BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of: DOCKET NO. 120001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
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PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Monday, November 5, 2012

TIME: Commenced at 9:30 a.m.
Concluded at 12:19 p.m.

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

REPORTED BY: JANE FAUROT, RPR
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APPEARANCES:

JOHN T. BUTLER and KENNETH M. RUBIN, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

JOHN T. BURNETT and DIANNE M. TRIPLETT, ESQUIRES, Post Office Box 14042, St. Petersburg, Florida 33733, appearing on behalf of Progress Energy Florida.

JEFFREY STONE, RUSSELL BADDERS, and STEVEN GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950, appearing on behalf of Gulf Power Company.

JAMES D. BEASLEY and J. JEFFRY WAHLEN, ESQUIRES, Ausley Law Firm, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

BETH KEATING, ESQUIRE, Gunster Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1804, appearing on behalf of Florida Public Utilities Company.

JON C. MOYLE, JR., ESQUIRE, Moyle Law Firm, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

APPEARANCES (Continued):

JAMES W. BREW, ESQUIRE, c/o Brickfield Law Firm, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington D.C., 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc./PCS Phosphate.

CHARLES REHWINKEL, PATRICIA A. CHRISTENSEN, and JOSEPH MCGLOTHLIN, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison St., Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of Florida.

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, c/o Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of Florida Retail Federation.

MAJOR CHRIS THOMPSON, ESQUIRE, Federal Executive Agencies, c/o USAF/AFLOA/JACL/ULFSC, 139 Barnes Drive, Suite 1, Tyndall AFB, Florida 32403-5319, appearing on behalf of Federal Executive Agencies.

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

APPEARANCES (Continued):

SAMANTHA CIBULA, ESQUIRE, 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	Comprehensive Exhibit List	31	31
2-19, 22-114	(As shown in Comprehensive Exhibit List)	32	32
20	MO-1	118	118
21	MO-2	118	118
115	Stipulation on Issue 32	31	31
116	FPL Filing with FPSC Clerk	34	34
117	Revised CDY-2	35	35
118	Revised CDY-8	35	35
119	NEIL 2011 Annual Report	77	118
120	October 1, 2012, Letter; Alex Glenn of PEF to Ms. Cole	82	118
121	NEIL Accidental Outage Policy, April 1, 2009, to April 1, 2010	85	118
122	NEIL Accidental Outage Policy of 4-1-10 through 4-1-11	97	118
123	Florida Secretary of State Certificate of Non-Authorization for NEIL	99	118
124	OIR Document	99	118

P R O C E E D I N G S

CHAIRMAN BRISÉ: Good morning. We're going to go ahead and call this hearing to order, and I'll request that our staff read the notice.

MS. BROWN: By notice issued September 18th, 2012, this time and place was set for a hearing in the following dockets; Docket Number 120001-EI, Docket Number 120002-EG, Docket Number 120003-GU, Docket Number 120004-GU, Docket Number 120007-EI. The purpose of the hearing is set forth in the notice.

CHAIRMAN BRISÉ: Thank you.

At this time we're going to go ahead and take appearances. There are five dockets to address today. Staff suggests that all appearances be taken at once, so we will do so. All parties should enter their appearance and declare the dockets that they are entering an appearance for. So we will go through the process with everyone from the parties, and then as usual, we'll take appearances from our staff.

Okay. I guess we'll start from my left, your right.

MR. BUTLER: Thank you, Mr. Chairman.

John Butler and Ken Rubin appearing on behalf of Florida Power and Light Company in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MS. TRIPLETT: Good morning, Commissioners.

Diane Triplett and John Burnett appearing on behalf of Progress Energy Florida in the 01, 02, and 07 dockets, and I would also like to enter an appearance for Gary Perko in the 07 docket.

CHAIRMAN BRISÉ: Thank you.

MR. BADDERS: Good morning, Commissioners.

Russell Badders appearing on behalf of Gulf Power in the 01, 02, and 07 dockets. I would also like to enter an appearance for Jeffrey A. Stone and Steven R. Griffin in the same dockets.

CHAIRMAN BRISÉ: Thank you.

MR. BEASLEY: Good morning, Commissioners. Jim Beasley and Jeff Wahlen for Tampa Electric Company in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: All right.

MS. KEATING: Good morning, Commissioners. Beth Keating with the Gunster law firm appearing today on behalf of FPUC in the 01, 02, and 03 dockets, as well as Florida City Gas in the 03 docket; and Florida City Gas, Chesapeake, FPUC, and Indiantown in the 04 docket.

CHAIRMAN BRISÉ: Thank you.

MR. MOYLE: Good morning. Jon Moyle on behalf of the Florida Industrial Power Users Group. I'm with the Moyle law firm, and we are appearing in the 01, 02, and 07 dockets.

MR. BREW: Good morning, Mr. Chairman, Commissioners. I'm James Brew with the firm of Brickfield, Burchette, Ritts & Stone. I'm here for White Springs Agricultural Chemicals, PCS Phosphate, in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. REHWINKEL: Good morning, Commissioners. Charles Rehwinkel, Office of Public Counsel. I am appearing in the 01 and 07 dockets.

MS. CHRISTENSEN: Patty Christensen with the Office of Public Counsel. I'm appearing in the 01, 02, 03, 04, and 07 dockets. And I would also like to put in an appearance for Joe McGlothlin in the 01, 02, and 07 dockets.

CHAIRMAN BRISÉ: Thank you.

MR. WRIGHT: Good morning, Mr. Chairman, Commissioners. Robert Scheffel Wright and John T. LaVia, III, appearing in the fuel docket, 120001, on behalf of the Florida Retail Federation.

MAJOR THOMPSON: Good morning, Commissioners. For FEA, it's Major Chris Thompson appearing in 01, 02, and 07.

CHAIRMAN BRISÉ: Okay. Thank you.

MS. BROWN: Good morning, Commissioners. Martha Brown and Michael Lawson appearing in the 03 docket.

CHAIRMAN BRISÉ: Thank you.

MS. ROBINSON: Pauline Robinson appearing in the 04 docket.

MS. TAN: Lee Eng Tan appearing for the 02 docket.

MS. BARRERA: Martha Barrera appearing, thankfully, on the 01 docket along with Lisa Bennett.

CHAIRMAN BRISÉ: Okay.

MS. CIBULA: Samantha Cibula, Advisor to the Commission in all dockets.

CHAIRMAN BRISÉ: Okay. Thank you.

MR. MURPHY: Charles Murphy in the 07 docket.

CHAIRMAN BRISÉ: All right. Thank you.

Is that everyone that needs to make an appearance this morning? Okay.

For the record, there are some companies that have asked to be excused from the hearing: St. Joe Natural Gas in Docket 03 and 04, Peoples Gas System, 03 and 04, and Southern Alliance for Clean Energy in Docket 02.

Okay. The order of the dockets that we are going to -- the order that we're going to take up the dockets is the 03 docket, 04 docket, 02 docket, 07, and then 01.

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CHAIRMAN BRISÉ: And let's proceed with Docket 120001. And I guess we will give everyone a minute or two to get whatever they need so we can proceed.

All right. Are there any preliminary matters?

MS. BARRERA: Yes, Commissioners, there are several stipulations in the prehearing order as amended. A stipulation in Issue 32 was handed out this morning relating to jurisdictional separation factors for capacity revenues and costs. Everyone should have a copy of it.

The only issues remaining are for Progress Issue 1C, which is whether PEF included the 129 million refund in the calculation of the 2013 factor, and Issue 1D concerning insurance payments to Progress for CR3.

For FPL, Issues 2C and 24B through D remain. These issues are the RTR-1 rider, FP&L incremental security costs, the West County recovery of nonfuel revenue requirements, and the GBRA factor for the Canaveral modernization project, and there are also fallout issues related to the foregoing Progress and FPL issues.

For Issues 1C and 1D, Progress will present its Witness Marcia Olivier. It is our understanding that there is cross-examination for that witness by several intervenor parties.

For FPL Issues 2C and 2B through D, the parties and staff have no questions for these witnesses. Okay. Staff believes that the parties may have waived opening statements. Yes? No?

(Inaudible response; microphone off.)

Okay. All right. So there will be opening statements.

At a meeting on Friday morning, OPC and FPL stated that they would like to brief the FPL issues. Is that correct? Okay. The briefing schedule is as follows, the transcripts will be available November 7th; the order establishing procedure states that briefs were due on November 13. At this time the order establishing procedure has also stated that briefs were due -- I mean, that the staff recommendation would be due November 13th, but staff requests at this time that the Commission direct that the briefs be filed no later than 9:30 a.m. on November 13th for the following reasons: Staff's recommendation is now due by noon, November 16th; it is important for staff to have the parties' briefs to write the recommendations.

The recommendation will appear on the

Commission's November 27th Agenda Conference.

CHAIRMAN BRISÉ: Okay.

MS. BARRERA: There is prefiled testimony for excused witnesses. All the issues except the ones discussed above and their fallout issues are the subject of proposed stipulations, thus all witnesses except one have been excused from the proceeding by stipulation.

Staff requests that the prefiled testimony of all the witnesses identified with an asterisk in Section VI, Pages 4 and 5 of the Prehearing Order, be inserted on the record as though read.

Cross-examination has been waived for the witnesses excused through stipulation. And as I said before, the only witness who is left to testify at this time is Marcia Olivier on behalf of PEF.

CHAIRMAN BRISÉ: Okay. So there's a couple of things that we need to do here. First of all, something simple, let's deal with the briefs. In terms of seeing that staff has a short turnaround time, I think it's relatively reasonable to ask that on the 13th that those briefs be in by 9:30.

Okay. I'm seeing heads nod like that works, and so, therefore, we certainly appreciate your cooperation with us on that issue.

Has everybody had an opportunity to look at the stipulations? Are there any objections to those issues that have been identified as stipulated?

Okay. And I think we may have some questions from Commissioners. So, Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

And I know we still have to enter the prefiled testimony and the exhibits and all that, but I do appreciate the opportunity to ask a question. And I recognize that there are stipulations, but I did have a question on Issue 36, which is to my recollection a little different treatment, or a little different than we generally have issues.

I see that it would be directing our staff to initiate an investigation. I'd like to have a little better understanding of what would be involved in an investigation and how the results of that investigation would come forward to the Commission for our understanding and consideration, and why this is included in the factors for next year. That seems a little odd to me.

MR. LESTER: Commissioner, Pete Lester with Commission staff. Staff has done some discovery, two rounds of discovery regarding GPIF issues, and mainly we're doing a policy review. GPIF has been around since 1980, and it has not really been thoroughly looked into comprehensively from a policy viewpoint. We have looked at the issue of the numbers and all, but we're going more into the detail of why, just a review of it. And I think the idea at this point is to review the discovery we currently have, and then go forward with perhaps a workshop in the spring or something, and take it from there.

COMMISSIONER EDGAR: Did I hear the W word?

MR. LESTER: Workshop; yes, ma'am. That was our idea as of right now.

COMMISSIONER EDGAR: Okay. So I understand the process would be review discovery that has already been filed with the Commission. Has that discovery not been reviewed yet?

MR. LESTER: Yes, ma'am, we have. But I think we have to follow up to see if there is further questions to ask and to use it to set up a type of workshop to where we can sit down with all the parties and discuss GPIF.

COMMISSIONER EDGAR: Does that need to be an issue in this proceeding? I mean, if Commissioners -- because this kind of popped up new to me, candidly. So if Commissioners were to -- I mean, is this something that staff is requesting that this be included in this docket? And then how -- couldn't you do a workshop without an issue here in this docket if, indeed, the Commissioners requested one or directed one?

COMMISSIONER BALBIS: Mr. Chairman, I hate to interrupt, but I was trying to --

COMMISSIONER EDGAR: I'm sorry; I apologize.

COMMISSIONER BALBIS: Just to shed a little bit of light on this issue, as Prehearing Officer and moving through this docket, I did have discussions with staff as they worked with the response to the interrogatory on the best way to handle this. And staff recommended that this be added as an issue. And I thought it was a clean way to handle it for us to vote on it and decide on that we do want to direct staff to look into the GPIF that has been in place since 1980 to see if it's providing the proper incentive to increase O&M efficiency for their base generating units.

CHAIRMAN BRISÉ: Okay.

COMMISSIONER EDGAR: Thank you. May I?

CHAIRMAN BRISÉ: Sure.

COMMISSIONER EDGAR: So review discovery, have a workshop with interested parties in the spring, and then what?

MR. LESTER: Possibly at that point we may want to bring on -- come up with a recommendation at that point for the Commission to hear at agenda, or follow it through as a fuel clause issue in next year's hearing.

COMMISSIONER EDGAR: I'm sorry, I didn't hear that last piece.

MR. LESTER: Follow it through with an issue in next year's fuel proceeding on if there needs to be a change in the way we carry out GPIF.

COMMISSIONER EDGAR: So the staff would be making a recommendation to the Commission, but we would not consider that until we had the actual hearing a year from now?

MR. LESTER: I think we could possibly do it sooner, but I'm saying that --

COMMISSIONER EDGAR: Well, if it's an issue, if it's a stated issue, the way this is worded, staff should be instructed to commence an investigation in the 2013 annual fuel cost-recovery clause proceedings. How would something come before the full Commission prior to the hearing for the fuel cost-recovery clause?

MR. LESTER: I was contemplating after we met through the parties and all, we might want to do an agenda item in the docket.

COMMISSIONER EDGAR: But that's not what this says. I mean, I don't recall ever seeing an issue from the fuel clause docket come before us separately at agenda. Am I not recalling one?

MR. LESTER: We have done --

COMMISSIONER EDGAR: We have.

MR. LESTER: Yes, ma'am. We have done midcourse corrections, and we have also done --

COMMISSIONER EDGAR: I would consider a midcourse correction, which is authorized under the statute, to be different than a staff investigation.

MR. LESTER: I believe we have done others, although I'm not --

MS. BARRERA: Commissioner, once the policy is established, whether it's changed or not, we did not envision it coming into effect until basically 2014 year. Thus, I personally don't see any problem with bringing it to the Commission at the fuel hearing in November of 2013.

COMMISSIONER EDGAR: Well, I personally think it's a little odd, and a little messy, candidly. I mean, if there's something that we want to direct our staff to review and bring something to us, I don't know that it needs to be an issue in a proceeding that then rolls it into an issue in the next proceeding, but then what would not be a change should we want to change in policy until two years from now?

MS. BENNETT: Can I address --

COMMISSIONER EDGAR: Certainly.

MS. BENNETT: The GPIF mechanism was created through a massive number of workshops in the 1980s. Really staff, working with the Prehearing Officer, was looking for direction from the Commission; are you interested in looking at the GPIF?

COMMISSIONER EDGAR: Okay. Well, this doesn't ask me if I'm interested. This says --

MS. BENNETT: Should you initiate, should staff initiate an investigation. And maybe I should -- we could more artfully word it, but basically that's what we're looking for is direction from the Commission. Is this something that is ripe now for us to begin to look at again? Is it still an effective mechanism/tool to incent utilities to be efficient in the use of their baseload units?

COMMISSIONER EDGAR: I understand what the issue is. It's how it came before us and what we are being asked to do, and the process as to how it will come before us again, and what the ramifications of that would be in the timing in future proceedings that I'm trying to have a better understanding of.

So, Commissioners, I would say -- I don't want to throw a wrench into the proceedings. I realize that this is far down the way. I, however, do have a concern about throwing issues into a prehearing order and asking the parties to stipulate to something that had not even been discussed by the Commissioners as to whether it was something that we were interested in pursuing or not.

I do think if there is an issue that staff thinks is ripe for us to discuss and consider future review, that certainly could have been brought to agenda. It certainly could have been brought to IA. If any one or more Commissioners have an issue that we believe we would like to ask staff to hold workshops on, again, we could raise that in an agenda item, we could raise it in IA.

I am not comfortable with this, and I would not like to see this be precedent for future direction to staff for investigations and workshops to come up in annual clause hearings. So with that said, Mr. Chairman, if all of the Commissioners want to approve the stipulation and handle it this way, again, I don't want to throw a wrench into the whole thing, but I do think it's somewhat of an unusual procedure and one that gives me pause.

The parties are asked as to whether we should direct our staff to do something before it has even been brought to our consideration or discussion, I think, is maybe putting the cart before the horse. And I will leave it at that. Thank you, Mr. Chairman.

CHAIRMAN BRISÉ: All right. Commissioners, any further comments on -- since we are on Issue 36, discussing how we may want to move on that particular issue and then decide how we'll deal with the rest of the stipulation.

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you. And just to clarify, you're asking for additional discussion on Issue 36?

CHAIRMAN BRISÉ: Right, as to what do we want to do with it before we get into dealing with the rest of this docket.

COMMISSIONER BALBIS: Okay. Yes, as I indicated before, this was something that staff brought to my attention and we had discussion as to the best way to handle it. The GPIF factor is recovered during this proceeding. You know, obviously the fact that we have this proceeding every year and handle this specific issue, it was recommended by Staff that the easy way to do it, the easy way to gauge an interest in a transparent process in this docket would be just to add it as an issue so we can have this type of discussion.

And the true issue as written -- and, you know, could it be worded better, maybe -- but it's whether or not the Commission is interested in looking at the GPIF factor. It has been in place for a number of years. Staff has some concerns about it. Is there a way we can tweak it to provide additional incentive to companies to operate and maintain their base units better? Is there something that it's working just fine? I think this Commission, especially the five of us have shown an interest on making changes to make things more efficient, more productive, and have a better outcome, and I think this is a good way that we can take a look at this as we are looking at all of the things that we do on a regular basis to see if there is a way to improve it. And I think that this is a way to, again, gauge our interest, and then the next step would be work with staff as to what process that is.

But, you know, I think it's appropriate to include here. It's not making a decision as to GPIF as a whole, what changes to be made, it's just -- you know, is staff going to be directed to take a look at it and bring it to us for consideration. So I think it's appropriate, and I would recommend that we approve it.

And I also point out that, you know, all the parties have agreed to it. The utilities have taken no positions and the intervenors have agreed with staff. So this issue is a Type B Stipulation, along with many of the other issues in this docket.

CHAIRMAN BRISÉ: Commissioner Brown.

COMMISSIONER BROWN: Thank you.

And I was just going to say, it is a Type B Stipulation, and the utilities have taken no position. So I would be curious to hear from the intervenor parties as well as the utilities about inclusion of this issue?

MR. BUTLER: You're looking at me, so I will respond to your question.

As stated, we take no position on it. We think the GPIF mechanism is working well as it exists, but we don't object to evaluating it. Now, there have been a couple of at least partial evaluations of it over the last four or five years, but, you know, it's always within your purview to review these sorts of mechanisms, again, if you choose.

One thing that probably does argue in favor of doing some sort of investigation that starts early in the year, if that is, indeed, your preference to, you know, review the mechanism again is that we always find ourself at these hearings in a little bit of an awkward position in terms of the evidence, if an issue hasn't been raised pretty early on. I mean, our GPIF testimony just supports what the GPIF factors ought to be.

It doesn't talk about any of the policy issues behind it, whether it's appropriate to continue, modify or whatever. And nobody else filed testimony saying it ought to be changed, so it would make for kind of an awkward and probably incomplete record to be trying to make a decision in one of these hearings if it isn't queued up fairly early for discussion.

And without taking any position on whether you should or shouldn't queue it up, if you do decide to have it evaluated, I think some sort of early identification of it is a good idea just so we don't find ourselves in the same posture, you know, when it rolls around again.

COMMISSIONER BROWN: Thank you.

Progress.

MS. TRIPLETT: Thank you. Dianne Triplett for Progress Energy.

We don't have a position on the substance of the issue or the procedure. I think it's really the will of the Commission as far as when and how you want to investigate this and probably a number of other issues. So that's why we took no position.

MR. BADDERS: Russell Badders on behalf of Gulf.

Much the same as Progress, we have not taken a position on this. We will fully participate in whatever mechanism the Commission desires to set up to look at this, if you decide to. We have not identified any issues with the current process.

MR. BEASLEY: Jim Beasley for Tampa Electric. We adopt the positions as stated by our colleagues to the right.

MS. KEATING: Beth Keating for FPUC. Likewise, we don't have a position on this. And, frankly, GPIF doesn't have a direct impact on FPUC at this time.

MR. MOYLE: Jon Moyle on behalf of FIPUG. And we actually support this. It was an issue raised by staff, and whether this is the right mechanism or not, I think that's the issue and the concern about how to raise it. But from our perspective, if the 1980s were the last time it was reviewed, you know, looking in my rearview mirror and where I was in 1980, that's a long time ago. So we think that given the passage of time from the '80s to where we are now, that it's probably not a bad idea to take a look at it.

MR. BREW: What he said.

(Laughter.)

MR. REHWINKEL: The Public Counsel is of a like mind as far as it being looked at. Whether it's in this mechanism or a spin-off, we are completely open to the process, and we agree with what Mr. Moyle and Mr. Brew said.

MR. WRIGHT: What they said. Thanks.

MAJOR THOMPSON: FEA backs FIPUG.

COMMISSIONER BROWN: Thank you.

CHAIRMAN BRISÉ: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I, quite frankly, think it's a little backwards to ask the parties to stipulate to whether we should ask our staff to do an investigation before it was brought to the attention of all of us. And I'm told by the Prehearing Officer that it's a concern that the staff raised, but for something this comprehensive, I certainly think that maybe the rest of us should have had it raised to us before it was put in a stipulation included in this clause. So I am very concerned about the process.

And I understand that our Prehearing Officer, who has done a great job, thinks it's exactly the right way to handle it. I, quite frankly, find it a little offensive, so -- and I understand that the purpose was to gauge interest. But, again, to have a stipulation put in front of us as part of this proceeding doesn't seem to me to be gauging interest. Gauging interest would have been the opportunity for a discussion.

There is no written information about it. I am familiar with the issue, obviously, but I still think this is the wrong process. And I hope I don't see this process come before me again without having the opportunity to really have our interests and concerns gauged and the opportunity for the Commissioners to add some structure and direction to whatever the investigation will be, and when it will come before us and how, and what impact that will have on the discovery process and on the fuel clause hearing a year from now and a year subsequent to that. So with that, I will make it clear in my dissent that it is not whether or not we look at the issue itself that is my concern, but how this was brought to me I am strongly opposed to.

So, Mr. Chairman, I am in a position where I'm ready to vote for all of the stipulations, but I would like to make it clear on the record that due to the process and not necessarily the review that I will be voting no on that particular stipulation. And I thank you for the opportunity to raise my concerns.

CHAIRMAN BRISÉ: Sure.

Okay. Any further comments on this issue? Okay.

MS. BARRERA: Commissioner, at this point staff would like to deal with the exhibits into the record.

CHAIRMAN BRISÉ: Thank you.

All right. So we are dealing with the issue with the stipulations and so forth. I just want to make sure that there are no further comments by fellow Commissioners on this issue? I will just give you my two cents on this.

COMMISSIONER BALBIS: Mr. Chairman, I just want to add one thing before you add your final comments.

CHAIRMAN BRISÉ: Sure; it may help me.

COMMISSIONER BALBIS: Yes. And I think it will help all of us, and especially Commissioner Edgar. And it sounds like a lot of her concerns are dealing with, you know, some of the process of how it got here and then going forward. So maybe I can alleviate the concerns about going forward, and that after we decide on this issue, then at a future, whether it's IA, et cetera, we can discuss what that process will be so that we can get things on track.

And I'm not sure if it alleviates all of your concerns, but at least the process at which we proceed, once again, assuming the Commission wants to direct staff to look into it is that then we can step back and look at what is the best way to address it. So hopefully that alleviates some of the concerns. But, again, I think I agree with staff that this issue needs to be looked at. I mean, 1980 is a long time ago, and that's something that I think is worthy of a second look.

CHAIRMAN BRISÉ: Thank you. I think I agree with -- I think we all agree that, you know, taking a second look at the issue is probably important and is probably ripe for us to look at it. I, too, have some slight concerns as to us having to deal with it through this process.

I think my preference probably would have been that we either take it up as something coming through IA, set it up, and then move forward that way. I think we could get the same result if we tee it up early enough -- we probably could have gotten there. We could have made a decision at IA that we bring it up for agenda, open a docket, do the investigation if the investigation needs to be done, and, you know, by the end of January we could be in that posture and have the time moving forward to deal with it. But, you know, we are where we are. So we'll move forward when we get to that point on making that decision.

All right. Let's go back to some of the other things that we need to deal with here. We weren't done with exhibits and prefiled testimony, so let's deal with the prefiled testimony that we have.

Ms. Barrera.

MS. BARRERA: Yes, sir. All witnesses except one have been excused from the proceedings, and the only witness who's left is Marcia Olivier.

Staff requests at this time that the Comprehensive Exhibit List be marked as Exhibit 1.

CHAIRMAN BRISÉ: Okay. Go ahead.

MS. BARRERA: And at this time we move that Exhibit 1 be admitted into evidence.

CHAIRMAN BRISÉ: Okay. We will move Exhibit 1 into the record, seeing no objections.

(Exhibit Number 1 marked for identification and admitted into the record.)

MS. BARRERA: Okay. Staff also requests that the Stipulation on Issue 32 be marked as Exhibit 115.

CHAIRMAN BRISÉ: Okay. Exhibit 115.

MS. BARRERA: Yes.

CHAIRMAN BRISÉ: Are there any objections to Exhibit 115?

Okay. Seeing none, we'll move that into the record.

(Exhibit Number 115 marked for identification and admitted into the record.)

MS. BARRERA: Staff now moves that Exhibits 2 through 114 listed in the Comprehensive Exhibit List be admitted into evidence. This includes all the prefiled exhibits of the excused witnesses.

CHAIRMAN BRISÉ: Okay. So we will move Exhibits 2 through 114, seeing no objections.

(Exhibits 2 through 19 and 22 through 114 marked for identification and admitted into the record.)

MS. BARRERA: And at this time staff advises that FIPUG and FPL have additional exhibits to enter into the record.

CHAIRMAN BRISÉ: Okay. FPL.

There's a question from a Commissioner.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you.

Again, I'm just trying to think it through. So we have entered in the prefiled exhibits of Witness Olivier that we will be hearing from?

MS. BARRERA: Yes, ma'am.

COMMISSIONER EDGAR: Okay. Don't we usually do that after the opportunity to hear from the witness and for cross?

MS. BARRERA: Oh, Marcia Olivier? I'm sorry; yes, we do.

COMMISSIONER EDGAR: So, Mr. Chairman, are we entering those exhibits at this time, or are we waiting -- I think it's 20 through -- oh, just 20 and 21?

CHAIRMAN BRISÉ: And that was included in the 2 through 114; right?

MS. BARRERA: Yes. And, I'm sorry.

Her exhibits are 20 and 21.

CHAIRMAN BRISÉ: Right. So that should have been 2 though 19 and then 22 through 114.

MS. BARRERA: Yes, sir.

CHAIRMAN BRISÉ: Thank you for catching that, Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

MS. BARRERA: I'm sorry.

CHAIRMAN BRISÉ: Okay. So we'll go back a little bit. Exhibits 2 through 19 will be entered into the record, and then 22 through 114 will be entered into the record, as well.

Okay. Now we are at the exhibits from FPL and FPUC.

MR. BUTLER: Mr. Chairman, for FPL we would ask you to mark, I think it would be Exhibit 116, a filing that we made on Friday with the Commission Clerk's Office. It is a revision to the capacity cost-recovery factor schedules that reflects what staff has proposed and we agree with, and we believe everybody else is in agreement with, that the initial capacity factors to go into effect at the beginning of January 2013 would reflect the West County 3 revenue requirement recovery limited by the projected fuel savings of that unit. This was a variation on the theme that we hadn't filed in the original case, and we were requested to do so by staff, and that would be our Exhibit 116.

CHAIRMAN BRISÉ: Okay. Are there any objections to Exhibit 116? Seeing none, we will enter Exhibit Number 116.

(Exhibit Number 116 marked for identification and admitted into the record.)

CHAIRMAN BRISÉ: Now, FPUC.

MS. KEATING: Mr. Chairman, Commissioners, in light of stipulations on the remaining issues for FPUC, on Wednesday FPUC filed two revised exhibits, Third Revised CDY-2 for Mr. Curtis Young, as well as a new CDY-8. Third Revised CDY-2 is the estimated/actual filings made by Mr. Young. They are the E-Schedules for both the northwest and the northeast division. CDY-8 is a completely Revised E-1 Schedule through E-10 Schedule for both divisions. I have copies of those. But we would ask that CDY-2 be marked as 117, I believe, and CDY-8 be marked as 118.

CHAIRMAN BRISÉ: Thank you. We will move Exhibits 117 and 118 into the record, if there are no objections?

Okay. Thank you.

(Exhibit Numbers 117 and 118 marked for identification and admitted into the record.)

CHAIRMAN BRISÉ: Any further exhibits? Did we skip 115? Yes.

So we will move that back and make FPL's Exhibit 115, and FPUC's Exhibits 116 and 117.

MR. BUTLER: Mr. Chairman, no objection in doing so, except I think that 115 was this proposed stipulation on Issue 32, and had been marked. That is what I had written down, at least.

CHAIRMAN BRISÉ: Oh, that's right. That was the last one.

COMMISSIONER EDGAR: 115, I think, was Issue 32, the stipulation.

CHAIRMAN BRISÉ: That's correct.

COMMISSIONER EDGAR: I would like to get copies, if I could, of what we are now marking as 116, 117, and 118, if that's all right, Mr. Chairman.

CHAIRMAN BRISÉ: Okay.

MS. KEATING: Mr. Chairman, may I approach?

CHAIRMAN BRISÉ: Staff is going to make themselves available to pass that out to us.

If I can get someone to get FPUC's documents, please. Thank you.

MR. BUTLER: Mr. Chairman, we do not have copies to distribute here at the moment of what was marked as Exhibit 116. I can certainly get copies of that made and have those available to you shortly.

CHAIRMAN BRISÉ: Okay. That would be helpful.

Any further exhibits that we need to deal with this morning? Okay.

All right. With that, we are moving on to -- we have dealt with the prefiled testimony?

MS. BARRERA: Yes, sir.

CHAIRMAN BRISÉ: Yes, we have. Okay.

MR. BUTLER: Mr. Chairman?

CHAIRMAN BRISÉ: Yes, sir.

MR. BUTLER: I may have missed it. I don't think I heard the testimony of the excused witnesses being stipulated into the record as though read. If I did, my apologies. I just wanted to be sure that we covered that.

CHAIRMAN BRISÉ: All right.

MS. BARRERA: Yes, sir, the testimony, the prefiled testimony would be contained in Exhibits 2 through 19, 22 through 64.

CHAIRMAN BRISÉ: All right. Let's deal with the exhibits. You're talking about the exhibits that go with the prefiled testimony? Okay. We have the exhibits itself, but now we need to deal with the actual prefiled testimony?

MS. BARRERA: Yes, sir.

CHAIRMAN BRISÉ: All right. So let's enter the prefiled testimony into the record as though read, seeing no objections. All right. Thank you very much.

(REPORTER NOTE: For the convenience of the record, the prefiled testimony of the stipulated witnesses is inserted into the record after Witness Olivier.)

CHAIRMAN BRISÉ: So we have dealt with the prefiled testimony and the accompanying exhibits. We have dealt with all the other exhibits except the exhibits for Ms. Olivier, which will be dealt with when she comes to the stand. And so now we are on proposed stipulations.

Okay. Now we are on proposed stipulations. Staff suggests that we make a bench decision on stipulated issues in the Prehearing Order on Pages 31 through 57. They have also prepared a chart showing the stipulated issues and another chart showing the non-stipulated issues. Staff is available to answer any questions regarding the proposed stipulations.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

If you are ready for it, I can make a motion that the Commission approve all prefiled -- excuse me, all stipulated issues as contained in the amended prehearing order.

CHAIRMAN BRISÉ: Okay. So there is a motion. Is there a second?

COMMISSIONER BROWN: Second.

COMMISSIONER GRAHAM: Second.

CHAIRMAN BRISÉ: Okay. Any further discussion? Seeing none, all in favor say aye.

(Vote taken.)

COMMISSIONER EDGAR: And, Mr. Chairman, I would like to reflect that my vote will support all stipulations except for Issue 35, and that my concern is based on the process and undefined procedure, but that I am comfortable with --

CHAIRMAN BRISÉ: 36.

COMMISSIONER EDGAR: 36?

CHAIRMAN BRISÉ: Yes, Issue 36.

COMMISSIONER EDGAR: It is 36. Thank you. I apologize. Thank you, Commissioners. That I'm voting for the stipulation on 35, but opposed to 36. Thank you.

CHAIRMAN BRISÉ: All right. Thank you very much. And let the record reflect that there is a dissent on Issue 36 from Commissioner Edgar.

All right. Are there any outstanding motions?

MS. BARRERA: Commissioners, there are a number of outstanding motions regarding confidentiality that will be addressed by the Prehearing Officer after the fuel hearing. We would remind everyone that the record does include confidential information, so when discussing issues that are supported by evidence that is confidential, take every precaution to avoid stating the confidential information aloud.

CHAIRMAN BRISÉ: All right. Thank you. Are there any additional preliminary matters?

MS. BARRERA: No, sir.

CHAIRMAN BRISÉ: Okay.

MR. BUTLER: Mr. Chairman?

CHAIRMAN BRISÉ: Yes, sir.

MR. BUTLER: For FPL, I'm going to propose an additional preliminary matter, if I may, and it is this. At this point we have no evidence to present. By agreement of the parties, we are going to be briefing the issues that remain to be addressed with respect to us, and so I believe that our participation is no longer required in this hearing. And I would ask that FPL be excused from further attendance at this hearing, unless any of the Commissioners have questions for FPL regarding the status of our matter in this docket.

CHAIRMAN BRISÉ: Commissioners?

Okay. I think I saw heads nodding up here, so I think that is fine with me if you all are excused.

MR. BUTLER: Thank you very much.

MR. BADDERS: Chairman Brisé, Russell Badders on behalf of Gulf Power. I have a similar request. All of my issues have been stipulated, and I have no witness appearances. I would ask that Gulf be excused.

CHAIRMAN BRISÉ: Okay. Works for me.

MR. BEASLEY: Chairman, Jim Beasley for Tampa Electric. We would like to make the same request on behalf of Tampa Electric. All of our issues have been stipulated.

CHAIRMAN BRISÉ: All right.

MS. KEATING: Mr. Chairman, Beth Keating for FPUC. We are in the exact same position and would very much like to be excused.

CHAIRMAN BRISÉ: All right.

MR. BREW: We're going to stay.

(Laughter.)

CHAIRMAN BRISÉ: You're going to stay? Good deal.

MS. TRIPLETT: So am I.

CHAIRMAN BRISÉ: All right.

MR. MOYLE: Chairman, maybe if we could just have a minute of informal recess.

CHAIRMAN BRISÉ: Sure.

MR. MOYLE: And we can spread out and the other counsel for intervenors may be able to --

CHAIRMAN BRISÉ: Yes, I think it is probably a good time for us to take a five-minute break, give our court reporter a few minutes so that we get into the second part. Five minutes.

(Recess.)

CHAIRMAN BRISÉ: All right. We will reconvene at this time. And I believe we have some -- we have a witness to swear in. If you would rise.

(Witness Olivier sworn.)

CHAIRMAN BRISÉ: And we have opening statements, and per the prehearing order, we have five minutes per party. And we will start with Progress.

MR. BURNETT: Thank you, Commissioner.

Commissioner, as you heard your staff, Commissioners, two issues remain for Progress Energy.

Issue 1 Charley is whether we have properly accounted or properly calculated and given the customers the full benefit of the $129 million refund that is called for in our global settlement agreement. Ms. Olivier's prefiled testimony and schedules will show that we have on all fronts, and any questions that Ms. Olivier receives will show that that amount has been properly accounted for and the customers received the full benefit. So we don't anticipate any issues there.

With respect to Issue 1D, that issue is what amount, if any, should Progress Energy Florida include in the 2013 factors to account for any potential NEIL recovery that may happen. And I think it is beneficial to get a little bit of history of where were we last year with this. So in 2011 we were still receiving payments from NEIL. We knew that NEIL had at least acknowledged one event, although they had withheld and reserved their rights. We knew that we had a calculable amount of receivable, and we had a calculable amount of receives to date, and that we had a start date that was undisputed with NEIL.

So we said that being the case we can include a projection of what we may get in 2012 from NEIL for insurance proceeds for replacement power. We didn't get those in 2012. So as we approached the end of this year we said, okay, what do we do for 2013? What assumptions do we make?

The company had two reasonable choices to make. First, we looked to accounting guidance and say what are our accountants doing? What are we telling our investors in 10-Q space and SEC space? That accounting guidance says, look, if you don't know what you're going to get or when you're going to get it, book it as zero. Don't assume you're going to get anything, and if you get it, great. Account for it when you get it. That's a reasonable assumption. That is something we could have done and still a reasonable position as we sit here today.

The second option is to say, well, we still have the same known facts we knew in 2011 when we were setting the 2012 factors. We know that we have at least one event that was acknowledged that was paid on. We have a certain amount that we have received, a certain amount due and owing, and we have a start date for that. Is that concrete enough to include a projection in 2013? And we came to the conclusion that it did, that that was concrete enough. So we included approximately $327 million in the projection as a recoverable for 2013 knowing that we're going to enter into nonbinding mediation with NEIL at the end of this year. So it's not likely we're going to receive any proceeds in 2012, but it's possible we could in 2013. It's possible that we may not, and it's possible that amount may be at least that or something different.

So with that, we said that's what we're going to do. So we maintain that amount. If we don't get that amount in 2013, then that's going drive an underrecovery which will cause bills to go up in 2014 if we don't have that, so that will be an underrecovery. But in the near term, including that $327 million in the projections acts to lower the customer bills in the near term. So that is the decision the company made out of the two reasonable ones; include zero, raise the factors a little this year, or include the 327, lower them this year knowing that if we don't recover that in 2013 the bills do go up for an underrecovery.

Now, what I expect you may hear today is that we should include two events, three events, four events, who knows, a multiple set of events to increase more money in the near term to say don't assume the 300 million, assume 700 million, or assume a billion, or something that you may hear.

Well, the problem with that is that unlike the known information that we have today, we don't have that information for two events. We don't have at least an acknowledgment from NEIL that there was two events. We don't have a start date. There are unknown facts that prevent us from reasonably making any sort of assumption for anything more than what we know.

So, in our opinion, it is unreasonable to assume anything more than either zero, the known facts that we have. And Ms. Olivier, if asked those questions, her testimony will make that clear. And also her testimony will make clear that if we do start assuming multiple events based on speculative information, that just drives the potential for a higher underrecovery and pushing that money out further. That if we don't receive that in 2013, it is going to make the factors that more greater in 2014.

And to close, one thing I think that we should make clear is not at issue in this fuel docket is the timing of our NEIL negotiations, the pace of our NEIL negotiations, the substance of our NEIL negotiations, the prudence of our NEIL negotiations, or our interactions with NEIL. That's all to be taken up in another docket at a different time when those issues are ripe.

So, again, what's here today is did we out of two reasonable choices, zero or a projection made on the known facts, make a good decision to carry over what we did last year and that the Commission approved last year, and in making that assumption to say let's go with what we have on known facts and at least include some amount this year.

Thank you, Commissioners.

CHAIRMAN BRISÉ: Thank you. Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

Mr. Burnett gave you a lot of information about where things are, and it's common practice for lawyers not to object on opening, and I did not, and actually welcome the information, because I think it's pertinent and useful information about where are things with NEIL. And the witness may have that information, maybe not. Last year I asked her some questions about NEIL, and she essentially said, well, that number was given to me as a plug-in, so we'll have some questions about it. But FIPUG is here because we have concerns about the NEIL insurance monies, where they are, when they're coming, how much is going to be due the ratepayers.

And why does FIPUG care? Because the ratepayers we contend are really, you know, on the hook for this, because the premiums are paid with ratepayer money. As you will hear, the assumptions that are made, whether you assume that there is one event or two events, that translates directly into how much ratepayers have to pay in the fuel clause.

And FIPUG is going to put on some evidence, you are going to have some documents, we are going to put in the insurance policies, we are going to put in the NEIL annual report, we are going to put in a letter from Mr. Glenn. We think those documents will show that unlike what Mr. Burnett suggested, that there's two options, to assume nothing or to assume one event, that you ought to assume two events. And that it's not that hard to get to that point if you look at what the companies have said. NEIL calls it a 2009 delamination event and a 2011 delamination event. There were 18 months between the events. Different parts of the building.

The policies are annual policies. And after a year, Progress pays another premium and the policy, you know, reloads. So we are going to make the case we believe that the proper assumption is that there are two events.

I think there will also be some questions about where are we, where are we on getting the money? And I think it's telling that the event, the first event was October 2009, okay? According to my math that's more than three years ago. And the monies paid to date for the replacement fuel -- there's two policies; one is for the property damage, and that's 2.25 billion, and the other is for the replacement fuel, and that's 490 million. I will call it 500 million, because I rounded it up, but it is 490 for the replacement fuel.

So for the first event, I don't know that anybody is disputing the first event, but in the first event they have paid 162 million on replacement fuel. Where's the rest? You know, what is going on with that? And the question becomes why are they not stepping up? Why are they not paying? Why are they not paying more on a second event? You know, what's happening?

So FIPUG has looked into this. We have concerns. Progress is in a tough position, because they have a pending claim before these folks, so they are going to try to, you know, work with them. FIPUG admittedly is going to be a little aggressive on this issue, because, you know, we think that the NEIL folks need to step up and need to pay the monies that are due and owing.

If you were in the State of Florida on a property insurance claim with a residential claim, I'm not sure the Office of Insurance Regulation would let somebody, quote, unquote, investigate for more than three years before paying on a claim. And as we looked into this, we discovered that NEIL, the Nuclear Electric Insurance Limited, is not licensed to do business in the State of Florida. They are not licensed to sell insurance, and you'll have the authenticated certificate of authority from the Office of Insurance Regulation saying we have no record of NEIL.

The Secretary of State, I also have a document that I will introduce that says they are not registered to do business. So it starts maybe making a little more sense that if they are not doing business down here and nobody can call them in, you know, the Commission, the Office of Insurance Regulation, the Legislature, and ask them what's up with this money, you know, maybe the three-year delay makes a little more sense in that context.

So we're making an issue of this. It's a big deal because the numbers -- and this Commission, a lot of times we deal with, you know, tens of thousands, hundreds of thousands, millions, hundreds of millions. But FIPUG contends these insurance policies, that the number starts with a B, the billions. 2.25 billion on repair and 500 million on the replacement policies. You know, we're just arguing there's two, there's two that ought to come in.

Now, there was a third event --

CHAIRMAN BRISÉ: Mr. Moyle, you have thirty seconds.

MR. MOYLE: Okay. There was a third event, as well. But that's why we're making an issue of this today, and I think that this is helpful to have this opening so you'll have some context as to why we are bringing this forward to the Commission's attention.

In sum, we will ask you to say it's just as reasonable to assume two events. But as Mr. Brew and others have asked, they would say open a docket to look at this whole insurance issue. It's too important, too much money to not dig into it.

So thank you for the chance to make an opening statement.

CHAIRMAN BRISÉ: Thank you.

MAJOR THOMPSON: Good morning, Commissioners. Originally, FEA on Issue 1D said no position, but we are going to adopt the positions from FIPUG.

CHAIRMAN BRISÉ: Okay. Thank you.

Mr. Brew.

MR. BREW: Thank you, Mr. Chairman.

Good morning. In one sense we have dodged the bullet this year, and we are fortunate that the proposed fuel factor is actually going down in terms of what's in the current factors now. And a big part of that, as you know, is that the Commission approved the settlement back in February that fixed the rate recovery for Levy for the next several years, and that has provided some needed stability in terms of the factors. And it also provided some interim relief related to the CR3 outage.

But as both Mr. Moyle and Mr. Burnett mentioned from their different perspectives, the CR3 unit outage looms over what the Commission is doing now as well as the decisions to come in the future. And just to comment, in addition to Issue 1D, that issue also comes up in Issue 27 as both of those are fallouts of what has been briefed and argued in the nuclear cost-recovery docket.

But the fact is, as Mr. Moyle mentioned, that Progress has been assessing the unit repair for a year and a half. We don't know whether Progress will even attempt the repair. You don't know, Progress doesn't know, and I don't think even Duke knows what they are going to yet.

My point is simply that the decision and lack of action and the delays associated with that represent real cost to consumers, and PCS's point in this docket has been first with respect to capacity. That as we argued in the NCRC, that recovery of the power uprate costs needs to be held in abeyance because the company cannot carry its burden of proof. I won't repeat that, but it is a pending issue in the NCRC docket.

And on the fuel side, as both Mr. Burnett and Mr. Moyle mentioned, the company has imputed $327 million in expected fuel recoveries under the replacement fuel portion of the NEIL coverage. Now, remember that NEIL has paid about $163 million, and then discontinued that payment. And while that is stuck in litigation, or mediation, or arbitration, the fact is, as far as we know, the only reason for NEIL -- whether it is one event or two, to not pay that remaining balance was if they determined that it wasn't an accident, meaning it was Progress' fault. And so we want to make sure that the 327 million imputation, which we think is absolutely appropriate in this year's factor, does not come bouncing back at ratepayers at a later date.

We don't have an issue with that in this factor, but I just want to caution that may be an issue we will need to debate in the future. Thank you.

CHAIRMAN BRISÉ: Thank you.

MR. REHWINKEL: Mr. Chairman and Commissioners, Public Counsel had not planned on making an opening statement, but I will make brief remarks in two areas.

Our basis for cross-examining Ms. Olivier is to put on the record some information about the status of the $129 million refund and to get her understanding of how that is going to be handled. I don't think there is a lot of controversy there.

With respect to the one event, two event, or multiple event issue, the Public Counsel believes from our standpoint that this issue may not be ripe at this time, although we do fully understand FIPUG's basis for raising the issue here. Paragraph 11A of the stipulation has a provision that in the event of retirement, if that is the chosen path, that all NEIL insurance proceeds will, unless otherwise agreed among the parties, be applied to first offset the consumers' share of replacement fuel costs incurred after December 31, 2012.

Because to a large extent that issue is open among the parties, we would be reluctant to take a position about whether additional insurance proceeds above what has been imputed, where that should hit the books, so to speak, or where on the customer's bill that should go. But beyond that we have no position on this matter other than as stated in our prehearing statement.

Thank you.

CHAIRMAN BRISÉ: Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman. We agree with the comments of the Public Counsel's Office.

Thank you.

CHAIRMAN BRISÉ: All right. Thank you. I think that covers --

MS. BENNETT: Mr. Chairman, with regards to FEA, it's a little unusual, and we'd like a little clarification from the parties. Usually once you have taken no position you have waived your right to address this issue, and that's in the order establishing procedure. I didn't hear any objection from any of the parties, and I think it would be up to the Commission to determine if it's okay for FEA to now change its position.

CHAIRMAN BRISÉ: All right, Commissioners. I don't see any objection from the party, Progress. And I'm looking across here at other parties. I don't see any objections.

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

And maybe this might help. It's kind of an unusual situation here. We did have a status conference on CR3 where there were some parties that started to ask questions pertaining to this issue. And, you know, we stopped them from asking those questions as they were more pertinent here. So it's kind of unusual in this situation, so I'm glad to hear no one objects to having FEA take a position at this point, but I certainly would not object to that.

CHAIRMAN BRISÉ: Okay. Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. I have no objection to it, recognizing that it's kind of a unique situation.

CHAIRMAN BRISÉ: Okay. So then we will entertain the changing of the position. Okay.

MS. TRIPLETT: We're ready to call the witness.

CHAIRMAN BRISÉ: Okay. Progress, you may call your witness.

MS. TRIPLETT: Thank you. Progress Energy Florida calls Marcia Olivier.

MARCIA OLIVIER

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

DIRECT EXAMINATION

BY MS. TRIPLETT:

Q. Good morning, Ms. Olivier. Will you please introduce yourself to the Commission and provide your address.

A. Good morning, Commissioners. My name is Marcia Olivier, and my address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. And you have been sworn, and so who do you work for and what is your position?

A. I am employed by Progress Energy Service Company as the Manager of Retail Riders and Rate Cases for Progress Energy Florida.

Q. And have you filed Prefiled Direct Testimony and exhibits in this proceeding?

A. Yes, I have.

Q. Do you have a copy of your testimony and exhibits with you?

A. Yes.

Q. Do you have any changes to make to that testimony or those exhibits?

A. No.

Q. If I asked you the same questions in your prefiled testimony today, would you give the same answers?

A. Yes.

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

CHAIRMAN BRISÉ: Okay. At this time we will enter the prefiled testimony into the record as though read.

MS. TRIPLETT: Thank you.

PROGRESS ENERGY FLORIDA
DOCKET NO. 120001-EI

Fuel and Capacity Cost Recovery
Estimated/Actual True-Up Amounts
January through December 2012

DIRECT TESTIMONY OF
MARCIA OLIVIER

August 1, 2012

Q. Please state your name and business address.

A. My name is Marcia Olivier. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC as the Supervisor of PEF Regulatory Planning Strategy.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission approval, Progress Energy Florida's (PEF or the Company) estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2012.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (MO-1), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2012 estimated/actual fuel and purchased power true-up balance, and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required per Order No. PSC-12-0061-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2012 estimated/actual capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2012 and estimated data from July through December 2012.

FUEL COST RECOVERY

Q. What is the amount of PEF's 2012 estimated fuel true-up balance and how was it developed?

A. PEF's estimated fuel true-up balance is an under-recovery of $145,366,912. The calculation begins with the actual under-recovered balance of $317,325,152 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2012. This balance, less a projected over-recovery for the months of July through December 2012, comprise the estimated $145,366,912 under-recovered balance at year-end. The projected December 2012 true-up balance includes interest which is estimated from July through December 2012 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.010% per month.

Q. How does the current fuel price forecast for July through December 2012 compare with the same period forecast used in the Company's 2012 projection filing approved in Order No.PSC-11-0579-FOF-EI?

A. Natural gas costs decreased by $1.19/mmbtu (18%), coal costs decreased by $.05/mmbtu (1%), heavy oil costs decreased by $.68/mmbtu (5%) and light oil decreased by $.44/mmbtu (2%).

Q. Have you made any adjustments to your estimated fuel costs for the period July through December 2012?

A. Yes, we made one adjustment to reduce fuel costs by $10,928,571 for Nuclear Electric Insurance Limited (NEIL) replacement power proceeds that PEF has received from NEIL. This adjustment is included on Schedule E1-B (sheet 2), line A5, in the December column.

Last year, PEF assumed that it would receive additional funds from NEIL in 2012 and PEF included an estimated amount of proceeds in its projection filing to reduce projected fuel costs. PEF has not received those projected funds in 2012 and PEF does not expect to receive any additional funds from NEIL in 2012 given that PEF expects to enter into mediation with NEIL in the fourth quarter of this year. Accordingly, PEF now assumes that it will receive further funds from NEIL sometime in 2013, and PEF will include an estimate of those funds in its 2013 projection filing to reduce projected fuel costs as it did last year.

Q. Does PEF expect to exceed the three-year rolling average gain on non-separated power sales in 2012?

A. No, PEF estimates the total gain on non-separated sales during 2012 will be $384,706, which does not exceed the three-year rolling average of $896,041.

CAPACITY COST RECOVERY

Q. What is the amount of PEF's 2012 estimated capacity true-up balance and how was it developed?

A. PEF's estimated capacity true-up balance is an under-recovery of $10,485,622. The estimated true-up calculation begins with the actual under-recovered balance of $11,914,476 for the month of June 2012. This balance plus the estimated July through December 2012 monthly true-up calculations comprise the estimated $10,485,622 under-recovered balance at year-end. The projected December 2012 true-up balance includes interest which is estimated from July through December 2012 based on the average of the beginning and ending commercial paper rate applied in June. That rate is .010% per month.

Q. What are the primary drivers of the estimated year-end 2012 capacity under-recovery?

A. The $10,485,622 under-recovery is primarily attributable to $1,567,550 of lower than projected capacity revenues, the 2011 final true-up under-recovery of $4,389,550, and higher projected retail jurisdictional capacity costs of $4,510,499.

Q. Has PEF included the costs approved in Order No. PSC 11-0547-FOF-EI

A. Yes, PEF has included $85,951,036 of 2012 recoverable expenses associated with the Levy and CR-3 Uprate projects approved in Order No. PSC 11-0547-FOF-EI.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 120001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2013

DIRECT TESTIMONY OF
MARCIA OLIVIER

August 31, 2012

Q. Please state your name and business address.

A. My name is Marcia Olivier. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC as Manager of Retail Riders and Rate Cases in Florida.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the fuel and capacity cost recovery factors of Progress Energy Florida (PEF or the Company) for the period of January through December 2013.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__(MO-2), consisting of Parts 1, 2 and 3. Part 1 contains our forecast assumptions on fuel costs. Part 2 contains fuel cost recovery (FCR) schedules E1 through E10, H1 and the calculation of the inverted residential fuel rate. I have not included the schedule that supports the rate of return applied to capital projects recovered through the fuel clause pursuant to Order No. PSC-12-0061-PCO-EI, as we have no capital projects for which we are requesting recovery herein. Part 3 contains capacity cost recovery (CCR) schedules.

FUEL COST RECOVERY CLAUSE

Q. Please describe the fuel cost factors calculated by the Company for the projection period.

A. Schedule E1 shows the calculation of the Company's levelized fuel cost factor of 3.698 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.30283 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.00400 ¢/kWh, and an estimated prior period under-recovery true-up of 0.33885¢/kWh. Utilizing this factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for service taken at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors.

The levelized fuel cost factor for residential service is 3.703 ¢/kWh. Schedule E1-D shows the Company's proposed tiered rates of 3.393 ¢/kWh for the first 1,000 kWh and 4.393 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rate" schedule in Part 2. Schedule E1-E develops the Time of Use (TOU) multipliers of 1.413 On-peak and 0.803 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level which results in the final TOU fuel factors to be applied to customer bills during the projection period.

Q. What is the amount of the 2012 net true-up that PEF has included in the fuel cost recovery factor for 2013?

A. PEF has included a projected under-recovery of $145,366,912. This amount includes a projected actual/estimated over-recovery for 2012 of $55,996,082 net of the final 2011 true-up under-recovery of $201,362,994 as included in the Direct Testimony of Will Garrett on March 1, 2012.

Q. What is the change in the levelized residential fuel factor for the projection period from the fuel factor currently in effect?

A. The projected levelized residential fuel factor for 2013 of 3.703 ¢/kWh is a decrease of 1.472 ¢/kWh or 28% from the 2012 projected levelized residential fuel factor of 5.175¢/kWh.

Q. Please explain the decrease in the 2013 fuel factor compared with the 2012 fuel factor.

A. The primary drivers of the decrease in the 2013 fuel factor are lower natural gas prices and the refund of $129 million pursuant the Stipulation and Settlement Agreement approved in Order No. PSC-12-0104-FOF-EI.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2013?

A. Yes, on Schedule E1, line 4, we made two adjustments totaling a net reduction of $456,990,441. We made an adjustment to reduce fuel costs by $327,600,000 for estimated Nuclear Electric Insurance Limited (NEIL) replacement power reimbursements. We also made an adjustment to refund $129,000,000 (grossed up to $129,390,441 from retail to system) pursuant to the Stipulation and Settlement Agreement approved in Order No. PSC-12-0104-FOF-EI.

Q. Is PEF proposing to continue the tiered rate structure for residential customers?

A. Yes. PEF is proposing to continue use of the inverted rate design for residential fuel factors to encourage energy efficiency and conservation. Specifically, the Company proposes to continue a two-tiered fuel charge whereby the charge for a customer's monthly usage in excess of 1,000 kWh (second tier) is priced one cent per kWh higher than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000 kWh price change breakpoint is reasonable in that approximately 69% of all residential energy is consumed in the first tier and 31% of all energy is consumed in the second tier. The Company believes the one cent higher per unit price, targeted at the second tier of the residential class' energy consumption, will promote energy efficiency and conservation. This inverted rate design was incorporated in the Company's base rates approved in Order No. PSC-02-0655-AS-EI.

Q. How was the inverted fuel rate calculated?

A. I have included a page in Part 2 of my exhibit that shows the calculation of the fuel cost factors for the two tiers of the residential rate. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 3.703kWh shown on Schedule E1-D. The two factors are then calculated by allocating the total revenues to the two tiers for residential customers based on the total annual energy usage for each tier.

Q. How do PEF's projected gains on non-separated wholesale energy sales for 2013 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2013 is estimated to be $365,693 which is below the benchmark of $617,914 by $252,221. 100% of gains below the benchmark and 80% of gains above the benchmark will be distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-00-1744-PAA-EI. Therefore, since the total gain on non-separated sales was below the benchmark none of the gains will be retained for the shareholders. The benchmark was calculated based on the average of actual gains for 2010 of $1,116,387 and 2011 of $352,650 and estimated gains for 2012 of $384,706 in accordance with Order No. PSC-00-1744-PAA-EI.

Q. Please explain the entry on Schedule E1, line 17, "Fuel Cost of Stratified Sales."

A. PEF has several wholesale contracts with SECI. One contract provides for the sale of supplemental energy to supply the portion of their load in excess of SECI's own resources. The fuel costs charged to SECI for supplemental sales are calculated on a "stratified" basis in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. There are other contracts with SECI, the City of Tallahassee in accordance with Order No. PSC-99-1741-PAA-EI, Reedy Creek, Gainesville, the City of Homestead and Winter Park for fixed amounts of base, intermediate, peaking and plant-specific capacity. PEF is crediting average fuel cost of the appropriate strata in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified and plant-specific sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's fuel cost recovery factor was calculated.

A. The process begins with a fuel price forecast and a system sales forecast. These forecasts are input into the Company's production cost simulation model along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. The model then computes system fuel consumption and fuel and purchased power costs. This information is the basis for the calculation of the Company's fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. System sales are forecasted by the PEF Finance Department using normal weather conditions based on 20-year system weighted average weather conditions, population projections from the Bureau of Economic and Business Research at the University of Florida, and economic assumptions from Economy.Com.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecasts for natural gas and fuel oil (residual and distillate) are based on observable market data in the industry and are prepared jointly by the Company's Enterprise Risk Management Department and Fuels and Power Optimization Department. For coal, a third party forecast is used. Additional details and forecast assumptions are provided in Part 1 of my exhibit.

Q. Are current fuel prices the same as those used in the development of the projected fuel factor?

A. No. Fuel prices can change significantly from day to day, particularly in the storm season. Consistent with past practices, PEF will continue to monitor fuel prices and update the projection filing prior to the November hearing if changes in fuel prices warrant such an update.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the schedules that are included in Exhibit__(MO-2) Part 3.

A. The following schedules are included in my exhibit:

<u>Schedule E12-A – Calculation of Projected Capacity Costs – Year 2013</u>

Page 1 of Schedule E12-A includes estimated 2013 calendar year system capacity payments to qualifying facilities (QF) and other power suppliers, as well as recovery of nuclear costs pursuant to Rule 25-6.0423. The retail portion of the capacity payments is calculated using separation factors consistent with Exhibit 1 in the Stipulation and Settlement Agreement approved on March 8, 2012 in Order no. PSC-12-0104-FOF-EI. Total nuclear costs of $145,479,597 are made up of costs for the Levy and CR3 nuclear plants. 1) Revenue requirements for Levy of $105,417,097 are calculated by applying the factors in Exhibit 5 of the settlement agreement approved in Order PSC-12-0104-FOF-EI to the sales in Exhibit E12-E. 2) The revenue requirements for CR3 are $40,062,500 as filed with the FPSC on August 14, 2012 in Document 05578-12 in Docket 120009-EI. Schedule E12-A, page 2, provides dates and MWs associated with the QF and purchase power contracts.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2012

Schedule E12-B, which is also included in Exhibit __(MO-1) to my direct testimony filed on August 1, 2012 in the 2012 estimated/actual true-up filing, calculates the estimated true-up capacity under-recovered balance for calendar year 2012 of $10,485,622. This balance is carried forward to Schedule E12-A to be collected from customers from January through December 2013.

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-D is the calculation of the currently approved 12CP and 1/13 annual average demand allocators for each rate class.

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Schedule E12-E calculates the CCR factors for capacity and CR3 costs for each rate class based on the 12CP and 1/13 annual average demand allocators from Schedule E12-D. The factors for capacity and CR3, excluding Levy, for each secondary delivery rate class in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity (including revenue taxes) from Schedule E12-A by the class demand allocation factor, and then dividing by estimated effective sales at the secondary metering level. For Levy, the factors are based on Exhibit 5 in the Settlement approved in order PSC-12-0104-FOF-EI. The revenues were calculated by multiplying the effective sales at secondary metering level for each class by the rates in Exhibit 5. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor. The factors allocate capacity and CR3 costs to rate classes in the same manner in which they would be allocated if they were recovered in base rates.

Q. Has PEF used the most recent load research information in the development of its capacity cost allocation factors?

A. Yes. The 12CP load factor relationships from PEF's most recent load research conducted for the period April 2011 through March 2012 are incorporated into the capacity cost allocation factors. This information is included in PEF's Load Research Report filed with the Commission on July 31, 2012.

Q. What is the 2013 projected average retail CCR factor?

A. The 2013 average retail CCR factor is 1.449 ¢/kWh, made up of capacity and nuclear costs of 1.060 ¢/kWh and 0.389 ¢/kWh, respectively.

Q. Please explain the change in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The total projected average retail CCR factor of 1.449 ¢/kWh is 0.26 ¢/kWh or 22% higher than the 2012 factor of 1.192 ¢/kWh. This increase is primarily attributable to a nuclear recoveries increase of $59,466,677 and a collection of the prior period under-recovery of $10,485,622 in 2013 compared to a prior period over-recovery refunded in 2012 of $20,667,503.

Q. Does this conclude your testimony?

A. Yes

BY MS. TRIPLETT:

Q. Ms. Olivier, do you have a summary of your testimony?

A. Yes, I do.

Q. Would you please provide it.

A. Good morning, Commissioners. My name is Marcia Olivier and my testimonies address Progress Energy Florida's estimated/actual fuel and capacity cost-recovery true-up amounts for the period of January through December 2012, and projection amounts for 2013. I look forward to answering any questions you may have.

MS. TRIPLETT: Short and sweet.

We tender Ms. Olivier for cross-examination.

CHAIRMAN BRISÉ: All right. Thank you.

Mr. Moyle.

CROSS EXAMINATION

BY MR. MOYLE::

Q. Good morning.

A. Good morning.

Q. Mr. Burnett in his opening statement, which are typically done by lawyers to say here is what the evidence is going to show, said quite a bit. Would you be comfortable if I asked you questions related to what he said factually? I mean, do you have that information?

A. Yes.

Q. Okay. So let's just start with the insurance policies that Progress Energy has in place. And I made some comments, as well, but would you just confirm that there are multiple policies with NEIL?

A. I can't answer whether there are multiple policies with NEIL. I have not seen the insurance policies with NEIL.

Q. Okay. Well, then do you have information as, with respect to is there a replacement fuel policy for NEIL? So that to the extent that there is an event that causes the nuclear power plant not to operate and it doesn't operate for a lengthy period of time that NEIL has a contractual obligation to step up and make payments for replacement fuel that Progress has to purchase? Do you have information as to whether, you know, a policy like that is in place?

A. I am aware that there is a provision for replacement fuel coverage within the policy.

Q. And Office of Public Counsel referenced a provision in a settlement agreement that said, in essence, that NEIL monies, if they were recovered, they are used to offset fuel that ratepayers may have to pay for otherwise. In your testimony this year you have a provision and you have made an assumption for some monies that may be coming from NEIL that would offset monies that ratepayers might have to pay, correct?

A. That's correct.

Q. Okay. And what is the assumption, you know, that you made?

A. The assumption that we made is that looking at the policy, the full $490 million allowable for replacement fuel cost assuming one event, we have received $162 million from NEIL thus far, so we have included the remaining amount of 320 -- it's actually $327.6 million, as a reduction of fuel costs in 2013.

Q. Okay. And you had mentioned the policy that -- you didn't review the policy to make that assumption, did you?

A. I did not review the policy. I based that, though, on we have provided information on that, and I have provided in prior testimonies, I know Mr. Garrett provided that in his testimony, the assumptions regarding the replacement fuel. And we have also answered discovery questions on that last year, and it is also being disclosed publicly in our SEC filings, the 10-Qs.

Q. And given the fact that in this year's case you have recommended a $327 million downward adjustment for NEIL monies, you would agree that the NEIL monies directly and primarily benefit ratepayers, correct?

A. I do agree, yes. They serve to reduce the fuel costs.

Q. Right. So I have a bunch of questions. I think maybe the easiest way to do it will be to give you a document and ask you to just publish by reading, you know, a couple of paragraphs, and then I'm going to ask you if you disagree with anything in those paragraphs. So, if I could have some assistance, maybe, with the document.

CHAIRMAN BRISÉ: Mr. Moyle, are you looking to enter this into the record?

MR. MOYLE: Yes, sir, I'd like to have it marked.

CHAIRMAN BRISÉ: So this is 119, a short title would be NEIL 2011 Annual Report.

(Exhibit Number 119 marked for identification.)

BY MR. MOYLE:

Q Ms. Olivier, I think this will save time, because I won't have to have to ask you these questions, but if I could just refer you to Page 45 of the exhibit that you have been provided which has been marked as 119?

A. Okay. I'm there.

Q. And I've highlighted the last paragraph on Page 45. Do you see that?

A. Yes.

Q. Would you just read that paragraph and the other, I think, three paragraphs following that into the record?

A. "In October 2009, during an outage for normal refueling and maintenance, and a steam generator replacement project to increase the generating capability of a unit, a Member notified the company of the discovery of property damage in the form of delamination (or separation) within the concrete at the periphery of the reactor containment building, which resulted in an extension of the outage period ('2009 delamination'). The Member found the delamination in the 42-inch thick wall about nine inches from the outside surface of the wall. The wall contains both horizontal and vertical tension steel tendons and a steel-plate liner. The Company worked with the Member to evaluate the extent of the damage resulting from the incident and the cost to return the unit to service. Repairs commenced and were progressing when the work was suspended due to an additional delamination damage that occurred in 2011 to different sections of the containment building walls, called the 2011 delamination. The unit remains off-line.

"The Member maintains property insurance through the Company to a maximum of $2.25 billion, with a $10 million deductible. The Member also maintains a separate accidental outage policy with the Company whereby, after a 12-week deductible period, the Member is entitled to weekly payments of $4.5 million for the first 52 weeks following the deductible period. After the initial 52-weeks of indemnity, the policy pays $3.6 million per week for up to an additional 110 weeks, to a total of policy limit of $490 million.

"The Company has made a provision for the initial 2009 delamination damage in its reserves based on an estimate of the loss exposure and information available at this time. To date, the company has paid $136 million in property repair costs and $162 million for accidental outage to the Member, related only to the 2009 delamination damage.

"The Member has publicly disclosed a preliminary estimate for the cost of repairing substantial portions of the containment structure walls to be in the range of $900 million to $1.3 billion, with a potential completion date of 2014. Due to the size, complexity, and unique aspects of the 2011 delamination damage, the Company has not yet made a determination as to potential coverage, if any, for this additional damage. While significant amounts of information have been exchanged between the Company and the Member, the applicability of policy coverage provisions and exclusions remains an active assessment. Additional discussions and analyses will be required before a specific coverage determination can be made. In the interim, no one outcome has been identified as having a materially greater likelihood of applying based on the consideration of information available to date. In addition, the company has not yet established a timeline for resolution of the claims determination process. As such, the company is currently unable to predict the ultimate outcome of, or reasonably establish a reserve for the possible losses or range of losses resulting from the 2011 delamination damage."

Q. Thank you. And that was a bit long, but in this document they refer to the member. Could I just get to confirm that what you read generally describes the Crystal River 3 situation?

A. I haven't read the whole document, so I can't say that, but I will accept that, if you are saying that is the member.

Q. And I'm not asking you to confirm as it relates to the whole document, just the paragraphs that you read.

A. I'll accept that.

Q. And do you have you any information or any belief that any of the statements that you read are not true and accurate as we sit here today?

A. I wouldn't be able to confirm or deny the statements in this report.

Q. Well, some of them you probably could, couldn't you?

A. I could confirm some of them.

Q. Okay. So could you confirm that to date on the outage, on the accidental outage policy, only 162 million has been paid?

A. That's correct. I can confirm that.

Q. And you could confirm that that amount, 162 has been paid from a policy that has a face value of 490?

A. Yes.

Q. And do you know why the remaining amounts have not been paid?

A. No, I do not.

Q. Do you have any financial background with the company? I was going to ask you -- I mean, it seems in this business that having the ability to have cash, that cash in hand has value. Would you agree with that?

A. I agree that, yes, cash in hand has value, yes.

Q. And you would agree that in terms of talking about, just generally talking about the Crystal River 3, that oftentimes there is reference made to the initial delamination and then a second delamination, correct?

A. Yes, I have heard that reference.

Q. Okay. And I want to use another document with you that the president of your company used that reference, if I could. If I could get --

CHAIRMAN BRISÉ: Sure. Mr. Moyle, would you like to have this marked?

MR. MOYLE: Yes, please.

CHAIRMAN BRISÉ: Okay. This will be 120.

(Exhibit Number 120 marked for identification.)

BY MR. MOYLE:

Q Ms. Olivier, I'm showing you what has been marked as Exhibit 120, which is an October 1, 2012, letter to Ms. Ann Cole, the Commission Clerk of the Florida Public Service Commission, and it was authored by Alex Glenn.

The position that Mr. Glenn currently has -- at the back of the letter on Page 6, it doesn't have a position or a title, but just so the record is clear, would you please tell us what his position is?

A. I'm sorry, you want me to read something on Page 6?

Q. No, ma'am. Do you see Page 6 where it says sincerely at the bottom?

A. Yes.

Q. It doesn't have a position, you know, or title, and I just wanted -- what is the position presently held by Mr. Glean, if you know?

A. Well, Mr. Glenn is in the process of transitioning his position to the -- well, currently he is the General Counsel for Progress Energy Florida, but he will be transitioning that to the President of Progress Energy Florida.

Q. Okay. And I have highlighted some words on Page 2 of this document. Thankfully it's not as long as the previous one, but would you just please read and publish into the record the highlighted sections of this letter?

A. Sure. "The original delamination (or separation) in the concrete within one (called Bay 3-4) of six walls in the CR3 containment building occurred in October 2009 while our workforce was creating an opening in the structure to facilitate the replacement of two 500-ton steam generators. On March 14th, 2011, during the final stages of returning the unit to service, a second delamination occurred in a different wall (Bay 5-6). Similar to the October 2009 delamination, the second separation is about nine inches from the outer surface of the concrete. The second delamination occurred during the final stages of re-tensioning the building's steel tendons located within the concrete containment wall."

Q. And you have no reason to disagree with these statements, do you?

A. No, I don't.

Q. Okay. And Mr. Glenn refers to the March 14th, 2011, event as a second delamination, correct?

A. Yes, he does.

Q. And you would agree that he also is indicating that it occurred in a different location of the building?

A. Yes, I would agree.

Q. And there is more than one year time separation between October 2009 and March 14, 2011?

A. Yes.

Q. And would you also agree that different things were being done relative to the first event as it relates to the second event? The first event, there was a hole being cut, an opening in the structure that was taking place when the first delamination was discovered?

A. Yes.

Q. And, in the second one, the second one took place while re-tensioning was occurring, correct?

A. Correct.

Q. And you would agree that that's different, the cutting of a pole is different from re-tensioning, correct?

A. Yes.

MR. MOYLE: I have another document, Mr. Chair, if I could.

CHAIRMAN BRISÉ: Sure. We will mark this as 121. What is the short title?

MR. MOYLE: NEIL Accidental Outage Policy, April 1, 2009, to April 1, 2010.

CHAIRMAN BRISÉ: Okay. Thank you.

(Exhibit Number 121 marked for identification.)

BY MR. MOYLE:

Q I want to just ask you a few questions about this document and test your understanding of the policies and see how it stacks up with respect to the policy. If you would flip into the first page after the cover sheet, at the top it says NEIL accidental outage insurance policy. Do you see that?

A. Yes.
Q. Okay. Do you see Item 4, the annual premium?
A. Yes.
Q. And that is 600,400, is that right?
A. Yes.
Q. Do you have any information as to whether that has been paid?
A. No, I don't.
Q. Okay. And then there's something called a retrospective premium adjustment. Do you see that on Item 5 under B?
A. Yes.
Q. And what is the amount there?
A. $6,004,000.
Q. The same question, do you know whether that amount has been paid?
A. No, I don't.
Q. Okay. But you do know as a general practice that insurance premiums that are paid, that that is a business expense that the company looks to ratepayers for ultimately, correct?
A. That's correct.
Q. Okay. If you would flip over to the next page. The amount of the insurance under Item 6, do you see that?

A. Yes.

Q. 490 million, is that right?

A. For the limit of liability, yes.

Q. And then on Item 7 it covers the Crystal River Unit 3 nuclear generating plant, correct?

A. Yes.

Q. And do you see up at the top where it says the weekly indemnity is 4.5 million?

A. Yes.

Q. And then under the payment periods, the first payment period is 52 weeks, the second payment period is another 52 weeks, and then there is another payment period of 19 weeks. Do you see that?

A. Yes.

Q. Do you know the monies that were paid by NEIL, whether they were paid consistent with this payment schedule, the 163 that has been paid?

A. Well, the 162 that has been paid --

Q. Yes, ma'am.

A. -- is consistent with this payment schedule as far as there was a 12-week deductible period, and then after that 12-week deductible period they began paying 4.5 million per week, and then they stopped at 162 million.

Q. Did they tell you why they stopped, was it just kind of cold turkey, or what happened there?

A. They did not tell me why they stopped. I don't know why they stopped.

Q. You would agree that at least it seems that if somebody starts paying money in the amount of -- were they paying 4.5 million a week?

A. Actually, they weren't making weekly payments. They had made a total of six payments over a period from June of 2010 through May of 2011.

Q. So they didn't adhere to the weekly indemnity, but they let some weeks run and then would issue a check for a period of time?

A. That's correct.

Q. Okay. But the payments that you received, I assume, totaled up to a number of weeks, right?

A. It did.

Q. Okay. You would agree, or you would think that if somebody is paying, you know, 4.5 million, or 163 million, that that would suggest there is an obligation, at least initially, that was determined that monies should be due under this insurance policy, wouldn't you?

A. I would agree.

Q. There's a couple of provisions, a couple of other provisions that I just want to discuss with you.

If you would go back to the very first page, Item 3.

A. Okay.

Q. The policy period, what was the policy period for Exhibit Number 121?

A. The policy period is from April 1st, 2009, to April 1st, 2010.

Q. Okay. So the event, the first event, that occurred during this policy period, correct, in October of 2009?

A. Well, that was when we took the plant down for the outage, and then the event occurred during that outage in the December time frame. So, yes, it did occur during this policy period time frame.

Q. Did the company file a notice of claim, do you know, with NEIL for this event?

A. It is my understanding that we did.

Q. Do you know if the company has filed a notice of claim for the second delamination event?

A. I don't know what the company has filed with NEIL.

Q. All right. Let me flip you over. At the bottom of the pages, I'm going to take you to Page 2. There's a provision that says coverage for accidental property damage at the unit. Would you just read that sentence into the record, please?

MS. TRIPLETT: Mr. Chairman?

CHAIRMAN BRISÉ: Yes.

MS. TRIPLETT: I'm sorry, this is the third document that we have had Ms. Olivier reading from, and I don't know if that's an objection, just maybe to speed things along. Not to interrupt the flow, but --

CHAIRMAN BRISÉ: Okay.

MR. MOYLE: I mean, I think, I think she can publish it. I'm not going to have her read the whole thing. I'm trying to prove the case that there should be two events, not one. And part of the way I'm doing that is by directing and having the witness publish certain key provisions in the insurance policy. I'm not going to go through every provision in the policy, but a couple of key provisions that I think support FIPUG's argument that they ought to be making two claims, not one, and there ought to be an assumption of two events, not one.

CHAIRMAN BRISÉ: Yeah. The, the issue wasn't -- I don't think it was an objection.

MR. MOYLE: Okay.

CHAIRMAN BRISÉ: It was just a matter of trying to be more efficient.

You may proceed.

BY MR. MOYLE:

Q Okay. Would you mind just reading that? It's one sentence. Would you just read it for the record, please?

A This is on page 2, part A?

Q Right.

A It says, This policy provides insurance for an outage at a unit specified in the declarations resulting from accidental property damage occurring to insured property.

Q Right. And then there's another provision that's pretty important that I want to refer you to, and this is entitled Aggregate Limit of Liability and Reduction of Policy Amount by Loss, and it's found on page 8.

A Okay.

Q And I'm not going to ask you, to move it along, the whole thing, but if you would just read the first sentence.

A The amount of insurance for any unit as stated in the declarations is the limit of the insurer's liability for the aggregate of all losses resulting from outages occurring within the policy period for that unit.

Q All right. And so -- just the question is the policy period for the unit, we've, we've looked on the first page, and the policy period for this, this insurance policy runs from April 1, 2009, to April 1, 2010; correct?

A Yes.

Q Okay. And so to the extent that there was a subsequent event outside of this time frame, would it be fair to assume that that would be covered by another policy related to accidental disruption?

A I'm not sure if I can answer that. It, it kind of depends on, on, on what is determined by NEIL. And right now NEIL has not determined that this is a second event, so I can't say.

Q Okay. But do you know, did Progress pay premiums for a policy that would start at the end of this policy period? So do you know if, if Progress said, well, you know, this accidental outage insurance policy is a good thing to have, we need to pick it up for the next year, kind of like people do with their homeowner's insurance policy? Do you know if the company bought a policy for April 1, 2010, to April 1, 2011?

A I haven't seen it, again, so I don't know for sure. But I can accept that and I can -- it makes sense to me that we would have a policy for the following year.

Q Okay. And would it also make sense to you, based on the language we read, that to the extent something happened that was covered in a second period of time in a second policy, that it seems that a claim could be made related to that second event?

A A claim could be made, but it depends on what NEIL is going to determine whether this is a second event or a continuation of the first event.

Q Right. But typically you, you have to make a claim, you have to, in insurance you have to make a claim, you have to make an assertion as to whether you think it's a covered event before the insurance company will tell you something; right?

MS. TRIPLETT: Mr. Chairman --

CHAIRMAN BRISÉ: Yes.

MS. TRIPLETT: -- if I may. I'm just going to object here. I think that Ms. Olivier -- and I've given -- I haven't objected, but I think Ms. Olivier testified that she's, she hasn't read this policy and she's not an insurance expert. So I'm just concerned that there's maybe a lack of, of foundation here.

CHAIRMAN BRISÉ: Mr. Moyle.

MR. MOYLE: Well, I think it tests her assumption that she's made, that she's testified to, and

Mr. Burnett has made reference to in the beginning of his opening statements, the assumption that, that, you know, there's either -- there's one event. I mean, if she's not read the policy and has no familiarity with the policy, I think it undermines the basis for the assumption that there shouldn't be two events if she has no knowledge about a subsequent policy.

MS. TRIPLETT: If I may briefly. I would disagree that the, that the fact that she's not read the policy undermines the assumption she's made in this docket just because now we're arguing about it. So just to be clear, Ms. Olivier had facts that she knew that she based that assumption upon. She did not need to have the policy or be an expert in insurance to, to make that assumption that she did.

CHAIRMAN BRISÉ: Okay.

MR. MOYLE: Let me come at it this way, if I could.

CHAIRMAN BRISÉ: Go ahead.

BY MR. MOYLE:

Q Why did you assume that there was not additional monies for a second event that might be covered under a second insurance policy related to accidental outage insurance?

A Well, we based what we included in there on our known information, the best available information we have today, which is that NEIL has acknowledged the first event. We haven't received any determination from NEIL on the second event. So we're just basing it on what we know today.

Q But they, but, but they've only paid you 163; right? They haven't paid you the 300, the additional 300 that you've assumed; right?

A That's correct. So we had a choice. We had to, we had to come up with an estimate for the fuel filing and we had a choice. We could have, based on the fact that they haven't paid us anything since May of 2011, we could have included zero in the fuel clause. But we went ahead, and based on a reasonable assumption that as we go into the nonbinding mediation followed by, possibly followed by arbitration, that this will get resolved. And we, we have included the full amount of the insurance proceeds based on the one event in prior years. So we continue to include that this year as a reasonable assumption based on what we know today.

Q Do you know if the company intends to argue, if you go into mediation, that there's two events as compared to one event?

A I don't know what the argument is going to be in mediation.

Q You would agree that if they do make that argument, it's worth approximately 490 million to the ratepayers?

A No, I wouldn't agree with that because it depends on what day that second event is determined to be, if in fact a second event is, is deemed to have happened by NEIL. And then what happens is then the first policy would stop at that point and then it would start over again. So it wouldn't be a full $490 million because the first 490 wouldn't have gotten -- it would have only gone up to the point of the second event.

Q Would you agree that having two policies in place provides more money for the ratepayers as compared to having one policy in place?

A I think that depends on what's in the policy. So I -- that's kind of a general question and I'm not sure I can answer that.

Q And you haven't read the policies?

A Correct.

MR. MOYLE: I have another exhibit I'd like to have put in so we can brief this issue, but it's the NEIL policy for the next subsequent period of time.

CHAIRMAN BRISÉ: Sure.

MR. MOYLE: April 1, 2010, to April 1, 2011.

CHAIRMAN BRISÉ: That would be 122.

(Exhibit 122 marked for identification.)

A short title for this one will be NEIL Accidental Outage Policy, April 1, 2010, through April 1, 2011.

BY MR. MOYLE:

Q And I'm not going to walk you through and ask you the same questions, but you would, you would agree, would you not, that the monies that are due Progress, and ultimately it would benefit the ratepayers, will be determined by the insurance policies themselves, that that's the document that governs the, governs the relationship?

A Yes. And it'll be determined through this either nonbinding mediation or through the arbitration process.

Q And you understand that, that FIPUG is arguing and contending that, that there are two events, and that the policy that I just handed you should apply to the second event; correct?

A Yes.

Q And can you confirm that the second event occurred during the time frame as referenced in this policy?

A Well, I can't actually because we haven't gotten a determination from NEIL on that second event.

So I don't have a date of a second event from NEIL.

Q Do you have any information on your own as to when you think the second event occurred?

A Well, I know that we have gone out here, and I just read that on March 14th, during the final stages of returning the unit to service, a second delamination occurred. So we have that date, but that doesn't mean that that would be the date that NEIL would have that second event be. It's probably based on more information. It's more complex than just choosing a date.

Q And that would be March 14th of what year?

A Of 2011.

Q And the policy runs through April 1, 2011?

A Yes.

MR. MOYLE: I have a couple of other exhibits, if I could get some help, please.

CHAIRMAN BRISÉ: Sure.

MR. MOYLE: Mr. Chairman, to move it along, I'm going to pass two out at once.

CHAIRMAN BRISÉ: Thank you.

MR. MOYLE: And for the record, maybe the first one, the Florida Secretary of State Certificate of Non-Authorization for Nuclear Electric Insurance Limited, it's a composite exhibit, if we could mark that as 123.

CHAIRMAN BRISÉ: Okay. So the Secretary of State document is 123, and the OIR document is 124.

MR. MOYLE: 124.

(Exhibits 123 and 124 marked for identification.)

BY MR. MOYLE:

Q So, Ms. Olivier, do you know if NEIL is authorized to do business in the state of Florida?

A No, I don't know.

Q Okay. Do you know -- we've agreed that it's taken them more than three years to resolve the first claim for replacement fuel following the first outage; correct?

A Well, I would agree that the time frame from that first outage to today is approximately three years.

Q And do you have any information or do you know what the Office of Insurance Regulation does in the state of Florida?

A I don't have specific information. I'm going to guess that they regulate insurance.

Q I think, I think that's probably fair. It's like who was -- who's buried in Grant's tomb; right?

The -- do you know if the company, Progress, if they check -- do they check regularly to see if somebody is licensed to do business in the state of Florida before they enter into contracts with them or engage in business, do you know?

A I don't know.

Q And do you know, has, has NEIL company, during the course of their investigation, have they, have they come down and looked at, at the Crystal River 3 unit?

A I'm not involved in that process and I don't know what they have done.

Q You would expect that that would be part of what would be undertaken in an investigation, wouldn't you?

A That makes sense to me. Yes.

Q Right. And you also know, don't you, that in the recent letter Mr. Glenn sent, that he was submitting a report, the Zapata report related to Crystal River 3; correct?

A I'll accept that.

Q Okay. And do you know that the Duke board asked for a complete investigation of Crystal River 3 from Zapata and it took approximately six months to get that report done from beginning to end?

MS. TRIPLETT: Mr. Chairman, I just have to object to the relevance of this line of questioning.

CHAIRMAN BRISÉ: Mr. Moyle.

MR. MOYLE: I think it kind of goes to the delay in getting resolution to a claim that's been pending, you know, for three years. And I'm trying to understand what they've done to move it along and what NEIL has done and where we are, and these documents, I think, suggest and shed light that if there's no incentive for the insurance company to step up because nobody has regulation over them, that may explain it. So that's what the line is intended to, to get to.

MS. TRIPLETT: If I may. I'm sorry. So first the question was about Zapata reports and Duke board of directors, not about insurance and whether NEIL is, is licensed in Florida. But neither one of those has anything to do with the issues here, which is what is reasonable to anticipate NEIL will pay for 2013 fuel factor setting, not -- all those other issues will be taken up in another docket.

CHAIRMAN BRISÉ: I agree. I think these issues are being dealt with in, in another current open docket.

MR. MOYLE: Okay. And so 123 is the Certificate of Non-Authorization from the Florida Secretary of State. And it's self-authenticating, so I would, I would offer that.

And 124 is a similar document from OIR that follows a public records request that I made that cites certain Florida statutory provisions that relate to doing business in the state of Florida.

If I could, if I could just ask her one question about the OIR, and then I think I'll be pretty close to being done.

CHAIRMAN BRISÉ: Sure.

BY MR. MOYLE:

Q So --

CHAIRMAN BRISÉ: If it pertains to the issues to this case.

MR. MOYLE: Yeah. Right.

BY MR. MOYLE:

Q So with respect to the NEIL coverage that you're assuming, do you know, has -- strike that.

If I could just have a minute to review my notes.

CHAIRMAN BRISÉ: Sure. No problem.

(Pause.)

BY MR. MOYLE:

Q Just a couple of final questions. The information that you had testified to today, you haven't reviewed the insurance policies. Have you reviewed any other documents, documents to support your testimony?

A Well, I've reviewed our, our SEC filings that we've made where we've explained the provisions under the policy with respect to the amount of replacement fuel that, that is provided, and so I've relied on that. And then I have, you know, our internal experts on insurance that have explained to me what, you know, what the policy calls for to be able to figure out how much to put in the fuel clause for insurance.

Q And who are those individuals?

A Well, first of all, the quarterly filings that we make, the 10Qs, reflect the information there. And then we have our risk management department, our insurance group. That's Gary Little.

Q So just to follow up, you had said you talked to insurance experts, internal insurance experts is Mr. who? Gary Little?

A Mr. Little. He's, he's our insurance expert.

Q Okay. Any, any other people that you've talked to to assist with your testimony today related to the NEIL insurance?

A No. I mean, we've had internal discussions about the insurance as we have recorded the insurance that we've received. And to understand what that's based on, we've had kind of some -- just within the accounting department.

Q Okay. And then a final line of questioning.

Do you know if there was an assumption of two events as compared to one event, how much money would that reflect in adjustment; i.e., how much would ratepayers benefit if two, two events was assumed as compared to one event, if you know?

A Well, the problem is we don't have a date on that second event from NEIL. So the math is pretty simple. We would just base it on another 12-week deductible period and then 4.5 million per week for 52 weeks, and then an additional 71 weeks at 3.6 million. So that's the simple math part of the equation.

But as far as figuring out what day to start that and whether there will be two events, we just don't have that information to do that.

Q But in conclusion, it would be safe to assume that every day that the Crystal River 3 nuclear power plant is not operational to the extent that there was a second event and a second policy providing coverage, that that would benefit ratepayers directly; correct?

A I would agree, yes, that if there were a second event and a second coverage, that there would be a benefit to ratepayers by more. But we don't know that we're going to receive the amount under the first policy, so it would be speculative at this point to increase that.

Q Right. And have you -- are you aware of any communication with NEIL related to the second event in a claim for a second event or discussions related to a second event?

A I'm not an expert in that. I'm not a part of that process, so I don't know how that's going.

Q And have you ever met anybody from NEIL?

A No, I have not.

Q Have you ever talked to them on the phone?

A No, I have not.

Q Have you ever seen them in Florida?

A I may have, but I just wouldn't recognize them.

Q Maybe at a football game.

MR. MOYLE: Thank you. That's all. That's all I have.

CHAIRMAN BRISÉ: Thank you. FEA.

MAJOR THOMPSON: No questions from FEA, sir.

CHAIRMAN BRISÉ: All right. Thank you.

Mr. Brew.

MR. BREW: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. BREW:

Q Just made it. Good morning, Ms. Olivier.

A Good morning.

Q Very quickly, you discussed briefly with Mr. Moyle exhibits that are marked as 121 and 122, which were the NEIL policy coverage for, from April 2009 to '10 and from April 2010 to '11. Do you recall that generally?

A Yes.

Q And those documents state the annual premiums payable under the insurance policy; is that right?

A Yes.

Q Okay. As manager of rates, do you know whether or not NEIL insurance premiums are recovered in the cost of service?

A Yes. They're recovered as part of base rates.

Q Okay. And that's always been so?

A It's my understanding.

Q And there's never been a lapse in NEIL coverage for failure to make a premium payment?

A I'm not aware of that. But I can't answer to that. I'm just not aware that there has been.

Q As far as you know though, the premium costs have always been recover -- paid and recovered in rates?

A That's my understanding.

Q Okay. Do you know if a failure to pay premiums is at all an issue in dispute with respect to

NEIL at this time?

A I do not know.

Q Okay. Is it correct that all of the NEIL insurance reimbursements for the CR3 outage claims that are received will be applied for the benefit of Progress ratepayers?

A Yes.

Q Both fuel and for repair?

A Well, with respect to the fuel, the fuel would go directly back through the fuel clause. And then as far as the repairs, it just depends, I guess, on, on -- they would go, serve to reduce the amount of the, of the cost to repair the unit, except that there's this, the stipulation and settlement that says if we end up retiring, then that would go back through the fuel clause.

Q But the intent is that one way or the other the reimbursement proceeds would be applied to benefit customers?

A Yes.

Q Okay. During your discussion with Mr. Moyle, you mentioned that Progress has -- did receive six payments related to reimbursements for replacement fuel from July 2010 through May 2011; is that right?

A From June 2010 through May of 2011. Correct.

Q Okay. And those payments covered which of the 110 weeks under the initial claim? When did they -- what was the final week covered?

A The final week covered, the final date that was covered was December 17th of 2010.

Q Okay. And so the, the 327.6 million in reimbursements that are imputed to the fuel clause that's in your testimony, that would represent the remaining replacement fuel payments calculated as being due under that claim through the remaining covered weeks, which would have been through mid-August 2011?

A That's correct.

Q Okay. And you stated earlier, I believe, that NEIL has acknowledged the first event as a covered event?

A That's correct. And when I say they've acknowledged it, they've acknowledged it by beginning to make the payments on that first event.

Q And they began to make the payments, and they made the $162,000,000 in replacement fuel payments.

A That's correct.

Q And they also made $136 million in repair cost payments?

A I will accept that. I don't have that exact dollar amount with me.

Q Are you aware that some dollars were paid by NEIL towards the repair costs?
A Yes, I am.
Q How were those booked for your rate purposes?
A The repair, the repair costs?
Q The repair costs.
A Well, they would have been a reduction to the construction project that we have out there to repair the delamination.
Q So it's at this point treated as an accounting entry?
A Yes.
Q Okay. But that, that recovery is not reflected in the fact recovery here; right?
A That's, that's correct, because what we're looking at here is just the replacement fuel costs.
Q Okay. The 327.6 million that you've imputed for reimbursement in your testimony for the proposed recovery, how was that treated for accounting purposes? Are you booking that as a receivable?
A No. We have actually removed that receivable from our books and records. So we've included it as a reduction to our fuel costs in 2013, but we have removed those from our, from our accounts receivable records.
Q So I guess you need to explain to me, on the

one hand it sounds like you're, you're expecting to receive the 327 million. On the other hand, you're -- by not treating it as a receivable, you're saying that it's not owed?

A Yes. Accounting standards require that the full amount of that receivable has to be probable in order to record it. And so we made a decision that, or determination that it is not at this time probable due to the fact that we haven't received anything from NEIL since May of 2011. We made a decision that it is not probable at this time that we would receive full recovery of those insurance proceeds, and therefore we made an adjustment to remove that receivable from our books and records.

Q Okay. So you were receiving replacement fuel payments for a period of time.

A That's correct.

Q Basically for a little over a year of the outage time.

A That's correct.

Q Including the deductible period.

A Yes.

Q And then NEIL unilaterally suspended making those payments.

A That's correct.

Q But it's acknowledged the event.

A It's acknowledged it by beginning to make those payments. And, of course, now we're going into this process of nonbinding mediation. And that would be followed, if unsuccessful, by binding arbitration or some other form of negotiations. So as we sit here today, we're -- NEIL has stopped making the payment.

Q I'm trying to get a handle on why you would not treat it as a receivable. If they had acknowledged the event or making the payments, don't you consider it as something that's owed the company at this point?

A Well, we definitely believe that it is something that is owed the company, and that's what is going to get resolved here in this negotiation process, the mediation and/or arbitration process. We believe it is owed to us, but we have removed it from the books based on the fact that they haven't made that payment, a payment since May of 2011.

Q So do you have any idea under what circumstances NEIL could discontinue the replacement fuel payments and not make good on the coverage?

A I'm sorry.

Q Would it only be if there was not a valid claim?

A I don't know the provisions of the policy, so

I can't say what NEIL would decide.

Q Okay. Okay. And just to make something clear, you said that NEIL stopped making the payments related to replacement fuel. But they did not give any formal notice or written reason to Progress?

A I'm not aware if there was any formal notice or reason to Progress.

Q Okay. So for your purposes, you're simply recognizing the fact that the policy calls for the coverage but the payments have not been received?

A That's correct.

Q And this relates to a period that stretches back into -- or should have been completed in mid 2011.

A That should have been completed in mid 2012.

Q The 110 weeks initially would have run through April -- August of 2011?

A Through August of 2012.

Q August of 2012?

A Yes.

MR. BREW: Okay. Thank you. That's all I have.

THE WITNESS: Thank you.

CHAIRMAN BRISÉ: Thank you.

Office of Public Counsel.

MR. REHWINKEL: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q Good afternoon, Ms. Olivier.

A Good afternoon.

Q If I could get you to turn first to your testimony on page 4, and you reference on lines 7 and 8 two adjustments totaling a net reduction of $456,990,441. Do you see that?

A Hold on. I'm sorry.

Q Sorry.

A Okay. Yes.

Q Okay. And you further break those down to the $327.6 million estimate for NEIL replacement power reimbursements, and then $129 million grossed up to 129,390,441 for the refund called for under the stipulation. Do you see that?

A Yes.

Q Okay. And if I took you back to your Schedule MO-2, part 2.

A And which schedule is that?

Q E1. We see -- do you have that?

A Yes.

Q We see the $456.9 million number on line 4; right?

A Yes.

Q Now you show that as an adjustment to fuel cost.

A That's correct.

Q Okay. The NEIL proceeds are specifically designated under the policy that you've been discussing today as replacement power reimbursements; is that right?

A The NEIL proceeds, yes.

Q Yes. So those are intended to offset the cost of additional generation costs caused by the outage. Is that right?

A That's correct.

Q Okay. But the $129 million that is a refund, that is not considered a reduction to -- it's not designated in the stipulation as a, as a fuel refund; is that right?

A That's correct.

Q It is just a refund, and the fuel clause is the mechanism to get that refund to the customers, is that your understanding?

A Yes, it is.

Q Okay. And what you've done here on Schedule E1 is essentially, if I looked at the -- if I just considered the refund, the 129,390,441, and I looked on, let's say, line 27 or twenty -- 27 or 26, those megawatt hours of 37,383,374, would I be correct that those are essentially the forecasted billing determinants to flow the 129 million back to the customers?

A That's, that's correct.

Q Okay. Now that number is forecasted; correct?

A Yes.

Q All right. So if there's anything that's a certainty, is that that number is not going to be right at the end of the year when you do your actuals; is that right?

A Well, actually, the way that we'll do it is that number -- we will take that $129 million, divide it by 12 months, so we'll come up with 10,750,000 per month, and then we'll make an adjustment on our actual A schedules, Schedule A2, for that amount. So that will sort of, if you want to call it earmark the, that amount to go to the refund so that we will provide the entire amount of the $129 million refund in 2013.

Q Okay. So at the end of the year the Commission, the Commission staff and the parties can verify that all 129 million called for in the stipulation was returned to the customers --

A Yes.

Q -- through the fuel clause; is that right?

A Yes. They'll be able to see that on Schedule

A2 as an adjustment to fuel costs.

MR. REHWINKEL: Okay. Mr. Chairman, if I could have just a minute.

CHAIRMAN BRISÉ: Sure.

(Pause.)

MR. REHWINKEL: Mr. Chairman, those are all the questions I have.

Thank you, Ms. Olivier.

THE WITNESS: Thank you.

CHAIRMAN BRISÉ: Okay. Thank you.

Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman. I hope I have exactly three questions. Let's see how it works out.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good afternoon, Ms. Olivier.

A Good afternoon.

Q You've had some colloquy with Mr. Moyle and others about the one event/two event business. And I just want to ask you kind of a big, maybe three big picture questions.

Would I be safe to believe that Progress Energy Florida is committed to getting the maximum amounts due -- or recovering the maximum amounts that

Progress could recover under its NEIL policy from NEIL?

A Yes, you would.

Q And would I be equally safe to believe that Progress is committed then to applying those proceeds recovered for the benefit of customers?

A Yes.

Q And is Progress still actively evaluating, considering, or pursuing the possibility of arguing that there are two events rather than one event in order to possibly maximize proceeds for the benefit of customers?

A Yes. It's my understanding that we are trying to maximize the proceeds. I don't know what those arguments are, but we are, we are trying to get as much as we can for the customers.

Q Does that include continuing to look at the one event/two event issue?

A It's my understanding that will come up as part of that, the mediation process, yes.

MR. WRIGHT: Thank you.

Thanks, Mr. Chairman.

CHAIRMAN BRISÉ: All right. Thank you.

Staff?

MS. BARRERA: Staff has no questions.

CHAIRMAN BRISÉ: Okay. Commissioners?

Redirect?

MS. TRIPLETT: No, sir.

CHAIRMAN BRISÉ: All right. Thank you very much. Let's deal with exhibits.

MS. TRIPLETT: Yes. Progress Energy would move Exhibits 20 and 21 into evidence.

CHAIRMAN BRISÉ: Okay. We will move 20 and 21 into the record, seeing no objections.

(Exhibits 20 and 21 marked for identification and admitted into the record.)

Okay. Mr. Moyle.

MR. MOYLE: FIPUG would move 119 through 124.

CHAIRMAN BRISÉ: Okay.

MS. TRIPLETT: No objection.

CHAIRMAN BRISÉ: Okay. Seeing no objections, we will move 119 through 124 into the record at this time.

(Exhibits 119 through 124 admitted into the record.)

Okay. Is there anything else for this witness?

MS. TRIPLETT: No, sir. We would ask that she be excused.

CHAIRMAN BRISÉ: All right. Thank you, Ms. Olivier. You may be excused. And sorry for botching your name a little bit earlier.

THE WITNESS: That's fine. Thank you.

(REPORTER NOTE: For the convenience of the record, the prefiled testimony of the stipulated witnesses is inserted into the record after Witness Olivier as follows:)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 120001-EI

AUGUST 31, 2012

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power and purchased power transactions. I also review the interim results of FPL's 2012 hedging program and its 2013 Risk Management Plan. Lastly, I present the projected fuel savings resulting from the operation of West County Energy Center Unit 3 (WCEC 3) during 2013 and the projected fuel savings resulting from the commercial operation of the Cape Canaveral Next Generation Clean Energy Center (CCEC) from June through December 2013.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-2: 2013 Risk Management Plan
- GJY-3: Hedging Activity Supplemental Report for 2012 (January through July)
- GJY-4: Appendix I
- Schedules E2 through E9 of Appendix II

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies has FPL used for the 2013 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time and are consistent with the prices at which FPL can execute transactions for its hedging program. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the future is incorporated into the curves at all times. The methodology allows FPL to execute hedges consistent with its forecasting method and to optimize the dispatch of its units in changing market conditions. FPL utilized forward curve prices from the close of business on August 3, 2012 for its 2013 projection filing.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2013 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to their quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the supply and demand for heavy oil in the domestic market; (8) the terms of FPL's supply and fuel transportation contracts; and (9) domestic and global inventory.

Average heavy oil prices are forecasted to be slightly lower in 2013 compared with projected 2012 average levels primarily due to the assumed reduction in the global crude oil price. Despite some assumed strengthening in the crude oil market over the next several months, the fundamentals are not particularly supportive in 2013. Although expected demand in 2013 is forecasted to be 1.1% above projected 2012 levels and 2.2% above actual 2011 demand, non-OPEC production is projected to be 2.1% above forecasted 2012 levels and 2.7% above actual 2011 levels. With non-OPEC supply growing faster than demand, the demand for OPEC crude oil will decline and OPEC spare capacity will increase, supporting lower crude oil and petroleum prices in 2013 compared with 2012. A greater-than-expected increase in demand or a lower-than-expected increase in non-OPEC production would put upward pressure on the price of heavy oil. Conversely, a weaker-than-expected growth in demand or a greater-than-expected increase in non-OPEC production would put further downward pressure on the price of heavy oil.

Q. **Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2013 period.**

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. **What are the key factors that could affect the price of light fuel oil?**

A. The key factors are similar to those described for heavy fuel oil.

Q. **Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2013 period.**

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. **What is the basis for FPL's projections of the dispatch cost of coal for St. Johns' River Power Park (SJRPP) and Plant Scherer?**

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal, delivered to the plants.

Q. **Please provide FPL's projection for the dispatch cost of coal at SJRPP and Plant Scherer for the January through December 2013 period.**

A. FPL's projection for the system average dispatch cost of coal for this period, by plant and by month, is shown on page 3 of Appendix I.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2013 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) LNG and Canadian natural gas imports; and (3) the terms of FPL's natural gas supply and transportation contracts.

The major driver for natural gas prices during the remainder of 2012 and all of 2013 are forecasted changes in natural gas production. With the number of working natural gas rigs being down approximately 69% since the peak in August 2008, and with this trend expected to continue into 2013, domestic production is projected in 2013 to have its first year-on-year decline since 2006, which would result in average 2013 natural gas prices being higher than average 2012 levels. In addition, natural gas storage levels are now expected to end the 2012 summer injection season at the end of October 2012 at a level slightly lower level than the prior year, for the first year-on-year decline since 2008, further supporting higher prices in 2013 compared with 2012.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December

2013 period?

A. The key factors are (1) the capacity of the Florida Gas Transmission (FGT) pipeline into Florida; (2) the capacity of the Gulfstream Natural Gas System (Gulfstream) pipeline into Florida; (3) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; and (4) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is approximately 3,100,000 MMBtu/day and the current capacity of Gulfstream is approximately 1,260,000 MMBtu/day. FPL's total firm transportation capacity on FGT ranges from 1,150,000 to 1,304,000 MMBtu/day, depending on the month. FPL has firm transportation capacity on Gulfstream of 695,000 MMBtu/day.

Additionally, FPL has 580,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline and 200,000 MMBtu/day of firm transport on the Transcontinental Pipe Line Gas Company, LLC (Transco) Zone 4A lateral. The firm transportation on the SESH and Transco pipelines does not increase transportation capacity into the state, but FPL's firm transportation rights on these pipelines provide access to 780,000 MMBtu/day of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2013 period, 55,000 MMBtu/day to 175,000 MMBtu/day of non-firm natural gas transportation capacity will be available into the state, depending on the month. FPL projects that it could acquire some of this capacity, if economic, to supplement FPL's firm allocation on FGT and Gulfstream.

Q. Please provide FPL's projections for the dispatch cost and availability of natural gas for the January through December 2013 period.

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

<u>PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY</u>

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Heat Rates were calculated by the POWRSYM model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to POWRSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2013?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2013.

Q. Please describe the significant planned outages for the January through December 2013 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. Turkey Point Unit 4 is scheduled to be out of service from November 5, 2012 until March 15, 2013 or 73 days during the period to complete extended power uprate (EPU) work. St. Lucie Unit 1 is scheduled to be out of service from September 5, 2013 until October 13, 2013 or 38 days during the period. Turkey Point Unit 3 is scheduled to be out of service from October 21, 2013 until November 28, 2013 or 38 days during the period.

Q. Please list any changes to FPL's fossil generation capacity projected to take place during the January through December 2013 period.

A. FPL projects to put CCEC into commercial operation on June 1, 2013. This unit will add an additional 1,210 MW of summer capacity and 1,355 MW of winter capacity.

<u>WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS</u>

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2013?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. FPL's customers benefit from both purchases and sales as savings on purchases and gains on sales are credited to customers through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction. Additionally, FPL is a member of the Florida Cost-Based Broker System (FCBBS). The FCBBS matches hourly cost-based bids and offers to maximize savings for all participants. Currently, the FCBBS is comprised of 11 members, including FPL. FPL can also purchase and sell power during emergency conditions under several types of Emergency Interchange agreements that are in place with other utilities within Florida.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales.

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) power sales?

A. FPL has projected 413,400 MWh of wholesale (off-system) power sales for the period of January through December 2013. The projected fuel cost related to these sales is $16,352,230. The projected transaction revenue from these sales is $21,800,230. The projected gain for these sales is $4,238,116.

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2013 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 1,060,000 MWh at a cost of $42,063,927. If FPL generated this energy, FPL estimates that it would cost $72,971,010. Therefore, these purchases are projected to result in savings of $30,907,083.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases energy under three Unit Power Sales Agreements (UPS) with the Southern Companies. The agreements are comprised of 790 MW of gas-fired, combined cycle generation (Franklin Unit 1-190 MW and Harris Unit 1-600 MW) and 165 MW of coal generation (Scherer Unit 3). The UPS agreements have a term that runs through December 31, 2015. FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units. Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2012 period.

A. UPS energy purchases for the period are projected to be 2,698,220 MWh at an energy cost of $96,036,724. The UPS energy projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of SJRPP are projected to be 2,027,889 MWh for the period at an energy cost of $86,564,000. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 538,023 MWh at a cost of $4,230,560. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide

3,209,622 MWh at a cost of $143,346,388.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the POWRSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects to sell 563,881 MWh of energy at a cost of $4,340,025. These projections are shown on Schedule E6 of Appendix II.

<u>HEDGING/ RISK MANAGEMENT PLAN</u>

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program has been, and remains, the reduction of fuel price volatility. Reducing fuel price volatility helps deliver greater price certainty to FPL's customers. FPL does not engage in speculative hedging strategies aimed at "out guessing" the market.

Q. Has FPL filed a comprehensive risk management plan for 2013,

consistent with the Hedging Order Clarification Guidelines as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2013 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up filing on August 1, 2012. The 2013 Risk Management Plan is included as Exhibit GJY-2.

Q. Please provide an overview of FPL's 2013 Risk Management Plan.

A. FPL's 2013 Risk Management Plan remains consistent with FPL's overall objectives that I previously described. It addresses Items 1-9 and 13-15 of Exhibit TFB-4, which is required per the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOF-EI dated October 30, 2002. FPL's 2013 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2013 for its projected natural gas requirements in 2014. FPL plans to hedge the percentages of its 2014 projected natural gas requirements over the time periods in 2013 that are described in the plan. As described in the plan, FPL does not intend to execute hedges for its 2014 heavy fuel oil requirements, due primarily to extremely low consumption projections. With low consumption projections, small changes in projected heavy oil burns can cause FPL to rebalance insignificant volumes of heavy oil to remain within required hedge percentage bands. This rebalancing activity would add unnecessary costs while providing little price certainty.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2012, consistent with the Hedging Order Clarification Guidelines, as required by Order PSC- 08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2012 (January through July) on August 15, 2012. The Hedging Activity Supplemental Report is included as Exhibit GJY-3.

Q. Have FPL's 2012 hedging strategies been successful in achieving FPL's hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers. Additionally, FPL's customers have been able to benefit from the decrease in natural gas prices from the unhedged portion of FPL's portfolio. At the time FPL was placing its hedges for its 2012 projected natural gas and heavy oil requirements, market prices were different than the actual settlement prices that have occurred in 2012.

For example, at the beginning of January 2011, the average monthly NYMEX forward price for natural gas for the January through July 2012 time period was approximately $5.098 per MMBtu. At the end of July 2011, the average monthly NYMEX forward price for the January through July 2012 time period was approximately $4.530 per MMBtu. The actual average NYMEX monthly settlement price for this same time period was $2.520 per MMBtu or $2.578 per MMBtu lower than the forward prices seen in January and $2.010 per MMBtu lower than the forward prices seen in July. Conversely, in January 2011, the average forward price for heavy oil for the January through July 2012 time period was approximately $83.82 per barrel. In July 2011, the average forward price for heavy oil for the January through July 2012 time period was approximately $104.09 per barrel. The actual average settlement price for heavy oil for this same time period was $107.26 per barrel or $23.44 per barrel higher than the forward prices seen in January and $3.17 per barrel higher than the forward prices seen in July. As acknowledged in the Hedging Order Clarification Guidelines, hedging in the type of market conditions described above for natural gas results in lost opportunities for savings in the fuel costs paid by customers; however, this lost opportunity is a reasonable trade-off for reducing customers' exposure to fuel price increases when market conditions change in the other direction. Conversely, hedging in the type of market conditions described above for heavy oil results in savings for customers. As previously stated, however, FPL's hedging objective is to reduce fuel price volatility and deliver greater price certainty.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF WCEC 3

Q. Will the operation of WCEC 3 during 2013 result in fuel savings to FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the January through December, 2013 period, the operation of WCEC 3 is projected to save FPL's customers $133,225,000.

Q. How did FPL calculate the projected fuel savings associated with the operation of WCEC 3?

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the operation of WCEC 3. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the WCEC 3 fuel savings. In order to calculate the WCEC 3 fuel savings, FPL ran two separate production cost simulations, one without WCEC 3 and one with WCEC 3. A comparison of the total system fuel costs from POWERSYM for the two simulations showed that the fuel costs were $133,225,000 lower in the case that included WCEC 3 than in the case without WCEC 3.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF CCEC

Q. Will the operation of CCEC during 2013 result in fuel savings to FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the June through December, 2013 period, the operation of CCEC is projected to save FPL's customers $100,908,000.

Q. How did FPL calculate the projected fuel savings associated with the operation of CCEC?

A. FPL utilized its POWRSYM model to quantify the fuel savings associated with the operation of CCEC. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the CCEC fuel savings. In order to calculate the CCEC fuel savings, FPL ran two separate production cost simulations, one without CCEC and one with CCEC. A comparison of the total system fuel costs from POWERSYM for the two simulations showed that the fuel costs were $100,908,000 lower in the case that included CCEC than in the case without CCEC. Please note that, because WCEC 3 is already in service, both the "with CCEC" and "without CCEC" scenarios assumed that WCEC 3 is in service.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 120001-EI

MARCH 1, 2012

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

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL or the Company) as the Director, Cost Recovery Clauses, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery (FCR) Clause and Capacity Cost Recovery (CCR) Clause Net True-Up amounts for the period January 2011 through December 2011. The Net True-Up for the FCR is an under-recovery, including interest, of $51,121,025. The Net True-Up for the CCR is an under-recovery, including interest, of $44,704,575. FPL is requesting Commission approval to include the FCR true-up under-recovery of $51,121,025 in the calculation of the FCR factor for the period January 2013 through December 2013. FPL is also requesting Commission approval to include the CCR true-up under-recovery of $44,704,575 in the calculation of the CCR factor for the period January 2013 through December 2013.

Q. **Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this proceeding?**

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. In addition, FCR Schedules A-1 through A-12 for the January 2011 through December 2011 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. **What is the source of the data that you will present in this proceeding?**

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE (FCR)

Q. **Please explain the calculation of the FCR net true-up amount.**

A. Appendix I, page 3, entitled "Summary of Net True-Up," shows the calculation of the Net True-Up for the period January 2011 through December 2011, an under-recovery of $51,121,025.

The Summary of the Net True-up amount shown on Appendix I, page 3 shows the actual End-of-Period True-Up under-recovery for the period January 2011 through December 2011 of $57,422,937 on line 1. The Actual/Estimated True-Up under-recovery for the same period of $6,301,912 is shown on line 2. Line 1 less line 2 results in the Net Final True-Up for the period January 2011 through December 2011 shown on line 3, an under-recovery of $51,121,025.

The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the FCR actual true-up by month?

A. Yes. Appendix I, pages 4 and 5, entitled "Calculation of Actual True-up Amount," show the calculation of the FCR actual true-up by month for January 2011 through December 2011.

Q. Have you provided a schedule showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2011?

A. Yes. Appendix I, page 6 provides a comparison of jurisdictional fuel revenues and costs on a dollar per MWh basis. Appendix I, page 7 compares the actual End-of-Period True-up under-recovery of $102,921,431 to the Actual/Estimated End-of-Period True-up under-recovery of $51,800,406 resulting in the variance of $51,121,025.

Q. Please describe the variance analysis on page 6 of Appendix I.

A. Appendix I, page 6 provides a comparison of Jurisdictional Total Fuel Revenues and Jurisdictional Total Fuel Costs and Net Power Transactions on a dollar per MWh basis. The ($51,121,025) variance was due primarily to an increase in the fuel cost per MWh of $40.03/MWh vs. $39.64/MWh that resulted in a cost variance of $40,102,971, and a decrease in fuel revenues per MWh of $41.65/MWh vs. $41.74/MWh that resulted in a decrease of ($9,281,741), for a total variance due to cost of ($49,384,713).

The increase in fuel cost per MWh resulted in a variance due to consumption of ($32,780,708) and the decrease in fuel revenues per MWh resulted in a variance due to consumption of ($34,518,519), for a total variance due to consumption of ($1,737,810). Finally, the variance reflects a decrease of $1,499 in interest primarily due to higher than expected commercial paper rates.

Q. What was the variance in Adjusted Total Fuel Costs and Net Power Transactions?

A. The variance in Adjusted Total Fuel Costs and Net Power Transactions was $7,356,915. As shown on Appendix I, page 7, this $7.4 million increase in Adjusted Total Fuel Costs and Net Power Transactions was due primarily to a $14.5 million (0.4%) increase in the Fuel Cost of System Net Generation, a $3.2 million (16.2%) variance in the Fuel Cost of Power Sold, and a $0.9 million (14.8%) variance in Gains from Off-System Sales. These amounts were partially offset by a $6.4 million (4.1%) decrease in Energy Payments to Qualifying Facilities (QF), a $2.8 million (3.3%) decrease in Energy Cost of Economy Purchases and a $1.9 million (0.7%) decrease in Fuel Cost of Purchased Power.

Fuel Cost of System Net Generation ($14.5 million increase)

FPL's natural gas cost averaged $5.83 per MMBtu or $0.04 per MMBtu (0.7%) lower than projected during the period. FPL consumed 7,307,653 more MMBtu (1.3%) than projected during the period. Of the total $19.0 million variance for natural gas, $42.9 million was due to higher than projected consumption. This volume variance was partially offset by $23.9 million due to lower than projected unit costs.

FPL's heavy oil cost averaged $12.93 per MMBtu or $0.05 per MMBtu (0.4%) lower than projected during the period. FPL consumed 223,556 more MMBtu (3.2%) than projected during the period. Of the total $2.5 million variance for heavy oil, $2.9 million was due to higher than projected consumption. This volume variance was slightly offset by $0.4 million due to lower than projected unit costs.

FPL's light oil cost averaged $19.46 per MMBtu or $0.10 per MMBtu (0.5%) lower than projected during the period. FPL consumed 68,715 more MMBtu (3.7%) than projected during the period. Of the total $1.2 million variance for light oil, $1.4 million was due to higher than projected consumption. This volume variance was slightly offset by $0.2 million due to lower than projected unit costs.

FPL's nuclear cost averaged $0.61 per MMBtu or $0.02 per MMBtu (3.2%) lower than projected during the period. Additionally, FPL consumed 92,485 less MMBtu (0.04%) than projected during the period. Of the total $4.9 million variance for nuclear, $4.8 million was due to lower than projected unit costs and $0.1 million was due to lower than projected consumption.

FPL's coal cost averaged $2.84 per MMBtu or $0.02 per MMBtu (0.7%) higher than projected during the period. FPL consumed 1,602,023 less MMBtu (2.7%) than projected during the period. Of the total $3.3 million variance for coal, $4.5 million was due to lower than projected consumption. This volume variance was partially offset by $1.2 million due to higher than projected unit costs.

Fuel Cost of Power Sold ($3.2 million variance)

The variance in the fuel cost of power sold was primarily due to lower than projected economy sales and lower than projected fuel costs for economy sales. FPL sold approximately 76,000 MWh less (13.9%) of economy power than projected. Additionally, FPL's average fuel cost attributable to economy sales was $1.75/MWh lower (6%) than projected. Of the total $3.2 million variance for the fuel cost of power sold, $1.8 million is due to lower than projected economy sales and the remaining $1.4 million is due to lower than projected fuel costs for economy sales.

Gains from Off-System Sales ($857,119 variance)

The variance in gains from off-system sales was primarily due to lower than projected economy sales. FPL sold approximately 76,000 MWh less in economy sales than originally projected. Approximately 97% of the total variance of $857,119 is attributable to lower than projected economy sales. Approximately 3% is attributable to lower than projected average margins ($0.12/MWh) on economy sales.

Energy Payments to Qualifying Facilities ($6.4 million decrease)

The variance in energy payments to qualifying facilities is attributable to both lower than projected fuel costs and lower than projected volumes related to QF purchases. Approximately 53%, or $3.4 million, of the variance was due to lower than projected QF purchases. FPL purchased approximately 77,000 MWh less than projected from QFs. Approximately 47%, or $3.0 million, of the variance was due to lower than projected unit energy costs. The actual unit cost of energy was $0.87/MWh lower than projected.

Energy Cost of Economy Purchases ($2.8 million decrease)

The variance in the energy cost of economy purchases is primarily due to energy that FPL returned in-kind to Tampa Electric Company (TECO). FPL inadvertently took energy from TECO, during 2010, due to a meter error in a tie-line, and returned most of this power in 2011. Approximately 93%, or $2.6 million, of the variance is attributable to this return of energy. The remaining $0.2 million variance is attributable to lower than projected economy purchases (approximately 19,000 MWh) and slightly higher than projected unit costs ($0.65/MWh) for economy purchases.

Fuel Cost of Purchased Power ($1.9 million decrease)

The variance in the fuel cost of purchased power is primarily due to lower than projected UPS purchases. FPL purchased approximately 116,000 MWh less of UPS power than originally projected, resulting in a volume variance of approximately $4.8 million. This volume variance was partially offset by $2.8 million due to higher than projected unit costs for UPS purchases ($0.74/MWh), resulting in a net UPS variance of approximately $2.0 million. The balance of the variance was caused by greater than projected volumes related to PPA and St. Lucie Reliability Exchange purchases, partially offset by lower than projected SJRPP purchases.

Q. What was the variance in retail (jurisdictional) Fuel Cost Recovery revenues?

A. As shown on Appendix I, page 7, line C3, actual jurisdictional FCR revenues, net of revenue taxes, were approximately $43.8 million (1.1%) lower than the actual/estimated projection, reflecting lower than projected jurisdictional sales, a variance of 826,923,742 kWh (0.8%).

Q. Pursuant to Commission Order No. PSC-11-0579-FOF-EI, FPL's 2011 gains on non-separated wholesale energy sales were to be measured against a three-year average Shareholder Incentive Benchmark of $10,707,967. Did FPL exceed this benchmark?

A. No.

Q. What is the appropriate final Shareholder Incentive Benchmark level for calendar year 2012 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-

1744-PAA-EI in Docket No. 991779-EI?

A. For the year 2012, the three year average Shareholder Incentive Benchmark consists of actual gains for 2009, 2010 and 2011 (see below) resulting in a three year average threshold of $6,680,369.

2009	$10,700,431
2010	$ 4,421,987
2011	$ 4,918,688

Gains on sales in 2012 are to be measured against the three-year average Shareholder Incentive Benchmark of $6,680,369.

CAPACITY COST RECOVERY CLAUSE (CCR)

Q. Please explain the calculation of the CCR net true-up amount.

A. Appendix II, page 3, entitled "Summary of Net True-Up" shows the calculation of the CCR Net True-Up for the period January 2011 through December 2011, an under-recovery of $44,704,575, which FPL is requesting to be included in the calculation of the CCR factors for the January 2013 through December 2013 period.

The actual End-of-Period under-recovery for the period January 2011 through December 2011 of $19,460,973 (shown on page 3, line 1) less the Actual/Estimated End-of-Period over-recovery for the same period of $25,243,602 (shown on page 3, line 2) that was approved by the Commission in Order No. PSC-11-0579-FOF-EI, results in the Net True-Up under-recovery for the period January 2011 through December 2011 of $44,704,575 (shown on page 3, line 3).

Q. Have you provided a schedule showing the calculation of the CCR actual true-up by month?

A. Yes. Appendix II, pages 4 and 5, entitled "Calculation of Final True-up Amount," shows the calculation of the CCR End-of-Period true-up for the period January 2011 through December 2011 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision" for the FCR clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity charges and applicable revenues for 2011?

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to actual/estimated capacity charges and applicable revenues for the period January 2011 through December 2011.

Q. What was the variance in net capacity charges?

A. Appendix II, Page 6, Line 12 provides the variance in Jurisdictional Capacity Charges, which is a decrease of $1,342,034 or (0.2%). This $1.3 million variance was primarily due to a $3.4 million (6.7%) decrease in Incremental Plant Security Costs, a $0.7 million (0.3%) decrease in Payments to Non-cogenerators, a $0.5 million (3.3%) decrease in Transmission of Electricity by

Others and a variance of $53,341 (3.5%) associated with Transmission Revenues from Capacity Sales. These decreases were partially offset by a $3.2 million (1.2%) increase in Payments to Cogenerators.

Incremental Plant Security Costs ($3.4 million decrease)

The variance in incremental plant security costs was primarily due to lower than projected Part 73 Cyber Security Digital Assessment costs resulting from a change in scope. FPL is waiting for additional NRC guidance on assessment criteria, therefore, the assessments required for the Cyber Security critical systems and digital assets were not completed as planned and mitigation efforts have been delayed into 2012.

Payments to Non-cogenerators ($0.7 million decrease)

Approximately $1.4 million of the variance in payments to non-cogenerators was primarily due to SJRPP. The SJRPP variance was due to lower debt service costs and lower JEA O&M expense charges to FPL, which resulted from purchasing approximately 34,000 fewer MWh than originally projected. This was partially offset by approximately $0.7 million attributable to UPS as a result of timing differences associated with the Capacity Availability Performance Adjustment costs.

Transmission of Electricity by Others ($0.5 million decrease)

The variance in the costs of transmission of electricity by others was primarily due to higher than projected UPS power purchases, resulting in lower than projected unutilized transmission costs. FPL purchased approximately 148,000 more MWh than originally projected for the last five months of 2011.

Transmission Revenues from Capacity Sales ($53,341 variance)

The variance in transmission revenues from capacity sales was primarily due to higher than projected transmission unit costs related to economy power sales. FPL sold approximately 26,000 MWh less economy power than projected during the forecast period; however, the transmission unit costs were higher than initially projected.

Payments to Cogenerators ($3.2 million increase)

The variance in payments to cogenerators was primarily due to higher than projected capacity payments to both Cedar Bay and Indiantown. Capacity payments to Cedar Bay were approximately $2.6 million higher than estimated and capacity payments to Indiantown were approximately $613,000 higher than originally estimated. Higher payments resulted from a higher realized annual capacity billing factor for both Cedar Bay and Indiantown than had been projected. Capacity payments to Broward North were approximately $62,000 lower than estimated.

Q. What was the variance in Capacity Cost Recovery revenues?

A. As shown on page 6, line 14, actual Capacity Cost Recovery Revenues (Net of Revenue Taxes), were $46,036,301 (7.7%) lower than the actual/estimated projection. This $46,036,301 decrease in revenues, plus the $1,342,034 decrease in costs and $10,307 increase in interest (page 6, line 16), result in the final under-recovery of $44,704,575.

Q. Have you provided Schedule A12 showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Appendix II as pages 7 and 8. Page 7 shows the actual capacity payments for Qualifying Facilities, the Southern Company UPS contract and the SJRPP contract for the period January 2011 through December 2011. Page 8 provides the Short Term Capacity payments for the period January 2011 through December 2011.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF PAUL FREEMAN

DOCKET NO. 120001-EI

AUGUST 31, 2012

Q. Please state your name and address.

A. My name is Paul Freeman. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed in NextEra Energy, Inc.'s Nuclear Business Unit as Vice President of Organizational Effectiveness.

Q. Please describe your duties and responsibilities in that position.

A. I am currently responsible for the governance and oversight of the following areas for the NextEra Nuclear Plants, including Florida Power & Light Company's (FPL) St. Lucie and Turkey Point Nuclear Plants: Training, Licensing/Nuclear Regulatory Affairs, Performance Improvement, and Nuclear Security.

Q. Please describe your educational background and business experience in the nuclear industry.

A. I earned my Bachelor of Marine Engineering degree from Massachusetts Maritime Academy in 1984 and earned my Master of Business Administration degree from Boston College in 1990. I am a career nuclear professional with approximately 27 years of nuclear operating experience. In 1985, I joined Public Service Company of New Hampshire at the Seabrook Nuclear Power Plant (owned by NextEra Energy since 2002). I served in various roles of increasing responsibility at Seabrook until June 2012. My positions included Control Room Operator, Operations Shift Manager, Engineering Manager and Director, Plant General Manager and Site Vice President. In June 2012, I was appointed Vice President of Organizational Effectiveness. I have accountability for Training, Licensing/Nuclear Regulatory Affairs, Performance Improvement, and Nuclear Security.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy (MMBtu) to be produced by our nuclear units and the costs of disposal of spent nuclear fuel. I am also updating the status of certain litigation that affects FPL's nuclear fuel costs; plant security costs and new Nuclear Regulatory Commission (NRC) security initiatives; new NRC requirements resulting from Fukushima; and outage events. Both nuclear fuel and disposal of spent nuclear fuel costs were input values to POWERSYM used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2013 through December 2013.

<u>Nuclear Fuel Costs</u>

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using projected energy production at our nuclear units and current operating schedules, for the period January 2013 through December 2013.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2013 through December 2013.

A. FPL projects the nuclear units will produce 285,258,283 MMBtu of energy at a cost of $0.7441 per MMBtu, excluding spent fuel disposal costs, for the period January 2013 through December 2013. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 18.

<u>Spent Nuclear Fuel Disposal Costs</u>

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2013 through December 2013 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $24.8 million are provided in Appendix II, on Schedule E-2, starting on page 14. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9363 mills per net kWh generated, including transmission and distribution line losses.

<u>Litigation Status Update</u>

Q. Is there currently an unresolved dispute relating to the spent fuel disposal fee?

A. Yes. On June 1, 2012, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit ruled that the DOE failed to perform a valid evaluation of whether the spent fuel disposal fee should be adjusted in light of the Federal Government's decision not to develop the Yucca Mountain site as the disposal location for spent nuclear fuel from nuclear power plants. The Court did not grant the requested relief -- suspension of the fee -- but remanded the matter to DOE with directions to perform a valid evaluation of a potential fee adjustment within six months. The D.C. Circuit retained jurisdiction over the case so that any further review of DOE's revised analysis can be expedited. This ruling came in response to a petition filed by FPL and other utilities that was supported by a joint filing by this Commission and the Office of Public Counsel.

<u>Nuclear Plant Security Costs</u>

Q. What is FPL's projection of incremental security costs at FPL's nuclear power plants for the period January 2013 through December 2013?

A. FPL projects that it will incur $39.5 million in incremental nuclear power plant security costs in 2013.

Q. Please provide a brief description of the items included in this projection.

A. The projection includes maintaining a security force as a result of implementing NRC's fitness for duty rule under Part 26, which strictly limits the number of hours security personnel may work; additional personnel training; maintaining the physical upgrades resulting from implementing NRC's physical security rule under Part 73; and impacts of implementing NRC's rule under Part 73 for Cyber Security. It also includes Force on Force (FoF) modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force (CAF) as required by NRC inspection procedures.

Q. Are there new impacts from the NRC's recent revisions to the security-related Orders that affect FPL's 2013 security cost projections?

A. Yes. On March 27, 2009 the NRC issued a new rule under Part 73.54 of the Code of Federal Regulations that involves the protection of station digital computer, communications systems and networks which impose significant requirements for monitoring, hardening and responding to cyber intrusions. Full regulatory implementation for this new Part 73.54 is scheduled for completion in 2014. The NRC Cyber Security rulemaking costs for 2013 are estimated to be $5.1 million for the St. Lucie and Turkey Point nuclear sites.

Also, in February 2009, the NRC updated the Enhanced Adversary Characteristics (EAC) of the Design Basis Threat (DBT). These enhancements are now being utilized during the triennial FoF inspections performed at the nuclear stations. The DBT is the measure that all nuclear stations are designed to defend against. Some examples of changes are: enhanced intrusion detection, adversary delay barriers, and additional vehicle barriers.

FoF inspections are scheduled on a repeating three year cycle. Consequently, St. Lucie and Turkey Point will receive third round FoF inspections in the 2011-2013 cycle and FPL sites may require additional modifications to ensure successful regulatory inspection conclusions. Adversary Characteristics are constantly being reviewed by the NRC due to the potential change in adversary capabilities. Consequently, future enhancements of nuclear facilities may be required. St. Lucie and Turkey Point FoF modifications are estimated to be $1.0 million for each facility for 2013.

<u>Fukushima Costs</u>

Q. Please describe the natural disaster that occurred in Japan in 2011 and its impact on nuclear power plants.

A. On March 11, 2011, an earthquake occurred off the coast of Japan, which resulted in a tsunami. The earthquake and tsunami caused significant damage to the units of the Fukushima Daiichi (Fukushima) nuclear power station. Following the earthquake and tsunami, off-site power was lost and cooling water systems were damaged, resulting in difficulties in cooling all of the units' reactor cores and spent fuel pools, and leading to explosions and radiation leaks from the site. The events at Fukushima raised questions about nuclear safety which have been explored by all US nuclear plant sites, the NRC and INPO.

Q. What changes has the NRC implemented resulting from the event in Japan?

A. Even though the NRC has concluded that all U.S. plants are safe, incorporation of lessons learned for the Fukushima event is expected to be significant. In March 2012, the NRC issued three Orders and three Requests for Information (RFIs). The Orders address Mitigation Strategies, Hardened Vent (not applicable to FPL nuclear sites) and Spent Fuel Pool Instrumentation. The RFIs address Seismic and Flooding Walkdowns, Seismic and Flooding Re-evaluations and Emergency Planning Communications and Staffing. The response to the Orders and RFIs follow varying schedules from 60 days to several years.

Q. What steps has FPL already implemented as a result of the new Orders and RFIs?

A. As of June 2012, FPL has taken steps to comply with 2012 action requirements, which include acquiring additional diesel generators and water pumps, initiating seismic and flooding walkdowns and responding to all information requests.

Q. What types of further steps does FPL anticipate taking as a result of the new NRC Orders and RFIs?

A. FPL will make modifications and enhancements to current beyond design basis mitigation strategies to deal with potential events that are beyond current plant design basis. The project scope is still evolving based on NRC communications and currently expected to include modification for the following:

- Seismic Design Basis
- Flooding Design Basis
- Station Blackout Mitigation
- Spent Fuel Pool Instrumentation
- Onsite Emergency Response Capabilities
- Station Blackout/Emergency Plans

Q. Does FPL have enough information currently to project with confidence the cost to complete the modifications and enhancements as a result of the NRC requirements?

A. No. FPL currently has a conceptual estimate range of $17 million - $25 million per site. However, the estimate is subject to significant change as more information is gathered at FPL and other nuclear plants.

Q. When does FPL currently expect to complete the modifications and enhancements?

A. Based on currently available information, FPL believes that implementation of the modifications will be completed in 2016.

Q. Has FPL included any costs to comply with the Fukushima Orders and RFIs in the 2013 Test Year Forecast that was filed in Docket No. 120015-EI?

A. Yes. FPL included $5.1 million of capital expenditures and $144k of O&M expenses for the 2013 Test Year. However, at the time the 2013 Test Year Forecast was developed in the Fall of 2011, not enough information was available to estimate the full impact of the Fukushima event. FPL currently anticipates that actual costs in 2013 and beyond will be significantly above these levels, though we will not be able to make definitive estimates until further regulations are issued later this year and FPL has evaluated what will be required to comply with them.

Q. What is FPL's current projection of Fukushima costs at FPL's nuclear power plants for the period January 2013 through December 2013?

A. FPL projects that it will incur an additional $6.1 million of capital expenditures in Fukushima power plant costs above the 2013 Test year amounts.

Q. Is FPL's exposure to Fukushima response costs similar to the exposure that FPL has had to post-9/11 power plant security costs?

A. Yes. Both events were unanticipated disasters that are having significant impacts on the regulatory requirements and resulting costs for operating nuclear power plants. Both fundamentally changed the landscape of expectations for the protection of nuclear plants. In 2001, it was the nature and scope of terrorist threats. In 2012, it is the nature and scope of potential seismic and flooding events. In both instances, there has been substantial uncertainty as to the cost impacts beyond the test year.

<u>2012 Outage Events</u>

St. Lucie

Q. Has FPL experienced any unplanned outages at its St. Lucie plant in 2012?

A. Yes. In April 2012, while Unit 1 was shut down to perform a scheduled refueling outage, operational issues associated with the Steam Bypass Control System (SBCS) were the primary cause that delayed the restart of the unit.

Q. Please describe the circumstances related to the operational issues with the SBCS.

A. There were four separate events that occurred during the outage related to the SBCS which was replaced in the spring 2012 Unit 1 outage.

1. On 3/31/2012, Unit 1 was at 10% reactor power conducting preoperational testing on the SBCS. One of the pressure control valves (PCV) in the SBCS experienced unstable operation and opened causing increased steam flow. The Unit was manually tripped in accordance with operating procedural requirements. Testing and inspections were performed and repairs made. Most probable cause was determined to be manufacturing quality issues.

2. On 4/7/2012, Unit 1 was at 10% power preparing to startup the turbine generator when a leak into the main condenser occurred. Unit 1 was manually shut down per station operating procedures. The cause was determined to be condenser tube damage caused by the failure of one of the discharge spargers into the condenser from SBCS. The discharge sparger failed due to high cycle fatigue. A new sparger was designed, fabricated and installed.

3. On 4/15/2012, Unit 1 was at 10% reactor power and performing capacity testing on the SBCS. While performing the testing, a decrease in steam pressure was identified due to several PCVs operating abnormally. Consequently, the operators placed alternate valves in service to safely control the plant. The Unit reduced power to 2%.

4. On 4/17/2012, Unit 1 was at 10% reactor power and the turbine was being started up per plant operating procedures. After simulated turbine trip testing was performed, one of the SBCS valves operated abnormally and was removed from service. The operators placed alternate valves in auto to safely control the plant. The unit reduced power to 2%. The direct cause of this event was a valve failure. The valve was repaired and returned to service.

Q. What corrective actions have been initiated to address these events?

A. Considerable effort was expended in determining the cause of these four events. A dedicated team of station and industry experts reviewed all the data from each event. However, the direct cause for the observed SBCS valve response remains indeterminate. To ensure successful operation of the unit, one of the SBCS valves has been removed from service and plant start-up procedures have been revised to operate the remaining SBCS valves at conditions which will ensure their proper operation. Future plans include replacement of these valves with upgraded design.

Q. How many days was the St. Lucie Unit 1 refueling outage delayed due to these issues?

A. The Unit 1 refueling outage was delayed approximately 21 days.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 1 in 2012?

A. Yes. In April 2012, shortly after Unit 1 returned to service from a scheduled refueling outage, switchyard breaker 8W30 faulted, causing an automatic turbine trip and subsequent shut down of the unit.

Q. What caused the switchyard breaker to fault?

A. An internal C-phase-to-ground fault occurred in the switchyard breaker. An investigation determined that the fault was caused by either failure of the Transient Recovery Voltage Capacitors or the presence of conductive particles within the C-phase, causing a short to ground.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. FPL replaced the failed breaker with a new upgraded breaker. Additionally, testing was conducted on the other existing St. Lucie Unit 1 output breaker to ensure operating performance. As a long-term preventative measure, FPL replaced the one other breaker of same vintage and style during the planned LAR outage in mid-July.

Q. How many days was the St. Lucie Unit 1 outage due to this issue?

A. The Unit 1 outage due to the breaker was approximately 1 day.

Q. Has FPL experienced any other unplanned outages at St. Lucie Unit 1 in 2012?

A. Yes. In June 2012, Unit 1 automatically shut down due to a malfunction of the Turbine Control System (TCS).

Q. What caused the malfunction of the TCS?

A. The TCS was replaced during the spring 2012 Unit 1 outage. The TCS is designed with redundant controllers, a primary and backup. A fiber optic cable connection in the primary controller malfunctioned, functionally affecting the interface between the primary and backup controllers. An investigation determined that this malfunction was caused by either improper installation of the fiber optic cable connector or inadvertent damage to the connector caused by other work performed in the vicinity of the connector after installation and testing.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A. FPL revised the procedure to include a post maintenance stress test to fiber optic equipment and has hired outside services that specialize in this work to avoid recurrence.

Q. How many days was the St. Lucie Unit 1 outage due to this issue?

A. The Unit 1 outage was approximately 4 days.

Q. Has St. Lucie Unit 2 experienced any unplanned outages in 2012?

A. Yes. In May 2012, Unit 2 initiated a manual shut down due to lowering 2A Steam Generator water levels.

Q. What caused the lower Steam Generator water level?

A. A malfunction of the Feedwater Regulating Valve controller caused the valve to operate abnormally, reducing the feedwater flow to the 2A Steam Generator.

Q. How many days was the St. Lucie Unit 2 outage due to this issue?

A. The Unit 2 outage was approximately 2 days.

Q. What corrective actions did FPL initiate to avoid this problem in the future?

A FPL replaced the feedwater regulating valve controller feedback devices with a different improved design. Additionally, FPL added a requirement to the risk management procedure to periodically validate input assumptions to decisions and response plans.

<u>**Turkey Point**</u>

Q. Has FPL experienced any unplanned outages at its Turkey Point plant in 2012?

A. Yes. In August 2012, while Unit 3 was shut down to perform a scheduled refueling outage, issues associated with installation of the new Electro Hydraulic Control System (EHC) and activities required to complete major modifications to the Condensate System were the primary causes that delayed the restart of the unit.

Q. Please describe the circumstances related to the EHC and Condensate System.

A. Installation of the new EHC system and Condensate system upgrades were major Extended Power Uprate (EPU) activities During the construction phase, in-progress changes were made to the EHC design that required additional tubing to be installed. This increased the time required to complete the activity, with the delay mostly attributed to fitup, welding, and flushing of the new tubing. The Condensate System upgrade was a major construction activity that included the installation of new condensers and piping. Due to the cleanliness requirements for Condensate water, emphasis was placed on post-modification system clean-up. During the construction phase it became clear that insufficient time had been incorporated into the schedule for the Condensate flushing. Incorporating the proper time for the flushing resulted in a delay to the end of the outage, compared to the original, unrealistically short estimate for this activity.

Q. How many days was the Turkey Point Unit 3 outage due to this issue?

A. The Unit 3 outage is still ongoing, but is expected to return to service in early September.

Q. What corrective actions has FPL initiated to avoid this problem in the future?

A. The Turkey Point Unit 3 part of the EPU project will be completed at the end of the current refueling outage. EPU will be completed on Unit 4 during the refueling outage scheduled to begin in November 2012. Since the Unit 3 refueling outage (including post-outage power ascension) is in progress, corrective actions to prevent similar occurrences on Unit 4 have not been specifically identified. However, FPL utilizes a rigorous outage performance review process that will be employed following the Unit 3 outage to identify and implement corrective actions that are intended to prevent schedule delays.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF J. CARINE BULLOCK

DOCKET NO. 120001-EI

AUGUST 31, 2012

Q. Please state your name and business address.

A. My name is J. Carine Bullock, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you currently employed and in what capacity?

A. I am employed by Florida Power & Light Company ("FPL") and I am the Vice President of Production Assurance and Business Services in the Power Generation Division of FPL, where I am responsible for providing production standardization and commercial management of FPL's fossil generating assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor (EAF) targets and average net operating heat rate (ANOHR) targets used in determining the Generating Performance Incentive Factor (GPIF) for the period January through December, 2013.

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control, any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit JCB-1. This exhibit supports the development of the 2013 GPIF targets (EAF and ANOHR). The first page of this exhibit is an index to the contents of the exhibit. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2013 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December, 2013, FPL projects a weighted system equivalent planned outage factor of 7.2% and a weighted system equivalent unplanned outage factor of 7.4%, which yield a weighted system equivalent availability target of 85.4%. The targets for this period reflect planned refuelings for St. Lucie Unit 1 and Turkey Point Unit 3 and an Extended Power Uprate (EPU) outage and refueling for Turkey Point Unit 4. FPL also projects a weighted system ANOHR target of 8,841 Btu/kWh for the period January through December, 2013. As discussed later in my testimony, these targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established individual target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit JCB-1, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for nine generating units that FPL proposes to be considered as GPIF units for the period January through December, 2013. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining equivalent availability targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the equivalent planned outage factor (EPOF) and the equivalent unplanned outage factor (EUOF). The EPOF for each unit is determined by the length of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor (EFOF) and the equivalent maintenance outage factor (EMOF). The EUOF is then adjusted to reflect recent or projected unit overhauls following the projection period.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, historic ANOHR vs. unit net output factor curves are developed for each GPIF unit. The historic data is analyzed for any unusual operating conditions and changes in equipment that affect the predicted heat rate. A regression equation is calculated and a statistical analysis of the historic ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor from the production costing simulation program, POWERSYM. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the POWRSYM model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the 9 units which FPL proposes to use for the period January through December, 2013 represent the top 81% of the total forecasted system net generation for this period excluding the new West County Energy Center units. These three units are new for 2009 and 2011 and were excluded from the GPIF calculation because there is insufficient historical data to include them. Therefore, consistent with the GPIF Manual, the West County Energy Center units will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2013 EAF and ANOHR performance targets represent reasonable level of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 120001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January through December, 2011

DIRECT TESTIMONY OF
Will Garrett

March 1, 2012

Q. Please state your name and business address.

A. My name is Will A. Garrett. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC as Controller of Progress Energy Florida.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe PEF's Fuel Adjustment Clause final true-up amount for the period of January through December 2011, and PEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __(WG-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. __(WG-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. __(WG-3T), Schedules A1 through A3, A6, and A12 for December 2011, year-to-date; and Exhibit No. __(WG-4T), a schedule outlining the 2011 capital structure and cost rates applied to capital projects. Schedules A1 through A9, and A12 for the year ended December 31, 2011, were previously filed with the Commission on January 24, 2012.

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Would you please summarize your testimony?

A. Per Order No. PSC-11-0579-FOF-EI, the projected 2011 fuel adjustment true-up amount was an under-recovery of $123,159,202. The actual under-recovery for 2011 was $324,522,196 resulting in a final fuel adjustment true-up under-recovery amount of $201,362,994 (Exhibit No. __(WG-1T)).

The projected 2011 capacity cost recovery true-up amount was an over-recovery of $20,667,503. The actual amount for 2011 was an over-recovery of $16,277,953 resulting in a final capacity true-up under-recovery amount of $4,389,550 (Exhibit No. __(WG-2T)).

FUEL COST RECOVERY

Q. What is PEF's jurisdictional ending balance as of December 31, 2011 for fuel cost recovery?

A. The actual ending balance as of December 31, 2011 for true-up purposes is an under-recovery of $324,522,196.

Q. How does this amount compare to PEF's estimated 2011 ending balance included in the Company's estimated/actual true-up filing?

A. The actual true-up amount attributable to the January - December 2011 period is an under-recovery of $324,522,196 which is $201,362,994 higher than the re-projected year end under-recovery balance of $123,159,202.

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional under-recovery of $324,522,196 shown on your Exhibit No. __(WG-1T)?

A. The factors contributing to the under-recovery are summarized on Exhibit No. __(WG-1T), sheet 1 of 7. Net jurisdictional fuel revenues were favorable to the forecast by $32.6 million, while jurisdictional fuel and purchased power expense increased $197.9 million, resulting in a difference in jurisdictional fuel revenue and expense of $165.3 million. The $197.9 million increase in jurisdictional fuel and purchase power expense is primarily attributable to an unfavorable system variance from projected fuel and net purchased power of $180.7 million as more fully described below. The $324.5 million under-recovery also includes the deferral of $158.8 million of 2010 under-recovery approved in Order No. PSC-11-0579-FOF-EI. The net result of the difference in jurisdictional fuel revenues and expenses of $165.3 million, plus the 2010 deferral of $158.8 million and the 2011 interest provision calculated on the deferred balance throughout the year is an under-recovery of $324.5 million as of December 31, 2011.

Q. Please explain the components contributing to the $201,362,994 variance between the actual under-recovery of $324,522,196 and the approved, estimated/actual under-recovery of $123,159,202.

A. The major factor contributing to the $201,362,994 variance is the projected recovery of outstanding NEIL replacement power reimbursement funds of

$220.4 million as of December 31, 2011, offset by a reduction of $20.8 million in fuel cost associated with lower than projected natural gas prices.

The NEIL funds are related to the 2010-2011 period, and will be applied to reduce fuel costs as received. As of December 31, 2011, PEF has received $162.0 million of NEIL replacement power reimbursement funds, of which $45.0 million was received in 2011. Funds totaling $108.2 million and $39.2 million were applied to the fuel clause in 2010 and 2011, respectively, and $3.7 million was applied to the capacity cost recovery clause in 2010. The remaining $10.9 million has been recorded as a regulatory liability and is accruing interest. Once insurance proceeds for a full month have been received, these insurance recoveries will be applied to the fuel clause.

Q. What is the current status of NEIL replacement power reimbursement insurance proceeds owed PEF as of December 31, 2011?

A. Discussions continue with NEIL regarding these issues.

Q. Please explain the components shown on Exhibit No. __(WG-1T), sheet 6 of 7 which helps to explain the $180.7 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(WG-1T), sheet 6 of 7 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate of generated energy (BTU's per KWH); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH). The $180.7 million unfavorable system variance is mainly attributable to the original 2011 projection assuming that CR3 would be back in service for all of 2011.

Therefore, PEF has prepared Exhibit _(WG-1T), sheet 7 of 7 that updates the variance analysis calculated in Exhibit _(WG-1T), sheet 6 of 7 assuming that the original 2011 projection had not placed CR3 back into service during 2011. The updated variance analysis shows an overall $8.8 million unfavorable system variance. This variance starts with the original $180.7 million unfavorable variance, shown in Exhibit _(WG-1T), sheet 6 of 7, and backs out the credit of $39.2 million associated with the NEIL replacement power reimbursement, assumed to be collected in 2010 per the original projection filing (WG-1T, sheet 7 of 7, Line 19). This recalculated variance of $219.9 million is then offset by removing the CR3 replacement power costs directly contributed to the outage of CR3 as provided by Portfolio Management based upon historical practices.

Q. After considering the impact of the CR3 replacement costs, what effect did these components have on the system fuel and net power variance for the true-up period?

A. As shown on sheet 7 of 7, the dollar variance due to MWHs generated and purchased (column B) produced a cost increase of $29.9 million. The primary reason for this unfavorable variance was a decrease in supplemental sales and other power sales. The favorable heat rate variance (column C) of $9.0 million is due to changes in the generation mix to meet the energy requirements. The favorable price variance of $12.1 million (column D) was caused mainly by a favorable variance in Other Jurisdictional Adjustments. The leading components of the Other Jurisdictional Adjustments variance is related to replacement power provided to thé joint owners of CR3 as discussed below.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. __(WG-3T) in the footnote to line 6b on page 1 of 2, Schedule A2. Included in the footnote to line 6b on page 1 of 2, Schedule A2, is the allocation of $39.2 million of Nuclear Electric Insurance Limited (NEIL) replacement power reimbursement funds to the fuel clause and a reduction of $23.8 million for the incremental cost of replacement power provided the joint owners of CR-3 per PEF's Joint Ownership Agreements. These adjustments also include an unfavorable adjustment to coal inventory due to an aerial survey of $1.0 million, offset by an adjustment to remove the replacement power costs, therefore reducing incremental fuel costs by $971,389, related to the CR1 and 2 outage that occurred on January 16, 2011.

Q. Please explain the adjustment of $39.2 million related to the Nuclear Electric Insurance Limited (NEIL) replacement power reimbursement.

A. Pursuant to an insurance policy held by PEF with NEIL, in the event an unplanned outage of our nuclear unit (CR-3) extends beyond a deductible period of 12 weeks, PEF is entitled to receive reimbursement payments in the amount of $4,500,000 per week for 52 weeks to cover a portion of the replacement power costs associated with the outage. An additional 71 weeks of coverage is provided at $3,600,000 per week. When insurance proceeds for a full month are received, they are then applied to the fuel and capacity clause at a system level. The $39.2 million credit represents the application of NEIL funds to the fuel clause.

Q. Please explain the adjustment of $23.8 million for the incremental cost of replacement power provided the joint owners of the Crystal River nuclear unit (CR-3).

A. Per agreements with the joint owners of CR-3, if PEF does not meet a specific capacity factor for this unit per a designated two-year interval, PEF must replace enough power to meet the capacity factor or reimburse the joint owners for their cost of replacing the power. PEF decided to replace CR-3 joint owner power throughout 2011. For each hour replacement power was provided the joint owners of CR-3, PEF calculated the fuel costs on the incremental generating units that ran during those hours and the replacement MW. The incremental cost of the replacement power was then adjusted from generated fuel expense in order to remove these costs from fuel expense recovered from our retail ratepayers.

Q. Please explain the Aerial Survey Adjustment of $1.0 million.

A. This adjustment is attributable to the semi-annual aerial survey conducted on April 26, 2011 in accordance with Order No. PSC-97-0359-FOF-EI, found in Docket No. 970001-EI. This adjustment represents 0.3% of the total coal consumed at the Crystal River facility in 2011.

Q. Did PEF exceed the economy sales threshold in 2011?

A. No. PEF did not exceed the gain on economy sales threshold of $1.1 million in 2011. As reported on Schedule A1, Line 15a, the gain for the year-to-date period through December 2011 was $353 thousand; which fell below the threshold. This entire amount was returned to customers through a reduction of total fuel and net power expense recovered through the fuel clause.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November, 2011 hearings been updated to incorporate actual data for all of year 2011?

A. Yes. PEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2009 through 2011, as follows:

Year	Actual Gain
2009	1,219,086
2010	1,116,387
2011	352,650
Three-Year Average	$896,041

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2011 for capacity cost recovery?

A. The actual ending balance as of December 31, 2011 for true-up purposes is an over-recovery of $16,277,953.

Q. How does this amount compare to the estimated 2011 ending balance included in the Company's estimated/actual true-up filing?

A. When the estimated 2011 over-recovery of $20,667,503 is compared to the $16,277,953 actual over-recovery, the final capacity true-up for the twelve month period ended December 2011 is an under-recovery of $4,389,550.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission in Order No. PSC-96-1172-FOF-EI. The true-up amount was determined in the manner set forth on the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the actual period-end capacity over-recovery of $16.3 million?

A. Exhibit No. __(WG-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $16.3 million over-recovery is due primarily to the difference in the 2010 actual/estimated true-up of $52.3 million approved in Order No. PSC-10-0734-FOF-EI, and the actual 2010 prior period true-up of $67.0 million.

OTHER MATTERS

Q: Please explain the adjustment found on line C. 12 (Other) of Schedule A2 in Exhibit No. __(WG-3T)?

A: Line C. 12 of Schedule A2 represents an adjustment to the allocation of fuel expense between the retail and wholesale jurisdictions for 2011.

Q: Have you provided Schedule A12 showing the actual monthly capacity payments by contract consistent with the Staff Workshop in 2005?

A: Yes. A confidential version of Schedule A12 is included in Exhibit No. __(WG-3T).

Q. Does this conclude your direct true-up testimony?

A. Yes

PROGRESS ENERGY FLORIDA

DOCKET NO. 120001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2011

DIRECT TESTIMONY OF JOSEPH MCCALLISTER

April 2, 2012

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 410 South Wilmington Street, Raleigh, North Carolina 27601.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas in the capacity of Director of Gas, Oil and Power.

Q. Have your duties and responsibilities remained the same since you last testified in this proceeding?

A. Yes. My responsibilities for the Gas, Oil and Power section activities within the Fuels and Power Optimization Department have remained the same.

Q. Please briefly describe your work experience.

A. I joined Progress Energy Service Company in 2003. Prior to my current position, I served as the Director of Portfolio and Market Risk Assessment through mid 2006, and the Director of Gas and Oil Trading from mid 2006 through early 2009. Prior to joining Progress Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies supporting and managing commercial activities. Summary experience over this time period includes gas and power scheduling, real time power trading, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets, wholesale power agreements, fuel agreements, and corporate planning.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August-December 2011 hedging true-up data and summarize the results of PEF's hedging activity for calendar year 2011 as required by Commission Order No. PSC-02-1484-FOF-EI and further clarified by Commission Order No. PSC-08-0667-PPA-EI issued in October 2008.

Q. Have you prepared exhibits to your testimony?

A. Yes. I have attached Exhibit No.___ (JM-1T) which summarizes the hedging information for calendar year 2011 and cumulative results from 2002 to 2011.

Q. What are the objectives of PEF's hedging strategy?

A. The objectives of PEF's hedging strategy are to reduce the impacts of fuel price volatility over time and provide a greater degree of fuel price certainty to PEF's customers.

Q. What hedging activities did PEF undertake for 2011 and what were the results?

A. PEF utilized approved physical and financial agreements to hedge a portion of its projected natural gas, heavy oil and light oil fuel burns, and a portion of the estimated fuel surcharge exposure embedded in PEF's coal river barge and railroad transportation agreements. These activities resulted in a net hedge cost for 2011 of $231.2 million.

Q. Did PEF execute its hedging activities consistent with its approved Risk Management Plan?

A. Yes. The hedging activities executed by PEF were consistent with those outlined in its 2011 Risk Management Plan ("Plan"). In the Plan filed in August 2010, PEF's hedging target ranges were to hedge [redacted] to [redacted] of its forecasted natural gas burns for calendar year 2011 with a target to hedge approximately [redacted] of the forecasted natural gas burns over time. With respect to heavy oil and light oil forecasted to be burned at PEF's owned generation facilities for calendar year 2011, PEF targeted to hedge a minimum of [redacted] and [redacted], respectively. With respect to the coal river and rail transportation estimated fuel surcharge exposures for calendar year 2011, PEF targeted to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposures based on contractual provisions in the coal rail and river barge transportation agreements. In December 2010, based on PEF's forecasted burns and estimated coal rail and river barge transportation agreements, PEF's hedge percentages were approximately [redacted], [redacted], [redacted], [redacted] and [redacted] respectively for forecasted natural gas, heavy oil, and light oil burns, and estimated fuel surcharge exposures in the coal river and rail transportation agreements. As such, PEF was within its targeted hedge ranges for calendar year 2011 going into the year.

For calendar year 2011, PEF's actual hedge percentages based on actual burns for natural gas, heavy oil and light oil, were approximately [redacted], [redacted] and [redacted], respectively. PEF hedge percentages for the estimated fuel surcharges embedded in PEF's coal river and rail transportation in 2011 were [redacted] and [redacted], respectively. The actual hedge percentages for natural gas, light oil, and the estimated fuel surcharges for coal river and rail transportation were within the ranges outlined in the Plan. As outlined in the Plan, actual hedge percentages for any monthly period, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns. As outlined previously, based on forecasted heavy oil burns and hedges in place as of December 2010, PEF was approximately [redacted] hedged for calendar year 2011. Given the actual to forecasted 2011 burn variances, the resulting actual hedge percentage for heavy oil was lower than the targeted minimum of [redacted] based on forecasted calendar basis.

Q. What were the results of PEF economic purchase and sales activities for 2011?

A. With respect to economic purchases and sales, during 2011 PEF's economic energy wholesale purchases and power sales resulted in savings of approximately $16.1 million and $0.4 million, respectively.

Q. Did PEF hedging activities meet the stated objective and are the activities consistent with the Commission's Orders for hedging?

A. Yes. PEF's hedging activity met the stated objective of PEF's hedging strategy to reduce the impacts of fuel price volatility over time and provide a greater degree of fuel price certainty to PEF's customers. The hedging activities are consistent with Commission Orders No. PSC-02-1484-FOF-EI and No. PSC-08-0667-PPA-EI. PEF's hedging activities are conducted in an environment of strong internal controls and executed in a structured manner. PEF's hedging activities do not attempt to outguess the market and may or may not result in net fuel cost savings, but have achieved the objectives.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 120001-EI

Fuel and Capacity Cost Recovery
January through December 2013

DIRECT TESTIMONY OF JOSEPH McCALLISTER

August 31, 2012

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy. I am responsible for the Natural Gas, Oil and Emissions group activities in the Fuel Procurement Section of Fuels and Systems Optimization Department for Duke Energy. The group is responsible for natural gas and emission allowance acquisition for Duke Energy Indiana ("DEI"), Duke Energy Kentucky ("DEK"), Duke Energy Carolinas ("DEC"), PEF and Progress Energy Carolinas ("PEC") systems. In addition, this position is currently responsible for the fuel oil acquisition for the PEF and PEC systems. The fuel oil procurement management activities for DEC, DEI and DEK are expected to transition into the group throughout the next several months.

Q. Have you previously filed testimony before this Commission?

A. Yes, I have.

Q. Have your duties and responsibilities remained the same since you last testified in this proceeding?

A. Yes. With the completion of the, merger between Progress Energy and Duke Energy, my responsibilities for the Gas, Oil and Emissions activities for PEF and PEC have remained the same. However, with the completion of the merger, I am responsible for the Gas, Oil and Emissions activities for DEI, DEK and DEC. As noted above, the fuel oil procurement management activities for DEC, DEI and DEK are expected to transition into the group throughout the next several months. In addition to these changes, with the merger, I no longer have responsibility for Power Trading activities. These activities are now under a new Section within the Fuels and System Optimization Department.

Q. Please briefly describe your work experience.

A. I joined Progress Energy Service Company in 2003. Prior to my current position at Duke Energy, I served as the Director of Portfolio and Market Risk Assessment through mid 2006, the Director of Gas and Oil Trading from mid 2006 through early 2009, and the Director of Gas, Oil and Power Trading from early 2009 through July 2012. Prior to joining Progress Energy, I spent approximately 10 years in management positions at energy trading and asset generation based companies supporting and managing commercial activities. Summary experience over this time period includes gas and power scheduling, real time power trading, commercial management of gas storage and transportation agreements, commercial management of fuel and power optimization activities for unregulated generation assets, wholesale power agreements, fuel agreements, and corporate planning.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to outline PEF's hedging objectives and activities for 2013, outline PEF's hedging results for January 2012 through July 2012, and summarize PEF's economy purchase and sales savings for the period January 2012 through July 2012.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits:

- Exhibit No. ___ (JM-1P) – 2013 Risk Management Plan *(originally filed on August 1, 2012)*; and
- Exhibit No. ___ (JM-2P) - Hedging Results for January 2012 through July 2012 *(originally filed on August 15, 2012).*

Q. What are the objectives of PEF's hedging activities?

A. The objectives of PEF's hedging strategy are to reduce price risk and provide greater cost certainty for PEF's customers.

Q. Describe PEF's hedging activities that the company will execute for 2013.

REDACTED

A. PEF will hedge a percentage of its projected natural gas and light oil fuel oil burns, and a portion of the estimated fuel surcharge exposure embedded in PEF's coal river barge and railroad transportation agreements. PEF will utilize approved physical and financial agreements. With respect to hedging activity, natural gas represents the largest component of PEF's overall hedging activity given it is the largest fuel cost component. PEF's target hedging percentage ranges are between [redacted] to [redacted] of its current 2013 forecasted calendar annual burns. The current expectation is for PEF to target to hedge a minimum of [redacted] of its forecasted natural gas burn projections for 2013. .With respect to light oil forecasted to be burned at PEF's owned generation facilities for calendar year 2013, during the balance of 2012 and during 2013, PEF will target to hedge a minimum of [redacted] of its forecasted light oil burns for the 2013 calendar period. As outlined in the Risk Management Plan, due to the decline in overall forecasted heavy oil usage for future periods, PEF made the decision not to execute heavy oil hedges for periods beyond 2012. With respect to coal river and rail transportation estimated fuel surcharges, for calendar year 2013 PEF will target to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposure in the coal rail and river barge transportation agreements. Hedging in the ranges will allow PEF to monitor actual fuel burns, updated fuel forecasts and make any adjustments as needed throughout the year.

PEF's hedging activities do not involve price speculation or trying to "out-guess" the market. All hedging transactions are executed at the prevailing market price for any given period that exists at the time the hedging

REDACTED

transactions are executed. The results of hedging activities may or may not result in net fuel cost savings due to differences between the monthly settlement prices and the actual hedge price of the transactions that were executed over time. The volumes hedged over time are based on periodic updated fuel forecasts and the actual hedge percentages for any month, rolling period or calendar annual period may come in higher or lower than the target minimum hedge percentages and hedging ranges because of actual fuel burns versus forecasted fuel burns. Actual burns can deviate from forecasted burns because of variables such as weather, unforeseen unit outages, actual load and changing fuel prices. PEF's approach to executing fixed price transactions over time is a reasonable and prudent approach to reduce price risk and providing greater cost certainty for PEF's customers.

As of August 20, 2012, for 2013 PEF has hedged approximately [redacted] of its forecasted natural gas burns and [redacted] of its forecasted light oil burns. In addition, as of August 20, 2012, for 2013 PEF has hedged approximately [redacted] and [redacted] of its estimated fuel surcharge exposure based on the contractual provisions in the coal rail and river barge transportation agreements, respectively. PEF will continue to execute additional hedges for 2013 throughout the remainder of 2012 and during 2013 consistent with its on-going strategy.

Q. What were the results of PEF's hedging activities for January through July 2012?

REDACTED

A. The Company's natural gas hedging activities for January through July 2012 have resulted in hedges being above the closing natural gas settlement prices for the periods of January 2012 through July 2012 by approximately [redacted]. The Company's overall fuel oil hedging activities have resulted in hedges being below the closing settlement prices for the periods of January 2012 through July 2012 by approximately [redacted]. This overall hedge results were driven primarily as a result of continued declines in natural gas prices after the execution of PEF's 2012 hedging transactions. The hedging activities were executed consistent with its Risk Management Plan. Although PEF's hedging activity did not result in net fuel cost savings, the activities did achieve the objective to reduce the impacts of fuel price risk and provide greater cost certainty for PEF's customers.

Q. What are the results of the economy purchase and sales power activity for January 2012 through July 2012?

A. During the period January 2012 through July 2012, PEF has made economic energy purchases and wholesale power sales to third parties that resulted in net savings of approximately $1.3 million and $0.2 million, respectively.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 120001-EI

GPIF Schedules for January through December 2011

DIRECT TESTIMONY OF ROBERT M. OLIVER

March 15, 2012

Q. Please state your name and business address.

A. My name is Robert M. Oliver. My business address is 410 S. Wilmington St., Raleigh, North Carolina, 27601.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas as Manager of Portfolio Management.

Q. Describe your responsibilities as Manager of Portfolio Management.

A. As Manager of Portfolio Management, I am responsible for managing the development and application of the model, analysis and data used for the short term generation planning. As relates to this process, my duties include responsibility for the preparation of the information and material required by the Commission's GPIF True-Up and Targets mechanisms.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of PEF's GPIF reward/penalty amount for the period of January through December 2011. This calculation was based on a comparison of the actual performance of PEF's 10 GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. ______ (RMO-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 30-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount has been calculated for this period?

A. PEF's calculated GPIF incentive amount is a reward of $1,495,572. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward (penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 18 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

Q. How did you determine Crystal River 3's heat rate performance in 2011 when the unit did not generate any energy nor use any fuel for the twelve month period of January through December 2011?

A. Strictly speaking, the heat rate for Crystal River 3 during 2011 is an undefined value. As described in the Implementation Manual, average net operating heat rate is defined as the fuel burned during the period while the unit is synchronized to the system, exclusive of start-up BTU, divided by the total net generation, exclusive of station use, produced during the period while the unit is synchronized to the system. Because Crystal River 3 never synchronized during 2011, the amount of fuel, zero, divided by the generation, also zero, equals an undefined value. To account for this, Crystal River 3's heat rate performance in its Actual Unit Performance Data table is represented as zero.

Q. How did you adjust the Incentive Points for Crystal River 3's heat rate?

A. Because Crystal River 3, with a zero Net Operating Factor and a zero actual heat rate, has an adjusted heat rate less than zero, it would earn 10 incentive points for beating the lower limit of its target range. However, since Crystal River 3's actual heat rate performance is essentially incalculable, its heat rate incentive point was adjusted to zero to prevent it from earning a reward on this measure.

Q. How did you determine Crystal River 3's availability performance in 2011 and what adjustments were made to its final EAF measure?

A. Crystal River 3 was in a forced outage for all 2011 and all of its 8,760 hours for the year have been logged as FOH, as is reflected in its Actual Unit Performance Data table on page 21 in the exhibits. Since Crystal River 3 was completely unavailable for 2011, its EAF is 0. There were no adjustments made to Crystal River 3's EAF performance.

Q. What is the impact of Crystal River 3's EAF performance on GPIF?

A. Because Crystal River 3's EAF performance is at or below the bottom end of its EAF Range, it earns -10 Equivalent Availability points, incurring the maximum penalty it can receive for EAF performance.

Q. Have you provided the as-worked planned outage schedules for PEF's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 29 of my exhibit summarizes the planned outages experienced by PEF's GPIF units during the period. Page 30 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 120001-EI

GPIF Targets and Ranges for January through December 2013

DIRECT TESTIMONY OF MATTHEW J. JONES

August 31, 2012

Q. Please state your name and business address.

A. My name is Matthew J. Jones. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy as Director of Analytics for Fuels and Systems Optimization.

Q. What are your duties and responsibilities in that capacity?

A. As Director of Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Progress Energy Florida, Inc. ("Progress Energy" or "Company"), as well as Progress Energy Carolinas, Inc., Duke Energy Carolinas, Inc., Duke Energy Indiana Inc., and Duke Energy Kentucky, Inc. My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a B.A. in Anthropology from State University of New York in 2001. From 2001 until 2004, I worked as an Account Representative for National Loop Company in Green Island, NY. From 2004 until 2008, I attended graduate school at Indiana University – Bloomington, where I earned a Master of Business Administration and a Doctor of Jurisprudence, *cum laude*. While at Indiana University, I also studied Comparative and International Law at a study aboard program at Christ Church College at Oxford University. In 2008, I joined Duke Energy as a Commercial Associate, spending a six month rotation working in Business Development Analytics where I worked on Wholesale Ratemaking and another six month rotation in the FERC Legal group where I worked on wholesale contract drafting and compliance issues. In 2009, I entered the Business Development Analytics group where I worked in dispatch pricing, production cost modeling, and fuel burn forecasting for the Duke Energy Carolinas system. In 2010, I entered the Integrated Resource Planning group to help rebuild the Kentucky model in preparation for environmental legislation analysis and later in 2010, I became the Director of Wholesale and Commodities Business Support, where I had the responsibility to manage wholesale ratemaking, dispatch pricing, production cost modeling, fuel burn forecasting, position reporting, budgeting for bulk power marketing, and general analytical support for Fuels Hedging, Bulk Power Marketing, and Wholesale Origination for North and South Carolina, Indiana, and Kentucky. In July of 2012, I become the Director of Analytics for Fuels and System Optimization, where, in addition to the responsibilities outlined in the previous question, I also manage the Contract Administration and Fuels System Support organizations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period of January through December 2011 and also to present the development of the Company's GPIF targets and ranges for the period of January through December 2013. These GPIF targets and ranges have been developed from individual unit equivalent availability and average net operating heat rate targets and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. What GPIF incentive amount was calculated for the period January through December 2011?

A. PEF's calculated GPIF incentive amount for this period was a reward of $1,495,572. Please refer to Robert M. Oliver's testimony filed March 15, 2012 for the details of how this incentive amount was calculated.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. ____ (MJJ-1P) which consists of the GPIF standard form schedules prescribed in the GPIF Implementation

Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This 77-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2013 projection period, the GPIF program includes the following units: Bartow Unit 4, Crystal River Units 4 and 5; and Hines Units 1 through 4. Combined, these units account for 86% of the estimated total system net generation for the period.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my Exhibit No. ___ (MJJ-1P).

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined through a review of three years of monthly data points during the three year period. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage <u>rates</u> can then be converted into an overall equivalent unplanned outage <u>factor</u> (EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%.

The supporting tables and graphs for the target and range rates are contained in pages 41-77 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Were adjustments made to historical unit availability to account for significant anomalies in the historical period?

A. No.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my Exhibit No. ___ (MJJ-1P).

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data within ranges having a 90% confidence level of including all data. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 26-40 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. Were adjustments made to historical heat rates to account for estimated net output changes associated with scrubber and SCR installations?

A. Yes. Historical heat rates for Crystal River units 4 and 5 were restated as if the scrubbers and SCRs were in place during the historical data period prior to the in-service dates of the scrubbers and SCRs.

Q. Please describe the overall impact of the adjustment on the Crystal River Units 4 and 5 heat rate targets.

A. The adjustment raised the heat rate targets, making the targets higher than if using the unadjusted historical average.

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of simulations was made using a production costing model in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2013?

A. The estimated maximum incentive for the Company is $20,720,532. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MJJ-1P).

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2011 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis Young, 1641 Worthington Road, Suite 220, West Palm Beach, Fl 33409.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period January 2011 through December 2011.

Q. Have you included any exhibits to support your testimony?

A. Yes. Exhibit________ (CDY-1) consists of Schedules M1, F1 and E1-B for the Northwest Florida (Marianna) and Northeast Florida (Fernandina Beach) divisions. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period January 2011 through December 2011?

A. For Northwest Florida the final remaining true-up amount is an under recovery of $1,316,601. For Northeast Florida the calculation is an over recovery of $360,592.

Q. How were these amounts calculated?

A. They are the difference between the actual end of period true-up amounts for the January through December 2011 period and the total true-up amounts to be collected or refunded during the January - December 2012 period.

Q. What was the actual end of period true-up amount for January - December 2011?

A. For Northwest Florida it was $251,187 over recovery and for Northeast Florida it was $3,509,614 over recovery.

Q. What have you calculated to be the total true-up amount to be collected or refunded during the January – December 2012 period?

A. Using six months actual and six months estimated amounts, we calculated an over recovery for Northwest Florida of $1,567,788 and an over recovery of $3,149,022 for Northeast Florida, as approved by the Commission in Order No. PSC-11-0579-FOF-EI.

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel clause for each respective division.

Q. Please explain how these costs were determined to be recoverable under the fuel clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the costs included in the fuel clause are directly related to fuel, have not been recovered through base rates, and the fuel related costs are specific to a division rather than related to the consolidated entity. Specifically, as illustrated in item 10 of Order 14546, the costs the Company has included are fuel-related costs that would normally have been recovered through base rates, but were not anticipated or included in the cost levels used to establish the current base rates. Expenditure of these costs was, nonetheless, directly related to issues that resulted in fuel savings for the Company's customers, as I will discuss in greater detail below. To be clear, these costs are not tied to the Company's internal staff involvement in fuel and purchased power procurement and administration. Instead, these costs are associated with external contracts, which were unanticipated in the Company's last rate case, and which, consequently, tend to be more volatile depending upon the issue. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of Fuel costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. What were the costs outside of purchased fuel costs, included in the 2011 true up for Florida Public Utilities Company?

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. and Christensen and Associates for assistance in the development and enactment of three projects/programs designed to reduce their fuel rates to its customers. We had separate types of administrative costs included in our true up for the Northwest division and Northeast division.

Northwest division:

The costs associated with legal and consulting work on the development of the time-of-use (TOU) and interruptible rates are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPU's time of use and interruptible rates, as designed and approved, adjust the fuel costs to customers, but not base rates. As such, the legal and consulting expenses are solely and directly related to the fuel costs and therefore should be recovered through the Fuel and Purchased Power cost recovery clause. Moreover, these costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates. Additionally, the TOU and interruptible rates are available only to Northwest Division customers and the fuel clause provides for recovery of the TOU and interruptible rate related costs from the fuel rates approved for the Northwest Division customers.

The costs associated with the legal and consulting work on the PPA amendment are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPUC purchases all of its power requirements for its Northwest Division from Gulf Power through the existing PPA. FPUC was able to negotiate changes in the PPA that have resulted in measurable fuel savings (approximately $6 million), over the remaining term of the agreement, to the Northwest Division customers. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Northeast Division:

The legal and consulting costs associated with the development and negotiations of the renewable energy contract are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. The Rayonier renewable energy contract will be finalized in early 2012. This contract will provide for the purchase of power at rates lower than the existing Purchase Power Agreement between FPUC and JEA. FPUC expects to realize reduced fuel rates for the Northeast Division customers as a result of this agreement, beginning in mid- 2012. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

Direct Testimony of
Curtis D. Young
(Second Revised Actual/Estimated True-Up)
On Behalf of
Florida Public Utilities

Q. Please state your name and business address.

A. Curtis D. Young, 1641 Worthington Road Suite 220, West Palm Beach, FL 33409.

Q. By whom and in what capacity are you employed?

A. I am employed by Florida Public Utiiities as Senior Regulatory Analyst.

Q. Have you previously testified in this Docket?

A. Yes.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the Company's computations that were made in preparation of the revised schedules that have been submitted to support the calculation of the levelized fuel adjustment factor for January 2013 – December 2013.

Q. Were the schedules filed by the Company completed by you or under your direction?

A. Yes.

Q. Which of the Staff's set of schedules has the Company completed and filed?

A. The Company has filed Schedules E1-A, E1-B, and E1-B1 for the Northwest Division and Northeast Division. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2012 – December 2012 based on 6 Months Actual and 6 Months Estimated data. Revisions to Schedules E1-A, E1-B and E1-B1 for the Northwest Division were originally filed in Revised Composite Exhibit Number CDY-2 submitted on August 30, 2012. For the Northeast Division, the revisions addressed herein are with regards to the testimony only. The related Schedules E1-A, E1-B and E1-B1 are not affected. All schedules are included in Revised Composite Prehearing Identification Number CDY-2 for ease of reference.

Q. What is the final remaining true-up amount for the period January 2011 – December 2011?

A. In the Northwest Division, the final remaining true-up amount was an under-recovery for $1,316,601. In the Northeast Division, the final remaining true-up amount was an over-recovery of $360,592.

Q. What is the estimated true-up amount for the period January 2012 – December 2012?

A. In the Northwest Division there is an estimated under-recovery of $187,139. In the Northeast Division, there is an estimated under-recovery of $104,982.

Q. What is the total true-up amount to be collected or refunded during January 2013 – December 2013?

A. The Company has determined that at the end of December 2012, based on six months actual and six months estimated, the Company will under-recover $1,503,740 and will over-recover $255,610 in purchased power costs in the Northeast Division.

Q. Has the Company included any additional Schedules for consideration and possible approval in this Docket?

A. Yes, the Company had also prepared and included a set of additional Schedules in Composite Exhibit Number CDY-3 for its Northwest Division only, which was originally submitted on August 30, 2012 with revised Composite Exhibit Number CDY-2. The changes addressed by this filing have no impact on Exhibit CDY-3.

Q. For what purpose were these additional Schedules in Composite Exhibit Number CDY-3 being included?

A. The Schedules herein for the Northwest Division Composite Exhibit Number CDY-3 were prepared in light of the City of Marianna's ("City") appeal, filed with Florida Supreme Court, of the

Commission's Order(s) approving Amendment 1 to the Company's Purchased Power Agreement (PPA) with Gulf Power, PAA Order PSC-11-0269-PAA-EI, Order PSC-12-0056-FOF-EI, and Order PSC-12-0081-CO-EI. The Amendment reduces the monthly KW Peak Demand level and resultant costs while extending the Gulf Power Contract for two additional years. Because the status of the Amendment remains uncertain due to the City's appeal, Gulf Power is currently billing the Company at the original calculated Demand level until the Supreme Court has ruled on the City's appeal of the Commission's Order, or the matter is otherwise resolved in a manner that affirms and preserves the Amendment. The City's appeal of the Commission's Order disputes the benefits of the Amendment and its prudency for purposes of cost recovery. The City's appeal is also integrally tied to the City's separate appeal of the Commission's Order(s)(Order PSC-11-0112-TRF-EI, Order PSC 11-0290-FOF-EI, and Order PSC-12-0066-FOF-EI) approving the Company's implemented TOU and Interruptible Service rates, which are supported by the significant demand savings produced by the PPA with Gulf Power Company. The Schedules for Northwest Division Composite Exhibit Number CDY-3 present the Company's calculations of its fuel cost true-up amount to be used in its 2013 fuel cost recovery factors based on the contingency that the PPA is ultimately reinstated before the hearing date in November 2012.

Q. Please advise what would be the total true-up amount to be collected or refunded during January 2013 – December 2013 based on the Company's calculations within the Schedules for Northwest Division Composite Exhibit Number CDY-3?

A. The Company has determined that at the end of December 2012, based on six months actual and six months estimated, The Company will over-recover $3,248 in purchased power costs in the Northwest Division to be refunded during January 2013 – December 2013.

Q. What is the Company requesting with respect to this alternative set of Schedules and related fuel true-up calculations for its Northwest division?

A. The Company requests that the Commission review and consider these schedules for contingency approval if the legal proceedings regarding the Amendment to the Company's PPA with Gulf Power are resolved such that the Gulf Power contract, inclusive of the Amendment No. 1, is reinstated as of the original effective date of the Amendment. In addition, if the resolution of the referenced legal proceedings occurs after the hearing date in the Docket, but in the first half of 2013, the Company requests that the Commission consider these true-up amounts for purposes of a midcourse correction for the reduction of the rates to its customers in the Northwest Division, including the customers within the city limits of Marianna, to be immediately implemented upon notice provided by the Company to the Commission of the Court's reinstatement of Amendment No. 1 as of the original effective date.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2013 Projection Revised Testimony of
Curtis D. Young
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis D. Young, 1641 Worthington Road Suite 220, West Palm Beach, FL 33409.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Analyst. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. Have you previously testified in this Docket?

A. Yes.

Q. What is the purpose of your testimony at this time?

A. As a result of recent reductions in fuel costs from Gulf Power Company, we have re-filed our 2013 fuel projections to reflect the projected decrease. I will briefly describe the basis for the computations that were made in the preparation of the various Revised Schedules that the Company has submitted in support of the January 2013 - December 2013 fuel cost recovery adjustments for its two electric divisions. In addition, I will explain the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2012 – December 2012 and to establish a "true-up" amount to be collected or refunded during January 2013 - December 2013.

Q. Were the schedules filed by the Company completed by you?

A. Yes.

Q. Which of the Staff's set of schedules has your company completed and filed for approval in this Docket?

A. The Company has filed Revised Schedules E1, E1A, E2, E7, and E10 for the Northwest Division and E1, E1A, E2, E7, E8, and E10 for the Northeast Division. Revised Composite Exhibit Number CDY-4 contains this information.

Q. Did you follow the same procedures that were used in the prior period filings in preparing the projected cost factors for January – December 2013 for both the Northwest and Northeast Divisions?

A. Yes, the Company has generally used the same methodology as in prior period filings; however, in this filing it has made some changes in the process. The Company had, in previous filings, utilized data for the Northeast Division that was obtained from a 2010 Florida Power and Light ("FP&L") Load Research Study to allocate demand costs to the various Northeast Division rate classifications. Similarly, the Company had utilized 2009 Load Research Study data obtained from Gulf Power to allocate demand costs to the various Northwest Division rate classifications. As is further explained in this testimony, the Company has adopted a more representative method for allocating costs to the rate classifications for each Division.

Northwest Division

Purchased Power Amendment (PPA) with Gulf Power Company

Q. Has the Company included any additional Schedules for consideration and possible approval in this Docket?

A. Yes, the Company has also included and prepared a set of additional Schedules in Revised Composite Exhibit Number CDY-5 for its NW division only.

Q. For what purpose were these additional Schedules in Revised Composite Exhibit Number CDY-5 being included?

A. The Schedules herein for the Northwest Division Revised Composite Exhibit Number CDY-5 were prepared in light of the City of Marianna's ("City") appeal, filed with the Florida Supreme Court, of the Commission's

Order(s) approving Amendment 1 to the Company's Purchased Power Agreement (PPA) with Gulf Power, PAA Order PSC-11-0269-PAA-EI, Order PSC-12-0056-FOF-EI, and Order PSC-12-0081-CO-EI. The Amendment reduces the monthly KW Peak Demand level and resultant costs while extending the Gulf Power Contract for two additional years. Because the status of the Amendment remains uncertain due to the City's appeal, Gulf Power is currently billing the Company at the original calculated Demand level until the Supreme Court has ruled on the City's appeal of the Commission's Order, or the matter is otherwise resolved in a manner that affirms and preserves the Amendment. The City's appeal of the Commission's Order disputes the benefits of the Amendment and its prudency for purposes of cost recovery. The City's appeal is also integrally tied to the City's separate appeal of the Commission's Order(s) (Order PSC-11-0112-TRF-EI, Order PSC-11-0290-FOF-EI, and Order PSC-12-0066-FOF-EI) approving the Company's implemented TOU and Interruptible Service rates, which are supported by the significant demand savings produced by the PPA with Gulf Power Company. The Schedules for Northwest Division Revised Composite Exhibit Number CDY-5 present the Company's calculations of its fuel cost recovery factors based on the contingency that the PPA is ultimately reinstated before the hearing date in November 2012.

Q. What is the Company requesting with respect to this alternative set of

Schedules and related fuel adjustment rates for its Northwest division?

A. The Company requests that the Commission review and consider these schedules for contingency approval if the legal proceedings regarding the Amendment to the Company's PPA with Gulf Power are resolved such that the Gulf Power contract, inclusive of the Amendment No. 1, is reinstated as of the original effective date of the Amendment. In addition, if the resolution of the referenced legal proceedings occurs after the hearing date in this Docket, but in the first half of 2013, the Company requests that the Commission consider these rates for purposes of a mid-course correction for the reduction of the rates to its customers in the NW division, including the customers within the city limits of Marianna. The midcourse correction for the reduction of rates would be immediately implemented as soon as practical, upon notice provided by the Company to the Commission of the Court's reinstatement of Amendment No. 1 as of the original effective date.

Northeast Division including Demand Allocation Method

Q. Please explain the methodology that the Company has used to calculate the Northeast Division levelized fuel adjustment factor?

A. The Company's methodology to calculate the levelized fuel adjustment factor for the Northeast Division is generally the same as in previous filings. The Company obtains cost information from its purchased power supplier and utilizes this information to project the total purchased power costs (energy and demand costs) for 2013. The Company projects other expenses directly related to the Company's efforts to reduce fuel costs, including but not limited to consulting services incurred to negotiate contracts, other fuel related work and legal representation outside of costs already embedded in the Company's base rates. The Company also projects the over or under recovered amount at the end of 2012. In addition, the Company projects its expected KWH sales to customers in 2013. Based on these projections, the Company has calculated the required levelized fuel adjustment for each rate class that recovers the expected purchased power costs in 2013, as shown in Revised Composite Exhibit Number CDY-4. As has historically occurred, the GSLD1 and Standby rate classifications are directly assigned its expected purchased power costs.

Q Why does the Company directly assign the GSLD1 and Standby rate classes purchased power costs?

A. The Company directly assigns the purchased power costs to the GSLD1 and Standby rate classifications' only two customers because they both have the capability to generate their own power. Both customers only purchase power sporadically from the Company, generally when they have an outage of their power generation facilities. It is not feasible to produce a levelized fuel rate for this rate classification that appropriately allocates costs. Demand and other purchased power costs are assigned to the GSLD1 and Standby rate classes directly based on their projected CP KW and KWH consumption. This procedure for the GSLD1 and Standby classes has been in use for several years and has not been changed herein. Costs to be recovered from all other Northeast Division rate classifications are determined after deducting from total purchased power costs those costs directly assigned to the GSLD1 and Standby rate classifications.

Q. Who does the Company purchase power from for the Northeast Division?

A. The Company purchases power from Jacksonville Electric Authority ("JEA") for the Northeast Division. Effective January 1, 2008, the Company executed an Amended and Restated Electric Service Contract with JEA (the "JEA Contract") which has a term of ten years.

Q. What impact has the JEA Contract had on the Company's levelized fuel rates and customer consumption?

A. Prior to 2008, the Northeast Division had some of the lowest rates in the state, well below the other IOU's in the state. However, the JEA Contract resulted in higher prices that more closely reflect the then-current market conditions and pricing. As a result of higher fuel rates and the down turn in the economy, the Company has experienced significant usage reductions from its customer base. As a result of demand activity and weather patterns unique to the Northeast Division, the Company believes that the previous method of allocating demand costs to rate classifications, which utilized FP&L's 2010 Load Research Data, is no longer the most accurate basis for this purpose.

Q. What basis has the Company used to allocate the JEA demand costs in this filing?

A. The Company has engaged Christensen Associates Energy Consulting ("CA") to develop recommendations for a method to allocate demand costs to the various rate classifications. CA has completed this task and has provided a report to the Company (the "CA Report"). The Company's demand allocation method developed by CA has been utilized in our Projection filing and is shown on Schedule E1 of Revised Composite Exhibit Number CDY-4. The CA Report details the empirical data that forms the basis for the Company's conclusion that the FP&L Load Research Data is not the most accurate basis for use in allocating demand costs for the Northeast Division. The CA Report provides further empirical data that demonstrates that the Gulf Power load research data is a better fit for use to allocate demand costs for the Northeast Division, and is detailed in the testimony and related exhibit of Mr. Robert Camfield, consultant with CA.

<u>Northwest Division including Demand Allocation Method</u>

Q. Please explain the methodology that the Company has used to calculate the Northwest Division levelized fuel adjustment factor?

A. The Company's methodology to calculate the levelized fuel adjustment factor for the Northwest Division is generally the same as in previous filings. The Company obtains cost information from its purchased power supplier and utilizes this information to project the total purchased power costs (energy and demand costs) for 2013. The Company also projects the over or under recovered amount at the end of 2012. The Company projects other expenses directly related to the Company's efforts to reduce fuel costs, including but not limited to consulting services incurred to negotiate contracts and other fuel related work and legal representation outside of costs already embedded in the Company's base rates. In addition, the Company projects its expected KWH sales to customers in 2013. Based on these projections, the Company has calculated the required levelized fuel adjustment for each rate class that recovers the expected purchased power costs in 2013, as shown in Revised Composite Exhibit Numbers CDY-4 and CDY-5.

Q. Who does the Company purchase power from for the Northwest Division?

A. The Company purchases power from Gulf Power Company ("Gulf Power") for the Northwest Division. Effective January 1, 2008, the Company executed an Agreement for Generation Services Between Gulf Power Company and Florida Public Utilities Company with Gulf Power (the "Gulf Power Contract") which has a term of ten years. Revised Composite Prehearing Identification Number CDY-4 contains cost information utilizing this Contract. On January 25, 2011, the Company entered into

Amendment No. 1 to the Gulf Power Contract, which, among other things, reduced the KW Peak Demand provision while extending the Gulf Power Contract for two additional years. Revised Composite Exhibit Number CDY-5 contains cost information utilizing this Amendment to the Contract. If this amendment is reinstated, the rates contained within this Exhibit will be more appropriate for the Northwest division's customers.

Q. What impact has the Gulf Power Contract had on the Company's levelized fuel rates and customer consumption?

A. Prior to 2008, the Northwest Division had some of the lowest rates in the state, well below the other IOU's in the state. However, the Gulf Power Contract resulted in higher prices that more closely reflect the then-current market conditions and pricing. As a result of higher fuel rates and the down turn in the economy, the Company has experienced significant usage reductions from its customer base. As a result of demand activity, economic and demographic profiles of customers and weather patterns unique to the Northwest Division, the Company believes that the previous method of allocating demand costs to rate classifications, which utilized Gulf Power's 2009 Load Research Data, is no longer the most reasonable basis for this purpose.

Q. What basis has the Company used to allocate the Gulf Power demand costs in this filing?

A. The Company has engaged Christensen Associates Energy Consulting

("CA") to develop recommendations for a method to allocate demand costs to the various rate classifications. CA has completed this task and has provided a report to the Company. The Company continues to utilize Gulf Power's load Research Data, but has adjusted the application with use of a Statistical method to more appropriately reflect the weather patterns and the economic and demographic profiles unique to its customers as well as slightly changed the application of one group of customers within the study. The Company's demand allocation method developed by CA has been utilized in our Projection filing and is shown on Schedule E1 of Revised Composite Exhibit Numbers CDY-4 and CDY-5. Further explanation of this method and the reasons that it is more appropriate to use the statistically adjusted Gulf Power's load research data as a base for use in the NW division is provided in the testimony and related exhibit of Mr. Robert Camfield, consultant with CA.

Summary Rates

Q. What are the final remaining true-up amounts for the period January – December 2011 for both Divisions?

A. In the Northwest Division, the final remaining true-up amount was an under-recovery of $1,316,601. The final remaining amount for the Northeast Division was an over-recovery of $360,592.

Q. What are the estimated true-up amounts for the period of January –

December 2012?

A. In the Northwest Division, there is an estimated under-recovery of $187,139. The Northeast Division has an estimated under-recovery of $104,982.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2013 year?

A. The Company has determined that at the end of December 2012 based on six months actual and six months estimated. We will have under-recovered $1,503,740 in purchased power costs in our Northwest Division. Based on estimated sales for the period January - December 2013, it will be necessary to add .45374¢ per KWH to collect this under-recovery. In our Northeast division we will have over-recovered $255,610 in purchased power costs. This amount will be refunded at .07673¢ per KWH during the January - December 2013 period (excludes GSLD1 and Standby customers). Page 3 and 10 of Revised Composite Exhibit Number CDY-4 provides detailed calculations of the respective true-up amounts.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period?

A. In the Northwest Division the total fuel adjustment factor as shown on Line 33, Schedule E-1 is 5.790¢ per KWH. In the Northeast Division the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule

E-1, is 6.420¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2013 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on Schedule E-10 in Composite Exhibit Number CDY-4, a residential customer in the Northwest Division using 1,000 KWH will pay $137.35, a decrease of $.97 from the previous period. In the Northeast Division a residential customer using 1,000 KWH will pay $134.40, an increase of $5.33 from the previous period.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2013 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier if the contract amendment is reinstated with Gulf Power Company.

A. Pending successful resolution between of the litigation between the City of Marianna, and the Company, as shown on Schedule E-10 in Composite Exhibit Number CDY-5, a residential customer in the Northwest Division using 1,000 KWH will pay $129.94, a decrease of $4.70 from the previous period.

Q. Are there any additional documents that the Company has included in this filing?

A. The Company has also included sets of additional Schedules in Composite Exhibit Number CDY-6 (Northwest and Northeast divisions) and CDY-7 (Northwest division only). These schedules have been included for informational purposes for the Commission staff's review. They are identical to Exhibits CDY-4 and CDY-5 except that they have been prepared to exclude the new methodology for allocating demand; these schedules utilize the prior method approved for allocating demand. The Company has included these schedules to allow the Commission staff the ability to review the requested demand allocation methodology, and the related impact to customer's rates. The Company is not requesting approval of the rates associated with these two exhibits and feel the new demand allocation methodology is the more appropriate methodology for its customers and the fuel rates for 2013.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2013 Projection Testimony of
Cheryl Martin
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Cheryl Martin, 1641 Worthington Road Suite 220, West Palm Beach, FL 33409.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company (FPUC) as the Director of Regulatory Affairs for the Company.

Q. Can you please provide a brief overview of your educational and employment background?

A. I have been employed by FPUC since 1985 and performed numerous accounting and regulatory roles and functions including regulatory accounting (Fuel, PGA, conservation, rate proceedings, Surveillance reports, regulatory reporting), tax accounting, external reports, corporate accounting and Florida accounting. In August 2011 I was promoted to my current position of Director of Regulatory Affairs. I have been an expert witness for numerous proceedings before the Florida Public Service Commission (FPSC). I graduated from Florida State University in 1984 with a BS degree in Accounting. Also, I am a Certified Public Accountant in the state of Florida.

Q. Have you previously testified in this Docket?

A. Yes. I have provided testimony in this proceeding on behalf of Florida Public Utilities on numerous occasions in past years.

Q. What is the purpose of your testimony at this time?

A. To discuss the reasons that "other fuel costs" are appropriate for inclusion in the fuel cost recovery clause and fuel rates.

Q. In Curtis Young's testimony he stated that the Company projects other expenses directly related to the Company's efforts to reduce fuel costs, including but not limited to consulting services incurred to negotiate contracts, other fuel related work and legal representation outside of costs already embedded in the Company's base rates; please explain why these costs are recoverable through the fuel clause?

A. By Order No. 14546, in Docket No. 850001-EI-B, issued July 8, 1985, specific criteria was set forth for establishing the type of expense eligible for recovery through the fuel and purchased power cost recovery clause. Subsequently on December 23, 2005, the Commission, through Order No. PSC-05-1252-FOF-EI in Docket No. 050001-EI, approved recovery of the consulting fees paid to Christensen and Associates for the design of the RFP and subsequent evaluation of the responses through the fuel clause mechanism. Consistent with the Commission's policy, the costs included in the fuel clause are not tied to the Company's internal staff involvement in fuel and purchased power procurement and administration. Instead, these costs are associated with external contracts, which were unanticipated in the Company's last rate case, and which, consequently, tend to be more volatile depending upon the issue. The projected costs associated with legal and consulting work included in this filing are similar to the consulting fees approved through the aforementioned Order and to costs approved for recovery in the Company's prior years' true-ups in that they are directly related to fuel costs and the fuel clause, were not routine expenses nor were they included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Q. Specifically, what were the costs outside of purchased fuel costs included in the prior years' true-up for FPUC and deemed recoverable in the fuel clause?

A. Florida Public Utilities engaged Gunster, Yoakley & Stewart, P.A. and Christensen and Associates for assistance in the development and enactment of three projects/programs designed to reduce fuel rates to its customers. The Company had separate types of administrative costs included in the true-up for the Northwest Division and Northeast Division.

Northwest Division-Other

The costs associated with the legal and consulting work on the Purchased Power Amendment are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPUC purchases all of its power requirements for its Northwest Division from Gulf Power. FPUC was able to negotiate changes in the PPA with Gulf Power that have resulted in substantial and measurable fuel savings (approximately $6 million), over the remaining term of the agreement, to the Northwest Division customers. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

As a result of the above-described PPA Amendment and the resultant demand savings, the Company was able to develop and gain approval of certain time-of-use and interruptible rates. As such, these two items, the PPA Amendment and TOU/Interruptible rates, are inextricably linked. As such, the costs associated with legal and consulting work on the development of the time-of-use (TOU) and interruptible rates are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. FPU's time of use and interruptible rates, as designed and approved, have two purposes: 1) to determine how the substantial PPA Amendment savings get allocated to customers, both those that voluntarily select the TOU/Interruptible rates and those who remain on the levelized fuel rates; and 2) to preserve the savings achieved by the PPA Amendment. TOU and interruptible rates exist precisely to reduce peak demands on the system and therefore are specifically implemented to ensure that the PPA Amendment savings are sustainable. Base rates were not affected by the TOU/Interruptible rates. As such, the legal and consulting expenses are solely and directly related to the fuel costs and therefore should be recovered through the Fuel and Purchased Power cost recovery clause. Moreover, these costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates. Additionally, The TOU and interruptible rates and the related rate savings derived from the PPA Amendment are available only to Northwest Division customers and the fuel clause provides for recovery of the TOU and interruptible rate related costs from the fuel rates approved for the Northwest Division customers.

<u>Northeast Division-Other</u>

The legal and consulting costs associated with the development and negotiations of the renewable energy contract are appropriate for recovery through the Fuel and Purchased Power cost recovery clause. The Rayonier renewable energy contract, finalized and approved by PSC

Order earlier this year, provides for the purchase of power at rates lower than the existing Purchase Power Agreement between FPUC and JEA. FPUC expects to realize reduced fuel rates for the Northeast Division customers as a result of this agreement. These savings have been included in the 2013 Projections. These costs were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

Testimony of
Robert J. Camfield
(Allocation Methodology)
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Robert J. Camfield, and my business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705.

Q. By whom are you employed and what is your position?

A. I hold the position of Vice President with Christensen Associates Energy Consulting.

Q. What is the purpose of your testimony?

A. My testimony is focused on two related topics. First, my testimony presents the results of a study that addresses the appropriateness of the use of load research results of Florida Power and Light (FPL) and Gulf Power Company (Gulf Power), for the purpose of allocation of the wholesale demand charges incurred by Florida Public Utilities Company to retail customer classes of its Northeast and Northwest Divisions respectively. Second, for the consideration of the Florida Public Service

Commission and Staff, the testimony advances modest yet important changes to Florida Public Utilities Company's (FPU, Company) current approach for allocation of wholesale demand charges to customer classes. The recommended changes to the current approach draw from the results and technical analyses reported in the study.

Q. Can you please provide a brief overview of your professional background?

A. Yes. The scope of my professional work is focused on the energy industry and includes cost of capital and valuation, regulatory economics, economic analysis, and cost allocation. For over thirty years, I have been involved in numerous technical and policy issues facing energy utilities including electric and gas utilities. In both formal evidentiary proceedings and less formal settings before regulatory authorities, I have made appearances on behalf of consumer advocacy groups, transmission and distribution companies, RTOs, integrated electric utilities, generation companies, regulatory agencies, and utility associations. I have provided testimony on a variety of topics including power supply contracts, transmission congestion, marginal costs and cost allocation, tariff design and rate phase-in plans, corporate performance and cost benchmarking, and load and energy forecasts. My consulting assignments include the management of power procurement solicitation, and wholesale market restructuring. I have contributed materials to noted industry journals such as *The Electricity Journal* and *IEEE Transactions on Power Systems*, and presented papers before the *Council on Large Electric Systems*. I served as Program Director for the Edison Electric Institute's *Market Design and Transmission Pricing School*, 1999–2008. I have held the position of chief economist for a regulatory agency, and system economist for a large, integrated electric service provider. I hold a masters degree in economics from Western Michigan University, and I am a graduate of Interlochen Arts Academy.

Q. Have you previously testified in this Docket?

A. No, though I have filed testimony in fuel and non-fuel related dockets of the Florida Public Service Commission (Florida PSC) in previous years.

Q. Please provide background for the Company's proposed adjustments to the cost allocation methodology.

A. Under long-term contracts, the Company purchases generation and transmission services in wholesale power markets. The charges for purchased power and transmission services include energy and demand charges. In turn, the wholesale demand charges are allocated to retail customer classes. My testimony briefly describes the basis for the proposed fuel demand allocation computations that are used in the preparation of the various fuel projection schedules that the Company has submitted in support of the proposed January–December 2013 fuel cost recovery factors of the retail tariffs of the Company's two electric divisions, FPU Northeast and FPU Northwest.

Q. What are the Company's proposed adjustments to the method for allocation of demand charges recovered in retail fuel charges?

A. As mentioned above, FPU is proposing to incorporate modest but important modifications to the current approach to demand charge allocation, for the 2013 fuel rates. The proposed approach continues to utilize the Company's framework and structure of 2012 and earlier years, but with modified load factors. For 2013 forward, the proposed changes are threefold. First, the Company proposes to apply the load research results for the residential and business classes (GS, GSD, and GSLD) of Gulf Power to the Northeast Division in lieu of the corresponding load factors drawn from FPL's load research. Second, the load factor of Gulf Power's GSD class, also obtained from Gulf's load research, is applied to FPU's GS class in both the Northeast and Northwest Divisions. Third, the load factor estimated from Gulf Power's residential class is adjusted (increased) for FPU Northwest in order to account for clear differences in the residential load profile between the two utilities, driven by differences in economic and demographic conditions.

Q. To start, please describe the current demand allocation methodology used by Florida Public Utilities Company.

A. Currently, for FPU's Northeast and Northwest Divisions, the Company utilizes annual load factors obtained from the load research results reported to the Florida PSC. For the Northeast Division, FPU utilizes the load factors reported by FPL; for the Northwest Division, load factors are drawn from the load research reported by Gulf Power. Specifically, the two neighboring utilities report annual load factors, obtained through respective sample load research efforts, for each of the main customer classes including the Residential Class (RS) as well as main business classes, General Service (GS), General Service Demand (GSD), and Large General Service (GSLD), sometimes referred to as Large Power. The load factors reported by FPL and Gulf Power are assigned to the similarly defined customer classes of the Company's Northeast and Northwest Divisions respectively.

Q. Has not this approach worked acceptably well? What are the concerns that cause the Company to purpose an alternative methodology?

A. The Company has followed the current approach for several years. Since the Chesapeake acquisition, the Company has harbored concerns about the applicability of the load research results of FPL and Gulf Power to the retail electricity markets in the areas served by its Northeast and Northwest Divisions respectively. Retail class loads can be described in several ways, such as energy sales, seasonality of sales, peak loads, load factors, and load profiles sometimes referred to as load curves. Electricity class loads in turn are influenced by commonly recognized causal factors including weather patterns, household income and related demographic characteristics, employment, housing and building stock indicators, sector composition of the underlying regional economy, and the level of retail electricity prices.

Providing that key attributes of the FPL and Gulf Power service territories are sufficiently similar to the areas served by FPU's Northeast and Northwest Divisions, it is arguably appropriate to apply load research results of FPL and Gulf Power to FPU's electricity divisions, other factors constant. The Company's concerns can be succinctly expressed as two fundamental questions, as follows:

1) Are the economies, demographic characteristics, and weather patterns of the larger geographic areas of FPL and Gulf Power sufficiently similar to the areas served by the Company, insofar as load research results to a substantial degree reflect these causal factors?

2) If FPL and Gulf Power territories are found to be dissimilar from the areas served by FPU's Northeast and Northwest Divisions in important ways, what corrective actions are available in order to ensure that a fair cost allocation result across retail classes is achieved?

Essentially, should significant differences be found, it is necessary to consider alternative methods? For this reason, my testimony and accompanying exhibits as well as the supporting study (Study Report, Exhibit RJC-7), upon which the testimony is based, present a comparative assessment of key features of the regions—predominantly focusing on weather, economic, and demographic characteristics as well as supporting statistical analyses. This assessment is used to determine the structure of the proposed adjustments to the current method of demand charge allocation.

SUMMARY OF STUDY FINDINGS AND RECOMMENDATIONS

Q. Please summarize your testimony, including key findings of the Study Report to which you refer, and the proposed adjustments.

A. A summary of the findings contained in the Study Report and my recommendations are as follows:

For the Northeast Division: A comparison of weather patterns for the Northeast region and FPL's service territory is shown in Exhibit RJC-1, including two tables (Tables 2 and 3 of the Study Report). The first table presents heating degree days (HDDs) and the second table presents cooling degree days (CDDs). With the HDD's serving as a proxy for the demand for spatial heating, the heating loads of the two regions are likely to be remarkably different, with the heating loads for FPU Northeast (proxied by Jacksonville) 2.4 times that of the FPL region (1,350 HDDs vs. 554 HDDs). CDDs present similar though less dramatic differences: the cooling loads for the area served by FPU Northeast are 21% less than the corresponding loads for the FPL region, using the Jacksonville proxy (3,392 CDDs vs. 2,664 CDDs). Recognizing that the weather for Fernandina Beach suggests somewhat less variation, substantial differences in weather patterns are present. The variation is particularly important for the Northeast insofar as peak demands driving demand charges are specific to month regardless of season. Thus, winter weather differences matter.

It is not surprising to find that, in contrast, the comparison of weather patterns (HDDs, CDDs) for the FPU Northeast and Northwest Florida regions reveal remarkably similarity. The annual average HDDs for Jacksonville (JAX) and Fernandina Beach (F B) are 1,350 and 1,215, respectively, while Pensacola (PEN) is 1,537. Cooling demands are also similar, with 2,664 and 2,803 for Jacksonville and Fernandina Beach respectively; and 2,609 for Pensacola. Also, weather data for other locales in northern Florida paint a similar picture.

In brief, because weather is the major determinant of the level and profile of class loads, it is appropriate for FPU to consider the use of the load research results of Gulf Power for demand charge allocation for the Northeast Division, as opposed to the load research results of FPL.

For the Northwest Division: The analyses include a comparison of economic indicators and demographic characteristics of the region served by FPU's Northwest Division with respect to Gulf Power. The comparison focuses primarily on housing stock and economic indicators, and the implications for the underlying load factor. Summary results are shown in Exhibit RJC-2, and are further supported by a series of tables incorporated within the body of the Study Report (Report Tables 8, 11–12 and 14). For the Northwest Division and Gulf Power, pages 1 and 2 of Exhibit RJC-3 present a comparison of the housing stock and economic measures including household income and the incidence of poverty. Additionally, page 2 of the same Exhibit presents a comparison of the age distribution and household type, measured in terms of the proportion of elderly (aged 65 and above) living alone. The main finding is, predominantly because of comparatively low levels of household incomes, much higher shares of the housing stock in the Northwest area are mobile homes and older vintage stationary dwellings, when compared to the Gulf Power region.

Mobile and older vintage homes have a much higher saturation of window air conditioning (A/C) units for spatial cooling than more contemporary stationary homes. Because of the cycling patterns inherent to window A/C units, the residential load profile for the Northwest Division is significantly less sensitive to changes in summer temperatures during very high temperature, peak load days. This conclusion is reinforced by two types of statistical analyses contained in our Study Report (Section III.B and III.C of the report), which assess the relationships between loads, temperature and residential energy shares. The first analysis applies regression methods to determine the relationships between daily peak loads and a temperature index, and confirms the declining impact of temperature on peak loads. In other words, we find that the sensitivity of hourly system loads of the Northwest Division to be significantly less, during summer top load days than during less than the highest load days. For the Northwest Division, the sensitivity of loads to temperatures rises as progressive lower load days are incorporated into the analysis sample. Further details regarding the methodology and findings are provided later on in this testimony (named Statistics 1-Based Analysis). A snapshot of the main results of this analysis is shown on page 1 of Exhibit RJC-3.

The second analysis using regression methods to estimate the relationship between the weather-normalized system load factor and the residential class share of total energy share, for the Northwest Division. This second analysis finds that, as expected, a decrease in residential energy share within the total sales of Northwest increases (improves) the system load factor. This result is fully consistent with expectations: because the load factor of the residential class is above that of the Northwest system as a whole, decreases in the residential energy causes the system load factor to rise, a result that is confirmed by real world experience over recent years. The main results of this analysis are shown on page 1 of Exhibit RJC-4. Further details regarding the methodology and findings are provided later on in this testimony (referred to as Statistics 2-Based Analysis). In brief, the conclusion reached from the demographic and housing stock differences shown on Exhibit RJC-2 between FPU Northwest Division and Gulf Power have, historically, likely resulted in an overstatement of peak demand impacts attributable to the residential customer classification under the current demand allocation method. Thus, I believe that certain modifications to the Gulf Power Load Research data for demand allocation is appropriate.

RECOMMENDED ADJUSTMENTS TO COST ALLOCATION METHOD

Q. Please detail the proposed adjustments to the Company's cost allocation methodology.

A. In view of the above findings, reached from the comparative and statistical analyses contained in the Study Report. I propose that certain adjustments be incorporated into FPU's current framework for the allocation of wholesale demand charges. The recommendations are as follows:

Load Research of Gulf Power Applied to the Northeast Division: As discussed above, because of similar weather patterns of the underlying regions of these utilities, the load research results of Gulf Power are likely to be a better match to the Company's Northeast Division than the currently used load research of FPL. Consequently, I recommend using the load research results of Gulf Power as the basis for allocation of demand charges, for the Northeast Division.

Load Research Results of Gulf Power's GSD Class Assigned to GS Class, FPU Northeast and Northwest Divisions: For the main customer classes of the two divisions of FPU and Gulf Power, pages 1 and 2 of Exhibit RJC-5 presents calculations of average monthly energy, for months with low shares weather sensitive loads (March, April, and

November) and months with higher shares of weather sensitive months. Weather sensitive months are grouped into summer and winter groups. The tables present the ratios of the weather sensitive loads to the loads for low weather sensitive months. The analysis is presented for the Northeast and Northwest Divisions, each of which is compared to Gulf Power. As shown, for summer months of both Divisions, the ratio of weather sensitive to non-weather sensitive monthly energy for Gulf Power's GSD class is a better match to FPU's GS class than Gulf Power's GS class. This change in the assignment of Gulf Power's class load research results to FPU is important insofar as differences in weather sensitive loads have inverse though non-linear effects on load profiles and the estimated class load factors (effects are differentiated between summer and winter seasons). Accordingly, I recommend that Gulf Power's GSD load factors be assigned to the GS class, for both the Northeast and Northwest Divisions.

Adjustment to the Residential Load Factor, Northwest Division: As mentioned above, the residential class of the Northwest Division has high shares of mobile and older stationary homes within the housing stock. Because of the resulting high concentration of window air conditioners, the share of total monthly energy determined by the demand for spatial cooling (A/C loads) is comparatively small during summer months—

particular peak load days—when compared to Gulf Power. This result, as demonstrated by the ratio of weather to non-weather sensitive monthly energy ratios (above), as well as the statistical analysis outlined earlier in the testimony affirms that an adjustment is in order. The proposed adjustment mechanism results in a 2.557 MW reduction in the implied coincident peak demand for the residential class for the Northwest Division, approximately 7–8%. Arguably, the analyses contained in the Study Report suggest this proposed adjustment amount is somewhat conservative.

Q. As you mention, the Study Report appears to demonstrate that the weather of the regions served by FPU Northeast and FPL are not well matched. Please discuss in detail, focusing on why Gulf Power load research is better matched to the Northeast.

A. Exhibit RJC-1 discussed above reveals exceptionally high similarity in the weather patterns of FPU (Jacksonville and Fernandina Beach) and Northwest Florida, with Pensacola serving as an appropriate proxy for Gulf Power. We could, of course, incorporate within our Study Report the historical weather experience (HDDs and CDDs) for other locations across Florida's northern tier; results show further similarity. To conclude, the weather locales of the northern tier including areas served by Gulf Power are much better matched to the Northeast Division. The recommendation—use Gulf Power's load research results—logically follows.

I should mention that, generally speaking, county-population weighted economic and demographic indicators of FPL and Gulf Power appear to be similar, with both regions somewhat differentiated from Nassau County, located in northeast Florida, though such a comparison is not incorporated within the Study Report. However, we infer that, for these comparison metrics, Nassau county may not be a particularly good proxy for FPU's Northeast Division.

Q. Your comparative analysis of the underlying economies of FPU's Northwest Division and Gulf Power summarized above suggest major differences. Please elaborate.

A. The comparative analysis detailed in the Study Report has major implications for the levels and profiles of residential loads, as mentioned. We were initially surprised by the magnitude of the differences in the underlying economic indicators and demographic characteristics, particularly in view of the reasonably close proximity of much of Gulf Power's region to the counties served by FPU Northwest. It is thus appropriate to fully discuss how these differences, including household income, housing stock, employment, incidence of poverty, age composition, and educational attainment, translate into load differences between the residential classes for the Northwest and Gulf Power.

As affirmed by the statistical analysis, discussed below in detail (Section III.B of the Study Report), we find that these differences contribute to, and will likely cause, systematic bias in the estimates of residential peak demands for the Northwest Division, if unadjusted residential load factors, obtained from Gulf Power load research, are applied to the residential energy consumption of the Northwest Division. On this point, quantitative evidence is presented in pages 1 and 2 of Exhibit RJC-2, mentioned above. In particular, households in the Northwest have some three times the percentage share of mobile homes as households in the region served by Gulf Power. Moreover, the survey data are confirmed by direct observation, and is consistent with, and supported by, the larger share of comparatively low income households within the Northwest.

The implication is a truncated peak load-to-average energy ratio for FPU Northwest residential customers, as mobile homes predominantly use window A/C. Experience analyzing loads and temperatures provide the basis to infer the underlying reasons for the attenuated impacts of residential loads for the Northwest Division at very high levels of summer temperatures. First, window A/C units typically provide only compromised capability to manage exceptional temperatures, whereas central A/C units tend to be installed with capacity that approximates or exceeds expected maximum requirements. As a consequence, window A/C units will typically run up against constraints on output levels well before the peak hours on the hottest days. Conversely, central A/C units of stationary homes are often oversized; the spare capacity implies that usage continues to climb with temperatures, rather than reaching a plateau. Hence, loads on peak temperature days for window units are typically not much higher than the peak usage on cooler days.

Second, with central A/C, peak days lead to substantially higher loads when the A/C is 'over-designed', especially since unit efficiency tends to decline as temperatures increase. Third, households with central A/C units tend to be programmed to increase the cooling levels prior to residents returning home during week days, leading to more cooling demand during the peak hours of power systems, and less in the periods immediately before and after the peak hours. Fourth, single individual households (living alone and "at home" during mid-day hours) will tend to have reduced differences between average and peak hour loads during peak temperature days. As shown within the Study Report as well as in Exhibit RJC-2, the Northwest Division has a higher share of residential customers that are both older and living alone.

Q. Earlier, you indicated that the change in the estimated coincident peak demand for the residential class of the Northwest Division should be adjusted downward by 2,557 kW. How is this adjustment obtained?

A. The adjustment amount of 2,557 kW is obtained from the estimates obtained through statistical analyses including, for the Northwest Division, the regression analysis of: 1) daily system peak summer loads on temperatures, and 2) weather-normalized system load factor on residential energy shares. These two analyses, referred to as Stats 1 and Stats 2, respectively, are described in some detail within the Study Report (Sections III.B and III.C respectively of Exhibit RJC-7). The estimated equation from the Stat 1 analysis is presented on page 1 of Exhibit RJC-3; the Stat 2 equations are presented on page 1 of Exhibit RJC-4.

Statistics 1-Based Analysis: The overall findings from the comparative assessment of the Northwest Division and Gulf Power regions suggested that there is likely to be a greater prevalence of window air conditioner (A/C) units across FPU Northwest customers than within the Gulf Power residential class. The implication is a truncated peak load-to-average energy ratio for FPU Northwest customers, which can be seen in a plot of loads against temperature, which unequivocally demonstrates concavity toward the top end of the load-temperature function. This declining impact of temperature on peak loads has been substantiated by regression analysis of the daily peak load for FPU Northwest on an index of daily temperatures, plus three sets of binary variables for the maximum hour of the day, year and the beginning and end of the week. The analysis uses data for 11 years (1999–2010, excluding 2005), and the data is sorted in two ways, by temperature index and maximum usage (we primarily use the results of the maximum usage regressions). Regressions were run on the top 100 load days, the top load 200 days, and so on, till the top 1100 load days (the full sample). The analysis is discussed in some detail within the Study Report (Section III.B), and the regression specification is shown on page 1 of Exhibit RJC-3. Key results are shown on pages 1 and 2 of Exhibit RJC-3.

The main result of this analysis (from page 1 of Exhibit RJC-33) is that the slope (gradient) defined as, load change with respect to a change in temperature, is higher at temperatures that are less than the highest temperatures. This clear concavity in the relationship between peak loads and temperature is typical of window A/C units, which reach their maximum cooling capacity prior to reaching peak temperatures. This is consistent with the supposition of the greater prevalence of window A/C units among FPU Northwest residential customers. In light of this finding, we find that it is highly likely that, in the absence of appropriate adjustments, the use of Gulf Power load research will overstate the peak demand responsibility of FPU Northwest's residential customers.

The analysis procedures used to determine estimates of the differential in system peak demand attributed to the residential class of the Northwest Division is contained in page 2 of Exhibit RJC-3. Column 1 of the first table on page 2 presents the *total* estimated peak load (intercept plus the sum of the estimated slopes (coefficients) times the mean value of the respective variable), controlling for *all* variables, for the five selected models. For example, the total estimated peak load is 67,451 kW for the top 100 model. The other columns compute the estimated load based on the effects of each explanatory variable, holding all other effects constant. For example, for the top 100 model, the estimated load with respect to a given temperature and temperature slope is 1,897.8 kW, controlling for all else. The second table on page 2 of this Exhibit presents the estimated loads with respect to temperature effects. Aggregating the partial estimated loads in the first table gives us the total estimated load, for each model.

The load impacts attributed to the residential class can be gleaned from the third table on page 2 of Exhibit RJC-3.

(1) The first kW differential is the difference in the estimated system peak demand between the Top 100 Loads Model and the average of estimated system peaks for the Top 600–1,100 Loads Models (using the first table on page 2 of Exhibit RJC-3).

(2) The second kW differential is the difference in the estimated system peak demand using the estimated temperature coefficients for the Top 100 Loads Model, and the average of the estimated coefficient for the Top 600–1,100 Loads Models (using the second table on page 2 of Exhibit RJC-3).

Then, the average kW differential (average of 1 and 2) is -2,638 kW, as obtained from Stat-1 analysis.

Statistics 2-Based Analysis: The Stat 2 regression model is used to estimate the change in the weather normalized system load factor with respect to the change in residential energy shares, for FPU Northwest. Details on the computation of weather-normalized load factors are contained in Footnote 15 of the main report (Exhibit RJC-7). This analysis is based on time series data, for the five summer months over 2001–2009 (2005 is excluded because of missing load data) and is discussed in some detail within the Study Report. Key results are shown on pages 1 and 2 of

Exhibit RJC-4.

As discussed, the regression model specifies the load factor as a linear function of the residential energy shares (the main variable of interest), the real price of electricity, and four binary variables for the summer months of May through August (September is the base category). The objective is to estimate the sign and magnitude of the coefficient of the shares variable. In so doing, the effect of changes in the residential energy share on load factor, if it exists, is determined. As discussed earlier (as well as seen in Column 1 of the table on page 1 in Exhibit RJC-4), the relationship between the weather normalized system load factor and residential energy, for summer months, is negative and statistically significant; a residential share decrease of 1% translates into a system load factor increase of 0.723%.

The Stat 2 model also provides an estimate of the change in the weather normalized system load separately for two time periods, namely 2001–2007 and 2008–2009. This provides a basis to determine the incremental impact (decrease) occasioned by the change in the reduced residential energy and thus peak loads, from 2008 onwards. In order to implement this, we estimate the original model inclusive of a binary variable for the 2nd period (2008–2009), and interact the share variable with the newly introduced binary (2001–2007 is the base category). The results in Column 2 of the table on page 1 in Exhibit RJC-4 show that for both periods, residential energy share remains negative and significant, and is of a higher magnitude as compared to the previous model specification. Specifically, the coefficient on the shares variable provides the effect for the period 2001–2007 (a nearly two-fold impact of shares on load factor). The sum of the coefficients on the shares variable and the interaction dummy gives us the total effect for 2008–09, an effect of magnitude –1.603. These results provide evidence in favor of the fact that reductions in monthly residential energy shares are highly likely to be associated with equivalent reductions in the residential peak load class shares.

The increase in system load factor associated with declining residential energy shares translates into a reduction of 2,822.2 kW in the residential peak load (shown as Delta kW in the second table on page 2 in Exhibit RJC-4). In conclusion, the Statistic 1-based analysis results in a reduction of 2,638 kW in the residential peak load, while the Statistic 2-based analysis results in a reduction of 2,822.2 kW. I, therefore, recommend that for conservative purposes, the Company reduce the residential coincident peak demand by 2,557 kW, a result which is drawn from the above-cited statistical methods.

DETERMINATION OF DEMAND CHARGES, NORTHWEST DIVISION

The proposed adjustment to the residential peak demand of the Northwest Division shown in Exhibit RJC-6 is incorporated into the Company's current framework for allocation of wholesale demand charges. The procedure involves two steps. First, the coincident peak demand for the residential class is estimated under the current approach, which utilizes the residential class load factor (0.5731) reported in Gulf Power's load research to the FPSC. Given projected residential annual energy for 2013, the residential coincident peak demand is calculated. This result is adjusted downward by the amount of estimated bias in the coincident demand obtained for the residential class of the Northwest Division. The adjustment for bias, in the amount of 2,557 kW, is subtracted from the residential coincident peak demand. The second step involves the calculation of the effective load factor (0.6290), and is a direct result from the projection of sales for 2013 and the adjusted peak demand. The calculation is shown on Exhibit RJC-6, page 2.

Q. Does this conclude your testimony?

A. It does.

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony and Exhibits of

H. R. Ball

Docket No. 120001-EI

Date of Filing: March 1, 2012

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

A. My name is Herbert Russell Ball. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in 1978 with a Bachelor of Science Degree (Chemistry major) and again in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power Company (MPC) at Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Corporate Office and worked in the Fuel Department as a Fuel Business Analyst. In 1987 I was promoted and returned to Plant Daniel as the Supervisor of Chemistry and Regulatory Compliance. In 1998 I transferred to Southern Company Services, Inc. in Birmingham, Alabama and took the position of Supervisor of Coal Logistics. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern electric system (SES). I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's participation in the Intercompany Interchange Contract (IIC) between Gulf and the other operating companies in the SES.

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses, net power transaction expense, and purchased power capacity costs, and to certify that these expenses were properly incurred during the period January 1, 2011 through December 31, 2011. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Mr. Ball's exhibit consisting of four schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January 2011 through December 2011, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $553,761,039, which is $33,558,080 or 5.71% below the projected amount of $587,319,119. Actual net power transaction energy was 12,070,631,170 KWH compared to the projected net energy of 12,396,860,000 KWH or 2.63% below projections. The resulting actual average cost of 4.5877 cents per KWH was 3.16% below the projected cost of 4.7376 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2011 included in Appendix 1 of Witness Dodd's exhibit. The lower total fuel and net power transaction expense is attributed to a higher quantity of energy sales (KWH) than projected. The total quantity of energy sales is greater than projected as a result of Gulf's available energy being lower cost than other energy sources which resulted in these generating assets being economically dispatched to serve system load. The actual total cost of available energy was above projections by $28,634,215 or 4.52% and the total available quantity of energy was above projections by 3,177,427,254 KWH or 23.55%. The actual cost per KWH of available energy was 3.9688 cents per KWH which is lower than the projected cost of 4.6913 cents per KWH. The lower cost per KWH for available energy is due to a lower than projected cost per KWH for purchased power. These purchases were primarily from gas fired generating units that Gulf has under Purchase Power Agreements (PPA's). The lower market price for natural gas during the period yielded lower that projected energy purchase prices under Gulf's PPA's.

Q. During the period January 2011 through December 2011, how did Gulf Power Company's recoverable fuel cost of net generation compare with the projected expenses?

A. Gulf's recoverable fuel cost of system net generation was $496,570,367 or 13.44% below the projected amount of $573,663,069. Actual generation was 10,507,488,000 KWH compared to the projected generation of 11,971,929,000 KWH, or 12.23% below projections. The resulting actual average fuel cost of 4.7259 cents per KWH was 1.37% below the projected fuel cost of 4.7917 cents per KWH. The lower total fuel expense is attributed to a lower quantity of fuel burned than projected for the period. The actual quantity of fuel consumed was 99,422,421 MMBTU which is 12.87% below the projected quantity of 114,106,483 MMBTU. The generation mix was more heavily weighted to natural gas fired generation than projected due to efforts to utilize available natural gas fired generation which was lower in cost. The percentage of energy generated from natural gas fired resources was 37.30%, which was 24.75% higher than the projected percentage of 29.90%. The weighted average fuel cost for natural gas was $3.55 cents per KWH, which is 10.13% below the projected cost of $3.95 cents per KWH. The weighted average fuel cost for coal, plus lighter fuel, was $5.43 cents per KWH, which is 5.23% higher than the projected cost of $5.16 cents per KWH. This information is found on Schedule A-3, period-to-date, for the month of December 2011 included in Appendix 1 of Witness Dodd's exhibit.

Q. How did the total projected cost of coal purchased compare with the actual cost?

A. The total actual cost of coal purchased was $360,555,779 (line 17 of Schedule A-5, period-to-date, for December 2011) compared to the projected cost of

$441,272,537 or 18.29% below the projected amount. The lower total coal cost was due to the quantity (tons) of coal purchased for the period being 18.05% lower than projected. The actual weighted average price of coal purchased was $107.60 per ton which is only 0.30% below the projected price of $107.92 per ton. Gulf deferred some planned contract coal shipments to future periods and purchased no spot coal during the current period.

Q How did the total projected cost of coal burned compare to the actual cost?

A. The total cost of coal burned was $349,170,779 (line 21 of Schedule A-5, period-to-date, for December 2011). This is 18.98% lower than the projection of $430,987,989. The lower total coal cost was due to the quantity of coal burned being 19.14% below projections. The weighted average coal burn cost was only 0.19% above projections for the period.

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total actual cost of natural gas burned for generation was $137,407,877 (line 34 of Schedule A-5, period-to-date, for December 2011). This is 1.29% below the projection of $139,202,313. The quantity of gas burned was 11.21% higher than projected due to natural gas fired units being more economic to operate than coal fired generation on a cents per KWH basis. The actual weighted average gas burn cost was $5.00 per MMBTU, which is 11.19% lower than the projected burn cost of $5.63 per MMBTU.

Q. Did fuel procurement activity during the period in question follow Gulf Power's Risk Management Plan for Fuel Procurement?
A. Yes. Gulf Power's fuel strategy in 2011 complied with the Risk Management Plan filed on August 1, 2010.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of coal being delivered to Gulf's coal-fired generating units during the period?
A. Yes. The supply of coal and associated transportation to Gulf's generating plants is generally secured through a combination of long-term contracts and spot agreements as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These early purchase commitments and the planned diversity of fuel suppliers are designed to provide a more reliable source of coal to the generating plants. The result was that Gulf's coal-fired generating units had an adequate supply of fuel available at all times at a reasonable cost to meet the electric generation demands of its customers.

Q. For coal shipments during the period, what percentage was purchased on the spot market and what percentage was purchased using longer-term contracts?
A. As shown in Schedule 1of my exhibit, total coal shipments for the period amounted to 3,323,258 tons. Gulf purchased none of this coal on the spot market. Spot purchases are classified as coal purchase agreements with terms of one year of less. Spot coal purchases are typically needed to allow a portion of the purchase quantity commitments to be adjusted in response to changes in

coal burn that may occur during the year. There were no spot coal purchases for the period due to coal burn (tons) being 19.14% lower than projected during 2011 and a carry over of contract coal tons from the previous year. Natural gas prices were lower than projected and the low cost of gas fired generation allowed Gulf to shift generation from coal fired units to natural gas fired units. Gas fired generation was 9.48% above projections and coal fired generation was 21.55% below projections for the period. Gulf purchased all of its 2011 coal supply under longer-term contracts. Longer-term contracts provide a reliable base quantity of coal to Gulf's generating units with firm pricing terms. This limits price volatility and increases coal supply consistency over the term of the agreements. Schedule 1 of my exhibit consists of a list of contract and spot coal shipments to Gulf's generating plants for the period as reported on the monthly FPSC 423 reports.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in stable coal prices for the period?

A. Yes. Coal cost volatility was mitigated through compliance with the Risk Management Plan. Gulf uses physical hedges to reduce price volatility in its coal procurement program. Gulf purchases coal and associated transportation at market price through the process of either issuing formal requests for proposals to market participants or occasionally for small quantity spot purchases through informal proposals. Once these confidential bids are received, they are evaluated against other similar proposals using standard contract terms and conditions. The least cost acceptable alternatives are selected and firm purchase agreements are negotiated with the successful bidders. Gulf purchased coal and coal transportation using a combination of firm price contracts and purchase orders that either fix the price for the period or escalate the price using a combination of government published economic indices. Schedule 2 of my exhibit provides a list of the contract and spot coal shipments for the period and the weighted average price of shipments under each purchase agreement in \$/MMBTU. Because of the fixed price nature of longer term contract coal purchase agreements and the substantial amount of coal under firm commitments prior to the beginning of the period, there was only a small variance between the estimated purchase price of coal and the actual price for the period (0.30% as reported on line 16 of Schedule A-5, period to date, for the month of December 2011).

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of natural gas being delivered to Gulf's gas-fired generating units at a reasonable price during the period?

A. Yes. The supply of natural gas and associated transportation to Gulf's generating plants was secured through a combination of long-term purchase contracts and daily gas purchases as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These natural gas purchase agreements price the supply of gas at market price as defined by published market indices. Schedule 3 of my exhibit compares the actual monthly weighted average purchase price of natural gas delivered to Gulf's generating units to a market price based on the daily Florida Gas Transmission Zone 3 published market price plus an estimated gas storage and transportation rate based on the actual cost of gas storage and transportation Gulf paid during the period. The purpose of early natural gas procurement commitments, the planned diversity of natural gas suppliers, and providing gas suppliers with market pricing is to provide a more reliable source of gas to Gulf's generating units. The result was that Gulf's gas-fired generating units had an adequate supply of fuel available at all times at a reasonable price to meet the electric generation demands of its customers.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in lower volatility of natural gas prices for the period?

A. Yes. Gulf purchases physical natural gas requirements at market prices and swaps the market price on a percentage of these purchases for firm prices using financial hedges. The objective of the financial hedging program is to reduce upside price risk to Gulf's customers in a volatile price market for natural gas. In 2011, Gulf's weighted average cost of natural gas purchases for generation was $4.96 per MMBTU. This was 11.90% lower than the projection of $5.63 per MMBTU (line 29 of Schedule A-5, period-to-date, for December 2011). Gulf was able to hold per unit fuel costs to very reasonable levels for its customers by following its Fuel Risk Management Plan. The volatility of Gulf's natural gas cost has been reduced by utilizing financial hedging as described in the Fuel Risk Management Plan. As shown on Schedule 4 of my exhibit, the calculated volatility of Gulf's delivered cost of natural gas over the past four-year period is represented by a variance of 7.52 and standard deviation of 2.74. By contrast, the calculation of the volatility of Gulf's hedged delivered cost of natural gas over the same four-year period yields a variance of 5.75 and a standard deviation of 2.40. The lower values for variance and standard deviation for the set of hedged prices demonstrates that Gulf's financial hedging program is achieving the goal of reducing the volatility of natural gas cost to the customer.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or financial instrument?

A. Gulf Power hedged 13,560,000 MMBTU of natural gas in 2011 using financial instruments. This represents 55% of Gulf's 24,493,854 MMBTU of projected natural gas burn for Smith Unit 3 generation during the period as reported in witness Dodd's Schedule E-4, page 13 of 13, of Gulf's 2011 Projection Filing filed on September 1, 2010 and 50% of Gulf's 27,299,673 MMBTU of actual gas burn for Smith Unit 3 generation during the period as reported on Schedule A-4.

Q. What types of hedging instruments were used by Gulf Power Company, and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using a combination of financial swap contracts that fixed the price of gas to a certain price and option contracts. The option contracts consisted entirely of "costless collars" which established a floor and ceiling price between which the actual price would float. The option contracts settle only if the actual NYMEX last day price was outside the bounds of the collar. The total volume of gas hedged using financial swap contracts was 10,960,000 MMBTU and the total volume of gas hedged using option contracts was 2,600,000 MMBTU. These swaps settled against either a NYMEX Last Day price or Gas Daily price.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2011 through December 2011?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2011 hedging program resulted in a net financial loss of $15,444,523 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2011 included in Appendix 1 of Witness Dodd's exhibit. The settlements of Gulf's swap contracts resulted in a net loss of $15,135,963 and the settlement of Gulf's option contracts resulted in a net loss of $308,560 during the period.

Q. What is the current status of Gulf Power's litigation against Coalsales II, LLC for breach of contract?

A. As previously reported, Gulf filed a complaint with the U.S. District Court for the Northern District of Florida on June 22, 2006, against Coalsales for breach of contract. On September 30, 2009, the court issued its order granting Gulf's motion for partial summary judgment and denying Coalsales' motion for summary judgment on the breach of contract issue. The issue of Gulf's damages was heard by the court without a jury in February 2010. On September 30, 2010, the court issued an order initially ruling in favor of Coalsales on the question of damages. That order was later rescinded in response to Gulf's Motion to Alter or Amend Judgment, or Alternatively, for Relief from Judgment. In July 2011, the court granted Gulf's motion after finding that the cover coal purchases by Gulf in 2007 were reasonable and scheduled another evidentiary hearing on August 25, 2011 to address the issue of Gulf's 2007 cover damages. In September 2011, the court found that Gulf is entitled to a judgment against Coalsales in the amount of $20,527,789, which represents the difference between the contract price of Gulf's 2007 cover purchases and the price Gulf would have paid for the same quantity of coal under the coal supply agreement. Additionally the court denied Coalsales motion for its attorney's fees and costs to be recovered from Gulf. On January 19, 2012, the court amended its September 2011 judgment and entered a judgment in favor of Gulf Power for damages in the amount of $20,527,789 and prejudgment interest in the amount of $6,896,183.85 for a total judgment of $27,423,972.85 plus taxable costs and post judgment interest. The order and final judgment each specify that post-judgment interest is to be calculated from September 30, 2011, until the date the judgment is paid at a rate of 0.10%. The case is currently on appeal to the United States Court of Appeals for the Eleventh Circuit. Any damage recovery ultimately obtained from Coalsales will result in a credit to Gulf's retail customers through the fuel cost recovery clause and will necessarily result in reduced fuel costs for those customers.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. During the period January 2011 through December 2011 how did Gulf Power Company's recoverable fuel cost of power sold compare with the projection?

A. Gulf's recoverable fuel cost of power sold for the period is ($107,800,295) or 136.36% above the projected amount of ($45,608,000). Total kilowatt hours of power sales were (4,598,368,084) KWH compared to estimated sales of (1,094,712,000) KWH, or 320.05% above projections. The resulting average fuel cost of power sold was 2.3443 cents per KWH or 43.73% below the projected amount of 4.1662 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2011 included in Appendix 1 of Witness Dodd's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of power sold and the projection?

A. The higher total credit to fuel expense from power sales is attributed to the higher total quantity of energy sales (KWH) than projected. The more favorable position of Gulf's generating assets in system economic dispatch to serve load resulted in a greater quantity of energy sales. This was offset somewhat by below budget prices for natural gas which reduced the fuel reimbursement rate (cents per KWH) paid to Gulf for typical power sales.

Q. During the period January 2011 through December 2011, how did Gulf Power Company's recoverable fuel cost of purchased power compare to projected cost?

A. Gulf's recoverable fuel cost of purchased power for the period was $149,441,375 or 173.82% above the estimated amount of $54,576,000. Total kilowatt hours of purchased power were 6,161,511,254 KWH compared to the estimate of 1,519,643,000 KWH or 305.46% above projections. The resulting average fuel cost of purchased power was 2.4254 cents per KWH or 32.47% below the estimated amount of 3.5914 cents per KWH. This information is from Schedule

A-1, period-to-date, for the month of December 2011 included in Appendix 1 of Witness Dodd's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of purchased power and the projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of KWH at attractive prices to supplement its own generation to meet load demands. This includes energy supplied to Gulf through purchase power agreements. The average fuel cost of energy purchases per KWH was lower than projected as a result of lower-cost energy being made available to Gulf for purchase during the period. In general the actual price of marginal fuel (primarily natural gas) used to generate market energy was lower than projected for the period.

Q. Should Gulf's recoverable fuel and purchased power cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is otherwise curtailed or unavailable. Gulf's lighter oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf adhered to its Risk Management Plan for Fuel Procurement and accomplished the objectives established by the plan. Through its participation in the integrated Southern electric system, Gulf is able to purchase affordable energy from pool participants and other sellers of energy when needed to meet load and during times when the cost of purchased power is lower than energy that could be generated internally. Gulf is also able to sell energy to the pool when excess generation is available and return the benefits of these sales to the customer. These energy purchases and sales are governed by the IIC which is approved by the Federal Energy Regulatory Commission (FERC). Gulf also purchases power when economically attractive under the terms of several external purchase power agreements which have been reviewed and approved by the Commission.

Q. During the period January 2011 through December 2011, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual net capacity cost for the January 2011 through December 2011 recovery period, as shown on line 4 of Schedule CCA-2 of Witness Dodd's Exhibit, was $42,593,827. Gulf's total re-projected net purchased power capacity cost for the same period was $43,934,522, as indicated on line 4 of Schedule CCE-1B of Witness Dodd's exhibit filed September 1, 2011. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $1,340,695 or 3.05% lower than re-projected. This lower actual cost is due to Gulf's lower IIC reserve sharing costs. Gulf's actual reserves (MW) were higher than originally projected due to Gulf receiving capacity credits for one of Gulf's purchase power agreements during certain months of the year as a result of the economic dispatch of this resource. Therefore, Gulf's reserve purchases were lower and its associated reserve sharing costs were lower than the re-projected amount for the 2011 recovery period.

Q. Was Gulf's actual 2011 IIC capacity cost prudently incurred and properly allocated to Gulf?

A. Yes. Gulf's capacity costs were incurred in accordance with the reserve sharing provisions of the IIC in which Gulf has been a participant for many years. Gulf's participation in the integrated Southern electric system that is governed by the IIC has produced and continues to produce substantial benefits for Gulf's customers and has been recognized as being prudent by the Florida Public Service Commission in previous proceedings and reviews. Per contractual agreement in the IIC, Gulf and the other SES operating companies are obligated to provide for the continued operation of their electric facilities in the most economical manner that achieves the highest possible service reliability. The coordinated planning of future SES generation resource additions that produce adequate reserve margins for the benefit of all SES operating companies' customers facilitates this "continued operation" in the most economical manner. The IIC provides for mechanisms to facilitate the equitable sharing of the costs associated with the operation of facilities that exist for the mutual benefit of all the operating companies. In 2011, Gulf's reserve sharing cost represents the equitable sharing of the costs that the SES operating companies incurred to ensure that adequate generation reserve levels are available to provide reliable electric service to customers. This cost has been properly allocated to Gulf pursuant to the terms of the IIC.

Q. Mr. Ball, does this complete your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony of

H. R. Ball

Docket No. 120001-EI

Date of Filing: August 1, 2012

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama in 1998. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January 2012 through December 2012 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2012 through June 2012 and projected fuel and net power transaction costs for July 2012 through December 2012. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses, and purchased power capacity costs.

Q. During the period January 2012 through December 2012 how will Gulf Power Company's recoverable total fuel and net power transactions cost compare with the original cost projection?

A. Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $442,568,718 which is $145,204,450 or 24.70% below the original projected amount of $587,773,168. The lower total fuel expense for the period is attributed to a combination of lower than projected total fuel cost of system net generation combined with a higher total fuel cost of purchased power resulting in a lower total cost of available power. The lower total cost of available power combined with higher fuel revenue from power sales results in a further reduction in total fuel and net power transactions cost. The resulting average per unit fuel cost is projected to be 3.6954 cents per kWh or 18.83% below the original projection of 4.5524 cents per kWh. The lower average per unit fuel cost (cents per kWh) is attributed to a lower fuel cost of generated power and purchased power for the period driven primarily by lower costs for natural gas and a change in the generation mix to include more natural gas fired generation and purchased power. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 21.

Q. During the period January 2012 through December 2012 how will Gulf Power Company's recoverable total fuel cost of generated power compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable total fuel cost of generated power for the period is $369,544,949 which is $177,238,219 or 32.41% below the original projected amount of $546,783,168. Total generation is expected to be 8,716,233,000 kWh compared to the original projected generation of 11,923,813,000 kWh or 26.90% below original projections. The resulting average fuel cost is expected to be 4.2397 cents per kWh or 7.54% below the original projected amount of 4.5856 cents per kWh. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 6.

Q. What are the reasons for the difference between Gulf's original projection of the total fuel cost of generated power and the current projection?

A. The lower total fuel expense is due to lower than originally projected quantity of generated power (kWh) in addition to lower average per unit fuel costs (cents/kWh). Delivered coal prices per MMBtu are projected to be slightly above original projections for the period due to a higher percentage of contract coal in the coal supply mix. The quantity of contract coal in the supply mix for the period is expected to be above original projections due to a reduction in the quantity of coal burned which has eliminated the need for market priced spot purchases for the period. Coal burn is lower due to reduced economic dispatch of coal fired units relative to other sources of generation. Projected prices for natural gas for the period are expected to be lower than original projections for the period due to changes in market fuel prices. A higher projected supply of natural gas in the market has driven the projected price lower and prices are expected to remain lower for the remainder of the period. The quantity of natural gas burn is expected to be above original projections in response to the lower market prices for natural gas increasing economic dispatch of Gulf's gas fired generating units. The ability to change the mix of generating units operating to meet customer demand to a more heavily weighted natural gas mix has allowed Gulf to take advantage of lower natural gas prices and reduce the fuel cost of generated power.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2012?

A. The total fuel cost of system net generation for the first six months of 2012 was $166,223,227 which is $103,962,942 or 38.48% lower than the projection of $270,186,169. On a fuel cost per kWh basis, the actual cost was 3.80 cents per kWh, which is 17.21% lower than the projected cost of 4.59 cents per kWh. This lower cost of system generation on a cents per kWh basis is due to a combination of fuel cost in $/MMBtu being 13.22% lower than projected and heat rate (Btu/kWh) of the generating units operating being 4.75% lower than projected. This is a result of Gulf being able to operate its lower cost more efficient gas fired combined cycle unit at a higher capacity factor, thus making gas fired generation a higher percent of the generation mix. This information is found on Schedule A-3 Period to Date of the June 2012 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2012?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2012 was $113,653,418 which is $93,781,381 or 45.21% lower than the projection of $207,434,799. On a fuel cost per kWh basis, the actual cost was 5.30 cents per kWh which is 7.07% higher than the projected cost of 4.95 cents per kWh. The lower than projected total cost of coal burned (including boiler lighter) is due to total MMBtu of coal burn being 45.39% below the estimated burn for the period. The higher per kWh cost of coal fired generation is due to actual coal prices (including boiler lighter) being 0.22% higher than projected on a $/MMBtu basis and the weighted average heat rate (Btu/kWh) of the coal fired generating units operating being 6.70% higher than projected. This information is found on Schedule A-3 Period to Date of the June 2012 Monthly Fuel Filing. Gulf has fixed price coal contracts in place for the period to limit price volatility and ensure reliability of supply. Actual average prices for coal purchased during the period are higher due to a change in the timing of contract shipments to Gulf's coal fired generating plants in response to lower coal burn for the period. Another factor contributing to the higher cost of coal fired generation (cents/kWh) is that weighted average coal unit heat rates are higher than projected for the period. Generating unit heat rates have been impacted by the percentage of time these units operated at lower than projected loads. When generating units operate at lower loads, unit efficiency is reduced.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2012?

A. The total cost of natural gas burned for generation for the first six months of 2012 was $52,095,850 which is $10,314,461 or 16.53% lower than Gulf's projection of $62,410,311. The total gas fired generation was 2,218,960 MWH which is 32.09% higher than the projection of 1,679,889 MWH for the period. The total cost of natural gas burned for generation is lower than the forecast due to the market price of natural gas being lower than projected. Market prices for natural gas are lower due to increased supply of natural gas in the market. On a cost per unit basis, the actual cost of gas fired generation was 2.35 cents per kWh which is 36.83% lower than the projected cost of 3.72 cents per kWh. Actual natural gas prices were $3.25 per MMBtu or 36.27% lower than the projected cost of $5.10 per MMBtu. This information is found on Schedule A-3 Period to Date of the June 2012 Monthly Fuel Filing.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 10,630,000 MMBtu of natural gas for the period January 2012 through June 2012 using a combination of fixed price financial swaps and options. This equates to 68.2% of the actual natural gas burn for generation during the period of 15,580,343 MMBtu as reported on Schedule A-3 Period to Date of the June 2012 Monthly Fuel Filing.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price and options (collars) that established both a price ceiling and price floor for each deal. The swaps settled against either a NYMEX Last Day price or Gas Daily price. The options settled if the NYMEX Last Day price was outside the bounds of the collar. The amount of gas hedged for the period using financial swaps was 9,350,000 MMBtu and the amount of gas hedged using options was 1,280,000 MMBtu.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were incurred. Gulf's gas hedging program generated a hedging expense related to settlements of $19,332,593 for the period January through June 2012. This information is found on Schedule A-1, Period to Date, line 2 of the June 2012 Monthly Fuel Filing.

Q. During the period January 2012 through December 2012 how will Gulf Power Company's recoverable fuel cost of power sold compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost and gains on power sales for the period are $(87,956,948) or 158.00% above the original projected amount of $(34,092,000). Total kilowatt hours of power sales is expected to be (4,958,914,591) kWh compared to the original projection of (806,174,000) kWh or 515.12% above projections. This current projection of fuel cost of power sold is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 18.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost and gains on power sales and the current projection?

A. The greater total credit to fuel expense from power sales is attributed to a significantly higher quantity of power sales than originally projected, offset to a degree by a lower reimbursement rate (cents per kWh) for power sales. Lower marginal market prices for natural gas combined with a higher percentage of natural gas fired generation in the generation fuel mix during the period have decreased the fuel reimbursement rate for power sales.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2012?

A. The total fuel cost of power sold for the first six months of 2012 was $(59,625,948) which is $(42,207,948) or 242.32% higher than our projection of $(17,418,000). The quantity of power sales for the period was 752.28% higher than projected. The actual cost was 1.5125 cents per kWh which is 59.83% below the projected cost of 3.7656 cents per kWh. This information is found on Schedule A-1, Period to Date, line 17 of the June 2012 Monthly Fuel Filing.

Q. During the period January 2012 through December 2012 how will Gulf Power Company's recoverable fuel cost of purchased power compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of purchased power for the period is $160,980,717 or 114.41% above the original projected amount of $75,082,000. The total amount of purchased power is expected to be 8,218,972,591 kWh compared to the original projection of 1,793,621,000 kWh or 358.23% above projections. The resulting average fuel cost of purchased power is expected to be 1.9586 cents per kWh or 53.21% below the original projected amount of 4.1861 cents per kWh. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 13.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of energy to supplement its own generation to meet load demands. In the original projection of the fuel cost of purchased power Gulf assumed that the generating units associated with Gulf's Purchase Power Agreements (PPAs) would not be able to operate on a consistent basis due to the lack of firm electric transmission for the largest of these generators located at the Tenaska Central Alabama facility. Due to changed dynamics of loads on Southern Company's transmission system and incremental improvements to transmission infrastructure, incremental firm transmission service became available to serve the Central Alabama PPA unit. As a result, this generating unit actually operated for the period through June 2012 and is projected to continue to operate during most months through the end of the year. The lower projected price per kWh for purchased power is due to Gulf's ability to obtain power from this lower cost gas fired combined cycle unit under its existing PPA.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2012?

A. The total fuel cost of purchased power for the first six months of 2012 was \$80,528,718 which is \$52,272,718 or 185.00% higher than our projection of \$28,256,000. The higher than anticipated purchased power expense is due to the actual quantity of purchases being 630.29% higher than projected. The majority of these purchases are from Gulf's PPAs which are contracts associated with gas fired generating units. Purchase power quantity is higher due to the lower price of available power relative to Gulf's fuel cost of generated power making it the economic choice for providing energy to customers during certain periods of time. On a fuel cost per kWh basis, the actual cost was 1.5834 cents per kWh which is 60.97% lower than the projected cost of 4.0573 cents per kWh. This information is found on Schedule A-1, Period to Date, line 12 of the June 2012 Monthly Fuel Filing.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Were Gulf Power's actions through June 30, 2012 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

A. Yes. Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices. Over the long term, Gulf anticipates less volatile future fuel costs than would have otherwise occurred if these programs had not been utilized.

Q. Should Gulf's fuel and net power transactions cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf has followed its Risk Management Plan for Fuel Procurement in securing the fuel supply for its electric generating plants. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that natural gas is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery clause so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

Q. During the period January 2012 through December 2012, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 4 of Schedule CCE-1b in the exhibit to Witness Dodd's testimony, Gulf's total current net capacity payment projection for the January 2012 through December 2012 recovery period is $45,793,117. Gulf's original projection for the period was $48,106,587 and is shown on Line 4 of Schedule CCE-1B filed September 1, 2011. The difference between these projections is $2,313,470 or 4.81% less than the original projection of net capacity payments. The variance is due to a reduction in projected reserve sharing capacity payments per the provisions of the IIC. Gulf's ability to run the Central Alabama PPA unit during the period has reduced its reserve sharing commitment to the pool.

Q. How did the total projected net capacity transactions cost compare to the actual cost for the first six months of 2012?

A. Actual net capacity payments during the first six months of 2012 were $17,059,646 which is $123,149 or 0.73% higher than projected for the period. The variance is due to timing differences between actual payments and projected payments under Gulf's purchase power agreements for the period.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 120001-EI
Date of Filing: August 31, 2012

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern electric system. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 1, 2013 through December 31, 2013. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I have four separate exhibits I am sponsoring as part of this testimony. My first exhibit (HRB–2) consists of a schedule filed as an attachment to my pre-filed testimony that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short-term fuel expense projections. The second exhibit (HRB-3) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on March 30, 2012 and assigned Document Number DN 01946-12 (redacted) and 01948-12 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August through December 2011 in compliance with Order No. PSC-08-0316-PAA-EI. The third exhibit (HRB-4) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 15, 2012 and assigned Document Number DN 05596-12 (redacted) and 05595-12 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for January through July 2012 in compliance with Order No. PSC-08-0316-PAA-EI. The fourth exhibit (HRB-5) I am sponsoring is Gulf Power Company's "Risk Management Plan for Fuel Procurement." This exhibit was filed with the Commission Clerk pursuant to a separate request for confidential classification on August 1, 2012 and assigned Document Number DN 05202-12 (redacted) and 05201-12 (confidential information). The risk management plan sets forth Gulf Power's fuel procurement strategy and related hedging plan for the upcoming calendar year. Through its petition in this docket, Gulf Power is seeking the Commission's approval of the Company's "Risk Management Plan for Fuel Procurement" as part of this proceeding.

Counsel: We ask that Mr. Ball's four exhibits as just described be marked for identification as Exhibit Nos. _____ (HRB-2), _____ (HRB-3), _____ (HRB-4), and_____ (HRB-5) respectively.

Q. Has Gulf Power Company made any significant changes to its methods for projecting fuel expenses, net power transaction expense, and purchased power capacity costs for this period?

A. No. Gulf has been consistent in how it projects annual fuel expenses, net power transactions, and capacity costs.

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2013 through December 2013 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $469,415,596. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 19.

Q. How does the total projected fuel and net power transactions cost for the 2013 period compare to the updated projection of fuel cost for the same period in 2012?

A. The total updated cost of fuel and net power transactions for 2012, reflected on Schedule E-1B-1 line 21 of Witness Dodd's testimony filed in this docket on August 1, 2012, is projected to be $442,568,718. The projected total cost of fuel and net power transactions for the 2013 period reflects an increase of $26,846,878 or 6.07% more than the same period in 2012. On a fuel cost per kWh basis, the 2012 projected cost is 3.6954 cents per kWh and the 2013 projected fuel cost is 3.7860 cents per kWh, a increase of 0.0906 cents per kWh or 2.45%.

Q. What is Gulf's projected recoverable total fuel cost of generated power for the period?

A. The projected total cost of fuel to meet system generated power needs in 2013 is $359,914,837. The projection of fuel cost of system generated power for 2013 is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 5.

Q. How does the projected total fuel cost of generated power for the 2013 period compare to the updated projection of fuel cost for the same period in 2012?

A. The total updated cost of fuel to meet 2012 system generated power needs, reflected on Schedule E-1B-1, line 6 of Witness Dodd's testimony filed in this docket on August 1, 2012, is projected to be $369,544,949. The projected total cost of fuel to meet system net generation needs for the 2013 period reflects a decrease of $9,630,112 or 2.61% over the same period in 2012. Total system net generation in 2013 is projected to be 8,760,831,000 kWh, which is 44,598,000 kWh or 0.51% higher than is currently projected for 2012. On a fuel cost per kWh basis, the 2012 projected cost is 4.2397 cents per kWh and the 2013 projected fuel cost is 4.1082 cents per kWh, a decrease of 0.1315 cents per kWh or 3.10%. This lower projected total fuel expense and average per unit fuel cost is the result of a lower projected cost of coal and natural gas for the period. Weighted average coal burned price for 2012 as reflected on Schedule E-5, line 20 of Witness Dodd's testimony filed in this docket on August 1, 2012, is projected to be 108.14 $/ton. Weighted average coal burned price for 2013, as reflected on Schedule E-5, line 20 of the exhibit to Witness Dodd's testimony, is projected to be 104.88 $/ton. This reflects a cost decrease of 3.26 $/ton or 3.01%. Several of Gulf's coal supply agreements will expire at the end of 2012 and these are being replaced with lower priced coal supply agreements. Gulf's coal supply agreements have firm price and quantity commitments with the contract coal suppliers and these agreements will cover the majority of Gulf's 2013 projected coal burn needs. The remaining coal supply needs, if any, will be purchased on the spot market. Weighted average natural gas price for 2012, as reflected on Schedule E-5, line 29 of the exhibit to Witness Dodd's testimony filed in this docket on August 1, 2012, is projected to be 3.38 $/MMBtu. When the cost of natural gas hedging settlements (Schedule E-1-B1, line 1a) is included in the total delivered gas cost, the 2012 projected cost is 4.55 $/MMBtu. Weighted average natural gas price for 2013, as reflected on Schedule E-5, line 29 of the exhibit to Witness Dodd's testimony, is projected to be 4.52 $/MMBtu. This is a decrease in price of 0.03 $/MMBtu or 0.66%. The projected cost of landfill gas to supply the Perdido Landfill Gas to Energy Facility in the 2012 projection period is $715,030 and the rate as reflected on Schedule E-3, line 42 of the exhibit to Witness Dodd's testimony filed in this docket on August 1, 2012, is projected to be 2.73 cents per kWh. The total projected cost for landfill gas in 2013 is $704,503 and the total facility generation is projected to be 26,366,000 kWh. The average rate, as reflected on Schedule E-3, line 42 of the exhibit to Witness Dodd's testimony, is projected to be 2.67 cents per kWh.

Q. Does the 2013 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. No. As in the past, Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years by Southern Company Services - Fuel Services as agent for Gulf. Coal will be delivered under both existing and new negotiated coal transportation contracts. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements. Details of Gulf's fuel procurement strategy are included in the "Risk Management Plan for Fuel Procurement" filed as exhibit _____ (HRB-5) to this testimony.

Q. What actions does Gulf take to procure natural gas and natural gas transportation for its units at competitive prices for both long-term and short-term deliveries?

A. Gulf procures natural gas using both long and short-term agreements for gas supply at market-based prices. Gulf secures gas transportation for non-peaking units using long-term agreements for firm transportation capacity and for peaking units using interruptible transportation, released seasonal firm transportation, or delivered natural gas agreements.

Q. What fuel price hedging programs will be utilized by Gulf to protect its customers from fuel price volatility?

A. As detailed in Gulf's "Risk Management Plan for Fuel Procurement," natural gas prices will be hedged financially using instruments that conform to Gulf's established guidelines for hedging activity. Coal supply and transportation prices will be hedged physically using term agreements with either fixed pricing or term pricing with escalation terms tied to various published market price indexes. Gulf's "Risk Management Plan for Fuel Procurement" is a reasonable and appropriate strategy for protecting its customers from fuel price volatility while maintaining a reliable supply of fuel for the operation of its electric generating resources.

Q. What are the results of Gulf's fuel price hedging program for the period January 2012 through July 2012?

A. Gulf's coal price hedging program has successfully managed the price it pays for coal under its coal supply agreements for this period. Gulf has also had financial hedges in place during the period to hedge the price of natural gas. These financial hedges have been effective in fixing the price of a percentage of Gulf's gas burn during the period. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed a "Hedging Information Report" with the Commission on March 15, 2012 and also on August 15, 2012 detailing its natural gas hedging transactions for August 2011 through July 2012.

As noted earlier, I am sponsoring these reports as exhibits ______ (HRB-3 and HRB-4) to my testimony in this docket.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2012 through 2013?

A. Gulf has natural gas financial hedges in place for 2012 to adequately mitigate price risk. Gulf currently has natural gas hedges in place for 2013 and continues to look for opportunities to enter into financial hedges that we believe will provide price stability to the customer and protect against unanticipated dramatic price increases in the natural gas market.

Q. Should recent changes in the market price for natural gas impact the percentage of Gulf's natural gas requirements that Gulf plans to hedge?

A. Gulf has a disciplined process in place to evaluate the benefits of gas hedging transactions prior to entering into financial hedges that consider both market price and anticipated burn. The focus of this process is to mitigate the price volatility and risk of natural gas purchases for the customer and not to attempt to speculate in the natural gas market. Gulf's current strategy is to have gas hedges in place that do not exceed the anticipated gas burn at its Smith Unit 3 combined cycle plant and the gas fired PPA units for which Gulf has tolling agreements. Gas burn requirements change as the market price of natural gas changes due to the economic dispatch process utilized by the Southern System generation pool in accordance with the IIC. Typically, as gas prices increase, anticipated gas burn decreases and the percentage of gas requirements that are currently hedged financially increases. Gulf will continue to evaluate the performance of this hedging strategy and will make adjustments within the guidelines of the currently approved hedging program when needed.

Q. What are Gulf's projected recoverable fuel cost and gains on power sales for the period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $76,315,241. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 17.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2013 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2012?

A. The total projected recoverable fuel cost and gains on power sales in 2012, reflected on Schedule E-1B-1, line 18 of Witness Dodd's testimony filed in this docket on August 1, 2012, is projected to be $87,956,948. The projected recoverable fuel cost and gains on power sales in 2013 represents a decreased credit of $11,641,707 or 13.24%. Total quantity of power sales in 2013 is projected to be 2,527,086,000 kWh, which is 2,431,828,591 kWh or 49.04% less than currently projected for 2012. On a fuel cost per kWh basis, the 2012 projected cost is 1.7737 cents per kWh and the 2013 projected fuel cost is 3.0199 cents per kWh, which is an increase of 1.2462 cents per kWh or 70.26%. The lower total credit to fuel expense from power sales is attributed to a reduced quantity of energy sales for the period offset somewhat by a higher fuel reimbursement rate (cents per kWh) for power sales as a result of higher marginal fuel prices for the units operating to meet incremental system loads. The marginal fuel costs to operate Gulf generating units that run to meet power sales requirements are passed on to the purchasers of power and are reflected in the higher rate (cents/kWh) for the fuel cost and gains on power sales.

Q. What is Gulf's projected total cost of purchased power for the period?

A. Gulf's projected recoverable cost for energy purchases is $185,816,000. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 12.

Q. How does the total projected purchased power cost for the 2013 period compare to the projected purchased power cost for the same period in 2012?

A. The total updated cost of purchased power to meet 2012 system needs, reflected on Schedule E-1B-1, line 13 of Witness Dodd's testimony filed in this docket on August 1, 2012, is projected to be $160,980,717. The projected cost of purchased power to meet system needs in 2013 is $24,835,283 or 15.43% greater than is currently projected for 2012. The total quantity of purchased power in 2013 is projected to be 6,164,950,000 kWh, which is 2,054,022,591 kWh or 24.99% lower than is currently projected for 2012. On a fuel cost per kWh basis, the 2012 projected cost is 1.9586 cents per kWh and the 2013 projected fuel cost is 3.0141 cents per kWh, which represents an increase of 1.0555 cents per kWh or 53.89%.

Q. What are Gulf's projected recoverable capacity payments for the 2013 cost recovery period?

A. The total recoverable capacity payments for the period are $44,899,094. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 10. Schedule CCE-4 of Mr. Dodd's testimony shows there will be no projected cost associated with Southern Intercompany Interchange and lists the long-term purchased power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting cost. Also included in Gulf's 2013 projection of capacity cost is revenue produced by a market-based service agreement between the Southern electric system operating companies and South Carolina PSA. The total capacity cost of $45,646,478 is shown on Schedule CCE-4, line 34 in the exhibit to Witness Dodd's testimony. The total capacity cost included on Schedule CCE-4 line 34 is the sum of lines 1 and 2 of Schedule CCE-1.

Q. Have there been any new purchased power agreements entered into by Gulf that impact the total recoverable capacity payments?

A. No.

Q. What are the other projected revenues that Gulf has included in its capacity cost recovery clause for the period?

A. Gulf has included an estimate of transmission revenues in the amount of $167,000 in its capacity cost recovery projection. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 3.

Q. How do the total projected net jurisdictional capacity payments for the 2013 period compare to the current estimated net jurisdictional capacity payments for the same period in 2012?

A. Gulf's 2013 Projected Jurisdictional Capacity Payments, found in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 6, are $43,921,106. This amount is $295,433 or 0.67% less than the current estimate of $44,216,539 (Schedule CCE-1B, line 6) for 2012 that was filed in Mr. Dodd's actual/estimated true-up testimony in this docket on August 1, 2012. The projected capacity payment decrease is the result of a decrease in Gulf's estimated IIC reserve sharing payments, due to the projected availability of Gulf's Central Alabama purchased power resource, and a projected increase in transmission revenues for the period.

Q. Mr. Ball, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 120001-EI
Date of Filing: March 1, 2012

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

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the actual true-up amounts for the period January 2011 through December 2011 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will also present the actual benchmark level for the calendar year 2012 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2011 through December 2011.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. My exhibit consists of 1 schedule that relates to the fuel and purchased power cost recovery actual true-up, 4 schedules that relate to the capacity cost recovery actual true-up, and 1 appendix that includes Schedules A-1 through A-9 and A-12 for the period January 2011 through December 2011, previously filed monthly with this Commission. Each of these documents was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of 5 schedules and 1 appendix be marked as Exhibit No. _____ (RWD-1).

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes.

Q. Which schedules of your exhibit relate to the calculation of the fuel and purchased power cost recovery true-up amount?

A. Schedule 1 of my exhibit relates to the fuel and purchased power cost recovery true-up calculation for the period January 2011 through December 2011. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for January 2011 through December 2011 are incorporated herein in Appendix 1.

Q. What is the actual fuel and purchased power cost true-up amount related to the period of January 2011 through December 2011 to be refunded or collected through the fuel cost recovery factors in the period March 2012 through December 2012?

A. A net amount to be refunded of $21,979,880 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $21,979,880 was calculated by taking the difference in the estimated and actual over/under-recovery amounts for the period January 2011 through December 2011. The estimated under-recovery was $8,441,457 as shown on Schedule E-1A, Line 1 filed August 3, 2011 and approved in FPSC Order No. PSC-11-0579-FOF-EI issued on December 16, 2011. The actual over-recovery was $13,538,423 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2011 Schedule A-2, page 2 of 3, included in Appendix 1. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed August 3, 2011.

Q. Mr. Dodd, has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2011 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2009 through 2011 is calculated as follows:

Year	Actual Gain
2009	$ 982,077
2010	802,338
2011	463,514
Three-Year Average	$ 749,310

Q. What is the actual threshold for 2012?

A. The actual threshold for 2012 is $749,310.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements for the period of January 2011 through December 2011?

A. Yes. On line 2 of Schedule A-1, Period-to-Date, for December 2011 included in Appendix 1, Gulf has recorded a net loss of $15,444,523 related to hedging activities in 2011. Mr. Ball addresses the details of those hedging activities in his testimony.

Q. Mr. Dodd, you stated earlier that you are responsible for the purchased power capacity cost recovery true-up calculation. Which schedules of your exhibit relate to the calculation of this amount?

A. Schedules CCA-1, CCA-2, CCA-3 and CCA-4 of my exhibit relate to the purchased power capacity cost recovery true-up calculation for the period January 2011 through December 2011. In addition, Capacity Cost Recovery Schedule A-12 for the months of January 2011 through December 2011 is included in Appendix 1.

Q. What is the actual purchased power capacity cost true-up amount related to the period of January 2011 through December 2011 to be refunded or collected in the period January 2013 through December 2013?

A. An amount to be recovered of $353,030 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $353,030 was calculated by taking the difference in the estimated January 2011 through December 2011 over-recovery of $7,179,724 and the actual over-recovery of $6,826,694, which is the sum of lines 10, 11, and 14 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in FPSC Order No. PSC-11-0579-FOF-EI dated December 16, 2011. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed August 3, 2011.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period January 2011 through December 2011. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2011 through December 2011. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Please describe Schedule CCA-4 of your exhibit.

A. Schedule CCA-4 provides additional details related to Lines 1 and 2 of Schedule CCA-2.

Q. Mr. Dodd, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 120001-EI
Date of Filing: August 1, 2012

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

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator. In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Mr. Dodd's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (RWD-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2012 through December 2012 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2012 through December 2012 set forth in your exhibit?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case, the estimated true-up calculations include six months of actual data and six months of estimated data.

Q. Mr. Dodd, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2013 through December 2013?

A. The fuel cost recovery true-up for this period is a decrease of $26,425,418 or 0.2337 ¢/kWh. The derivation of this amount reflects the two mid-course fuel reductions Gulf implemented earlier in 2012. As shown on Schedule E-1A, this consists of three components: (1) an April 2012 over-recovery ending balance of $34,425,858; (2) an estimated over-recovery for the May through December 2012 period of $40,688,690; and (3) an over-recovery true-up component of ($48,689,130) currently being refunded in the period May through December 2012. The resulting net over-recovery of $26,425,418 will be included for refund during 2013.

Q. Mr. Dodd, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2013 through December 2013 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2013 through December 2013?

A. The true-up for this period is an increase of 0.0084 ¢/kWh as shown on Schedule CCE-1A. This includes an estimated under-recovery of $592,654 for January 2012 through December 2012. It also includes a final under-recovery of $353,030 for the period of January 2011 through December 2011 (see Schedule CCA-1 of Exhibit RWD-1 in this docket filed March 1, 2012). The resulting total under-recovery of $945,684 will be included for recovery during 2013.

Q. Mr. Dodd, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 120001-EI
Date of Filing: August 31, 2012

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

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you previously filed testimony before this Commission in this on-going docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2013 through December 2013. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2013 through December 2013.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes. I have one exhibit consisting of 15 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of 15 schedules, be marked as Exhibit No. _____(RWD-3)

Q. Mr. Dodd, what is the levelized projected fuel factor for the period January 2013 through December 2013?

A. Gulf has proposed a levelized fuel factor of 3.803¢/kWh. This factor is based on projected fuel and purchased power energy expenses for January 2013 through December 2013 and projected kWh sales for the same period, and includes the true-up and GPIF amounts.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2013 is 0.155¢/kWh more or 4.2 percent higher than the levelized fuel factor in place July 2012 through December 2012.

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the levelized fuel factor for the period January 2013 through December 2013.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $26,425,418 to be refunded during 2013 includes: (1) an April 2012 over-recovery ending balance of $34,425,858; (2) an estimated over-recovery for the May through December 2012 period of $40,688,690; and (3) an over-recovery true-up component of ($48,689,130) that is currently being refunded in the period May through December 2012. The estimated over-recovery for the January through December 2012 period includes 6 months of actual data and 6 months of estimated data as reflected on Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2011 through December 2011?

A. The GPIF result is shown on Line 31 of Schedule E-1 as an increase of 0.0092¢/kWh to the levelized fuel factor, thereby rewarding Gulf $1,040,660.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 29 of Schedule E-1.

Q. Mr. Dodd, how were the line loss multipliers used on Schedule E-1E calculated?

A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest MWh Load Flow Allocators.

Q. Mr. Dodd, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OSIII?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.832¢/kWh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Mr. Dodd, how were the time-of-use fuel factors calculated?

A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2013 through December 2013. These factors included the GPIF and true-up and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2012 and how would the change affect the cost of 1,000 kWh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2012 is 3.676¢/kWh compared with the proposed factor of 3.832¢/kWh. For a residential customer who uses 1,000 kWh in January 2013, the fuel portion of the bill would increase from $36.76 to $38.32.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2013 through December 2013.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2013 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $626,203 has been calculated for 2013 as follows:

2010 actual gains	802,338
2011 actual gains	463,514
2012 estimated gains	612,756
Three-Year Average	$626,203

This amount represents the minimum projected threshold for 2013 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2013 for the months of January through November and 80 percent once the threshold is met in December.

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 for 2013 of my exhibit RWD-3 relate to the calculation of the PPCC recovery factors for the period January 2013 through December 2013.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Ball has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense, which includes a credit for transmission revenue, for the period January 2013 through December 2013, is $45,479,478. The jurisdictional amount is $43,921,106. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What methodology was used to allocate the capacity payments by rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last rate case and approved by the Commission in Order No. PSC-12-0179-FOF-EI issued April 3, 2012, in Docket No. 110138-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs by rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2009 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

Q. Please describe the calculation of the ¢/kWh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, 12/13th of the jurisdictional capacity cost to be recovered is allocated by rate class based on the demand allocator. The remaining 1/13th is allocated based on energy.

The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kWh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kWh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1,000 kWh will be $4.67.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. The fuel and capacity factors will be effective beginning with Cycle 1 billings in January 2013 and continuing through the last billing cycle of December 2013.

Q. Mr. Dodd, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony of

M. A. Young, III

Docket No. 120001-EI

Date of Filing: March 15, 2012

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

A. My name is Melvin A. Young, III. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Alabama in Birmingham in 1984. I joined the Southern Company with Alabama Power in 1981 as a co-op student and continued with Alabama Power upon graduation in 1984. During my time at Alabama Power, I worked at Plant Gorgas, Plant Gadsden and in Power Generation Services where I progressed through various engineering positions with increasing responsibilities as well as first line supervision in Operations and Maintenance. I joined Gulf Power in 1997 as the Performance Engineer at Plant Crist. My primary responsibilities have been to monitor and test plant equipment and monitor overall plant heat rate. In addition to this, I have been responsible for major plant projects and was the primary reliability reporter. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company.

In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2011, through December 31, 2011.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Mr. Young's Exhibit, consisting of five schedules, be marked for identification as Exhibit MAY-1.

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 16 through 31 of Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 15 of Schedule 5. Pages 3 through 10 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-08-0030-FOF-EI is on page 11 of Schedule 2. The results are: Crist 4, -10.00 points; Crist 5, +10.00 points; Crist 6, -10.00 points; Crist 7, +10.00 points; Smith 1, +6.00 points; Smith 2, -10.00 points; Daniel 1, -10.00 points; and Daniel 2, -10.00 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 9 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 10 through 17 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in September 2010, are shown on page 20 of Schedule 3. As calculated on page 21 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: Crist 4, 0.00 points; Crist 5, +1.00 point; Crist 6, 0.00 points; Crist 7, 0.00 points Smith 1, +9.37 points; Smith 2, -6.55 points; Daniel 1, +10.00 points, and Daniel 2, +7.18 points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?
A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was +2.38 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $1,040,660.

Q. Please summarize your testimony.
A. In view of the adjusted actual equivalent availabilities, as shown on page 11 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 21 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $1,040,660 as provided for by the GPIF plan.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony of

M. A. Young, III

Docket No. 120001-EI

Date of Filing: August 31, 2012

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

A. My name is Melvin A. Young, III. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Alabama in Birmingham in 1984. I joined the Southern Company with Alabama Power in 1981 as a co-op student and continued with Alabama Power upon graduation in 1984. During my time at Alabama Power, I worked at Plant Gorgas, Plant Gadsden and in Power Generation Services where I progressed through various engineering positions with increasing responsibilities as well as first line supervision in Operations and Maintenance. I joined Gulf Power in 1997 as the Performance Engineer at Plant Crist. In this capacity, my primary responsibilities were to monitor and test plant equipment and monitor overall plant heat rate. In addition to this, I was responsible for major plant projects and was the primary reliability reporter. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company.

In this position I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2013 through December 31, 2013.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have prepared one exhibit entitled MAY-2 consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?
A. Yes, it was.

Counsel: We ask that Mr. Young's exhibit consisting of three schedules be marked for identification as Exhibit___(MAY-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?
A. We propose that Crist Units 6 and 7, Smith Unit 3, and Daniel Units 1 and 2, be included as the Company's GPIF units. The projected net generation from these units is approximately 81% of Gulf's projected net generation for 2013.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2013 through December 31, 2013?

A. I would like to refer you to page 29 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF Implementation Manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units and pages 4 through 25 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 26 through 28 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit indicated on page 29 of Schedule 1 of your exhibit calculated according to the appropriate GPIF Implementation Manual procedures?

A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?

A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of my exhibit.

Q. How were the target equivalent availabilities determined?

A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on page 2 of Schedule 2 of my exhibit.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?

A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of my exhibit, were determined per GPIF Implementation Manual procedures for Gulf.

Q. Mr. Young, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Mr. Young, would you please summarize your testimony?

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 6 and 7, Smith Unit 3, and Daniel Units 1 and 2 for inclusion under the GPIF for the period of January 1, 2013 through December 31, 2013.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 29 of Schedule 1 and also on page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and also on page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

Q. Mr. Young, does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 03/1/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 17 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory

Accounting. In January 2004, I became Manager Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all of the cost recovery clauses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2011 through December 2011 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"), the Capacity Cost Recovery Clause ("Capacity Clause") as well as the wholesale incentive benchmark for January 2012 through December 2012.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No.___ (CA-1), consisting of four documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2011 through December 2011?

A. The final true-up amount for the Capacity Clause for the period January 2011 through December 2011 is an under-recovery of $1,311,897.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2011 Through December 2011", provides the calculation for the final under-recovery of $1,311,897. The actual capacity cost under-recovery, including interest, was $1,741,480 for the period January 2011 through December 2011 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $429,583 actual/estimated under-recovery approved in Order No. PSC-11-0579-FOF-EI issued December 16, 2011 in Docket No. 110001-EI, results in a final under-recovery for the period of $1,311,897 as identified in Document No. 1, page 4 of 4. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2013 through December 2013.

Q. What is the estimated effect of this $1,311,897 under-recovery for the January 2011 through December 2011 period on residential bills during January 2013 through December 2013?

A. The $1,311,897 under-recovery will increase a 1,000 kWh residential bill by approximately $0.07.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2011 through December 2011?

A. The final Fuel Clause true-up for the period January 2011 through December 2011 is an over-recovery of $11,885,179. The actual fuel cost over-recovery, including interest, was $59,698,589 for the period January 2011 through December 2011. This $59,698,589 amount, less the $47,813,410 actual/estimated over-recovery amount approved in Order No. PSC-11-0579-FOF-EI, issued December 16, 2011 in Docket No. 110001-EI results in a net over-recovery amount for the period of $11,885,179.

Q. What is the estimated effect of the $11,885,179 over-recovery for the January 2011 through December 2011 period on residential bills during January 2013 through December 2013?

A. The $11,885,179 over-recovery would decrease a 1,000 kWh residential bill by approximately $0.62.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2011 Through December 2011". It shows the calculation of the final fuel over-recovery of

$11,885,179.

Line 1 shows the total company fuel costs of $794,229,163 for the period January 2011 through December 2011. The jurisdictional amount of total fuel costs is $791,086,539, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over-recovered fuel costs for the period, shown on line 4. The resulting $54,528,917 over-recovered fuel costs for the period, combined with a true-up of the revenue refund as part of Tampa Electric's retail rate case stipulation and settlement agreement in Order No. PSC-10-0572-FOF-EI, issued on September 16, 2010 in Docket No. 090368-EI, interest, true-up collected and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery of $59,698,589 shown on line 9. The $59,698,589 actual over-recovery amount less the $47,813,410 actual/estimated over-recovery amount shown on line 10, results in a final $11,885,179 over-recovery amount for the period January 2011 through December 2011 as shown on line 11.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2011 Through December 2011", shows the calculation of the actual over-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2011 through December 2011?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $75,200,397 less than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2011 through December 2011?

A. As shown on line C3 of Document No. 3, the company collected $17,193,967 or 2.0 percent less jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of the transactions for each of Commission Schedules A6, A7, A8, A9 as well as capacity information on schedule A12.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2012, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2012 benchmark is $2,461,613, which is the three-year average of $3,533,488, $2,948,964 and $902,388 actual gains on non-separated wholesale sales, excluding emergency sales, for 2009, 2010 and 2011, respectively.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 8/1/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 17 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all of the cost recovery clauses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2012 through December 2012 fuel and purchased power and capacity true-up amounts to be recovered in the January 2013 through December 2013 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2012, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2013 fuel and purchased power costs and capacity cost recovery factors.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. I have prepared Exhibit No. ____ (CA-2), which contains two documents. Document No. 1 is comprised of Schedules E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-

9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2012 through December 2012. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2012 through December 2012. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2013 through December 2013 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2012 through December 2012 is an over-recovery of $69,319,858.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2013 through December 2013 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2013 is the sum of the final true-up amount for the period January 2011 through December 2011 and the actual/estimated true-up amount for the period January 2012 through December 2012.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2011?

A. The final true-up was an over-recovery of $11,885,179. The actual fuel cost over-recovery, including interest was $59,698,589 for the period January 2011 through December 2011. The $59,698,589 amount, less the actual/estimated over-recovery amount of $47,813,410 approved in Order No. PSC-11-0579-FOF-EI, issued December 16, 2011 in Docket No. 110001-EI resulted in a net over-recovery amount for the period of $11,885,179.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2012 through December 2012?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $57,434,679 for the January 2012 through December 2012 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (CA-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2013 through December 2013 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2013 through December 2013 is an under-recovery of $6,702,505 as shown in Exhibit No. ____ (CA-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2013 through December 2013 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2013 capacity cost recovery factors is the sum of the final true-up amount for 2011 and the actual/estimated true-up amount for January 2012 through December 2012.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2011?

A. The final 2011 true-up is an under-recovery of $1,311,897. The actual capacity cost under-recovery including interest was $1,741,480 for the period January

2011 through December 2011. The $1,741,480 amount, less the actual/estimated under-recovery amount of $429,583 approved in Order No. PSC-11-0579-FOF-EI issued December 16, 2011 in Docket No. 110001-EI results in a net under-recovery amount for the period of $1,311,897 as identified in Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2012 through December 2012?

A. The actual/estimated true-up amount is an under-recovery of $5,390,608 as shown on Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 08/31/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs in the Regulatory Affairs Department.

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 17 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager, Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all cost recovery clauses.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2004, and I testified before this Florida Public Service Commission ("FPSC" or "Commission") in Docket Nos. 060001-EI and 080001-EI regarding the appropriateness and prudence of Tampa Electric's recoverable fuel and purchased power costs as well as capacity costs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2013 through December 2013. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2013.

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

A. Yes. Exhibit No. ____ (CA-3), consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors utilizing the Commission approved allocation methodology from Order No. PSC-09-0283-FOF-EI issued April 30, 2009, in Docket No. 080317-EI based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2013 through December 2013 as well as Schedule H1 for January through December, 2010 through 2013. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 provides the projected monthly Polk 1 Conversion capital costs for the depreciation and return as well as the related fuel savings.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4. The capacity factors reflect the company's approved rate design from Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ____ (CA-3), Document No. 1, Tampa Electric requests recovery of $36,457,223 after jurisdictional separation and prior year true-up, for estimated expenses in 2013.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2013 through December 2013.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.232	
GS and TS Secondary	0.214	
GSD, SBF Standard		
Secondary		0.73
Primary		0.72
Transmission		0.72
IS, IST, SBI		
Primary		0.60
Transmission		0.60
GSD Optional		
Secondary	0.173	
Primary	0.171	
LS1 Secondary	0.060	

These factors are shown in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.201 cents per kWh compare to the factor for January 2012 through December 2012?

A. The proposed capacity cost recovery factor is 0.036 cents per kWh (or $0.36 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.237 cents per kWh for the January 2012 through December 2012 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2013?

A. The appropriate amount for the 2013 period is 3.719 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. _____ (CA-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2013 through December 2013.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa

Electric has calculated a GPIF penalty of $538,019, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2012 through December 2012 period. The net true-up amount for this period is an over-recovery of $69,319,858.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2013 through December 2013. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. ____ (CA-3), Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2013 through December 2013.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	3.719
Tier I (Up to 1,000 kWh)	3.369
Tier II (Over 1,000 kWh)	4.369
Distribution Primary	3.682
Transmission	3.645
Lighting Service	3.697
Distribution Secondary	3.861 (on-peak)
	3.664 (off-peak)
Distribution Primary	3.822 (on-peak)
	3.627 (off-peak)
Transmission	3.784 (on-peak)
	3.591 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.719 cents per kWh compare to the levelized fuel adjustment factor for the January 2012 through December 2012 period?

A. The proposed fuel charge factor is 0.471 cents per kWh (or $4.71 per 1,000 kWh) lower than the average fuel charge factor of 4.190 cents per kWh for the January 2012 through December 2012 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2013 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events reflected in the 2013 projections: continued downward pressure on natural gas prices due to shale gas production after several years of steady price declines; and, the inclusion of Polk 1 capital conversion costs more than offset by the anticipated fuel savings of that project.

Q. Please describe the results of this natural gas pricing event.

A. With the addition of Bayside Station in 2004 and more recently the combustion turbines ("CT's") at Polk, Bayside and Big Bend Stations, Tampa Electric increased its reliance on natural gas as a fuel source. The prolonged economic downturn resulted in a decline in fuel commodity prices, particularly natural gas, which translated into a significant decrease in fuel and purchased power costs over the period. More recently fuel commodity prices have started to stabilize with an expectation of an economic recovery; however, the increase in shale gas production has kept natural gas storage supply levels high preventing any price increases. To mitigate fuel price volatility and comply with the company's Commission-approved Risk Management Plan, financial hedges have been entered into for natural gas in 2012 and 2013. The foundation for the company's natural gas forecast is based on the average of the New York Mercantile Exchange ("NYMEX") natural gas futures contract closing price published during five consecutive business days of between July 19 and July 25, 2012. Tampa Electric witness J. Brent Caldwell's direct testimony describes existing and forecasted natural gas costs and associated hedge results in more detail.

Q. Please describe the Polk 1 conversion project.

A. Under the Polk 1 conversion project the company is requesting to recover through the fuel adjustment clause the capital costs associated with the conversion of certain equipment at the company's integrated gasification combined cycle Polk Unit 1, because that conversion will enable Tampa electric to significantly reduce the input costs of fossil fuel used to operate Polk 1. Docket No. 120153 was established to allow Staff and interested parties to file discovery and review the anticipated project costs as well as the associated fuel savings of the project. Included in Exhibit No. ____ (CA-3), Document No. 4, are the anticipated depreciation costs and return on the project as well as the anticipated fuel savings. As reflected on line 33 of that document the project is projected to provide $595,258 in net fuel savings in 2013. A Commission agenda on the company's proposed petition is currently scheduled for September 18, 2012.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2013?

A. The company's projected 2013 benchmark is $1,365,169, which is the three-year average of $2,948,964, $902,388 and $244,154 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2010, 2011 and 2012 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2013 from non-separated wholesale sales to exceed its 2013 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2013. Therefore, all sales margins will flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its capacity, fuel and purchased power, environmental and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $4.32 beginning January 2013. These charges are shown in Exhibit No. _____ (CA-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2013.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 03/15/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Operations Planning.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In August 2008, I was promoted to Manager, Operations Planning. Currently, I am the Manager of Compliance and Performance responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2011 through December 2011. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, I prepared Exhibit No. _____ (BSB-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2011 - December 2011 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2011 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, respectively.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2011 through December 2011 period?

A. Yes, I have. This is shown on Document No. 1, page 2 of 32. Based upon -0.701 Generating Performance Incentive Points ("GPIP"), the result is a penalty amount of $538,019 for the period.

Q. Please proceed with your review of the actual results for the January 2011 through December 2011 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,885,986,154. This produces the maximum reward amount of $7,670,649 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 32, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 32, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 504.0 planned outage hours were originally scheduled for 2011. Actual outage activities required 509.7 planned outage hours. Consequently, the actual equivalent availability of 80.6 percent is adjusted to 80.7 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 2,089.0 planned outage hours were originally scheduled for 2011. Actual outage activities required 1,499.9 planned outage hours. Consequently, the actual equivalent availability of 57.3 percent is adjusted to 52.7 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 577.0 planned outage hours were originally scheduled for 2011. Actual outage activities required 749.6 planned outage hours. Consequently, the actual equivalent availability of 73.6 percent is adjusted to 75.2 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 576.0 planned outage hours were originally scheduled for 2011. Actual outage activities required 820.7 planned outage hours. Consequently, the actual equivalent availability of 75.5 percent is adjusted to 77.8 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 528.0 planned outage hours were originally scheduled for 2011. Actual outage activities required 384.0 planned outage hours. Consequently, the actual equivalent availability of 78.4 percent is adjusted to 77.0 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 1,848.0 planned outage hours were originally scheduled for 2011. Actual outage activities required 1,853.4 planned outage hours. Consequently, the actual equivalent availability of 77.5 percent is adjusted to 77.6 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 336.0 planned outage hours were originally scheduled for 2011. Actual outage activities required 277.2 planned outage hours. Consequently, the actual equivalent availability of 92.2 percent is adjusted to 91.6 percent, as shown on Document No. 1, page 13 of 32.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32, column 4. This number is entered into the respective GPIP table for each particular unit, shown on pages 7 of 32 through 13 of 32. Page 4 of 32 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's seven GPIF units are shown on Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32, column 9. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 14 through 20 of 32. Page 4 of 32 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2011 through December 2011 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation found on page 32 of 32. The resulting value, -0.701, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the penalty amount is $538,019.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 08/31/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Compliance and Performance.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1993 as a Co-op Student. Upon graduation, I continued my career in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa

Electric's power generating stations including operations, instrumentation and controls, performance planning and asset management. I was promoted to Manager, Operations Planning in 2008. As of 2012, I am the Manager of Compliance and Performance responsible for NERC compliance standards, unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's maintenance planning processes and presents Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor ("GPIF") as ordered by the Commission.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (BSB-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2013 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. One outage from Bayside Unit 1 was identified as an outlying outage; therefore, the associated forced outage hours were removed from the study.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2013 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2013 period, the projected EUOF for Bayside Unit 1 is 1.0 percent, and the POF is 4.9 percent. Therefore, the target EAF for Bayside Unit

1 equals 94.1 percent or:

$$100\% - (1.0\% + 4.9\%) = 94.1\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 1 - [0.80 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80 \ (1.0\%) + 0.95 \ (4.9\%)] = 94.5\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40 \ (EUOF_T) + 1.10 \ (POF_T)]$$

Again, continuing with the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40 \ (1.0\%) + 1.10 \ (4.9\%)] = 93.2\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2013 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2013; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from March 9, 2013 to March 17, 2013 and November 16, 2013 to November 24, 2013. There are 432 planned outage hours scheduled for the 2013 period, and a total of 8760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 4.9 percent or:

$$\frac{432}{8,760} \times 100\% = 4.9\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 6.6 percent. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 21.1 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 9.6 percent. Bayside Unit 1 has a POF of 4.9 percent, and Bayside Unit 2 has a POF of 5.5 percent.

Q. How did you determine the Forced Outage and Maintenance

Outage Factors for each unit?

A. For each unit the most current 12-month ending value, June 2012, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in a EUOF of 1.0 percent for Bayside Unit 1. The EUOF for Bayside Unit 1 is verified by the data shown on page 19, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(0 + 84)}{8,760} \times 100\% = 1.0\%$$

Relative to Bayside Unit 1, the EUOF of 1.0 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected EUOF for this unit is 29.2 percent. The unit will have a planned outage in 2013, and the POF is

6.6 percent. Therefore, the target equivalent availability for this unit is 64.2 percent.

Big Bend Unit 2

The projected EUOF for this unit is 18.7 percent. The unit will have a planned outage in 2013, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 74.8 percent.

Big Bend Unit 3

The projected EUOF for this unit is 18.1 percent. The unit will have a planned outage in 2013, and the POF is 21.1 percent. Therefore, the target equivalent availability for this unit is 60.8 percent.

Big Bend Unit 4

The projected EUOF for this unit is 9.8 percent. The unit will have a planned outage in 2013, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 83.6 percent.

Polk Unit 1

The projected EUOF for this unit is 15.3 percent. The unit will have a planned outage in 2013, and the POF is 9.6 percent. Therefore, the target equivalent availability for this unit is 75.1 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.0 percent. The unit will have a planned outage in 2013, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 94.1 percent.

Bayside Unit 2

The projected EUOF for this unit is 1.3 percent. The unit will have a planned outage in 2013, and the POF is 5.5 percent. Therefore, the target equivalent availability for this unit is 93.2 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 73.5 percent is shown on Page 5 of Document No. 1. This target is greater than the 2009 and 2010 January through December actual performances and the three year period average.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 1 on page 19 of Document No. 1. Except for the months of March and November, the Equivalent Unplanned Outage Rate and the EUOF are equal. This is because no planned outages are scheduled during these months. During the months of March and November, the Equivalent Unplanned Outage Rate exceeds the EUOF due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2013 period.

A. The heat rate target for Big Bend Unit 1 is 10,530

Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±653 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,199 Btu/Net kWh with a range of ±213 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,614 Btu/Net kWh, with a range of ±388 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,536 Btu/Net kWh with a range of ±412 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,437 Btu/Net kWh with a range of ±605 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,177 Btu/Net kWh with a range of ±150 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,325 Btu/Net kWh with a range of ±129 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $746,179,030 is shown on page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $23,316,906 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 8.8 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Bayside Unit 1, page 12, if the unit operates at 7,027 average net operating heat rate, fuel savings would equal $2,051,933 and 10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $23,316,906. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2013 is $2,010,138,931. This produces the maximum allowed jurisdictional incentive of $8,215,862 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met.

Q. Please summarize your testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$
\begin{aligned}
GPIP: = (\; & 0.1046\ EAP_{BB1} + 0.0269\ EAP_{BB2} \\
& + 0.0133\ EAP_{BB3} + 0.0686\ EAP_{BB4} \\
& + 0.0063\ EAP_{PK1} + 0.0005\ EAP_{BAY1} \\
& + 0.0199\ EAP_{BAY2} + 0.1782\ HRP_{BB1} \\
& + 0.0598\ HRP_{BB2} + 0.1075\ HRP_{BB3} \\
& + 0.1121\ HRP_{BB4} + 0.1391\ HRP_{PK1} \\
& + 0.0880\ HRP_{BAY1} + 0.0750\ HRP_{BAY2})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2013 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 8/31/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing group within the Fuels Management Department.

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and am a registered Professional Engineer within the State of Florida. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of

Energy Products and Structures in the Wholesale Marketing group. My responsibilities are to evaluate short and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale contract structure and help evaluate the processes used to value wholesale power opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers and other wholesale generators.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 030001-EI, 040001-EI, and 080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchased power needs and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, supplement generation during unit outages, and for economical purposes. When there is a purchased power need, the company aggressively searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs.

The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company's contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2012 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short and long-term purchases based on price and availability of supply. Approximately seven percent of the expected energy needs for 2012 will be met using purchased power. This purchased power energy includes economy purchases and existing firm purchased power agreements with Hardee Power Partners, RRI Energy Services (formerly known as Reliant), Pasco Cogen, qualifying facilities, and a new Calpine purchase. The RRI Energy Services purchase ended as of June 2012, and the Hardee Power Partners purchase continues through December 2012.

With the exception of the Calpine purchase, the testimony in previous years describes each existing firm purchased power agreement, which were subsequently approved by the Commission as being cost-effective for Tampa Electric customers. The current Calpine purchase, further described herein, results from the company's May 2011 solicitation for proposals. All of the aforementioned purchases provide supply reliability and help reduce fuel price volatility.

In addition to these purchases, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Has Tampa Electric entered into any other wholesale energy purchases beyond 2012?

A. Yes. As mentioned in my testimony submitted in 2011, Tampa Electric issued a solicitation for proposals (*i.e.*, request to purchase power) to the marketplace in May 2011. The purpose of the solicitation was to evaluate firm power purchase options capable of filling the company's 2013-2015 reserve margin needs, as shown in the company's 2011 Ten Year Site Plan. From this process, the company signed two new purchased power agreements--one with Calpine for 117 MW that began November 2011, and one with Southern Power Company for 160 MW that will begin January 2013.

The Calpine purchase is a natural gas peaking product and is the same 117 MW Auburndale resource that served customers during the 2011 summer season. Although the company's solicitation was for proposals beginning in 2013, Calpine proposed a low price option that began in 2011 and continues through 2016. An economic analysis of the earlier start date proposal showed $16.1 million of benefits to customers. This economic benefit, combined with the product also being available to provide coverage for unplanned unit outages and incremental peak demand needs, resulted in the November 2011 start date being in the best interest for Tampa Electric customers.

The Southern Power Company purchase is a 160 MW natural gas peaking product from their Oleander generating facility in Brevard County, Florida. The purchase begins January 2013, continues through 2015, and provides $16.6 million of benefits to customers. The purchase also contains an option to extend it for a period of two years (*i.e.*, 2016-2017). In addition to the economic benefits, both the Southern Power Company and Calpine purchases provide customers with additional supply protection for unplanned unit outages; market price volatility protection, because its energy price is based on a contracted heat rate; and fuel supply certainty, because of their dual fuel capability.

Q. Does Tampa Electric anticipate entering into any other wholesale energy purchases for 2013 and beyond?

A. In 2013, the Tampa Electric expects purchased power to meet approximately four percent of its energy needs. This energy includes contributions from the previously mentioned firm purchases. In addition, the company will continue to evaluate the short-term purchased power market as part of its purchasing strategy.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale power products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The Florida wholesale power market currently operates through bilateral contracts between various counterparties, and there is not a Florida trading hub where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity, the appropriate financial instruments to meet the company's needs do not currently exist. Tampa Electric has not purchased any wholesale energy derivatives; however, the company employs a diversified power supply strategy, which includes self-generation, short and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2012?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 117 MW Calpine purchase and the 121 MW purchase from Pasco Cogen are reliable, cost-based call options for power. These purchases serve as both a physical hedge and reliable source of economic power in 2012. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company's own generation for the year 2012 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather related events such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions during major weather related events. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing the seller's fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, most of the company's purchased power products, such as the RRI Energy Services and Pasco Cogen purchases, are from dual-fuel resources. This allows these resources to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short- and long-term purchase opportunities identified in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2012 and 2013.

A. Tampa Electric entered into various non-separated wholesale sales in 2012, and the company anticipates making additional non-separated sales during the balance of 2012 and in 2013. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2012, Tampa Electric anticipates its gains from non-separated wholesale sales to be $244,154, of which 100 percent would flow back to customers since they are less than the three-year rolling average threshold of $2,461,614. Similarly, in 2013, the company's projected gains from non-separated wholesale sales are $485,483, of which 100 percent would flow back to customers since they are less than the projected 2013 three-year rolling average threshold of $1,365,169.

The company also entered into a separated sale transaction with Florida Power & Light for calendar year 2012. This firm sale commits capacity that is a different amount each month, and that monthly amount varies within the range of 25 to 125 MW. In accordance with the Commission's March 11, 1997 Order, No.

PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, Tampa Electric separates the capacity associated with this sale from the retail jurisdiction in its monthly surveillance reporting and credits system average fuel to the fuel clause for all energy served under the sale.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. It also enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the Florida wholesale power market due to a lack of financial instruments appropriate for the company's operations. It does, however, employ a diversified power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 04/02/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

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

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering from the University of South Florida in 1988. I have over 16 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems and analysis. In October 2010 I assumed my current position where I am responsible for the long term fuel supply planning and procurement for Tampa Electric's generation plants.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Florida Public Service Commission's ("FPSC" or "Commission") review, information regarding the 2011 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. ___ (JBC-1), entitled Tampa Electric's 2011 Hedging Activity True-up, was prepared under my direction and supervision. This report explains the company's risk management activities and results for the calendar year 2011.

Q. What is the source of the data you present in your testimony in this proceeding?

A. Unless otherwise indicated, the source of the data is the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. What were the results of Tampa Electric's risk management activities in 2011?

A. As outlined in Tampa Electric's 2011 Hedging Activity True-up, filed as an exhibit to this testimony, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In particular, Tampa Electric established a financial hedging program to limit its exposure to spikes in the price of natural gas. Over time, this program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

The report indicates that Tampa Electric's 2011 hedging activities resulted in a net loss of approximately $34 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. A decrease in natural gas prices began in the middle of 2008 due to lower demand as a result of the recession as well as from increased supply from non-conventional, shale gas production. Natural gas prices continue to stay at a low price due to this supply surplus and have been further reduced by mild temperatures nationally.

Q. Does Tampa Electric implement physical hedges for natural gas?

A. No, Tampa Electric does not hedge natural gas pricing through physical gas supply contracts. However, Tampa Electric does hedge its supply through diversification. In addition to financial hedging, Tampa Electric uses a variety of sources, delivery methods, inventory locations and contractual terms to enhance the company's supply reliability and flexibility to cost-effectively meet changing operational needs.

Tampa Electric continually pursues new creditworthy counterparties and maintains contracts for gas supplies from various regions and on different pipelines. The company also contracts for pipeline capacity to access non-conventional shale gas production which is less sensitive to interruption by hurricanes. Additionally, Tampa Electric has storage capacity with Bay Gas Storage near Mobile, Alabama. All of these actions enhance the effectiveness of Tampa Electric's gas supply portfolio.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, risk exposure analysis and business report generation functions. The Nucleus system records all financial natural gas hedging transactions, and the system calculates risk management reports.

Q. Did the company use financial hedges for commodities other than natural gas in 2011?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2011.

Tampa Electric's generation is comprised mostly of coal and natural gas. Although the price of coal has increased, it is relatively stable compared to the prices of oil and natural gas. In addition, there is not an organized and liquid market for financial hedging instruments for the high-sulfur Illinois Basin coal that Tampa Electric uses at Big Bend Station, its largest coal-fired generation facility.

Tampa Electric consumes a small amount of oil; however, its low and erratic usage pattern makes price hedging impractical.

Similarly, Tampa Electric did not use financial hedges for wholesale energy transactions because a liquid, published market does not exist for power in Florida.

Q. How does Tampa Electric assure physical supply of other commodities?

A. Tampa Electric assures sufficient physical supply of coal and oil through inventory supply diversification, and bi-modal delivery options for coal. For coal, the company entered into a portfolio of contracts with differing terms and various suppliers to obtain the types of coal used on its system. Additionally in 2009, Tampa Electric added rail delivery capability for coal to Big Bend Station. The addition of rail to the already existing waterborne transportation enhances Tampa Electric's access to coal supply and increases the reliability.

For oil, Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. Tampa Electric requests cost recovery pursuant to the Commission Order No. PSC-02-1484-FOF-EI, in Docket No. 011605-EI that states:

> "Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas."

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

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

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering from University of South Florida in 1988. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed the long-term fuel origination responsibilities of Joann Wehle who was the previous witness in the fuel docket.

Q. Are you the same J. Brent Caldwell who previously filed direct testimony on behalf of Tampa Electric Company in this docket?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. ____ (JBC-2), entitled Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2013.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe this Exhibit.

A. My Exhibit, No. ____ (JBC-2) sets forth all of the various details of Tampa Electric's overall plan for mitigating risk in the company's procurement of generation fuel and purchased power during 2013.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120001-EI
FILED: 08/15/2012

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Are you the same J. Brent Caldwell who previously filed direct testimony on behalf of Tampa Electric Company in this docket?

A. Yes, I am.

Q. What is the purpose of your current testimony?

A. The purpose of my testimony is to sponsor and describe my Exhibit No. (JBC-3), entitled Tampa Electric Natural Gas Hedging Activities, January - July 2012.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe this exhibit.

A. My Exhibit ___ (JBC-3) shows details of Tampa Electric's hedging activities for natural gas for the seven month period January through July 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

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

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering in 1988 from the University of South Florida. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long-term fuel origination.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities. I also sponsor Tampa Electric's 2013 Fuel Procurement and Wholesale Power Purchases Risk Management Plan and Hedging Report submitted on August 1, and August 15, 2012 in this docket.

Q. Have you previously submitted testimony to this Commission?

A. Yes. I have filed testimony before this Commission in this docket since 2011.

2013 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2013?

A. In 2013, coal-fired generation is expected to be approximately 60 percent and natural-gas fired generation

40 percent of total generation. Generation from oil is expected to be less than one percent of the total expected generation.

Q. Please describe Tampa Electric's fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all of its fuel needs. The company strives to maintain a large number of creditworthy and viable suppliers. Tampa Electric also attempts to diversify the location from which its supply is sourced. Similarly, the company attempts to maintain multiple delivery paths wherever possible. Tampa Electric believes that increasing the number of fuel supply options provides increased reliability and lower costs for customers.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy.

A. Tampa Electric uses solid fuel as the sole fuel for the four pulverized-coal steam turbine units at Big Bend Station and as the primary fuel for the integrated-gasification combine cycle Unit One at Polk Station. The coal-fired units at Big Bend Station are all fully scrubbed for sulfur-dioxide and nitrogen-oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit One currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, price, availability, deliverability and creditworthiness of the supplier.

To minimize cost, maintain operational flexibility, and ensure reliable supply, Tampa Electric maintains a portfolio of bilateral coal supply contracts with varying term lengths: long, intermediate, and short. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market and shaping the company's coal procurement strategy to reflect current market conditions. This allows for stable supply of reliable sources while still providing flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize Tampa Electric's solid fuel, coal and petroleum coke, supply for 2012.

A. Tampa Electric supplied Big Bend's coal needs through a combination of two "base" coal supply agreements that continue through 2014 and a collection of shorter term contracts and spot purchases. These shorter term purchases allowed the supply to adjust for changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2013 delivery?

A. Yes, Tampa Electric has contracted approximately two-thirds of its 2013 expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Tampa Electric anticipates the remaining solid fuel purchases for Big Bend Station and Polk Unit 1 will be procured through spot market purchases during the balance of 2012 and in 2013.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements?

A. Tampa Electric can receive coal at its Big Bend Station via both waterborne delivery and rail delivery. Once delivered to Big Bend Station, Polk Unit 1 solid fuel is transported to Polk Station via trucks.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitively priced and diverse, delivered coal, 2) the flexibility to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. How was Tampa Electric impacted by the severe drought conditions in the Ohio River Valley?

A. There has been some media attention to the recent drought that has plagued the central U.S. and navigation along the Mississippi River system. Tampa Electric, to date, has not encountered any difficulties in transporting its coal. Although, there have been some delays in transit times and reductions in barge tow sizes, Tampa Electric has sufficient inventory at its plants and terminal facilities and does not anticipate any adverse inventory impacts. Tampa Electric and its ratepayers continue to enjoy the benefits of bi-modal transportation in terms of increased reliability and fuel diversity.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2012 and 2013?

A. Yes. Tampa Electric expects to receive over 1.7 million tons of coal in 2013 for use at Big Bend through the Big Bend rail facility.

As part of the CSX transportation agreement, Tampa Electric receives a per ton reimbursement for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause pursuant to the company's most recent rate case final order.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries?

A. Tampa Electric expects to receive the balance of its solid fuel supply needs as waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries may come through United Bulk Terminal, from other terminals along the Gulf Coast, or from foreign sources. The ultimate source is dependent upon quality, operational needs, and lowest overall delivered cost.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long and short term deliveries?

A. Similar to its coal strategy, Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate and swing natural gas supply contracts complemented with shorter term spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from approved counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric has improved the reliability and cost effectiveness of the physical delivery of natural gas to its power plants by diversifying its pipeline transportation assets, including receipt points, and utilizing pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. On a daily basis, Tampa Electric strives to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric's risk management activities reduce natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation arrangements.

A. Tampa Electric receives natural gas via the Florida Gas

Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. The ability to deliver natural gas directly from two pipelines enhances the fuel delivery reliability of the Bayside Power Station, comprised of two large natural gas combine-cycle units and four aero derivative combustion turbines. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the aero derivative combustion turbine and to Polk Station from FGT to support the four natural gas combustion turbines at that station.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama to provide operational flexibility and reliability of natural gas supply. Currently the company reserves 1,250,000 MMBtu of storage capacity.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH"). SESH connects the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase through non-conventional shale gas and the Rockies Express. Thus, SESH gives Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Has Tampa Electric entered any natural gas supply transactions for 2013 delivery?

A. Yes, by the end of October 2012, over two-thirds of the company's expected natural gas requirements will be under contract.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long, intermediate, and short term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Projected 2013 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), Wood Mackenzie, the Energy Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices and are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2013 projected fuel prices compare to the fuel prices projected for 2012?

A. Fuel prices are projected to be lower in 2013 than prices projected for 2012. However, natural gas prices are projected to be higher in 2013 than actual natural gas prices in 2012. Natural gas prices in 2012 were particularly low due to the extremely mild winter of 2012, the continuing stagnation of the economy, and abundant shale gas production.

Q. What are the market drivers of the expected 2013 price of natural gas?

A. The current market forecasts are projecting a slight increase to natural gas pricing in 2013 as compared to actual and estimated 2012 costs. An anticipated improvement to the economy, a return to more normal winter weather pattern in 2012 and 2013, and market adjustment to shale gas production is expected to slightly raise the price in 2013 compared to 2012.

Q. What are the market drivers of the change in the price of coal?

A. International demand for coal and petroleum coke has increased the price of coal for several years, and particularly in early 2012 for Illinois Basin coal as it found ways to be exported to Europe, South Africa and India. Additionally, the addition of FGD scrubbers on a number of coal plants has made the lower cost Illinois Basin coal viable in those units thus increasing the demand and price for Illinois Basin coal. Conversely, low natural gas prices caused higher cost coal-fired generation to be displaced by lower cost natural gas combined cycle units. These changes are expected to cap the price of Illinois Basin coal in 2013 at a level similar to the price in 2012. And, with the contract pricing of Tampa Electric's base agreements, most of the impact of coal market price changes should be mitigated through 2014.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected fuel prices?

A. Yes. Tampa Electric prepared a scenario in which the forecasted fuel prices were 35 percent higher for both natural gas and No. 2 oil. Similarly, Tampa Electric prepared a scenario in which the forecasted fuel prices were 35 percent lower for both natural gas and No. 2 oil. Due to Tampa Electric's generating mix as well as its Commission approved hedging strategy the impact the fuel cost under either scenario is mitigated.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Risk Management plan filed August 1, 2012 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2012 and 2013 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2012 natural gas supply needs and a portion of its expected 2013 natural gas supply needs in accordance with its plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with the company's approved Fuel Procurement and Wholesale Power Purchases Risk Management Plan. The current market position for natural gas hedges was provided in the company's Hedging Information Report submitted on August 15, 2012.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2012 and 2013 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are described in detail in Tampa Electric's Fuel Procurement and Wholesale Power Purchases Risk Management Plan filed August 1, 2012.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. Tampa Electric projects the quantity or volume of natural gas expected to be consumed in its power plants. The volume hedged is driven by the projected total natural gas consumption in its combined-cycle plants by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee and monitored by the Risk Management department. The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through July 31, 2012 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee. On April 2, 2012, the company filed its 2011 hedging results as part of the final true-up process. Additionally, Commission Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, requires the utilities to file a Hedging Information Report showing the results of hedging activities from January through July of the current year. The Hedging Information Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Hedging Information Report showing the results of its prudent hedging activities from January through July 2012 in this docket on August 15, 2012.

Q. Does Tampa Electric expect its hedging program to provide fuel savings?

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric employs a well-disciplined hedging program. This discipline requires consistent hedging based on expected needs and avoidance of speculative hedging strategies aimed at out-guessing the market. This discipline insures hedges will be in place should prices spike and also means hedges are in place when prices decline. Using this disciplined approach means that much of the volatility and uncertainty in natural gas prices are removed from the fuel cost used to generate electricity for our customers, but does not guarantee fuel savings.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF JOCELYN Y. STEPHENS

DOCKET NO. 120001-EI

SEPTEMBER 28, 2012

Q. Please state your name and business address.

A. My name is Jocelyn Y. Stephens. My business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Professional Accountant Specialist in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since January 1977.

Q. Briefly review your educational and professional background.

A. In 1972, I received a Bachelor of Science degree from Florida State University with a major in accounting. I am also a Certified Public Accountant licensed in the State of Florida.

Q. Please describe your current responsibilities.

A. My current responsibilities include planning and managing investigative audits. On an ongoing basis I manage conservation, capacity, environmental, hedging and rate cases. I also perform financial audits of electric, gas, and water and wastewater utilities.

Q. Have you previously presented testimony before this Commission?

A. Yes. I presented testimony in the Fuel and Purchased Power Cost Recovery Clause with generating performance incentive factor Docket Numbers 090001-EI and 030001-EI; Florida Cities Water Co., (South Fort Myers) transfer of certificate, Docket No. 910447-SU; Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc., Docket No. 041272-EI; and the Petition for rate increase by Peoples Gas System, Docket No. 080318-GU.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff's audit report of Progress Energy Florida, Inc. (PEF or Utility) which addresses the Utility's August 1, 2011, through July 31, 2012, hedging activities. The audit report is filed with my testimony and is identified as Exhibit JYS-1.

Q. Was this audit prepared by you or under your direction?

A. Yes. The audit was prepared by me.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

I reviewed PEF's supporting detail of the hedging settlements for the twelve months ended July 31, 2012. I traced the monthly balances of hedging transactions from PEF's Hedging Results Report for the period August 1, 2011, to December 30, 2011, and its Hedging Information Report for the period January 1, 2012 to July 31, 2012 to its Hedging Summary by Commodity Reports for 2011 and 2012. I selected 23 natural gas hedging transactions from August 2011 through July 2012 as a sample and traced them from the Hedging Results and Hedging Information Reports to the third-party confirmation notices, contracts and to the general ledger. I verified that the hedging settlements were in compliance with the Risk Management Plan. No exceptions were noted.

Gains and Losses

I recalculated the gains and losses by multiplying the volume by the difference between the fixed price and the settlement price from the trade confirmation documents and compared them to the recorded gains and losses per the general ledger. No exceptions were noted.

Hedged Volume and Limits

I obtained and reviewed PEF's Risk Management Plan. I reviewed the quantity limits and authorizations for all hedged fuel types. No variances were noted for natural gas. The actual monthly volumes of hedged burns for Numbers 6 and 2 Oils and Barge and Rail Transportation varied, but on an annual basis, all fell between the allowable percentages of actual and projected burn volumes. No exceptions were noted.

Separation of Duties

I reviewed PEF's written procedures for separation of duties related to hedging activities. I reviewed the evaluations performed by PEF's Audit Services Department and the external auditor's report. Both concluded that effective internal controls were in place in separating hedging activities.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DONNA D. BROWN

DOCKET NO. 120001-EI

SEPTEMBER 28, 2012

Q. Please state your name and business address.

A. My name is Donna D. Brown. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Professional Accountant in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since February 2008.

Q. Briefly review your educational and professional background.

A. I graduated from Florida A&M University's School of Business & Industry in 2006 with a Bachelor of Arts degree in accounting.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you presented testimony before this Commission or any other regulatory agency?

A. Yes. I filed testimony in Docket No. 110001-EI related to Gulf Power Company's Hedging Activities.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Gulf Power

Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 120001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 24, 2012. This audit report is filed with my testimony and is identified as Exhibit DDB-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2012. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

We traced the monthly balances of all hedging transactions from Gulf's Hedging Information Report to its transaction report and its general ledger for the period August 1, 2011 to July 31, 2012. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the confirmation notice, and compared the price to the gas futures rates published by the New York Mercantile Exchange (NYMEX) Henry Hub Gas futures contract rates. We compared these recalculated gains and losses with Gulf's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained Gulf's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2012, and compared them with the Utility's Risk Management Plan. There were immaterial variances for all the months between the percentages of actual and projected gas burned that were hedged, however the total variance for the year was within the limits in the Risk Management Plan and were accepted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. Audit staff reviewed the only internal audit specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this audit report, Exhibit DDB-1.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF KATHY L. WELCH

DOCKET NO. 120001-EI

SEPTEMBER 28, 2012

Q. Please state your name and business address.

A. My name is Kathy L. Welch, and my business address is 3625 N.W. 82nd Ave., Suite 400, Miami, Florida, 33166.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Public Utilities Supervisor in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since June, 1979.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Business Administration degree with a major in accounting from Florida Atlantic University and a Masters of Adult Education and Human Resource Development from Florida International University. I have a Certified Public Manager certificate from Florida State University. I am also a Certified Public Accountant licensed in the State of Florida, and I am a member of the American and Florida Institutes of Certified Public Accountants. I was hired as a Public Utilities Analyst I by the Florida Public Service Commission in June of 1979. I was promoted to Public Utilities Supervisor on June 1, 2001.

Q. Please describe your current responsibilities.

A. Currently, I am a Public Utilities Supervisor with the responsibilities of administering the District Office and reviewing work load and allocating resources to complete field work and issue audit reports when due. I also supervise, plan, and conduct utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you presented testimony before this Commission or any other regulatory agency?

A. Yes. I have testified in several cases before the Florida Public Service Commission. Exhibit KLW-1 lists these cases.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Public Utilities Company (FPUC or Utility) which addresses the Utility's filing in Docket No. 120001-EI Fuel Cost Recovery Clause. We issued an audit report in this docket on April 10, 2012. This audit report is filed with my testimony and is identified as Exhibit KLW-2.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have broken the audit work into the following categories.

<u>Revenue</u>

We reconciled the revenues in the ledger to the filing. We reconciled KWH usage to the billing system reports and recalculated the rates charged using ledger revenue divided by KWH usage and by testing individual bills and comparing them to the order rates.

<u>Expense</u>

We reconciled the expenses in the ledger to the filing. We traced the ledger detail to invoices. We traced the rates used in the co-generation invoices to the contracts and reviewed the utility testing of the invoices to the contracts. We verified the deduction of large use supplier revenues from the cost of fuel. We traced miscellaneous costs to supporting documentation.

True-up

We recalculated the true-up and interest provision amounts as of December 31, 2011 using the Commission approved beginning balance as of December 31, 2010, the Commercial paper rates, and the 2011 Fuel Revenues and Costs.

Q. Please review the audit findings in this audit report, Exhibit KLW-2.

A. There was one finding in this audit related to legal and outside professional work included in the Utility's fuel cost. Some legal invoices for the mid-course correction work were charged to Fernandina Beach. The mid-course correction was only for Marianna. Therefore $2,874 in charges made to Fernandina Beach should be transferred from Fernandina Beach to Marianna with $4 of interest.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF RONALD A. MAVRIDES

DOCKET NO. 120001-EI

SETEMBER 28, 2012

Q. Please state your name and business address.

A. My name is Ronald A. Mavrides. My business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Public Utility Analyst in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since October, 2007.

Q. Briefly review your educational and professional background.

A. In 1990, I received a Bachelor of Science Degree from the University of Central Florida with a major in accounting. I am also a Certified Government Auditing Professional and a Certified Management Accountant.

Q. Please describe your current responsibilities.

A. My current responsibilities include managing audits for conservation, capacity, environmental, nuclear, hedging, and rate cases. I also perform financial audits of electric, gas, and water and wastewater utilities.

Q. Have you previously presented testimony before this Commission?

A. Yes. I presented testimony in the Fuel and Purchased Power Cost Recovery Clause Docket Nos. 090001-EI and 110001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff's audit report of Tampa Electric Company (Company or Utility) which addresses the Utility's August 1, 2011, through July 31, 2012, hedging activities. The audit report is filed with my testimony and is identified as Exhibit RAM-1.

Q. Was this audit prepared by you or under your direction?

A. Yes. The audit was prepared by me.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

I reviewed TECO's Hedging Information Reports filed on April 1, 2011, and August, 16, 2012. I examined the report for reasonableness and used it as a basis for our sample tests. I requested a listing of each futures, options, and swap contracts executed by TECO for the 12-month period covered by the Hedging Information Report. I requested the volumes for each fuel TECO actually hedged using a fixed price contract or instrument. TECO only hedges natural gas. I tested 33 sample transactions, choosing two months of transactions from the 12-month period for natural gas, the only fuel type hedged. I traced the transactions to the general ledger and trade confirmation documents. No exceptions were noted.

Gains and Losses

I recalculated the gains and losses by multiplying the volume by the difference between the fixed price and the settlement price from the trade confirmation documents, and compared them to the recorded gains and losses per the general ledger. No exceptions were noted.

Hedged Volume and Limits

I obtained and reviewed TECO's Risk Management Plan. I compared the percentage limits of purchased power hedged in the Risk Management Plan with the actual volumes of hedged burns. The actual volumes of hedged burns varied from some of the percentage limits delineated in the Risk Management Plan.

Separation of Duties

I reviewed TECO's written procedures for separation of duties related to hedging activities. There were no internal and external auditor's workpapers specifically addressing the separation of duties. No exceptions were noted.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF YEN NGO

DOCKET NO. 120001-EI

SEPTEMBER 28, 2012

Q. Please state your name and business address.

A. My name is Yen Ngo, and my business address is 3625 N.W. 82nd Ave., Suite 400, Miami, Florida, 33166.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst IV in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since February, 1995.

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Business Administration degree with a major in accounting from Florida Atlantic University in 1994.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you presented testimony before this Commission or any other regulatory agency?

A. Yes. I filed testimony in Docket No. 120009-EI related to Florida Power & Light Company's Proposed Turkey Point Units 6 and 7.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Power &

Light Company (FPL or Utility) which addresses the Utility's filing in Docket No. 120001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 20, 2012. This audit report is filed with my testimony and is identified as Exhibit YN-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

We obtained FPL's supporting detail of the hedging settlements for the twelve months ended July 31, 2012. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

We traced the monthly balances of hedging transactions from FPL's April 2 and August 15, 2012 filings in this docket for the period August 1, 2011 to July 31, 2012 to FPL's Derivative Settlement Report. We selected 46 hedging transactions from two counterparties from May and June 2012 for natural gas, and eight hedging transactions from two counterparties in May 2012 for heavy oil as a sample and traced them from the Derivative Settlement Report to the third-party confirmation notices and contracts. FPL does not have any tolling agreements where natural gas is provided to generators under purchase power agreements. We recalculated the gains and losses, traced the price to the confirmation notice, and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with FPL's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained FPL's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2012, and compared them with the Utility's Risk Management Plan. There were variances for one of the twelve months between the percentages of actual and projected natural gas burned that were hedged, and for six of the twelve months between the percentages of actual and projected heavy oil. All variances were a result of inaccurate burn forecasting.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. However, all external audit work papers were reviewed in Docket No. 120015-EI. No exceptions were noted.

Q. Please review the audit findings in this audit report, Exhibit YN-1.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

CHAIRMAN BRISÉ: All right. Okay. At this point we have heard from the witness and we have dealt with all the testimony, so I guess we're at a decision point. Okay. Staff?

MR. MOYLE: I think, I think we were going to brief it. That was the intent of FIPUG, to submit written briefs on the issue.

MS. TRIPLETT: Well, of course, if we, if the Commission, it would be helpful for briefs, we're happy to do it, although I think you may have enough to make a bench decision, if you wanted to.

CHAIRMAN BRISÉ: Okay. Thank you. And I guess that will be up to my fellow Commissioners and I to determine if we have enough on Issues 1C and 1D to, to make a decision this morning. So, Commissioners? Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. If the time frames allow, I would appreciate the additional information on the legal issues that briefs can provide. And also one question. I know that FPL was excused, but I guess I was thinking that they were going to file a brief as well.

CHAIRMAN BRISÉ: Right.

COMMISSIONER EDGAR: Or was that a misunderstanding?

CHAIRMAN BRISÉ: No. My understanding is they are filing briefs.

COMMISSIONER EDGAR: Okay. So that would be for 24B through D?

CHAIRMAN BRISÉ: B through D.

COMMISSIONER EDGAR: Okay. Thank you.

MR. REHWINKEL: Mr. Chairman, if I might.

CHAIRMAN BRISÉ: Yes, sir. Sorry.

MR. REHWINKEL: I think Issue 1C, the issue on the amount of the refund, Issue 1C, that was raised by the Public Counsel. And I can state for the record that we now do not have a concern about that issue. So if that's helpful to the parties though, our position is we would agree with, with Progress on that, for what it's worth. I don't believe it needs to be briefed at this point.

CHAIRMAN BRISÉ: Okay. Thank you.

Mr. Brew.

MR. BREW: PCS would agree with that.

CHAIRMAN BRISÉ: All right.

MR. MOYLE: As would FIPUG. We have no quarrel with 1C. It's 1D that we would like to have the opportunity to brief.

CHAIRMAN BRISÉ: Sure. Understood.

All right. Okay. Go ahead, Commissioner

Edgar.

COMMISSIONER EDGAR: I'm sorry. So would that be, from what has just been shared with us, would that reflect a change in positions for OPC, FEA, and FIPUG on Issue 1C?

MR. MOYLE: FIPUG would just take no position and make it ripe for, I guess, a type B stipulation.

COMMISSIONER EDGAR: Okay. Well, then -- I mean, "no position" is different than "no" the way the question is worded.

CHAIRMAN BRISÉ: Right.

COMMISSIONER EDGAR: So that's a change in position?

MR. MOYLE: Yes, ma'am.

COMMISSIONER EDGAR: Okay. Which, I mean -- which my understanding from earlier in the day is a change from what the Prehearing Order required, but yet at our discretion we are allowed to do, so I just wanted to be clear.

MS. BARRERA: That's correct.

COMMISSIONER EDGAR: Okay. Thank you.

CHAIRMAN BRISÉ: All right. Thank you.

So does that put us in a different posture with respect to 1C? Commissioners.

MS. BARRERA: Yes, Commissioner, at this point it would be a type B stipulation. And should the Commission prefer, it can make a decision on that issue.

CHAIRMAN BRISÉ: Okay. Thank you.

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. If it's appropriate, I'm prepared to make a motion. And I move that on Issue 1C we find that the answer is yes as far as to the question of has PEF correctly reflected, et cetera, et cetera.

CHAIRMAN BRISÉ: Okay. It's been moved. Is there a second?

COMMISSIONER EDGAR: Second.

CHAIRMAN BRISÉ: Okay. Any further discussion or comments? Seeing none, all in favor, say aye.

(Vote taken.)

Okay. So we have approved Issue 1C, so therefore that issue does not have to be briefed.

Commissioner Edgar.

COMMISSIONER EDGAR: I'm sorry, Mr. Chairman. I just wanted to clarify for the record, I did make the motion by which we approved all of the stipulations, and in that motion I said that it would be all stipulations in the amended Prehearing Order. And I think it's encompassed, but I just want to make sure for the record that my intent was to also include the language on

Exhibit 115, which was a little additional information to the stipulation on Issue 32. And I think that that was included, that was certainly my intent, but just for clarity I wanted to state that.

CHAIRMAN BRISÉ: Thank you, Commissioner Edgar, for that clarification.

All right. So with Issue 1D, it seems that there is an interest from the Commission to, to have briefs on that. And as we stated before, briefs are due November 13th, 2012, by 9:30 a.m., at which time staff will then prepare a recommendation that will be before us at the 27th of November Agenda Conference.

Are there any other matters that we need to deal with at this time?

MS. BARRERA: No, sir.

CHAIRMAN BRISÉ: All right. Thank you.

The final order in this case will be issued by December 21st, 2012. November 12 -- November 27th will be our bench decision, as stated earlier.

With that, we're going to say thank you to all of you for your participation. Thank you, staff, for your hard work on all of these dockets. Mr. Prehearing Officer, Commissioner Balbis, thank you for your hard work. And with that, we adjourn.

(Proceeding adjourned at 12:19 p.m.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTERS
COUNTY OF LEON)

WE, LINDA BOLES, CRR, RPR, and JANE FAUROT, RPR, Official Commission Reporters, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 7th day of November, 2012.

Jane Faurot Linda Boles

JANE FAUROT, RPR LINDA BOLES, CRR, RPR

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