood of a prolonged outage to the segment of population being served. Additionally, some of the breakers use mineral oil as the insulating medium which could have resulted in environmental issues should a failure occur.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. Any delay would have increased the risk of long interruptions of service to customers and possible penalties for failure to maintain equipment up to code.

D. Upgrade of a Substation Buss at one Substation

Q. What did the projects to upgrade the substation buss entail?

A. These projects consisted of several activities at the Company's Amelia Island Plantation substation, the largest element of which was the replacement and re-insulation of the substation main buss. In conjunction with the replacement and re-insulation of the buss, the Company replaced a roof and purchased additional property around the substation for future reconfiguring the equipment.

Q. What were the costs associated with these projects?

A. Total project costs were about $800,000. The projects and costs are shown in Exhibit MC/DS-2.

Q. Why were these projects necessary?

A. The Amelia Island Plantation substation is located next to a water treatment plant and near the Atlantic Ocean, which results in a very corrosive environment. The 12.47 KV portion of the substation is metal enclosed switchgear. However, the enclosure/building has not provided adequate protection from the environment. As it was, the roof over the switchgear was problematic because there was no opportunity for rain to wash chemicals and particulates off the enclosed insulators and buss. This raised the likelihood of a flashover and subsequent catastrophic outage. Upon preparing to perform an initial test on the system, FPU determined, prior to the upgrade, that even testing the insulators and buss was unsafe due to the visible deterioration of the equipment. The replacement and re-insulation of the buss therefore significantly reduced the risks of equipment failure.

Q. What benefit has the Company seen as a result of these projects?

A. There have been no flashovers or equipment failures and the new equipment has extended the life of the substation. The purchase of the additional property has also provided easy access to the substation and will allow additional modifications to the substation as needed in the future due to capacity increases or further modifications in substation design. The additional property purchase also resolved a long time issue related to access rights to the substation by eliminating the need to cross private property to access the substation.

Q. What benefits have customers seen as a result of these projects?

A. Customers have not experienced outages due to failure of this equipment and have enjoyed overall better reliability because of this and other reliability enhancement projects.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. As with other projects discussed, any delay would have increased the risks of extended outages to customers and the possibility of a significant substation failure and posed a serious safety concern for FPU employees required to maintain and operate the switchgear.

E. <u>Replacement of Wood Distribution Poles</u>

Q. What did the distribution pole replacement project entail?

A. The Company has employed Osmose to perform extensive testing of its wood distribution pole system. This project, as of year-end of 2013, consists of the inspection of approximately 3,000 poles each year which has resulted in the inspection of a total of 21,235 (81.2%) poles since the beginning of the program in 2008. The inspection results have identified a total of 1,745 poles that required replacement. Of that number, 888 have already been replaced with 857 remaining to be replaced. The exact cost associated with the replacement of these poles is not available, but we estimate it to be approximately $1,800,000. Previous results indicate that approximately 600 additional poles will be identified as requiring replacement during the 2014 and 2015 inspection cycles. The total cost to replace the 857 pole backlog, along with the 600 additional poles we anticipate will be identified for replacement, will be approximately $2,900,000 over the next few years. This will complete the initial eight (8) year inspection cycle.

Q. Is this a component of your approved Storm Hardening Plan?

A. Yes, it is.

Q. What were the costs associated with this project?

A. The costs for pole replacement over the life of the project are anticipated to be approximately $4,700,000, which equates to approximately $580,000 per year.

Q. Why was this project necessary?

A. Damaged or rotted wooden poles are among the first casualties of weather related events. As part of the Storm Hardening Plan, the testing program and associated replacement of wood poles have demonstrated that it is imperative to replace decayed wooden poles on a regular basis.

Q. What benefit has the Company seen as a result of this project?

A. The Company is in compliance with its Storm Hardening Plan as approved by the Commission. In addition, unusual increases in operations and maintenance expenses should be avoided in future years as more of the decayed/weaker poles are identified and replaced.

Q. What benefit have customers seen as a result of this project?

A. Customers have enjoyed overall better reliability due to this and other projects described here, as well as a reduced risk of outages during significant weather events..

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would have increased the risk of outages and hurt the reliability of the system. Furthermore, the Company would not have been in compliance with the Commission Storm Hardening requirements.

F. <u>Replacement of Wood Transmission Poles</u>

Q. What did the project to replace wood transmission poles entail?

A. This project entailed the replacement of 34 wood poles with concrete poles.

Q. Is this a component of your approved Storm Hardening Plan?

A. Yes, it is.

Q. What were the costs associated with this project?

A. The costs are anticipated to be approximately $1.4 million.

Q. Why was this project necessary?

A. A detailed inspection in 2013 of the FPU 138 KV and 69 KV transmission systems found that 34 of our 69 KV wood transmission poles needed to be replaced due to severe woodpecker damage or the decayed/rotted condition of the pole with the major cause of the damage to poles being woodpecker damage. These poles are critical to the integrity of the transmission system on the island.

Q. What benefit has the Company seen as a result of this project?

A. In addition to complying with our Commission-approved Storm Hardening Plan, the replacement of these wood poles with concrete poles should avoid any unusual increases in operations and maintenance expense in future years.

Q. What benefit have customers seen as a result of this project?

A. Customers will experience improved reliability as a result of this and other reliability enhancement projects.

Q. Could the company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would result in increased risks to customers.

G. <u>Relocation of Distribution Lines</u>

Q. What did the project to relocate inaccessible lines entail?

A. This project included relocating/rebuilding several lines and line segments from wooded rural areas to roadways primarily in the Northwest Division.

Q. What were the costs associated with this project?

A. The costs were approximately $495,000.

Q. Why was this project necessary?

A. In the Northwest Division, there are numerous distribution lines located in wooded areas that are difficult or impossible to reach by vehicle. Part of the Company's Storm Hardening Plan is to place facilities on public rights-of-way and/or easements. This project was important to reliability and necessary to comply with our plan.

Q. What benefit has the Company seen as a result of this project?

A. Relocating these distribution lines to roadways has provided several benefits: employees can monitor and assess the condition of these lines in a more efficient manner; when there is maintenance to be performed or repairs/restoration to be accomplished the employees and truck-mounted equipment can be placed right at the work location; and safety is enhanced because employees aren't walking through woods at night during a storm to locate and physically climb poles to repair/restore service.

Q. What benefits have customers seen as a result of this project?

A. As with our other projects, reliability has been improved as a result of relocating these lines out of areas subject to vegetation issues to areas that are better maintained and more accessible. Outages are less frequent and of shorter duration.

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. This issue was another source of repair and maintenance issues, which contributed further to our reliability issues. Reliability has now been enhanced because of this and other projects the Company has undertaken.

H. Replacement of Insulators along a Coastal Highway

Q. What did the project to replace insulators at locations along the referenced coastal highway entail?

A. The Company has overhead electric distribution facilities that are constructed along the coastal highway designated as A1A which extends down the east side of Amelia Island bordering the Atlantic Ocean. This project consisted of replacing insulators on this wooden pole line.

Q. Does the location of this equipment in close proximity to the coast necessitate more frequent or extensive maintenance and replacement?

A. Yes. The presence of fog and salt spray off the ocean create a corrosive environment. The buildup of salt and other particulates on insulators increase the likelihood of a flashover during foggy conditions which results in an outage.

Q. What were the costs associated with this project?

A. The costs were approximately $290,000.

Q. Why was this project necessary?

A. In addition to the corrosive environment common to all coastal areas, this is an older line with dated technology porcelain insulators. When cracks or chips occur on the glazing of the insulators, there is a higher likelihood of contamination that can cause a flashover and the resulting failure of the insulator. The replacement insulators employ newer technology insulators made of a rubber/silicone material that is more impervious to the damaging effects of the sun and salt environment.

Q. What benefit has the Company seen as a result of this project?

A. The Company should not experience an unusual increases or spikes in maintenance expense along this line in the future.

Q. What benefit have customers seen as a result of this project?

A. The customers will see fewer outages as a result of this and other reliability enhancement projects.

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would have increased the risk of faults/outages and therefore interruptions to customer service.

I. <u>Replacement/upgrade of Distribution Regulators/Reclosers</u>

Q. What did the project to replace regulators and reclosers entail?

A. Voltage regulators and reclosers along several distribution feeders and in certain substations in the Northwest Florida (Marianna) Division area were replaced.

Q. What were the costs associated with this project?

A. The costs were approximately $300,000.

Q. Why was this project necessary?

A. The Northwest Division is relatively rural in nature and has relatively long feeders. The voltage regulators are needed to regulate voltage along these lines and the reclosers serve to sectionalize the feeders as a critical part of the distribution system and are widely deployed in the area. Since some of the equipment has been in service for a number of years, the equipment was experiencing operational glitches and overt failures, was no longer reliable and had reached the end of its useful life; therefore, the replacement was critical. The Company needed to replace this equipment promptly to maintain proper voltage levels, as well as safe and reliable service to its customers.

Q. What benefit has the Company and its customers seen as a result of this project?

A. As with the other projects discussed, reliability is the most significant benefit. We were receiving numerous customer complaints about low voltage levels on some of the more heavily loaded feeders in the NW system which led to problems with proper appliance and equipment operation. The replacement of the old voltage regulators has dramatically reduced these complaints. The replacement and addition of new, digitally controlled reclosers has allowed us to better isolate and restore customer outages quicker. The

Company should not experience an unusual increase in operating and maintenance expense as a result of this replacement project.

Q. Could the Company have deferred this project without risk to its levels of service and service reliability?

A. No. Any delay in this project would have resulted in increased the risks of service interruptions, as well as prolonged interruptions, and continued voltage level complaints from customers.

J. Ongoing and Planned Capital Projects Relating to Reliability Improvement

Q. What additional projects relating to reliability are ongoing and planned to be completed in 2014/2015?

A. These projects include: additional distribution wooden pole replacements based on the 8-year replacement cycle established by the testing program, additional transmission wooden pole replacements, replacement of a large 40,000 kilovolt-ampere (kVA) substation transformer, upgrades of two distribution feeders, continued replacement of old voltage regulators, addition of reclosers and upgrading the transmission and substation system for improved reliability and in preparation for a planned additional cogeneration project. One of the two distribution feeder upgrades is required by the Company's Storm Hardening Plan, namely the upgrading of the feeder to a hospital in Marianna.

Q. What are the costs associated with these projects?

A. Total project costs for this category are expected to be approximately $9,145,500 for 2014 and 2015. Details of the projects with descriptions and individual project costs are shown on Exhibit MC/DS-5.

Q. Why are these projects necessary?

A. All of these projects are necessary to continue the improvement in reliability that our customers are now experiencing. The completion of these projects will lower the risk of outages, facilitate the inspection and testing of power lines/equipment, expedite the maintenance and repair of power lines and related equipment, allow for quicker and more effective restoration operations when outages do occur and provide access to additional purchased power that will be less expensive and more reliable that is currently available.

Q. What benefits do the Company expect to see as a result of these projects?

A. The Company will experience more efficient operations, continue to storm harden the distribution and transmission electric systems and should avoid large increases in maintenance expense in future years.

Q. What benefit should customers expect to see as a result of these projects?

A. The customer will realize continued improved reliability, both in terms of number and duration of interruptions as a result of additional storm hardening of the electric system. Customers should also realize a reduction in the overall rate of electricity as a result of these projects.

Q. Could the Company have deferred these projects without risk to its level of service and service reliability?

A. No. These projects are critical to maintaining and improving service levels for our customers.

Q. Were all of the reliability projects you have addressed part of the Company plan?

A. Yes. These projects were part of a comprehensive planning process directed towards materially improving the Company's service reliability and ensuring ongoing compliance with our Storm Hardening Plan.

Q. Were your efforts successful and beneficial to your customers?

A. Yes, in all respects. As explained later in this testimony, overall measures of service reliability have improved as a result of our attention to these areas. Moreover, the Company not only adheres to its Storm Hardening Plan, which was most recently approved by this Commission in Docket No. 130131-EI, but also endeavors to stay abreast of the latest methods, technologies, and engineering advancements to further enhance reliability and harden FPU's system against storm damage with the goal of further improving our ability to provide reliable service to our customers.

Q. How did the Company conclude that these projects were needed?

A. Many of the projects were identified and completed based on maintenance and inspection activities that have been conducted both on a routine basis, as well as part of our

Storm Hardening Plan. Examples of these include: review of reliability indicators, pole inspections, underground system inspections, substation inspections, vegetation management activities and input from employees and customers.

Q. Why does the Company engage in maintenance and inspection activities?

A. First of all, it has always been the Company's goal to maintain its system consistent with industry safety and operating standards and in such a way that interruptions of service to customers are minimized. Our employees strive, and have been successful, at operating a safe and reliable electric system. However, the hurricanes of 2004 and 2005, which impacted most of Florida, resulted in lengthy outages for millions of electric customers. Throughout Florida, storm restoration costs were much higher than ever experienced. In particular, on the FPU electric system, 2004 brought Hurricanes Bonnie, Charley, Frances, Ivan and Jeanne and 2005 brought impacts from Hurricane/Tropical Storms Arlene and Dennis. Although each storm impacted FPU's system differently, each resulted in damage to the electrical systems and customer outages. From that experience, we gained valuable information and lessons were learned. In particular, we determined that, as a Company, there were three areas that we needed to address in order to make sure FPU was better prepared for any future such events, those areas being: (1) the frequency of facility inspections; (2) the testing of physical transmission and distribution assets; and (3) implementation of a more proactive approach overall to protection of our electric system. Having addressed those areas of concern, FPU now has a robust maintenance and inspection plan, which encompasses its approved Storm Hardening Plan, and expects to continue its successful efforts to improve reliability through projects such as these.

Q. How do customers benefit from these activities?

A. As you can see, the importance of reliability is a recurring theme of our testimony. That is largely because it is a very important part of customer satisfaction. Outages and service interruptions can be much more than just a minor inconvenience for our customers. They can, in fact, create numerous issues for customers, ranging from food spoilage to loss of critical business functions to traffic problems and similar safety concerns. A well-maintained electric system providing consistently reliable service not only lessens the inconveniences associated with service interruptions, but also better protects the business interests and safety of our customers and our employees.

Q. Have you been able to document service improvements to your customers?

A. Yes, we have. As shown on Exhibit MC/DS-4 to our testimony, FPU has made dramatic improvements in reliability since 2009. The Customer Average Interruption Duration Index (CAIDI) improved from 108.81 in 2009 to 93.31 in 2013. The System Average Interruption Duration Index (SAIDI) improved from 218.40 in 2009 to 169.66 in 2013. The System Average Interruption Frequency Index (SAIFI) improved from 2.01 in 2009 to 1.82 in 2013. Finally, the L-Bar Index, which measures the Average Length of Service Interruption, improved from 116.74 in 2009 to 91.97 in 2013.

Ib OPERATING AND MAINTENANCE EXPENSES

Q. Has the Company reviewed operating and maintenance expenses to ensure all the prudent and justified.

A. Yes. Shortly after the merger with Chesapeake in 2009, the new management team began a thorough review of internal business organizations throughout FPU. The new team set out to establish better defined goals and to ensure those goals were being met.

Q. What types of reviews were conducted and what changes occurred?

A. During this review, areas such as improved safety, customer service, system reliability and employee efficiency were the underlying goals. Safety and training functions were expanded, which provided employees with additional training and also increased the visibility of safety personnel in the daily work. During the review of the customer service area, the Company quickly determined that the systems and personnel in place at that time were not providing the level of customer service that was required. Changes were implemented to upgrade the systems used for customer service, and personnel were expanded to increase the level of customer service. Also, system reliability was well below a reasonable standard and had to be addressed. Operation and maintenance procedures were evaluated to ensure that items, such as wood pole testing, underground distribution inspections, vegetation management activities, transmission system inspections, infrared inspections, and the like, were sufficient. Based on the reliability indices, it was apparent that all these needed to be increased if improvement was to be achieved. Another major area that needed to be addressed involved employees and how their work environment and resources impacted their overall productivity and efficiency. During this review, areas such as personal protective equipment, office and vehicle conditions, access to materials, and related issues were addressed to provide employees with an environment that was conducive to increased efficiency and productivity.

Q. What benefits have the Company seen as a result of these changes?

A. Safety results have been improving, customer service measures have indicated an overall improvement, our electric system reliability indices are improving, and overall, our employees are much more engaged and productive. Additionally, through the management team's focus and increased engagement of all employees, the Company has reviewed cost to ensure increases occurred only when prudent and justified. This also allowed the consolidation of certain positions and functions within the operations group which has contributed to offsetting some of the cost increases related to improved customer service, enhanced safety measures and other costs outside of the Company's control.

II. CAPITAL PROJECTS NOT SPECIFICALLY RELATED TO RELIABILITY IMPROVEMENTS

Q. What other capital projects have been executed since the Company's last test year?

A. In addition to reliability improvement projects, the Company has invested significant amounts in projects to improve our Company's operations and provide better customer service. These projects fall into several categories including: supporting customer growth that may occur, facilitating new generation supply, installing a new customer information system, replacement of general plant items and routine maintenance of the electric system.

Q. Please describe the most significant project in the category of increasing capacity to serve new growth?

A. We are engaged in an ongoing project to construct a new underground distribution feeder to serve areas where customer growth is anticipated in the near future. This feeder will provide a needed distribution tie between two substations for backup supply during emergency conditions or routine maintenance. This project involves the installation of approximately four (4) miles of distribution lines and associated distribution equipment.

Q. What are the projected costs associated with this project?

A. Total project costs are expected to be approximately $1,200,000 when the job is completed in 2015.

Q. Why are projects such as this necessary?

A. The Company has an obligation and a desire to serve all customers. There are however, areas in the Northeast and the Northwest Divisions where existing feeders will not accommodate the service requirements associated with new customers on our system. Therefore, in order to serve new customers in these areas, we much undertake this and similar such projects. Otherwise, we will be unable to meet our service obligations.

Q. What benefit does the Company expect to see as a result of these projects?

A. The Company will meet its obligations to serve new customers and realize a larger customer base on which to spread its fixed costs. Also, these projects will continue to provide more reliability to the systems and provide redundancy in areas in which it does not currently exist.

Q. What benefit should customers expect to see as a result of these projects?

A. New customers will receive reliable electric service that they expect and all customers should benefit from a larger energy usage base among which fixed costs will be spread.

Q. Could the Company have deferred these projects without risk to its levels of service and service reliability?

A. No. New customers will not be served if assets are not added.

III. OPERATIONS CENTER

Q. Has the Company implemented other improvements that have had an impact on operations?

A. Yes. In 2013, the Company opened a new operations center in Fernandina Beach, which serves as the headquarters for the Northeast Division.

Q. What prompted the decision to open the new operations center?

A. Prior to 2013, operations in the Northeast Division was split between an office facility (engineering, customer service, planning) at 911 S. 8th Street and a warehouse facility (construction, maintenance, warehouse) located at 611 Lime Street. The office facility was built in the 1970's and was insufficient to efficiently serve customers and employees. The warehouse was constructed in the 1940's and had deteriorated significantly over the years. The warehouse site had originally housed a generation facility for the island, as well as, an ice plant for its customers.

Q. What are the benefits to Company operations derived from the new operations center?

A. Combining the office, operations and warehousing groups into the new location is more efficient and promotes better communications among employees. Additionally, the old warehouse facility has significant structural issues and did not provide an environment that was conducive for employees comfort and well being. Moreover, the small multi-level facility was very difficult to move around in safely and efficiently.

Q. What are the direct benefits to customers of this new operations center?

A. In addition to more seamless customer service resulting from better employee communications, the new operations center is much more centrally located to the customers in the Northeast Division. As such, it provides easier access for customers, including an expanded parking area, as well as a conveniently located drop box that can be accessed by customers from their vehicles.

IV. PURCHASED POWER PARTNERS

Q. Does the Company own and operate any generation assets?

A. No, not at this time.

Q. Does the Company therefore purchase power from other entities in order to serve the two electric divisions?

A. Yes. For the Northwest Division, FPU purchases power from Gulf Power Company under a Commission-approved purchased power agreement. For the Northeast Division, the

Company is currently under contract with JEA for power supply, but also has contracts with certain Federal Energy Regulatory Commission ("FERC") certified "qualifying facilities" for additional power purchases. The additional power purchases are at costs less than the JEA contract prices which in turn provide a savings to customers.

A. Savings for the Northwest Division

Q. When did the Company enter into its contract with Gulf Power Company for power for the Northwest Division?

A. Dating back to the 1960's, the Northwest Florida division purchased its all requirements wholesale power from Gulf Power Company. Numerous contracts were executed through the years. Effective January 1, 1997, an eleven year agreement became effective that would continue through December 31, 2007. During the course of the contract, purchase power costs were very favorable and resulted in FPU having some of the lowest electric rates in the State of Florida. In 2006, as its then-current purchased power contract approached expiration, FPU again selected Gulf Power for a new ten-year power supply agreement to begin January 1, 2008. Implementation of that new contract was, from a customer relations perspective, very complex, because the expiring contract had been negotiated at a time when costs related to the provision of electric energy were relatively stable. As such, the expiring contract had included firm prices for the provision of electric service which incorporated transmission service in that firm price. The new contract that became effective in 2008 includes market-based costs, with environmental costs rolled into the energy costs. Under the new arrangement, transmission services have been separated out and are provided, and priced, under a separate contract with Southern Company Services.

The 2008 contract with Gulf Power was approved by the Commission in Docket No. 070108-EI, wherein the Commission acknowledged the Company's representations that Gulf Power has proven to be a good business partner, provides reliable service, and that the new contract was the best, most cost-effective offer available to FPU. The new contract did, however, result in a notable price increase to customers in the Northwest Division. The Company undertook significant efforts, including public relations and customer education campaigns, as well as regulatory proposals for rate consolidation and graduated increase, in an effort to lessen the initial impact to customers. Nonetheless, the impact of the new agreement for many FPU customers was hard felt, particularly because it was implemented during the early stages of the country's economic downturn.

As the economic downturn continued, FPU looked for ways to provide relief to its customers in both divisions. At different points between 2008 and 2009, FPU engaged in some limited conversations with Gulf Power about the possibility of adjusting the contract in some way that would provide benefits for both parties.

Q. How did the 2011 Amendment to the purchase power agreement with Gulf Power Company come about?

A. Subsequent to the Commission's approval of the 2008 contract with Gulf, the Company entered into a new franchise agreement with the City of Marianna. A notable component of the new franchise required the Company to implement Time of Use (TOU) rates and Interruptible rates by February 17, 2011.

Not long after the Company entered into the new franchise agreement, specifically October 28, 2009, Chesapeake Utilities Corporation and Florida Public Utilities Company consummated the transaction whereby Florida Public Utilities Company became a wholly-owned subsidiary of Chesapeake.

After the acquisition by Chesapeake, FPU, now under new management, began the process of reviewing and determining how best to develop and implement the TOU and Interruptible rates mandated by the Franchise. FPU quickly determined that, in order to develop TOU and Interruptible rates that would satisfy the requirements of the Franchise and also comply with Commission regulatory requirements, changes to the 2008 contract with Gulf would be necessary. Thus, the Company actively engaged Gulf in discussions to develop a negotiated Amendment that would provide FPU with the pricing flexibility necessary to develop TOU and Interruptible rates that are cost-based and otherwise in compliance with regulatory requirements. As a result, the companies reached an agreement reflected by Amendment No. 1 to the 2008 contract.

Q. Has the Amendment No. 1 proven to be beneficial?

A. Yes. The Amendment has proven very beneficial to FPU and its rate payers. Specifically, the Amendment provides, on average, annual savings of $900,000 for FPU's customers in the Northwest Division over the life of the contract by reducing the fuel and purchased power charge for FPU customers.

B. <u>New Renewable and Cogeneration Contracts</u>

Q. Has the Company investigated means to reduce costs for its customers in the Northeast Division as well?

A. Yes. The Company has aggressively sought opportunities to engage its current base load provider for the Northeast Division in discussions for an arrangement that would be more beneficial for the FPU customers. Since 2007, when purchased power rates began to increase significantly from JEA, FPU has been very assertive in challenging each cost of service study performed by JEA that resulted in an increase to the purchased power rate. These very focused and steady efforts have resulted in the mitigation of the rate of increase in purchased power cost for FPU and its customers. These same focused and steady efforts are continuing today and, in our opinion, have resulted in a reduced rate of increase to FPU and its customers.

During this same time period, the Company has investigated opportunities with other wholesale power suppliers. During the investigation relationships were developed with other suppliers, informal studies of generation and transmission capacity arrangements were reviewed and contract possibilities were discussed. Although these opportunities are not possible until the expiration of the JEA contract, this information does provide FPU with market knowledge and information that assist with discussions with JEA.

Also, the Northeast Division provides service to two paper mills on Amelia Island that have significant on site generation capabilities which has created opportunities for some limited purchased power for FPU. Based on this potential, FPU has entered into arrangements with these alternative power providers that have thus far proven very advantageous. FPU is continuing to look at these and all other avenues for reducing purchased power costs that are available to the Company.

Q. What type of investigation has the Company done related to reduction of purchased power cost?

A. Since the merger with Chesapeake in 2009, the Company has focused many resources on how to reduce the purchased power cost and its impact on customers. As previously mentioned, during this time other wholesale power providers have been approached and opportunities explored, review of new electric generation technology has been conducted, Combined Heat and Power (CHP) partners have been identified, experts in the area of CHP projects have been retained and parties have come together to evaluate electric generation projects. These partners and experts have assisted FPU with the review and evaluation process. Ultimately, most of the projects evaluated were not prudent ventures for the Company. However, the Company's review team found that certain limited projects, one partner in particular, are viable alternative power options for the Company and provide benefits to the partners and customers. FPU is continuing to evaluate this type of opportunity both inside and outside of the FPU service territory.

Q. To what arrangements with "alternative power providers" do you refer?

A. The first very successful arrangement that I am referring to is the renewable energy contract with Rayonier Performance Fibers, LLC, which was entered into in early 2012 and approved by the Commission in Docket No. 120058-EQ. Through a cooperative effort, FPU and Rayonier were able to develop a purchased power agreement that allows Rayonier to produce renewable energy and sell that energy to FPU at a cost below that of the current wholesale power provided while still being beneficial to Rayonier. Not only did this increase the amount of renewable energy in the area, it provides lower cost energy that is passed directly through to FPU customers in the form of reduced power cost.

Secondly, FPU is also working in partnership with [redacted] Eight Flags Energy, LLC, a subsidiary of Chesapeake Utilities Corporation (Chesapeake), [redacted] The details of the arrangement are currently being finalized and we anticipate filing with the Commission in the very near future. [redacted] will provide customers with a significant benefit in the reduction of purchase power cost. This detail of this benefit is included in Confidential Exhibit MC/DS-9.

Q. How have these two new arrangements proven beneficial to the Company?

A. With regard to the first contract with Rayonier, that agreement alone is expected to produce overall savings of $1.27 million over the 10-year term of the contract, and the Company has every expectation that the contract will be extended, thereby extending the benefits. The expected annual energy produced will be 16,980 mWh's and an incentive is provided to Rayonier to ensure this occurs in that any failure to maintain the agreed capacity factor will result in reducing the overall monthly payments to Rayonier.

[redacted] efforts are underway to get this completed, approved and in service by the first quarter of 2016. Once consummated and in service, this new project is expected to produce even more significant benefits for the Company and its customers. [redacted]

[redacted]

V. COST OF SERVICE

Q. Why is a cost of service study necessary?

A. It is necessary to analyze the costs to serve each rate class in order to fully analyze the Company's revenues and appropriately determine the allocation of contributions made by the various rate classes. Generally, in a cost of service study, costs are typically allocated to the rate classes according to the cost to serve each class. The results are, therefore, useful in helping to determine: (a) whether a rate increase is appropriate; and (b) what rate changes are necessary.

Q. Is FPU's cost of service study in this case consistent with the methodology used in past cases?

A. Yes. Certainly, there are other methods for allocating costs, but the methodology that FPU is proposing in this proceeding provides a fair and equitable allocation of costs to the rate classes, is accurate, and has been accepted by the Commission for FPU in other proceedings.

Q. Please describe the fully-allocated cost of service study that was used to determine this interclass revenue allocation.

A. The method used in this proceeding follows previous rate proceedings filed by FPU. The method used to allocate our costs closely follows the long-held ratemaking principles and practices for cost apportionment as specified in the "Electric Utility Cost Allocation Manual" developed by the National Associations of Regulatory Utility Commissioners (NARUC) in January 1992. Once the relevant data on rate base and net operating income are compiled, as the Company has done in Scheduled A-D, these costs are apportioned to customer classes through a three step process called functionalization, classification and allocation. I will describe these steps:

Functionalization: The costs are identified by the function they perform or, another way of looking at it, the service provided. FPU provides three services: transmission, distribution and customer services. Since FPU purchases all of its power from a third party and delivers it to the customer, there is no production service provided by the Company.

Classification: The costs identified for each function are classified based on the manner in which costs vary, i.e. costs will change by changes in the component of utility service provided. The three (standard) cost classifications used by FPU are demand related (costs vary by KW load); energy related (costs vary by kWh's used); and customer related (costs that are directly related to the number of customers using the service). Transmission services are treated predominantly as demand-related cost. Distribution services are separated into demand, energy and customer related. And, customer services are either demand related or customer related.

Allocation: Once the costs are functionalized and classified, they must be allocated to the different customer classes. This is done using allocation factors for each of the cost classification categories. The allocation factors used in the FPU study are listed and described in MFR Schedule E-13. As a summary, transmission costs are allocated according to the coincident peak plus $1/13^{th}$ demand factor (a weighted combination of contribution to the system peak and the average hourly demand of the class). Distribution demand costs are allocated according to each class' non-coincident peak demands. Customer costs are allocated by the number of customers and by a weighting of the specified customer-related cost, e.g. meter expense.

Q. Please explain how FPU determined the increase in review by class.

A. Our fundamental ratemaking objective is to apportion revenue recovery responsibility and design rates to reflect, to the maximum extent practicable, the cost of serving each customer and customer class. In order to determine the cost responsibility we used the results of a fully-allocated embedded cost of service study conducted on the consolidated division service by FPU as provided in MFR Schedule E-1. A comparison of rates of return by class for present rates is provided in Schedule E-3 along with the percentage increase in base rates required for each class to recover the target rate of return. It is our understanding that long-held Commission policy provides that the percentage rate increase for each class must be no more than 1.5 times the system average increase and that no rate class should receive a decrease in rates. Based on the results of the Cost of Service study, the RS, GS, GSD, GSLD GSLD1, SB, Outdoor Lighting and Street Lighting were found to match the parity percentages, as much as practical, that were accepted for FPU during the Company's last rate proceeding while still achieving the targeted return.

Q. What increase in rates was indicated for each of the class of customers served by FPU based on the cost of service results?

A. The total base rate revenue recovered from each of the customer classes and the total revenue impact on each rate class on a percentage basis is shown below:

Class	Base Rate Increase %	Total Rate Increase %
Residential	30.5%	7.0%
General Service	39.7%	10.6%
General Service Demand	49.1%	7.2%

General Service Large Demand	47.6%	5.1%
General Service Large Demand 1	55.9%	6.5%
Outdoor Lighting	17.3%	12.6%
Street Lighting	26.8%	19.3%

Q. Please explain what the differences are between direct and indirect costs.

A. Direct costs can be related to labor, transportation, materials, and the like that are specifically used and identified as related to a specific type of expense or project. Indirect cost can be the same types of costs but are allocated to specific types of expense or project by pre-determined allocation methodologies.

Q. Please describe the load data used to derive the class coincident and non-coincident demands used in the cost of service study.

A. FPU is too small to have its own load research program; therefore, we rely on the load research data collected by Gulf Power Company (Gulf). Gulf provided data for 2003, 2006 and 2010-2011 which was translated to billing determinants and load based cost of service allocators for the 2015 test year.

Q. Please describe any special studies performed and how they relate to the allocation methods you described above.

A. In order to allocate certain costs, a study was performed on distribution plant as it related to poles, conductors/conduit/devices, meters, outdoor lights and street lights. The poles and conductor/conduit/devices were evaluated to determine the appropriate contribution to either the primary or secondary distribution systems. Meters were evaluated to determine the appropriate contribution to each rate class. Customer lights and Street lights were evaluated to determine the appropriate contribution to each class. These factors were then used as a basis for allocating costs.

Q. Please describe the results of your cost of service study.

A. The initial results were analyzed to ensure that no rate class received an increase greater than a 1.5 times the system average and no rate class received a decrease. Adjustments were made to ensure compliance with these requirements and any difference in the revenue requirement was then allocated back to the other rate classes with each rate adjusted accordingly to provide for the target revenue return. Final percent increases were then determined. Every effort was made to ensure that the analysis was consistent with that employed in our last rate case proceeding and that the results achieved an appropriate level of parity across the rate classes.

Q. Please explain why you believe the cost of service methodology for allocating costs is most appropriate for FPU?

A. This methodology has been utilized for our prior rate proceedings and has resulted in excellent results. Data has been provided that works well with this methodology and once again seems to have provided excellent results.

VI. <u>RATE DESIGN</u>

Q. After you determined the interclass revenue allocation, how did you design

rates to achieve the revenue requirement?

A. The results of the cost of service study shown in Schedule E-1 include unitized costs for the customer and demand and energy charges within each specified class of service. We unitized these costs to adjust the pricing components within each class to the maximum degree possible.

Q. Have you restructured any rates?

A. Yes we have. The Residential Class rate (RS) and the Lighting Class rates (OL and SL) have been restructured and will be described below.

Q. Please describe the rate design changes for the Residential Class.

A. The current Residential (RS) rate consists of a $12.00 per month customer charge with a $0.01958 per kWh energy charge. To this we applied the percentage increase for the residential class and included a step rate in the energy charge to determine the new rates. The new Residential rate will now consist of a $16.00 per month customer charge with an energy charge of $0.02170 per kWh for usage less than or equal to 1,000 kWh per month and an energy charge of $0.03420 per kWh for usage above 1,000 kWh per month.

Q. Please describe the rate design changes for the General Service Non-Demand Class.

A. The current General Service Non-Demand (GS) rate consists of an $18.00 per month customer charge with a $0.01927 per kWh energy charge. To this we applied the percentage increase for the General Service Non-Demand class to determine the new rates. The new

General Service rate will now consist of a $24.00 per month customer charge with an energy charge of $0.02582 per kWh. The Sports Field rate in this class will be eliminated and customers will be transitioned to the new GS rate.

Q. Please describe the rate design changes for the General Service Demand Class.

A. The current General Service Demand (GSD) rate consists of a $52.00 per month customer charge with a $0.00340 per kWh energy charge and a $2.80 per KW demand charge. To this we applied the percentage increase for the General Service Demand class to determine the new rates. The new General Service Demand rate will now consist of a $65.00 per month customer charge with an energy charge of $0.00571 per kWh and demand charge of $4.20 per KW.

Q. Please describe the rate design changes for the General Service Large Demand Class.

A. The current General Service Large Demand (GSLD) rate consists of a $100.00 per month customer charge with a $0.00145 per kWh energy charge and a $4.00 per KW demand charge. To this we applied the percentage increase for the General Service Large Demand class to determine the new rates. The new General Service Large Demand rate will now consist of a $150.00 per month customer charge with an energy charge of $0.00218 per kWh and demand charge of $6.00 per KW.

Q. Please describe the rate design changes for the General Service Demand Large 1 Class.

A. The current General Service Large Demand 1 (GSLD1) rate consists of a $600.00 per month customer charge with a $0.00000 per kWh energy charge, a $1.12 per KW demand charge and a $0.24 per excess kilovolt-amperes reactive, or kVAR, demand charge. To this we applied the percentage increase for the General Service Large Demand 1 class to determine the new rates. The new General Service Large Demand 1 rate will now consist of a $900.00 per month customer charge with an energy charge of $0.00000 per kWh, a demand charge of $1.68 per KW and a $0.36 per excess KVAR charge.

Q. Please describe the rate design changes for the Standby Rate Class.

A. The current Standby rate (SB) rate consists of a $626.47 per month customer charge with a $0.00000 per kWh energy charge and a $0.53 per KW demand charge. To this we applied the percentage increase for the General Service Large Demand 1 class to determine the new rates. The new Standby rate will now consist of a $940.00 per month customer charge with an energy charge of $0.00000 per kWh and a demand charge of $0.80 per KW.

Q. Please describe the rate design changes for the Street Lighting and Outdoor Lighting Classes.

A. Within the COS model, we incorporated our intention to combine all lighting into one Lighting Rate Schedule. Standard allocation procedures were followed to determine the new revenue requirement for all lighting. The percentage impact for specific lights can be found within the E Schedules while proposed rates for lights can be found in Exhibit MC/DS-7. The existing SL and OL rate schedules have been deleted and they have been combined into a new Lighting Service (LS) rate schedule. For the existing mercury vapor lights, which are no longer available for new installations we created the Outdoor and

Street Lighting (OSL) rate schedule. As a result of the combination of these rate schedules, there will also be a change in the Rate Adjustment Rider for each division. The OL and SL purchased power factor will be consolidated to align with the combined LS and OSL rate schedules which will result in new fuel clause recovery amounts and rates for lighting in both divisions. The details and calculations of these proposed modifications are included in Exhibit MC/DS-8

Q. Please describe why you are proposing to combine the Street and Outdoor lighting rate classes.

A. Street Lighting and Outdoor Lighting are managed from the same types of materials using the same types of labor and transportation to install and maintain these lights. In reality, very little if any, difference should be apparent through the cost of service study results. However, the results do come out slightly different due to a long standing effort to keep these types of lights separate and the margin of error through years of COS modeling. Combining these rate classes will result in more equitable rates for lighting customers.

Q. Are you proposing any changes to the Service Charges in this filing?

A. Yes. The proposed service charges are provided in MFR Schedule E-7. Each service charge was evaluated in order to determine the appropriate cost and revenue requirement for each. Labor cost, transportation costs and overheads were applied to the typical task associated with each service charge. Based on typical costs, service charge amounts were determined for six different tasks.

A service charge for the initial establishment of service was set at $61.00, as compared to the existing amount of $53.00. A service charge for making changes to or reestablishing an existing account was set at $26.00, as compared to the existing amount of $23.00. A service charge to temporarily disconnect and then reconnect a service due to customer request was set at $65.00. The existing amount is $33.00. This increase was due to a change in the classification of personnel who will be involved with this type of work activity. A service charge to reconnect a service after a rule violation was set at $52.00 during normal business hours and $178.00 after normal business hours, as compared to the existing amount of $44.00 during normal business hours and $95.00 after normal business hours. A service charge used for connecting a temporary service was set at $85.00, as compared to the existing amount of $52.00. A service charge used during collection activities in the field was set at $16.00, as compared to the existing amount of $14.00.

When a customer requests that a new temporary service be installed and later removed a service charge was set in the amount of $230.00 for an overhead service and $200.00 for an underground service, as compared to the existing amount of $200.00 for an overhead service and $170.00 for an underground service. Should a pole be required in order to install the temporary service an additional service charge was set at $395.00 per pole for an overhead service and $560.00 per pole for an underground service, as compared to the existing amount of $200.00 per pole for overhead or underground services.

Q. Are you proposing any changes to the Transformer Ownership Discount?

A. No.

Q. Why are you proposing to include a step rate within the Residential rate class?

A. As has been thoroughly described in the current step rate included in the residential purchased power adjustment rate approved by the Commission in Order No. PSC-08-0030-FOF-EI, there are numerous benefits to the Residential rate class and the general body of rate payers based on this type of step rate. A very significant factor is the conservation benefit that this affords. Consumers are financially benefitted to conserve electricity and minimize usage below 1,000 kWh per month. As more customers are incented to this benefit, the overall system usage will be reduced which should translate into improved load factors and reduced purchased power cost. This will, in turn, directly benefit all rate payers through reduced charges. The step rate differential proposed in the base rate is equivalent to the amount currently included in the fuel adjustment.

Q. Are you proposing any changes to the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") or Time of Use Rates?

A. With the exception of the change associated with lighting rates which was mentioned above, there are no other changes at this time. However, FPU may seek approval to consolidate its 2015 fuel rates within the Fuel Clause filing in September 2014, which is consistent with the Commission's directive to the Company in the 2013 Fuel Clause proceeding, in Order No. 13-0665-FOF-EI. If approved, this will result in a single fuel factor for all FPU customers that will provide long term benefits for all rate payers through, among other things, a reduction in existing inequitable subsidization across our service territories. The TOU rates, which are based on our fuel costs, will also be impacted within the consolidation of fuel rates.

Q. Are you proposing any additional changes to the rates?

A. Yes. We will be adding an Economic Development Rider Program (EDRP) to the rates.

Q. What benefits will this EDRP provide to customer?

A. This program is intended to work along with local economic development organizations to attract additional business to the community which brings additional jobs and opportunities to the community. The participants will be required to have a minimum electrical load of 200 KW in order to take advantage of the discounted electrical rate. The program discount begins with a 20% reduction in base energy and demand charges in the applicable rate which decreases annually by 5% with the discount expiring in the fifth year. More detailed information regarding this rate is included in Testimony provided by Company Witness Aleida Socarras.

VII. <u>IMPACT ON OPERATIONS OF ACQUISITION BY CHESAPEAKE</u>

Q. With regard to the acquisition of FPU by Chesapeake Utilities Corporation, have there been additional benefits as it relates to FPU's electric system?

A. Yes. There have been meaningful improvements that have proven beneficial to the Company, its customers, as well as its employees. Specifically, prior to its acquisition by

Chesapeake, FPU was a relatively small operation in Florida with an overtaxed leadership team that was mainly focused on day-to-day tactical matters. On the electric side of the Company, there was insufficient attention and inadequate resources devoted to critical areas including system reliability, safety, purchased power costs, customer service and relationships with cities and towns that were being served. Upon the closing of the acquisition, Chesapeake immediately implemented initiatives to make improvements and upgrades to these and other areas. Although these efforts have resulted in some necessary increases in administrative and general expenses, they have much improved the electric utility, both for customers, as well as employees.

A. <u>Investment in Improving System Reliability</u>

Q. What specific improvement initiatives did Chesapeake undertake for FPU?

A. Historically, the FPU electric system had suffered from the poorest reliability statistics in the state of Florida. The frequency of outages on the FPU electric system was unsatisfactory. Likewise, the duration of outages on the FPU electric system was also unsatisfactory. Chesapeake responded by promptly installing a new executive leadership team in Florida, which initiated an assessment/review of what improvements needed to be made to the electric system to improve reliability. The executive team concluded it was necessary to take the following actions:

1. Bring in more experienced personnel in operations;
2. Add a safety coordinator in each of the electric divisions as described elsewhere in this testimony;

3. Replace the old warehouse facility on Amelia Island, as described elsewhere in this testimony, and upgrade the Marianna facility including painting, parking lot drainage and office remodeling. This greatly improved employee morale and has provided a greatly enhanced sense of pride about the Company and the physical systems;

4. Develop new training facilities in both electric divisions that include poles, transformers, switches, fuses and reclosers. This training has improved and enhanced the ability for climbing poles, working in buckets, rewiring transformers, switching and service work for restores;

5. Replace and upgrade tools and other equipment. One example is the replacement of manual tools to battery operated. This had greatly improved the speed and consistency of our linemen's work;

6. Implement online NERC compliance training, which has increased the thoroughness and consistency of training while decreasing the time away from field work;

7. Develop a formalized program of maintenance and capital investment; and

8. Increase involvement and input from the corporate headquarters, which has been important to this overall effort to improve our system.

As I have noted earlier in my testimony, these efforts have been successful. Reliability has improved overall as measured by SAIDI/CAIDI/SAIFI/L-Bar, complaints have been reduced, and FPU now compares more favorably with other electric utilities in the region.

B. Implementing a Safety Culture

Q. What other initiatives have been implemented by Chesapeake that benefit the Company's operations?

A. Prior to the acquisition, FPU promoted safety but had not ingrained it into the culture of the organization from top to bottom. Chesapeake Utilities, in contrast, has always placed the greatest importance on safety of its employees, its customers and the general public. In fact, Chesapeake Utilities has won numerous awards for its safety achievements. Chesapeake's new executive leadership team in Florida instituted an assessment of what needed to be done in Florida to instill a true culture of safety in FPU. These efforts included a Company-wide program called Service Excellence, which leads off with Company values regarding safety: (1) resolving safety issues and concerns first, (2) being proactive in creating a safe work and community environment, (3) honoring all safety regulations and procedures and (4) always wearing personal protective equipment. In addition, the following actions were taken:

1. We created a Safety and Training Coordinator position for each division to provide ready access for employees to safety and job related training;
2. We conducted multiple monthly safety meetings in each facility to ensure access for all employees to current and pertinent safety information;
3. We required FPU Safety coordinators to obtain certification in CPR/First Aid and OSHA 30 Hour General Industry in order to provide training to all employees;

4. We revised our Lineman Apprentice Training program to ensure adequate training and opportunities to promote apprentices to journeymen linemen;

5. We built training yards in our electric divisions to train apprentices and to provide climbing and pole top rescue training;

6. We began a daily Stretching and Flexibility program for all linemen to prevent sprains and strains and improve balance;

7. We initiated "Smith System" defensive driving for all employees to promote better driving habits and reduce accident potential;

8. We began providing monthly refresher training in job specific duties for all linemen;

9. We researched and acquired upgraded personal protective equipment and flame retardant uniform options; and

10. We instituted safety incentive programs to recognize safe employee behavior and promote culture of awareness.

Q. Have these efforts been successful?

A. Yes. These efforts have been enormously successful. FPU has indeed adopted a true safety culture and the results have been significant. In the vehicle accident area, incidents have declined slightly since 2011 while mileage has increased, resulting in a 25% reduction in the accident rate, from a rate of about 4 to a rate of about 3. The results in the Recordable Injury rate are even more impressive. The Incident Rate has decline from over 10.1 to about

1.7, an improvement of 83%. Detailed year by year statistics are available as shown on Exhibit MC/DS-5.

C. Additional Benefits to Operations

Q. Are there other areas where the Chesapeake acquisition has had a positive impact on FPU's electric division?

A. Yes. As it relates to the operations side of the business, in particular, the more proactive corporate philosophy has provided significant benefits in a couple of key areas – power purchases, as I have discussed, and franchise relationships.

[redacted]

Q. What changes did Chesapeake initiate to improve FPU's franchise management and relationships?

A. Prior to the acquisition by Chesapeake, FPU had inadequate administrative resources to appropriately manage franchise relationships with the cities and towns to which it provided electricity. For instance, in the Northwest division, the City of Marianna initiated efforts to purchase the franchise from FPU and provide the service to its own citizens. The resulting dispute, including court filings, involved a significant amount of time and effort being spent by FPU to retain the franchise. The time was, however, well-spent, in that negotiations with the City ultimately produced a settlement and the franchise was retained. If this sort of issue were to become an ongoing occurrence, it would be costly to customers and unduly distracting to Company personnel. Consequently, Chesapeake has directed the implementation of proactive initiatives to avoid, or at least limit, this situation in the future. These actions include:

1. Attending council meetings and building relationships with the cities and towns we serve;
2. Working closely with regional economic development organizations, chambers of commerce and trade organizations; and
3. Becoming involved in the communities we serve.

In other testimony in this case, Company Witness Aleida Soccaras provides more detail about our Community Involvement and related efforts.

Q. Please summarize your testimony.

A. In order to enhance customer service, FPU and its parent, Chesapeake, have invested significant amounts of time and resources over the last several years in a wide array of projects designed to improve reliability levels. The investment has been successful, resulting in improvement in the Company's overall reliability measures between 2009 and 2013 and further anticipated improvement in the future. These expenditures and other planned expenditures were, and will continue to be, well-planned, efficiently executed, and should be allowed for cost recovery in this proceeding. Never before in the history of FPU has such significant investment in system infrastructure occurred and never before has such an improvement in overall system reliability occurred. FPU is committed to maintaining the electrical systems by investing as necessary now and into the future.

As investment increases, so does the need to adjust electric rates accordingly. However, FPU is also committed to being proactive in working to keep overall electric rates at a reasonable level for FPU customers. In the Cost of Service study completed in conjunction with this proceeding, all cost items included have been subjected to intense scrutiny and are considered prudent by the Company. As such, we ask that the Commission reach the same conclusion and deem these costs justified for recovery through base rates. In our COS, we used standard methodologies throughout the analysis in order to fairly and reasonably allocate costs to the different rate classes and likewise determine appropriate rates. This method has been successfully used in previous filings and is consistent with Commission-defined parameters. With the exception of the consolidation of lighting rates, elimination of the sports field rate, addition of the residential step rate, and the addition of the Economic Development Program Rider, the overall rate structure remains the same. While rates are increased based upon the results of the COS, our methodology is not new. In sum, the proposed rates are fair and equitable for the customers of FPU and reflective of a fair allocation methodology that incorporates prudent costs and justifiable expenditures.

Currently, purchased power cost accounts for more than 70% of our customers' total bill. FPU is therefore committed to continuing to aggressively work to mitigate any increases, and potentially decrease, it's purchased power costs in the future. FPU, along with resources from Chesapeake, are prepared to continue to focus on ensuring fair and equitable rates for customers, improving system reliability, fostering a safety culture that benefits employees and customers, and continuing to improve relationships within our communities in which we work and serve.

Q. Does this conclude your testimony?

A. Yes.

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

A. My name is Matthew M. Kim. I serve as Vice President and Corporate Controller of Chesapeake Utilities Corporation ("Chesapeake"), which is the parent company of Florida Public Utilities Company ("FPU"). My business address is 909 Silver Lake Boulevard, Dover, Delaware.

Q. Please describe your educational background and professional experience.

A. I graduated with a Bachelor of Science degree in Business Administration with a major in Accounting from Georgetown University in Washington, DC in 1998. I am a Certified Public Accountant, licensed in the District of Columbia. I have 16 years of professional accounting experience. I joined Chesapeake in 2009 as Corporate Controller and was appointed as Assistant Vice President and Vice President by Chesapeake's Board of Directors in 2010 and 2012, respectively. Prior to joining Chesapeake, I was Vice President and Assistant Controller at The Carlyle Group, a global private equity firm, from 2005 to 2009. I also held various positions with public accounting firms for over seven years, from Staff Auditor to Senior Manager. Prior to leaving public accounting in 2005, I was a Senior Manager with PricewaterhouseCoopers LLC.

Q. Please describe your current responsibilities.

A. As Vice President and Corporate Controller, I am responsible for accounting, financial reporting and tax compliance functions within Chesapeake and all of its subsidiaries. This includes daily oversight, management, compliance and policy. I am also involved in the financial planning and budgeting functions within Chesapeake.

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. Yes. In 2012, I provided testimony before the Florida Public Service Commission (the "Commission") in Docket Number 120311-GU, which was FPU's petition for approval of the acquisition adjustment for its Indiantown division. In 2010, I also provided testimony before the Commission in Docket Number 110133-GU, which was FPU's petition for approval of the acquisition adjustment related to Chesapeake's acquisition of FPU.

Q. Have you previously provided testimony before other regulatory bodies?

A. Yes, in 2010, I provided testimony before the Federal Energy Regulatory Commission ("FERC") in Docket Number RP11-1670.

Q. What is the purpose of your testimony?

A. I am supporting certain schedules of historical data and projected data represented in the MFRs listed in my Exhibit MK-1. Specifically, I will address administrative and general ("A&G") expenses and the allocation of corporate costs included in A&G expenses, as well as some of the management, expense allocation, and accounting changes that have been implemented since FPU was acquired by Chesapeake, along with the benefits tied to those changes. I will also address income taxes, expenses associated with pension and other postretirement benefit plans, as well as Chesapeake's capital structure and financing plans as they relate to FPU.

Q. Do you have any exhibits to which you will refer in your testimony?

A. Yes. Exhibit MK-1 was prepared under my supervision and direction.

Q. Are you sponsoring any MFRs in this case?

A. I am supporting the MFRs listed in Exhibit MK-1. To the best of my knowledge, these MFRs are true and correct.

<u>A&G expenses</u>

Q. Please describe what is included in A&G expenses.

A. A&G expenses include payroll, benefits, outside services and other related costs associated with key administrative functions, including accounting and finance, human resources, communications, information technology ("IT"), corporate governance, and management functions. A&G expenses also include costs associated with various administrative facilities, insurance and expenses associated with FPU's pension and other postretirement benefit plans.

Q. Generally, please explain the accounting of A&G costs?

A. The merger with Chesapeake in 2009 changed the way A&G expenses are recorded for FPU, as well as the type of A&G costs being recorded by FPU. Prior to the merger, all of the A&G expenses were incurred by FPU and allocated within different businesses of FPU (mainly FPU's natural gas operation, FPU's electric operation and FPU's unregulated subsidiary). Subsequent to the merger, certain A&G functions remained in Florida and have continued to be performed by the management and employees dedicated to the Florida businesses, which include FPU and other Florida businesses of Chesapeake (mainly the Florida division of Chesapeake – d.b.a. Central Florida Gas). A&G expenses associated with the functions performed by the Florida management and employees dedicated to serve the Florida businesses are allocated among the Florida businesses only. Other A&G functions have been combined with or transferred to Chesapeake's corporate office for increased quality and efficiency. As a result, FPU is allocated a portion of A&G expenses incurred by Chesapeake's corporate office. The calculation of allocations to FPU is explained in greater detail below. However, generally, the accounting and finance, IT, human resources, corporate governance and certain management functions are some of the examples of the A&G functions now being performed by Chesapeake's corporate office in support of FPU's operations.

Q. What benefits are derived by FPU and its customers from Chesapeake's service of these functions post-merger?

A. This is discussed in much greater detail below but generally speaking, since the merger, FPU has benefited from certain functions and services provided by Chesapeake's corporate office, which were not previously available to FPU on its own. These new functions and services, which include communications, certain business development and expanded management support functions, have increased

FPU's quality of service by enhancing customer engagement, obtaining more accurate and relevant business and market information and providing reliable and efficient service to its customers. These resources and capabilities also enabled FPU to address newly emerging, complex business issues, such as the franchise dispute in Marianna and developing alternative electric fuel supply options. All of these functions and capabilities have increased FPU's customer satisfaction. With the help of Chesapeake's corporate office, FPU has also been able to address expanded business and compliance needs for IT infrastructure and security, accuracy in accounting and financial data, adoption of new regulations by the federal and state governments, and employee training and retention. All of these efficiencies have enabled FPU to continue its outstanding service to its customers and benefit from increased access to capital to maintain and improve its electric system.

Q. How are A&G expenses allocated to FPU?

A. A&G expenses are recorded by FPU in one of the following ways: (a) direct assignment of costs and (b) cost settlement designed to allocate the cost of shared functions and services to business units receiving the benefit of such functions and services. Whenever it is possible and practical, A&G expenses are directly assigned to the business unit incurring such cost. An example of direct assignment of A&G costs is an external audit fee associated with auditing FPU electric operation's annual report on FERC Form No. 1 filed with the Commission. This portion of the annual external audit fee is assigned and recorded directly to FPU. A&G expenses that cannot be directly assigned are allocated among Chesapeake's business units that receive a benefit from such functions and services. Chesapeake utilizes various methodologies in allocation of costs, depending on the type of expense. These methodologies are designed to reflect the relative size and benefit of each business unit receiving shared functions and services and may include direct payroll, profitability, adjusted gross plant, investment and/or the specific level of effort or focus, among others, in determining the allocation basis. Chesapeake utilizes a consistent methodology among all of its business units in allocating the same type of expense. Chesapeake reviews and updates the allocation basis at least annually at the beginning of each fiscal year. A&G expenses incurred by the Florida management and employees dedicated to serve the Florida businesses are allocated among only the Florida businesses. A&G expenses incurred by Chesapeake's corporate office are allocated among all of Chesapeake's businesses receiving benefits from such services.

Q. Please explain further how A&G expenses incurred by Chesapeake's corporate office are allocated.

A. Each of Chesapeake's corporate department has its specific allocation method, which is design to reflect the benefit of service provided by that department to all the business units receiving such service. Generally, Chesapeake's corporate departments use one of the following three allocation methods: task-based, Distrigas formula and investment-based. The first method is the task-based allocation, which identifies department's functions and assigns for each function the level of effort or focus to each business unit receiving its service. Chesapeake utilizes the task-based method to allocate the costs associated with the accounting and finance departments, management and specific IT systems. Based on the specific nature of these services, the task-based allocation method provides the most reasonable reflection of the benefit received by each business unit. The second method is the Distrigas formula, which is a FERC-approved formula attempting to weight various aspects of each of the business units to calculate the appropriate allocation. This formula incorporates three equally-weighted factors: gross plant, net operating revenues (operating income before interest and income taxes) and labor cost. Costs related to IT network, data and desktop maintenance and support, human resources and communications are allocated using the Distrigas formula. Due to the pervasive nature of these services, the Distrigas formula provides the most appropriate basis to allocate these costs. The third method is the investment-based allocation, which uses the level of Chesapeake's investment in each business unit to allocate costs. Costs associated with corporate governance, Chesapeake's Board of Directors and business development, all of which are closely related to the level of investment, are allocated using the investment-based method.

Q. How does Chesapeake ensure a fair distribution of its corporate costs to all of its business units, including unregulated businesses?

A. Chesapeake reviews and updates the allocation basis at least annually or when a significant change occurs to Chesapeake's overall business or corporate functions. Every business unit benefiting from a particular department is allocated a portion of the cost associated with that department, using a consistent methodology.

Chesapeake also reviews the relative size of each business unit, measured by investment, operating income, gross plant and payroll expenses, and compares it to the overall corporate cost being allocated to that business unit to assess the reasonableness of the allocation.

Q. What is FPU's A&G expense budget for the 2015 test year?

A. The projected A&G expense of FPU's electric operation in the 2015 test year is $5,563,777. Included in this projected A&G expense is $3,061,986 of A&G expense allocated from Chesapeake's corporate office.

Q. How does this amount compare with the A&G benchmark that the Florida Commission has historically used?

A. The test year benchmark for A&G expenses is $4,223,626, which was calculated based on the base year (2008) expenses of $3,720,601 and the compound multiplier of 1.1352. The projected A&G expenses in the 2015 test year are higher than the test year benchmark by approximately $1.3 million.

Q. Are these costs, including the costs allocated from corporate A&G, a legitimate and necessary cost to FPU of providing service to its customers?

A. Yes. A&G expenses for the 2015 test year include only the A&G costs that are projected to be incurred in supporting FPU's electric operation. The overall A&G costs in the 2015 test year are projected based on historic costs, recent trends and additional costs associated with increased business needs, which are necessary to continue providing outstanding service to FPU's customers. We monitor periodically FPU's A&G costs by comparing them on a per-customer-basis to other investor-owned electric utilities in Florida to ensure the level of A&G costs incurred and expected to be incurred is reasonable, compared to our peer utilities in Florida.

Q. Then, please explain the comparison of FPU's budgeted A&G expense to the historical benchmark.

A. There are four main factors contributing to the increase in A&G expense. First, there are two notable reclassifications of costs between the historic benchmark and the projected test year. In the projected 2015 test year, $66,156 of common depreciation expense was included in Account 921 in 2013. In the benchmark year, the common depreciation was charged to Account 403-Depreciation expense. In addition, in the 2015 projected year, rent expense of $124,609, which was not included in the benchmark year, was added. The inclusion of this rent expense is due to the sale of the West Palm Beach administrative office and the rent expense allocated from corporate facilities. The increase in rent expense is offset by reductions to rate base, depreciation expense, and taxes other than income that would have been included if the West Palm Beach corporate office was not sold. Second, in the 2015 projected year, administrative and general expense was increased by $120,000 to establish a general liability reserve. This reserve is in lieu of purchased insurance and to reduce the volatility associated with periodic claims. Third, IT costs also increased by approximately $350,000 to address increased compliance, security, data and network requirements, as well as to maintain enhanced system, website and software needs.

Finally, the remaining increase is due primarily to additional travel costs, higher costs associated with maintaining administrative facilities as a result of improved quality of those facilities, and expanded corporate functions and services not previously available to FPU. Travel costs have increased because of centralization of the Florida staff, additional training available to employees and increased focus in customer service and employee satisfaction, which require managers to travel to all locations within Florida. The transfer of certain A&G functions to the corporate office in Delaware for increased quality and efficiency has also necessitated additional travel. The increases in A&G expenses related to establishing a general liability reserve, additional IT requirements and expanded corporate functions and services, as well as their benefits to FPU and its customers, which are discussed in more detail below. These increases in A&G expenses provide FPU with the appropriate level of administrative support necessary to manage its business and provide the superior service to its customers. These increases are partially offset by efficiency and effectiveness gained in other areas of the Company. For example, the efficiency gained by combining the accounting and finance function with the corporate office allowed FPU to comply with the Sarbanes-Oxley requirements without incurring any additional costs (FPU was required to comply with the Sarbanes-Oxley requirements for the first time in 2009 and was expected to incur significant costs on its own as a result). Strengthening management oversight and enhanced treasury/finance capability allowed FPU to make necessary improvements in its electric system in the past several years to enhance reliability, which reduced maintenance expenses in the projected test year. These are just a couple of examples of how the expanded administrative functions and capabilities reflected in higher A&G expenses have helped FPU and its customers to benefit from lower costs or avoided costs in other areas.

Q. Please explain the general liability reserve.

A. With the help of an outside broker, Chesapeake assesses the Company's current risks, insurance needs and costs in determining the appropriate level of insurance coverage. The Audit Committee of Chesapeake's Board of Directors reviews Chesapeake's insurance coverage, the current insurance environment and related information to ensure it has the appropriate and necessary level of coverage. In the past five years, FPU's electric operation had one large insurance claim, which was settled for $2.75 million. Chesapeake's general liability insurance policy, which also covers FPU, had a maximum deductible of $250,000 per each claim. Since Chesapeake's general liability insurance policy covered this claim, FPU's financial exposure was capped at $250,000, which was the maximum deductible amount it had to pay. FPU's electric rates currently in place did not include any cost associated with general claims against the Company. As a result, the $250,000 deductible paid by FPU in this case has not been recovered. FPU is requesting recovery of $250,000 paid to satisfy the deductible requirement under the insurance policy over a five-year period. In addition, FPU is requesting an additional $250,000 to be included in the next five-year period to establish the general liability reserve sufficient to cover another potential claim with the similar financial exposure that may arise during that period, as well as $20,000 per year to cover any other smaller general liability claims.

Q. Please describe in more detail the increased IT costs.

A. Since 2008, FPU has been facing the increased needs to maintain network security, data integrity and system functionalities. A newly emerging threat of cyber attacks and increased functionalities of the Company's website and key systems (accounting, billing, payroll, etc.) are just some examples of those needs that have necessitated additional IT costs to expand network infrastructure and strengthen hardware and software maintenance. Chesapeake, like other businesses and utilities, has strengthened its IT software, hardware and network infrastructures to ensure the additional functionalities and increased use of its key financial, billing and other systems can be maintained in a safe manner without interruption. IT has also increased its staffing, as well as the expertise of its staff, to address this increased risk and demand for service. FPU has benefited from Chesapeake's increased IT infrastructure as it has enabled FPU to provide better customer service through enhanced website, more secure customer billing and other information, accurate and more timely financial information, and ability to engage customers and employees from remote locations.

Q. Please provide specific examples on how the expanded corporate A&G functions provided by Chesapeake benefit FPU's customers?

A. Expanded corporate A&G functions have benefited FPU and its customers in many different ways. Chesapeake's corporate communications team provides increased awareness of the Chesapeake and FPU brand through emphasizing core values and translating them into superior customer service. The communications team has assisted FPU in its effort to redesign the Company's website to enhance its look, content and functionality to better and more easily engage customers, thereby allowing customers to obtain accurate and more focused information through the website. For example, FPU's customers can utilize the website to make billing inquiries, request services, make payments and report power outages. They can also get energy saving ideas and information on electric rebates and incentives currently available. It has also assisted FPU with initiatives to increase its engagement with customers and communities, as well as employee satisfaction and training. Another corporate initiative benefitting FPU's customers is the Service Excellence initiative, which emphasizes customer service, engagement and satisfaction. Chesapeake's corporate office coordinates and provides necessary training to employees for the Service Excellence initiative and develops specific plans to measure and improve customer satisfaction. Business development is another example of the expanded corporate A&G functions now available to FPU. Business development assists the electric operations to assess alternative fuel supply options and provides market research data. It also coordinates the corporate-wide initiative to automate the infrastructure mapping to increase efficiency and reliability of the Company's system. Lastly, Chesapeake's management and Board of Directors also bring increased oversight of FPU's businesses and management. For example, Chesapeake's Board of Directors and senior management have seven people with over fifteen years of energy and utility industry experience. One director in particular has over 30 years of experience in the electric utility, generation and marketing industry and brings in-depth knowledge of regulations and power delivery. In addition to the industry knowledge, another director, for example, has extensive knowledge of best practice in human capital and customer experience, which helps FPU's effort in those areas. Four of Chesapeake's eleven independent directors are based in Florida to provide valuable business, regulatory, financial and other insights unique to Florida. All these examples of the expanded corporate functions and services have allowed FPU to continue its effort to enhance customer experience, improve employee education, and develop strategies, all of which are for the direct benefit of our customers.

Q. How does Chesapeake review the level of compensation for its officers?

A. Compensation of the named executive officers of Chesapeake, which include Chesapeake's President and Chief Executive Officer, Senior Vice Presidents and the President of FPU, is reviewed by the Compensation Committee of Chesapeake's Board of Directors. The Compensation Committee engages an outside consulting firm to review executive compensation. In March 2013, the Compensation Committee reviewed base salaries of the named executive officers based on a market analysis prepared by a third-party compensation consultant. Compensation of the named executive officers and related information, including the review of the

Compensation Committee, are disclosed in Chesapeake's proxy, which was filed with the Securities and Exchange Commission.

Q. Why is it important that FPU be allowed to recover the costs associated with corporate A&G through base rates?

A. The corporate A&G functions are integral part of FPU's ability to support its operations, comply with legal, regulatory and other requirements, finance the necessary capital required to maintain and grow its business, engage its customers to provide superior customer service, address complex financial and business issues and provide appropriate management oversight. As it was previously mentioned in my testimony, many of the A&G functions previously performed by FPU were combined with or transferred to Chesapeake's corporate office since the merger in 2009 for increased quality and efficiency. The corporate A&G functions allow the Florida electric operation to focus on its day-to-day business of serving its customers without burdening itself with having to establish and maintain separate support functions. By receiving support from the corporate office, which has expanded resources and capabilities, FPU benefits from superior quality of service, efficiency, more in-depth knowledge, higher level of professional service and increased ability to handle more complex and challenging business and compliance issues.

Income Taxes

Q. How was income tax expense determined?

A. Total income tax expense consists of income taxes currently payable and deferred income taxes. The currently payable income taxes for the projected test year were calculated by simply multiplying the currently effective income tax rate by the income that is currently taxable. Currently taxable income was calculated by deducting from the projected test year net operating income before income taxes, the interest expense inherent in the cost of capital and other permanent and temporary timing differences.

Q. What is the effective income tax rate of FPU?

A. Since the merger with Chesapeake in 2009, FPU has been a member of a consolidated federal tax return with Chesapeake and its other subsidiaries. Chesapeake's federal statutory income tax rate is 35 percent, which is effectively the federal statutory rate for FPU. FPU continues to file a separate state income tax return in Florida. Florida's statutory income tax rate is 5.5 percent. After taking into consideration the federal deduction of the state income taxes paid, the effective income tax rate for FPU is 38.575 percent.

Q. Please explain how you derived the projected amount for deferred taxes.

A. Deferred income taxes represent the tax effect of temporary differences between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable amounts or deductible amounts in future years when the reported amount of the asset is recovered or when the reported amount of liability is settled. The projected amount of deferred taxes were calculated by reviewing all existing timing differences and projecting the amount of timing differences that are expected to originate and reverse. The projected amounts of deferred taxes were added to the deferred income tax balances at the end of the historic base year. For example, in projecting deferred taxes related to plant, we estimated the tax depreciation of existing and new plant assets in service during the projected period (originating) and the book depreciation of the same plant assets during the same period (reversing). The difference, which is the change in a timing difference, was multiplied by the effective income tax rate to estimate the change in deferred taxes in the projected period.

Q. Please explain the South Georgia adjustment for income tax step-up included in this petition.

A. Prior to the merger with Chesapeake, FPU was required to pay federal income taxes at a statutory rate of 34 percent. Since the merger, FPU's statutory rate increased to 35 percent. This increase in the federal statutory rate increased FPU's effective income tax rate to 38.575 percent from 37.63 percent. The tax normalization rules require that utilities maintain their deferred income taxes, in Account 282, at the same income tax rate as the income tax rate used in calculating their income tax obligation to the IRS. This required FPU to adjust its deferred taxes to reflect the increase in its effective income tax rate to 38.575 percent to comply with the normalization rules at the time of the merger. Since FPU had a net deferred tax liability associated with its plant assets at the time of the merger, this resulted in a deficiency in the deferred tax reserve. This deficiency represents the amount of taxes associated with this timing difference, which FPU had previously been allowed to recover under the previous, lower effective income tax rate, that will be paid in the future by FPU at the current, higher effective income tax rate. The South Georgia method is one of the methods of the tax normalization accounting, which allows utilities to amortize the deficiency over the remaining lives of the property that gave rise to the deficiency. The total deficiency, including the appropriate gross-up for income taxes, is $353,307. FPU is proposing this amount to be amortized over 26 years, which is the average remaining life of the plant assets for the electric operation. The annual amortization is $13,589, which is required to comply with the tax normalization rules.

Pension and Postretirement Benefits

Q. Please explain how you derived the projected expense for pension and postretirement benefits.

A. The Company estimated the projected expense for pension and postretirement benefits by averaging the expenses in the past years. Due to the significant volatility in the discount rate assumptions in the past years, in which the discount rate assumptions fluctuated as low as 3.75 percent and as high as 5.75 percent, it was difficult to project the appropriate future discount rate assumption. In light of this challenge, the Company decided to use the average of the past four years of its pension expense (four years being the period since the merger with Chesapeake) to estimate the projected pension expense. For the postretirement medical plan, the Company used the average of the past two years since the plan had a significant amendment related to benefits, which was effective on January 1, 2012 (two years being the period since that amendment).

Q. Please explain the amortization of pre-merger unrecognized cost included in the Company's projected expense for pension and postretirement benefits?

A. FPU has accounted for benefit plan costs using accrual accounting in accordance with the Commission's practice, which is based on the accounting requirements under the accounting principles generally accepted in the United States of America (commonly referred to as US GAAP). The issuance of the Statement of Financial Accounting Standard No. 158 ("FAS 158") in September 2006 modified US GAAP for defined benefit employee benefit plans, such as FPU's pension and postretirement medical benefits. FAS 158 requires companies to record as an asset or liability the difference between plan assets at fair value and obligation of the defined benefit plans. In addition, FAS 158 requires companies to record, as a component of other comprehensive income (included in equity), the amount of the net benefit asset or liability that had previously not been recognized in earnings. Upon the issuance of FAS 158, FPU requested, and the Commission approved in Docket Number 080029-PU, the regulatory asset/liability treatment for the unrecognized portion of the benefit asset or liability (in other words, the portion FAS 158 required to be included as a component of other comprehensive income). The merger with Chesapeake in 2009 required a specific accounting treatment associated with defined benefit plans. US GAAP requires the acquisition accounting to recognize the full benefit obligations in excess of the plan asset value (similar to the net asset or liability required to be recorded under FAS 158) without recording the unrecognized portion of the benefit (the portion included in equity, or in FPU's case, regulatory asset). Essentially, US GAAP requires a one-time recognition of any unrecognized benefit costs associated with defined benefit plans at the time of a merger or acquisition. At the time of the merger with Chesapeake, FPU's electric operation had \$2,706,958 and \$31,450 of unrecognized benefit costs associated with its pension and postretirement medical plans, respectively, which were deferred as regulatory assets pursuant to the Commission's order in Docket Number 080029-PU. The Commission previously allowed a deferral treatment of the accelerated benefit cost recognition pursuant to the acquisition accounting. In Docket Number 060657-GU, Florida City Gas ("FCG") was allowed to defer the amount associated with accelerated pension cost recognition in its acquisition by AGL Resources Inc. and amortize it over the remaining service period of FCG employees expected to receive benefits from the pension plan, which was the period approximating the normal pension expense recognition without the acquisition. Consistent with this treatment approved by the Commission, FPU continued to defer \$2,706,958 and \$31,450 in unrecognized pension and postretirement medical benefit costs, respectively and amortize them over the remaining service period of FPU employees receiving benefits from those plans (9.88 and 11.30 years, respectively). The resulting amortization is \$276,767 per year.

<u>Cost of Capital</u>

Q. What is the Company's risk profile?

A. Chesapeake's long-term debt carries the NAIC 1 rating from the National Association of Insurance Commissioners ("NAIC"). According to NAIC, NAIC 1 is assigned to the highest quality obligations with the lowest credit risk. The NAIC 1 rating is equivalent to an A-bond rating or above for Moody's and S&P ratings.

Q. What is the capital structure of the Company?

A. The calculation of capital structure reflects investor sources of capital as follows: common equity of 58.21 percent, long-term debt (including the current maturity) of 35.29 percent and short-term debt of 6.50 percent. Chesapeake targets an equity ratio to total capitalization of between 55 and 60 percents. These targets have been reviewed with Chesapeake's Board of Directors.

Q. Why does the Company believe this structure is appropriate?

A. The capital structure is based on the historic capital structure as of September 30, 2013, and is updated through the end of the projected test period based on our most recent projection of capital requirements. The projection incorporates long-term debt placements committed by Chesapeake in 2014 and anticipated in 2015, as well as anticipated equity issuances necessary to maintain the desired ratio of equity to total capitalization between 55 to 60 percents. Also, the common equity ratio of 58.21 percent is consistent with the historic ratio in the past five years. The common equity ratio to the total capitalization as of December 31, 2013, 2012, 2011, 2010 and 2009, excluding accumulated other comprehensive income, which is further discussed in the testimony of Mr. Moul, was 55 percent, 60 percent, 62 percent, 59 percent and 56 percent, respectively. The simple five-year average for those five years was 58 percent.

Q. What is FPU's role in the decision-making process regarding financing for FPU?

A. Except for the remaining Secured First Mortgage Bond of $8 million issued by FPU prior to the merger, all of FPU's financing is provided by Chesapeake. FPU's financing needs are considered, along with the needs of Chesapeake's other subsidiaries, in establishing Chesapeake's financing plan and executing the associated financing strategy. Chesapeake has various budget, forecast and other planning processes that allow each of its businesses, including FPU, to present its capital requirements. Since Chesapeake finances with the consideration for the financing needs of all of its subsidiaries, including FPU, FPU's financing decisions are consistent with those of Chesapeake in terms of capital structure, terms and conditions. Chesapeake has directly assigned the one remaining series of FPU's Secured First Mortgage Bond to FPU as it was financed by FPU prior to the merger with Chesapeake. The remainder of FPU's capitalization is represented by the relative proportions of Chesapeake's components of capitalization as Chesapeake provides all of FPU's other financing needs.

Q. Has the merger with Chesapeake had an impact on FPU's overall cost of capital?

A. Yes, with Chesapeake's sound capital structure and superior ability to attract capital at reasonable cost, the merger has had a positive impact on FPU's overall cost of capital. Prior to the merger, FPU's credit rating (long-term debt rating of NAIC 2) and inability to access capital market at attractive rates impaired its ability to obtain the necessary capital to grow. By comparison, Chesapeake's long-term debt rating was (at the time of the merger) and continues to be NAIC 1. At the time of the merger, FPU had only one committed line of credit for $26 million. Chesapeake currently has access to short-term debt facilities totaling $165 million. In addition, FPU had obtained only $29 million of long-term debt financing over the 10-year period immediately prior to the merger. By contrast, in less than five years since the merger, Chesapeake has issued $56 million in long-term unsecured debt with an additional $50 million committed to be issued in May 2014. The debt issuances have been consummated at attractive interest rates ranging from 3.73 percent to 6.43 percent and on an unsecured basis with much less stringent covenants. Since the merger, Chesapeake successfully refinanced all but one series of FPU's Secured First Mortgage Bonds with Chesapeake unsecured senior notes and reduced the overall cost of debt.

Q. Does this conclude your testimony?

A. Yes.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Aleida Socarras. I am Director of Marketing & Sales for Florida Public Utilities Company (the "Company" or "FPU"). My business address is 911 South 8th Street, Fernandina Beach, FL 32034.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined Florida Public Utilities in March 2011. Prior to joining Florida Public Utilities Company, I was Senior Sales Manager of TECO Partners, a Florida sales and marketing company representing multiple energy related companies. Prior to that, I worked for TECO Peoples Gas in various management positions. I hold an M.S. degree in Organizational/Industrial Psychology from the University of Texas at El Paso.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. As Director of Marketing & Sales, I am responsible for the Company's marketing, sales and energy conservation departments, providing leadership for the Company's growth strategy and program and business development efforts.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A, My testimony addresses the critical role that FPU plays in promoting economic development in areas we serve and the corresponding benefits to consumers. The Company's Marketing & Sales team and the Company overall builds strong strategic partnerships with FPU's business and industrial customers and advises on conservation and energy efficiency measures. I explain the Company's approach to economic development and our desire to be a leader in assisting the areas we serve advance their economic development efforts. Finally, we propose in this rate case that the Commission approve our Economic Development Rider. I discuss the specifics of our request and explain how the rider will promote economic development.

Q. HAVE YOU FILED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION IN PRIOR CASES?

A. No. I do, however, regularly participate in the development of the Company's proposals and programs addressed in the Commission's Natural Gas and Energy Conservation Clauses.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit AS-1, which is a description of our electric economic development program. I also sponsor Exhibit AS-2, which contains the proposed tariff sheets and service agreement for the economic development rider component of our economic development program.

Q. ARE YOU SPONSORING ANY MFRS IN THIS CASE?

A. No, I am not.

Q. PLEASE EXPLAIN THE ROLE THAT FPU HAS IN ECONOMIC DEVELOPMENT.

A. As described in Rule 25-6.0426, Florida Administrative Code, economic development activities are those activities designed to improve the quality of life for all Floridians by building an economy characterized by higher personal income, better employment opportunities, and improved business access to domestic and international markets. To this end, the Company's Marketing & Sales team, and the Company overall, builds strong strategic partnerships with FPU's business and industrial customers and advises on conservation and energy efficiency measures. We work closely with regional economic development organizations, chambers of commerce, and trade associations to promote our service areas. We aggressively encourage new business growth and assist with retention and business expansions activities. By helping businesses reduce their energy costs and identifying and instituting energy efficiency measures, we help them become more competitive and prosper. This maintains and adds jobs to the local economy which in turn benefits the community and all rate payers.

Q. PLEASE EXPLAIN THE BENEFITS OF ECONOMIC DEVELOPMENT TO FPU'S CUSTOMERS.

A. Economic development activities improve quality of life in the communities we serve by creating jobs, expanding economic opportunities, and positively influencing demand for energy consumption. At the same time, economic growth creates a greater pool of users and additional wealth for communities to invest in energy efficiency measures. Economic development efforts in our areas have resulted in economic development organizations having a resource at their disposal to provide prospective businesses with infrastructure assessment, technical information, rate comparisons, and assistance in site identification where infrastructure is already in place to help expedite site certification. This assistance can help mitigate risk for prospective businesses and speed up the process.

Our participation in community chambers of commerce, trade shows, and other economic development activities strengthen the communities we serve. Our involvement not only demonstrates support for the community, but provides education and leadership from trained, knowledgeable professionals that can inform decisions made by community leaders. FPU staff members assist in providing business recruitment leads, researching prospects and target markets, and in providing data gathering and analysis. These collaborations also provide opportunities to address and promote conservation efforts. In addition, by hosting events and participating in community forums, we help share and disseminate information which helps increase cooperation among stakeholders and creates a positive image of the community. A unified community with a cohesive message helps to make the community more attractive to decision makers looking to the community as a place where they want to live, thereby bringing new businesses and people to our service area. Consequently, additional load added to our system enables us to spread fixed costs over a larger customer base, furthering an efficient system and keeping rates stable for all our customers.

Q. ARE THERE EXAMPLES OF FPU'S EXISTING ECONOMIC DEVELOPMENT INITIATIVES AND BENEFITS THERETO?

A. Yes. FPU has been actively involved with the Nassau County Business Development Board ("NCBDB") for many years through participation on the Board, as well as actively participating in many committees and events. NCBDB relies on us for technical assistance, industry knowledge, and man-hour resources to help them attract businesses and promote the area overall. Also, we work with them to identify business ready sites and provide projected rate analyses. Another example is our cooperation with the City of Marianna in making improvements to the downtown area that is being revitalized. We moved overhead lines near the courthouse, as well as around U.S. Highway 90, in order to make the area more attractive and with the intent of driving visitors towards the downtown area. We also provide educational resources and help promote "Buy Local" campaigns.

Q. PLEASE DISCUSS THE STATE OF FLORIDA'S FOCUS ON ECONOMIC DEVELOPMENT.

A. Governor Rick Scott and the Florida Legislature have strengthened the focus on economic development efforts. Collectively, they encourage all Florida businesses to place a priority on workforce development and job creation. As the Commission knows, the Governor has outlined two major goals for Florida: job creation and decreasing unemployment numbers. Correspondingly, the Commission has taken a leadership role in supporting and facilitating economic development. The Commission has supported efforts by other utilities to promote economic development by allowing recovery of reasonable associate expenses pursuant to Section 288.035, Florida Statutes and Rule 25-6.0426, Florida Administrative Code.

Q. IS FPU PROPOSING ANY NEW ECONOMIC DEVELOPMENT INITIATIVES AS PART OF THIS PROCEEDING?

A. Yes. FPU is seeking approval of our Economic Development Rider. We believe the Rider will further our economic development efforts and result in greater customer benefits in our service areas. When companies consider areas for relocation or expansion, electric rates are often a major consideration. By providing a rate discount, we will be able to assist the state and specifically our service area in being more competitive. Electric rate discounts are expected as part of the incentive packages offered to prospective companies evaluating an area of relocation or expansion.

Q. PLEASE DESCRIBE YOUR REQUEST.

As I have noted, for many years, FPU has been involved in economic development activities in the areas of the state in which we serve. In light of the current economic climate, FPU has concluded that we should further extend our efforts in economic development. To that end, we intend to implement a more robust, detailed and formalized Economic Development program to enhance even further our work to promote economic development. I have outlined below our Plan's components, the key to which is our Economic Development Rider Program.

Q. PLEASE BEGIN BY OUTLINING THE AVAILABILITY AND APPLICATION OF YOUR ECONOMIC DEVELOPMENT RIDER PROGRAM.

A. We intend to make the Economic Development Rider Program (the "Rider Program") available throughout the entire territory served by FPU. The Qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider. This Program would apply to new electric load associated with:

(1) Initial permanent service to new commercial and industrial establishments;

(2) Commercial or industrial space that has been vacant for more than six months prior to the application for service under the Rider Program; and

(3) The expansion of existing establishments.

The purpose of this new Rider Program is to provide an attractive service discount offering for commercial ventures considering locating their business or new facilities in areas within FPU's service territory or considering expanding existing facilities in a manner that will create new job opportunities for communities we serve. Notably, the jobs created by a new facility or facility expansion must be full-time positions that continue to exist as long as the customer takes service under the Rider Program, which can be up to five (5) years.

Q. HOW WILL YOU DETERMINE WHAT QUALIFIES AS NEW LOAD?

A. The new load applicable under this Rider Program for new and vacant establishments must be a minimum of 200 kW at a single delivery point added after December 31, 2014. In the case of the expansion of existing facilities, the added new load must be a minimum of 100 kW; however in order to qualify, the total load after the addition of the new load must be a minimum of 200 kW at a single delivery point. To qualify for service under this Program, the Customer must employ an additional work force of at least 10 full-time employees at the delivery point to which the load is added. Additionally, in order to take service under the Program, the Customer must provide sufficient evidence to FPU to establish that the availability of the Program is a significant factor in the Customer's location or expansion decision.

Q. WILL YOU MAKE THE RIDER PROGRAM AVAILABLE TO EXISTING LOAD?

A. No. Initial application for this Rider Program is not available to existing load. However, if a change in ownership occurs after the Customer contracts for service under this Program, the successor Customer may be allowed to fulfill the balance of the contract under the Program and continue the schedule of credits outlined below. The Program is not available, however, for load shifted from one establishment or delivery point on the FPU system to another one on the FPU system.

Q. WHAT ARE THE TERMS AND CONDITIONS FOR RIDER PROGRAM PARTICIPATION?

A. The specific rates, term of service, and service agreement are included in Exhibit AS-1 attached to my testimony and are similar to programs approved by the Commission for other electric utilities. To summarize the Rider Program, customers will be required to sign a five (5) year contract, which will not be eligible for renewal. The customer will, for that period of time, continue to take service under the tariffed rates and charges for their applicable rate class, but a percentage discount will be applied to the demand and non-fuel charges. The discount applied will gradually be reduced each year of the contract to zero in the final year. Throughout the contract period, the customer will still pay the applicable customer charge and any amounts associated with cost recovery clauses.

Q. WHAT ARE THE COMPONENTS OF FPU'S OVERALL ECONOMIC DEVELOPMENT PROGRAM?

A. As indicated, the Rider Program is but one piece of our plan to enhance our economic development efforts. In addition to the Rider Program tariff included in my Exhibit AS-2,, FPU's Economic Development Program will memorialize and promote our commitment to provide: 1) economic development assistance to the communities we serve; 2) recruitment resources for potential new businesses considering location options; 3) direct community involvement by FPU in key areas that attract new business; 4) leadership, as appropriate, on community chambers and economic development boards; 5) active involvement in commercial retention and programs developed in cooperation with local chambers of commerce; 6) programs, leadership and cooperation to encourage innovation in community economic development programs; 7) resources to enhance k-12 education, particularly in areas, such as STEM, that attract business; 8) resources and cooperation in community initiatives to promote sustainable practices; 9) active engagement on neighborhood revitalization programs; and 10) programs and information geared towards enhancing resiliency to disasters.

Specifically, FPU will provide assistance to local economic development organizations by providing information and resources, including timely responses to requests for information regarding data and infrastructure assessments, communication and assistance in the creation of a "business-ready" environment, as well as assistance in efforts to certify "shovel ready" construction sites. The Company will also encourage and participate in site visits, as well as recruitment and prospecting missions to showcase communities in our service areas, and provide financial assistance, as necessary, to support and strengthen these efforts.

FPU will also be engaged in offering assistance to businesses considering locating in our service areas. FPU will commit to providing prompt responses to new business inquiries regarding our service offerings, as well as information and technical guidance regarding the availability and requirements of gas and electric infrastructure for prospective new businesses. In addition, the Company will assist prospective business customers with projected rate analyses, review of reliability requirements, and back up powers supply, as needed.

FPU's broader community involvement will include active efforts to gain a greater understanding of the needs of the various communities we serve and work with communities and local governments in the development of community-specific economic development plans. FPU will also be engaged on community economic development boards and local chambers of commerce, providing leadership and financial resources as needed. The Company will also provide outreach and seminars regarding Florida's energy market and correlating opportunities for businesses.

In addition to efforts targeted at attracting new businesses, the Company will also undertake additional efforts to retain existing commercial enterprises, including commercial energy conservation rebate programs and energy audits, as well as active participation in retention and small business support programs promoted by local governments and chambers. We will also participate in the development and implementation of "Buy Local" campaigns, among other things.

Q. DOES YOUR ECONOMIC DEVELOPMENT PROGRAM INCLUDE ENGAGING SCHOOLS AND CHILDREN?

A. Yes. The Company's efforts will extend into the education arena through coordinated efforts to develop school programs that will build a stronger workforce in those areas most critical for attracting business opportunities. FPU will also engage direct with students through mentoring projects targeted at Science, Technology, Engineering, and Math ("STEM") programs and provide financial assistance as appropriate.

Q. ARE THERE ADDITIONAL EFFORTS NOT PREVIOUSLY DISCUSSED?

A. Yes. FPU will also develop programs, as well as Company policies, designed to encourage technical innovation, particularly as it relates to the development of viable renewable and cogeneration projects and installation of electric recharging stations.

FPU's program will also promote best practices for energy sustainability and include publications, seminars, and direct-mail marketing campaigns designed to encourage conservation, as well as economic growth.

As another means of attracting businesses to our communities, FPU will coordinate with communities engaged in neighborhood revitalization programs and assist by providing assistance with neighborhood enhancements such as improved street lighting and tree trimming. The Company will also provide communities with information and resources to assist in the pursuit of state and federal incentives and grant funding for community development projects. FPU will also actively engage in developing and implementing disaster resiliency initiatives, including locating back-up power supply and supporting emergency response drills.

All in all, each aspect of our overall Economic Development Plan is designed to assist communities that we serve in presenting the most compelling location package to businesses considering location options.

Moreover, our Plan is consistent with the Commission's Rule 25-6.0426, F.A.C., in all respects. Consistent with that Rule, financial support provided by the Company will only be pursuant to a prior written agreement. Likewise, the Company will only seek recovery of economic development expenses that are consistent with the limitations set forth in paragraph (7) of the Rule.

Q. WHAT IS THE STANDARD BY WHICH THE COMMISSION CAN APPROVE YOUR REQUEST?

A. Section 288.035, Florida Statutes, allows the Commission to authorize utilities to recover reasonable economic development expenses.

Q. CAN YOU DEFINE REASONABLE ECONOMIC DEVELOPMENT EXPENSES?

A. The Legislature has defined "reasonable economic development expenses" as: 1) expenditures for operational assistance, including the participation in trade shows and prospecting missions with state and local entities; 2) expenditures for assisting the state and local governments in the design of strategic plans for economic development activities; and 3) expenditures for marketing and research services, including assisting local governments in marketing specific sites for business and industry development or recruitment, and assisting local governments in responding to inquiries from business and industry concerning the development of specific sites. FPU believes that the expenses anticipated are fully consistent with this definition.

Q. WHAT IS THE EXPENSE AMOUNT INCLUDED IN THIS RATE CASE FOR ECONOMIC DEVELOPMENT?

A. The Company is seeking approval of $50,000 annually, which will have a negligible impact on rates to customers. Consistent with Rule 25-6.0426(4), F.A.C., we are asking that the Commission determine that this is a prudent level of economic development expenses for FPU and that this amount may be reported by the Company as such for purposes of its surveillance reports and earnings review calculations. Furthermore, FPU anticipates that some amount of the expenses incurred under this Program will be offset by additional load, allowing the Company to spread its fixed costs across a larger customer base.

Q. WITH REGARD TO THE RIDER PROGRAM, WILL THERE BE ANY LIMITATIONS ON THE NUMBER OF CUSTOMERS ABLE TO TAKE SERVICE UNDER THE TARIFF?

A. Yes. The tariff will initially be open to all customers that meet the service requirements in the tariff. However, in the event that the Company's economic development expenses exceed, in total, the amount approved for the Company in accordance with Rule 25-6.0426(3), F.A.C., the Rider Program will be immediately closed to new applicants.

Q. DO YOU BELIEVE THE COMPANY'S REQUEST MEETS THE PARAMETERS OUTLINED BY THE LEGISLATURE FOR APPROVAL OF ECONOMIC DEVELOPMENT INITIATIVES?

A. Yes.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND THE COMPANY'S REQUESTS IN THIS REGARD.

A. Certainly. FPU is seeking approval to recover $50,000 annually in economic development-related expenses associated with a new economic development program designed consistent with Commission Rule 25-6.0426, F.A.C. Our program is targeted at providing much needed economic development assistance to both our Northeast (Fernandina Beach) and Northwest (Marianna) service areas. The amount requested will have a minimal impact on customer rates, but the efforts undertaken through the program will be significant and beneficial. Moreover, we hope and expect that our efforts will lead to additional growth, jobs, and ultimately, additional customers on our system, which should help to offset some additional expenses. As part of the new program, FPU is also seeking approval of an Economic Development Rider tariff that will provide discounts for new businesses that meet certain load requirements, which in turn will provide an additional incentive for businesses to consider locating in our service areas. FPU's new Economic Development program and Rider Program tariff are consistent with the Commission's rules and similar to programs approved for other Florida investor-owned electric utilities; therefore, we are asking that the Commission approve our proposal and allow the Company to move forward with our economic development efforts.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Mariana Perea. I am the Director of Customer Care for Florida Public Utilities Company ("FPU"). My business address is 780 Amelia Island Parkway, Fernandina Beach, FL 32034.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I attended the University of Hawaii from 1976 to 1979 in the field of Travel Industry Management. I continued my studies at the University of Phoenix where I obtained my Bachelor of Science in Business Management and my Masters of Business Administration in 2009. I spent the first twenty years of my career employed by Mexicana International Airlines in a variety of leadership roles concentrating on customer service and operations. I was engaged by Quest Telecommunications for two years as a Resource Allocation Manager. I moved on to American Express for seven years in the area of Business and Consumer Travel Management. I have been employed with the Company in the capacity of Director of Customer Care for Florida, Maryland, and Delaware since March 2011.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. As Director of Customer Care, I am responsible for establishing the strategy, goals, and objectives for our customer contact centers serving approximately 126,000 customers.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. FPU has a great customer service record. We go through in-depth training to ensure our representatives understand and deliver high levels of service. The purpose of my testimony is to describe the improvements that the Company has made to ensure consistency in customer service. I will describe the strategic goals and objectives of the Company in this area, including the initiatives that have been implemented in support of the strategy. Finally, I will discuss the level of customer complaints to the Commission since the last rate proceeding in 2008 for FPU Electric and the impact of recent reliability improvements since the acquisition of FPU by Chesapeake Utilities Corporation.

INCREASED QUALITY OF SERVICE

Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENT TO CUSTOMER SERVICE.

A. We are fully committed to our customers and stand by our values. We aspire to provide excellence in service and caring for the customer and to ensure their experience with FPU is favorable; this is at the core of everything we do. We strive to exceed customers' expectations. The Company's goal is to establish a process to evaluate and implement changes that will result in an even more positive experience for our customers. This experience is defined as one which results in customers not just being satisfied customers; but rather when customers become promoters of our Company. "Promoters" are customers who refer potential customers to our Company, creating retention and profitable growth. In order to achieve this positive customer experience, the Company is committed to consistently exceeding our customers' needs during critical touch points. These touch points include incoming phone calls, walk-in contact, web site visits, billing, energy conservation program, sales & marketing activities, meter turn-on's, leak investigations at the customer premise and other opportunities to interact with customers. The Company has identified, and is implementing, best practices throughout its operational departments that are aligned with the goal of satisfying our customers to the extent that they become promoters. One of the key components required to achieve and maintain the goal of providing a positive customer experience is the gathering of critical performance measurements. The Company has identified many standard metrics that are critical to determining whether we are moving in the direction of providing a positive customer experience. Based on these metrics (speed to answer, call handle time, net promoter score encompassing the areas of field operations and customer contact, and quality monitoring of calls), the Company is able to improve processes, enhance employee training programs, and better focus collateral material messaging that enables the Company to deliberately provide services that meet and exceed customer expectations. This process encompasses all aspects of the Company, from Customer Care to Sales & Marketing to Operations and Engineering.

Q. PLEASE DESCRIBE THE PROCESS UNDERTAKEN BY THE COMPANY TO IMPROVE THE SERVICE QUALITY TO CUSTOMERS.

A. The Company has developed and implemented a Customer Care strategy with a goal to be recognized as an industry leader in the execution of all meter-to-cash activities, including Contact Center services, while ensuring all processes are designed to deliver a positive customer experience. There are four strategic objectives to the plan: 1) Customer Centric – excellent service to our customers is our number one priority; 2) Consistent Quality – we will provide professional, courteous, timely, and accurate service to every customer in a fair, consistent and accessible manner; 3) Efficient and Effective – we will measure and improve work processes by implementing innovative ideas, applying appropriate technology, and training staff to be helpful and knowledgeable; and 4) Accountability – we will use feedback from processes and customers to improve our performance.

Q. WHAT ARE THE SPECIFIC INITIATIVES THAT THE COMPANY IS IMPLEMENTING IN SUPPORT OF THE CUSTOMER CARE STRATEGY?

A. The Company has identified five (5) key initiatives that support the Customer Care strategy: 1) Consolidation; 2) Performance Management; 3) Development and Training; 4) Process Improvement; and 5) Implementation of Technology.

Q. CAN YOU PLEASE DESCRIBE EACH INITIATIVE?

A. Yes. After the acquisition we saw the need for structural change. First, the Company needed to consolidate its Customer Care activities organizationally. Prior to the acquisition of FPU, this function was performed at each physical location, under different managers who utilized different practices, resulting in an inconsistent customer service experience. The Company has now consolidated the Customer Care functions in one department, which meets the first objective of having a singular focus on the delivery of meter-to-cash activities efficiently in a manner that is easy for the customer and produces high-quality service at a lower cost. Second, the Company has established standards for each meter-to-cash discipline and the reporting requirements necessary to provide valuable feedback to those employees performing the activity. By establishing these clear standards, the Company is able to measure and manage performance of its employees as we strive to deliver a positive customer experience. Third, the Company has developed and implemented a series of employee training modules, hired The Profitable Group to perform training, which has provided employees with the skills and knowledge necessary to efficiently and effectively perform their assigned activities. In addition, the Company has contracted the Fred Pryor group for ongoing online training in a variety of areas. Fourth, many employees throughout the Company have been involved in a review of existing processes designed to improve the effectiveness and efficiency of the activities that are performed. As we move forward, feedback from customers and employees and the metrics results will be utilized in a continuous improvement process to move us closer to the strategic objectives of the Customer Care organization. Finally, the Company has made many technology improvements that enhance our ability to provide efficient and effective services to our customers.

Q. CAN YOU ELABORATE ON SOME OF THE TECHONOLOGY IMPROVEMENTS?

A. The Company, since the acquisition by Chesapeake, has implemented the following two technology improvements which provide the foundation for our ability to provide world-class services to all of our customers, including the Electric customers:

- Consolidation of Customer Information Systems (CIS); and
- Implementation of New Telephony Technology.

The Company is currently in the process of evaluating possible implementation of kiosk-based service for 24/7 payment access in a variety of locations across Chesapeake's Florida service platform with priority being focused upon the Electric divisions. Additionally, the Company is reviewing various Interactive Voice Recognition IVR systems for improved telephone payment options and bill information as well as a mobile friendly website for on the go payment processing and service requests.

Finally, the Company is upgrading its billing software to a new browser-based Customer Information System (CIS) version designed to increase the overall customer and user experience. Additional billing options will also be explored to enhance the customer service experience. The CIS utilizes streamlined guided processes that will create consistency in training and call handling. Additional safeguards have been built into the system to improve the accuracy of customer records. Improved reporting capabilities will increase the Company's ability to analyze data, ensure consistency, and provide services that meet and exceed customer expectations. This billing system will be used Company-wide.

Q. CAN YOU DESCRIBE HOW THE CONSOLIDATION OF THE CUSTOMER INFORMATION SYSTEM BENEFITS ELECTRIC CUSTOMERS?

A. In June 2010, the Company integrated the Customer Information Systems of Chesapeake's Florida operations with FPU's system, thus providing a consistent basis from which to operate. In November 2011, the Company completed the integration of all customers into the consolidated CIS system. The current CIS platform allows for the combined company to seamlessly coordinate all Customer Care (customer call centers, billing and collections and meter reading) and field services activities (turn-on's and off's, meter changes, etc.) that impact customers. As such, customer inquiries can be handled by virtually any customer representative. Previously, customers were required to contact the local office for service during normal business hours (8:30 am to 5:30 pm). Now, customers can contact the consolidated call center from 7:00 am to 7:00 pm or the after-hours service during all non-business hours. The consolidation has also allowed the Company to implement best practices, consistent training and, as described below, capture valuable customer service metrics to evaluate our success in providing the best possible customer experience.

Q. HAVE THE CUSTOMERS RECEIVED ANY OTHER BENEFITS FROM THEIR INTEGRATION INTO THE CUSTOMER INFORMATION SYSTEM?

A. Yes. Customers now receive a full page bill from the Company, which clearly describes all components of the bill, compares current usage with previous usage and provides other important information. Customers also receive a return envelope to facilitate payments made by check through the mail. Previously, customers received their bill on a post card sized statement, which contained the minimum required information, with no return envelope. Customers now also have available multiple payment options, including credit and debit cards, electronic funds transfer, payment by phone and, as more fully described below, walk-in payments at a multitude of locations that are available during and after normal business hours and on weekends.

Q. PLEASE DESCRIBE THE BENEFITS CUSTOMERS RECEIVE FROM IMPLEMENTING NEW TELEPHONY TECHNOLOGIES.

A. The Company has finalized the installation of state-of-the-art telephone systems that provide for seamless call center activities from agents located throughout the state, as well as, for the first time, having the ability to collect a wide variety of valuable customer call metrics. Information such as call waiting times, call abandonments and recording of actual customer calls provides us with the measurements needed to continuously improve our ability to provide world class customer service. The ability to provide call options via telephone prompts enables us to provide better specialized service to customers. Customer service representatives are continuing to receive intensive training that enhances their knowledge of all Company-offered programs, such as Energy Conservation programs, and system-based processes that allow for one-call resolution for most contacts.

Q. CAN YOU IDENTIFY AND DESCRIBE OTHER SPECIFIC CUSTOMER BENEFITS BEYOND THE TECHNOLOGY-BASED IMPROVEMENTS?

A. Yes. The Company has enhanced the customer experience through a variety of initiatives designed to benefit customers through improved services. The following specific improvements have been implemented:

- More thorough and more effective Employee Training;
- Implementation of Third Party Payment Centers;
- Online options for service, payments, and information; and
- Utilization of Third Party Providers for Certain Functions.

Q. CAN YOU DISCUSS THE EMPLOYEE TRAINING THAT HAS TAKEN PLACE?

A. Yes. As previously mentioned, the Company has engaged a firm out of Tampa, Florida, The Profitable Group, to provide employee training throughout the Company. Our employees are committed to serving our customers in such a way that our customers become "promoters." With that said, the employee training is specifically designed to enhance employee understanding of the importance of providing quality service to our customers.

Q. PLEASE DISCUSS WHAT THIRD-PARTY PAYMENT OPTIONS THE COMPANY HAS IMPLEMENTED.

A. Recently, the Company executed an agreement with Fiserv, Inc., a global leader in information management and electronic commerce systems and services, to accept utility payments at its network of locations, primarily at over 300 Wal-Mart stores in the state. Additional payment locations are also part of this service arrangement. This is a free service to our customers as the Company pays for any transaction fees imposed by the contract. This diverse and extensive access to payment locations is very convenient for customers and provides all customers, including all Electric customers, access to walk-in payment locations 24/7. This agreement with Fiserv, Inc. provides for a significant enhancement for customers who desire to pay at a walk-in facility.

Q. HOW HAS THE COMPANY UTILIZED THIRD PARTY PROVIDERS TO ENHANCE SERVICE TO CUSTOMERS?

A. The Company has initiated a comprehensive Dealer Network program that actively recruits, trains and provides continuous support for third party providers, such as plumbing and HVAC companies. These providers are able to perform certain functions that have traditionally been provided by Company personnel, such as turn-key operations from service line installation through meter turn-on. This has resulted in more timely customer connections at a lower cost to the Company.

Q. HOW HAVE CUSTOMERS RESPONDED TO THESE SERVICE IMPROVEMENTS?

A. The primary tangible measurement of customer satisfaction is the number of complaints filed with the Commission. Billing and service complaints were minimal prior to the changes (5) and dropped 20% within 3 months of the new implementations. In the last 7 months we have had no service complaints. The Company believes that this is an important indicator that the customers have embraced the changes from the deliberate implementation of the Customer Care strategy, initiative implementations, employee training and other customer service improvements made by the Company.

Q. PLEASE SUMMARIZE THE EFFORTS OF THE COMPANY TO IMPROVE CUSTOMER SERVICE.

A. The Company's Customer Care strategy, described above, is to provide a positive customer experience on a consistent basis. As discussed, the Company believes that it is not enough to have satisfied customers. Instead, the Company believes that a key component of long-term success is to develop the customer relationship to the point where the customer actively promotes the Company to others. In order to achieve the strategy, the Company has implemented several best practices designed to put the Company on a continuous improvement path towards the perfect customer experience. All of these activities are deliberately designed to identify how to create promoters from our customers and to predict what will be required to keep them as promoters in a rapidly changing environment. The Company has implemented an extensive employee training program designed to improve the knowledge and skill sets of employees that provide services to customers. By implementing systems that capture customer information and feedback, the Company will be able to modify the employee training programs and work management processes and procedures that will result in exceeding the needs of our customers. The company has increased staffing levels and operating hours to 7AM-7PM M-F to support servicing capabilities for customers. All of these efforts by the Company have clearly resulted in an improved quality of customer service to the electric Company customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(Transcript continues in sequence with Volume 2.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 16th day of September, 2014.

Linda Boles
____

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734