BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110009-EI

In the Matter of:

NUCLEAR COST RECOVERY CLAUSE.
_______________________________/

VOLUME 9
Pages 1324 through 1530

PROCEEDINGS: HEARING

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

DATE: Tuesday, August 16, 2011

TIME: Commenced at 9:30 a.m.
Concluded at 10:58 a.m.

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

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6732

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
135			1388
136			1388
137			1388
138			1413
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140			1413
141			1413
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143			1413
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177			1387
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179			1387
180			1387
181			1387
182			1387
203	Proposed Stipulations	1353	1354

EXHIBITS

NUMBER:		ID.	ADMTD.
204	Coston/Carpenter Depo	1353	1354

P R O C E E D I N G S

(Transcript follows in sequence from Volume 8.)

CHAIRMAN GRAHAM: Good morning, everyone.

MR. MOYLE: Good morning.

MR. WHITLOCK: Good morning.

CHAIRMAN GRAHAM: I am glad that everybody's here this morning and looking healthy.

I want to go over a few small little details, as we did last week. Let you know that we will be taking a five-minute break every two hours for the court reporter so she can rest her little fingers. We're probably going to shoot for taking lunch between 1:00 and 1:30, so if you guys could plan accordingly. And if you're interested in eating lunch on site, we'll have the, the Internal Affairs room open over here next-door, or you can go upstairs to Room 234, and there's plenty of table and seats up there.

If this does go to Friday, we plan on ending Friday probably about 1:00, 1:30 as well, so everybody can go and take care of what else you need to do, whatever you didn't do all week long, and then you can enjoy your weekend.

And there's one last thing I want to remind everybody of, and I'm sure Mr. Baldwyn over there knows exactly what this is, if you can reach down and make sure your phone is on silent or vibrate so we can move forward accordingly.

That all being said, we will officially reconvene the hearing. It's Docket Number 110009-EI. And that all being said, I think -- preliminary matters. Staff.

MR. YOUNG: Good morning, Commissioners.

Staff will note that the parties have a proposed stipulation they would like to present to the Commission before beginning the Progress Energy portion, Progress Energy Florida portion of the hearing, of this proceeding.

The proposed stipulation is attached as Attachment 1 to the script, and the effects of the approval of the stipulation, of the remaining issues, is attached as Attachment 2.

Also, you have a, you should have received a sheet labeled Proposed Stipulations that lists, that lists Progress's draft preliminary issues, that lists Progress's draft preliminary issues on the -- positions, excuse me, on the issues.

CHAIRMAN GRAHAM: Okay. I guess we'll go with OPC, Mr. Rehwinkel.

MR. REHWINKEL: Take appearances?

CHAIRMAN GRAHAM: Okay. We'll do that first. We'll take appearances first. Let's see who's here. Somebody.

MR. BURNETT: Good morning, sir. John Burnett for Progress Energy Florida, and with me I have Alex Glenn, Mike Walls, and Blaise Huhta.

MR. WHITLOCK: Good morning, Mr. Chairman, Commissioners. Jamie Whitlock on behalf of the Southern Alliance for Clean Energy. Thank you.

MR. MOYLE: Good morning. On behalf of the Florida Industrial Power Users, FIPUG, Jon Moyle.

MS. WHITE: Good morning. I'm Karen White on behalf of Federal Executive Agencies.

MR. BREW: Good morning. For White Springs Agricultural Chemicals, PCS Phosphate, I'm James Brew, and also with me is F. Alvin Taylor.

MR. REHWINKEL: Good morning. Charles Rehwinkel and Erik Sayler, Office of Public Counsel, on behalf of the customers of Florida.

MR. YOUNG: Keino Young and Anna R. Norris on behalf of Commission staff.

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

CHAIRMAN GRAHAM: Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. Chairman, and thank you, Commissioners.

We would like to thank the Commissioners -- and I say we -- I think all of the parties would like to thank the Commissioners for the additional time to work on stipulating a significant part of the case. The weekend proved to be beneficial for that, and what we have reached will take the CR3 aspects of the case out and allow us to focus on the Levy nuclear project.

The stipulation that you have before you encompasses several things. The first one is Item 1 on what you should have before you, which is that Progress, in compromise in settlement, agrees to permanently forgo collection of $500,000 in project management costs, which is a resolution of Issue 31. And all the parties have accepted that and agree to it.

The adjustment is intended to be recognized in this year's order, but the full revenue requirement effect will be reflected as a true-up in the March 2012 MFRs. The impact on the bottom line on the factor, we believe, is, is not material, such that the effort it would take to revise these schedules is necessary. And I think the Staff and all the parties are in agreement on that.

Item Number 2 is the, relates to Issue 33, and for 2009 and 2010 CR3 uprate costs. The parties do not object to the Commission taking the final prudent -- making a final prudence determination for these costs pursuant to the NCRC statutes, specifically 366.93 and 403.519(4). And we don't object to that being done in this docket this year.

The reservation of rights aspect of this is that in so agreeing, the parties maintain and do not waive, concede, or give up their right to offer any testimony in any other FPSC docket, nor do they waive, concede, or give up any remedy at law that may exist in any other docket.

Finally -- those are the two substantive stipulations by the parties.

CHAIRMAN GRAHAM: Let me --

MR. REHWINKEL: Yes.

CHAIRMAN GRAHAM: Let me make sure that we have everybody on board on the record before we move on past that point.

MR. REHWINKEL: Yes.

MR. BREW: Mr. Chairman, PCS Phosphate is agreeable to the stipulation as described.

MS. WHITE: FEA agrees.

MR. MOYLE: FIPUG is okay.

MR. WHITLOCK: SACE agrees, Mr. Chairman.

MR. BURNETT: Progress agrees as well, sir.

CHAIRMAN GRAHAM: Staff?

MR. YOUNG: Staff is -- Staff agrees.

But if Mr. Rehwinkel, and I think Mr. Whitlock can -- I think Mr. Whitlock, this was his reservation of rights he was concerned about. If he can -- if you can poll him for his interpretation of what that means, I think, for the record I think it would be a lot cleaner than just saying they agree to that.

CHAIRMAN GRAHAM: Mr. Whitlock?

MR. WHITLOCK: Sure. Thank you, Mr. Young.

I was -- I did request that that language be added in, and thank all the parties for working over the weekend on putting that language in.

My concern and SACE's concern specifically relates to the delamination, the ongoing delamination docket. I am not personally serving as counsel for SACE in that docket and won't sit here and represent that I know the ins and outs of that docket as well as others here do.

However, what I did want to -- out of an abundance of caution, I did want to make sure that, to the extent there is any overlap in the '09 and '010 costs, which the parties are not objecting to the Commission making a final prudence determination pursuant to the nuclear cost recovery statute and rule, that that could not somehow be used against any party to offer any testimony or, you know, or waive any remedy that they might have in the delamination docket.

So, and I think the language is written pretty narrowly, limiting, you know, the finding of prudence to the nuclear cost recovery statutes. And, therefore, you know, I just, I don't see it causing a problem. And again, you know, we just ask for this out of an abundance of caution.

So I don't know -- Keino, does that answer your question?

MR. YOUNG: That does. If we can have the Intervenors and Progress Energy Florida acquiesce or state whether they agree or disagree with Mr. Whitlock's interpretation.

CHAIRMAN GRAHAM: Let's do this polling again.

Mr. Rehwinkel.

MR. REHWINKEL: Yes, Mr. Chairman. Public Counsel agrees. We believe that your decision in this docket pursuant to the first sentence in Item 2 has no impact -- it is what it is, and you're not making a decision that -- well, let me just state this. I agree with Mr. Whitlock.

(Laughter.)

CHAIRMAN GRAHAM: I like it. You're learning my way.

MR. BREW: Mr. Chairman, while I would also like to restate the issues, I'm just going to say that we agree with Mr. Whitlock.

CHAIRMAN GRAHAM: Thank you.

MS. WHITE: As will I. FEA agrees with SACE.

MR. MOYLE: FIPUG agrees.

MR. BURNETT: I also agree with Mr. Whitlock's characterizations, sir.

CHAIRMAN GRAHAM: Thank you.

Mr. Young.

MR. YOUNG: Staff agrees with Mr. Whitlock, but wants to expand.

CHAIRMAN GRAHAM: You just what?

MR. YOUNG: We're just concerned, and Progress may want to speak to this too, is that a decision on the prudently incurred costs in this docket, administrative, whether administrative finality attaches or not. And Staff believes possibly that administrative finality attaches.

We understand that Mr. Whitlock is reserving his rights to any other -- if there is possibly any other statute outside of 366.93 and 403, that he may argue that -- and he may argue that statute or that law or that case. And any remedies that flow from that, he has the rights, he reserves that right.

And if that's the correct interpretation, if they can, all the parties can agree to that, then we're comfortable with moving forward on this, on this issue and proceeding with the hearing.

MR. WHITLOCK: Mr. Chairman, that certainly is the correct characterization, and again was why we framed it and limited that first sentence to just the Section 366.93 and the 403.519. So that would be an accurate characterization. Thank you.

CHAIRMAN GRAHAM: Let's make this simple. Who doesn't agree?

MR. MOYLE: I just have a point, that if I understand where we are, it sounds like the parties have agreed that, as discussed and outlined, administrative finality, you know, may not attach because we have an agreement that's been articulated and everybody has agreed to. So, you know, I think that speaks for itself.

CHAIRMAN GRAHAM: I was getting back to you. Don't worry.

(Laughter.)

So is there agreement on this side?

MR. REHWINKEL: The Public Counsel agrees with the way Mr. Whitlock characterized it, and we agree, and we agree with what the Staff said.

Just to be clear, you're making a decision in this docket, and your decision in this docket under the statute -- there's finality language in the statute, and it applies to your determinations. If there are other remedies that exist and other theories about damages that might come into play in another docket, by voluntarily agreeing to allow the Commission to make a determination in this docket about 2009 and 2010 costs, we do not want someone to say that you, because you voluntarily agreed in that docket, you cannot now raise something you otherwise could have wholly independent of 366.93 and 403.519.

And I think that's all it says. And so we don't have to debate administrative finality or anything like that here today. Finality -- you're, you're going to be operating entirely within 366.93 and 403.519, and we recognize that. I hope that is clear.

CHAIRMAN GRAHAM: I see everybody nodding their head. Progress.

MR. BURNETT: Thank you, sir.

We, I think we agree with what Mr. Rehwinkel said. And just to be abundantly clear now, since we've had this discussion, we've talked about this a lot and we actually had one example I think that really makes it perfectly clear. So we certainly believe that administrative finality attaches fully to your decision today with respect to the NCRC costs.

So the question of whether it was reasonable and prudent to incur these '09 and '10 costs in the realm of this project before the evidence of this NCRC, that will be decided. And absent active concealment or misrepresentation that's in the statute, those are final forever.

Now that being said, if, for instance, in the delamination docket someone makes an appropriate argument to say that, although those costs were reasonable and prudent to be incurred to move the project forward, because of something that happened in delam, those costs were more than they should have been, and they can show an unbroken, proximate, and actual cause and a proper measure of damages, they're not barred from making that argument. And if an imprudence determination is made, those costs would be subject to refund.

So that's a good example, I think, that's helped us put some concrete around this, and I think that's what we're agreeing here -- certainly that's what Progress is agreeing to.

MR. YOUNG: And Staff -- with that

clarification, Staff feels very, very comfortable moving forward.

CHAIRMAN GRAHAM: So there's no but this time?

MR. YOUNG: There's no but.

CHAIRMAN GRAHAM: Okay. Now that I have everybody on board, let's go to the Commission board, and we'll do these first two parts of the stipulation before we go back and finish the rest of this.

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I just have a point to make on the second proposed stipulation that was discussed, and Staff can confirm this. And I kind of hesitate to make the statement because everyone is in agreement, but I just want to point out that --

CHAIRMAN GRAHAM: Well, then don't do it.

(Laughter.)

COMMISSIONER BALBIS: But I already pressed the button, so I just -- I just want to point out that we're addressing the proposed stipulation. If we do not agree to the stipulation, we're going to be in the same place in October when we vote on the prudency or imprudency of this, so I think it's kind of a moot point, and if Staff can confirm that. But, again, I'm in agreement with the stipulation, but I think there's a lot of discussion maybe for not.

MR. YOUNG: Yes, Commissioner, you're correct. If, if the proposed stipulation is not accepted today, Staff would bring forth a recommendation to you as relates to the 2009, 2010 prudently incurred costs, and I think that was Issue 32, excuse me, Issue 31, Issue 32, and 33 encompassing all those.

CHAIRMAN GRAHAM: Okay. So, Commission board, we are dealing with number 1 and number 2 under the proposed stipulation.

And I guess the question I have is if there's any concerns or if we are agreeable and want to move forward with the stipulation.

Commissioner Brown, followed by Commissioner Edgar.

COMMISSIONER BROWN: Thank you, Mr. Chairman. Pardon my voice. I lost it last week.

But I guess I just want clarification, we're voting to -- or to approve Issue 31 for those two stipulations; is that correct?

CHAIRMAN GRAHAM: I believe it's 31, 32, and 33.

COMMISSIONER BROWN: Okay. I did want to make a comment regarding Issue 31, and I appreciate the parties addressing that particular language regarding retaining their right to offer additional testimony. And it really, that was really my biggest concern was having clarity. And I appreciate and I would support the proposed stipulations.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Mr. Chairman, I would move that we approve the stipulations before us in light of the discussion that we have had here this morning for Issues 31 and Issue 32.

CHAIRMAN GRAHAM: We're approving number 1 and number 2 on the Attachment Number 1?

COMMISSIONER EDGAR: Mr. Chairman, for clarity for me, I would suggest that we look to the three-page document that is titled Proposed Stipulations. And then it says, Issue 31, and then lays out in bold the positions as agreed to by Progress, OPC, SACE, FEA, FIPUG, and PCS.

And so for my motion I would incorporate this language for Issue 31 and Issue 32.

CHAIRMAN GRAHAM: What about Issue 33?

COMMISSIONER EDGAR: I thought you wanted to take that separately.

CHAIRMAN GRAHAM: No. What we're doing was covering Issue 31, 32, and 33.

COMMISSIONER EDGAR: Then if the other

Commissioners are ready to move forward, I am, and I would include Issue 33 as also incorporate -- described on this same document.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Thank you, Mr. Chairman.

I just have one question for Staff regarding Issue 33 and those costs, and whether Staff has had an opportunity -- I'm sure you have, but I just want to make that clear for the record -- to look at these costs and make sure that they are prudent and reasonable with regard to the CR3 uprate project.

MR. YOUNG: Yes, we have.

CHAIRMAN GRAHAM: Very good, Mr. Young.

COMMISSIONER BROWN: Then I would support -- with that, I would support Commissioner Edgar's motion.

MS. HUHTA: Chairman, if I may?

CHAIRMAN GRAHAM: Yes.

MS. HUHTA: On Issue 33, my understanding from Staff is that that capital cost system number for 2009 could change somewhat based on the, the proposed stipulation in Issue 31. That calculation had not been run until this morning, as the stipulation occurred over the weekend. So the actual numbers listed there could change, none of the substantive wording.

CHAIRMAN GRAHAM: You're talking about the system?

MS. HUHTA: Yes. 2009 capital cost system numbers listed under Issue 33.

MR. YOUNG: I think if -- Ms. Huhta can correct me if I'm wrong -- I think that would be a reduction by $500,000 based on the stipulation of 31.

MS. HUHTA: I think that that is correct, yes.

CHAIRMAN GRAHAM: Now "I think," is that a legal term?

MR. YOUNG: And that's the, that's the $118,140,493, and that will be reduced by 500,000.

MS. HUHTA: The new number would be 117,640,493.

CHAIRMAN GRAHAM: Mr. Young, agreeable?

MR. YOUNG: If the math is right, yes.

CHAIRMAN GRAHAM: The math is right.

MR. YOUNG: I think the math is right.

CHAIRMAN GRAHAM: Okay. So, Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I just wanted to make sure that I am clear then, and look to Progress first, and then I'll come back to our Staff, if I, if I may.

So my understanding of the stipulations that have been agreed to by all the parties and that are before us is that using this same document to adopt 31 and 32 and 33, the reduction of 500,000 in project management costs, as included in Issue 31, would then be what would trigger the change in the number under capital cost system 2009 for Issue 33.

MS. HUHTA: Yes, that's correct. And there would also be a slight change in the jurisdictional costs on that second line. The 87,458,545 would reduce to 87,028,310.

COMMISSIONER EDGAR: Could you do the 87 million number again for me, please?

MS. HUHTA: Certainly. The new 87 million number would be 87,028,310.

COMMISSIONER EDGAR: Mr. Chairman, I think what I, what I would like to do, if you can just give me a little, a little flexibility on this as we're moving forward, what, what I would suggest, if I may revise my motion and go back to where I was before, because I would like to make sure that I'm clear on the numbers and that the Staff are clear on the numbers and that everybody agrees to the numbers.

My initial understanding was that the numbers on Issue 33 had already reflected, since I see the stipulations, you know, as, as parts of a whole, that that had already been incorporated.

So what I would like to do, if you'll give me that leeway, Mr. Chairman, is make the motion that we approve the proposed stipulations for Issues 31 and 32, and then, as I was initially heading, that we hold off on 33 and have a little bit more discussion on that.

CHAIRMAN GRAHAM: Okay. We've admitted the motion to approve Issue 31 and 32 as stipulated. Any further discussion on 31 and 32? If not, all in favor, say aye.

(Ayes unanimous.)

Any opposed?

(No response.)

By your action, you've approved Issue 31 and 32 as stipulated.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I would like to ask to begin with Progress and then go down the line with the parties and come back to Staff to know, in light of the approvals of Issues 31 and Issue 32, what changes, if any, are required to the document that is before me for Issue 33.

CHAIRMAN GRAHAM: Progress?

MS. HUHTA: Certainly, Commissioner.

On, under Issue 33 of the proposed stipulation document you have in front of you, under what system and jurisdictional amount should the Commission approve as PEF's 2009 and 2010 prudently incurred costs for the CR3 uprate project, under PEF position, 2009 capital cost system, that number should be revised to 118 -- or, sorry, 117,640,493. Under jurisdictional net of joint owners, that number should be revised to 87,028,310.

COMMISSIONER EDGAR: Any other changes?

MS. HUHTA: No, Commissioner.

COMMISSIONER EDGAR: Okay. Can I look to all the Intervenor parties? Is there consensus on those numbers?

MR. REHWINKEL: Yes. Public Counsel agrees with those numbers.

COMMISSIONER EDGAR: Thank you. Is there anybody who does not?

MR. WHITLOCK: Commissioner Edgar, I do have one -- I'm fine with the numbers. I do have one comment on the position of the parties entered at the bottom of the page there when, when you're ready to hear that.

COMMISSIONER EDGAR: Okay. If I can just look to Staff then for confirmation and agreement of those, the revised numbers in light of the adoption of stipulations on 31 and 32.

MR. YOUNG: Commissioner, it's my understanding that Staff, these numbers, the numbers are correct in terms of, in light of the stipulation and reduction of $500,000.

COMMISSIONER EDGAR: Then, Mr. Chairman, if I may, I'd look to the parties, starting with SACE, to see if there's any other comments or discussion on proposed stipulation Issue 33.

MR. WHITLOCK: Thank you, Commissioner Edgar.

Just so we're entirely clear, under Issue 33, under the position of the parties, I think on the second line there into the first line it says, "The parties do not object to the Commission making a final prudence determination for those costs." I think it would be clearer if it said "for 2009 and 2010 CR3 EPU costs," instead of "those." And again, that's just --

COMMISSIONER EDGAR: Okay. And it took me a moment to find where, the place that you were directing us to. I think I found it now. So if you could do that suggested language one more time.

MR. WHITLOCK: Sure. Instead of the "those costs" on the end of the second sentence in the parties' position, I think it should say "2009 and 2010 CR3 EPU costs."

COMMISSIONER EDGAR: I read that as a nonsubstantive clarification, and that makes sense to me.

MR. WHITLOCK: Absolutely.

MR. REHWINKEL: That's correct. It takes the clause at the beginning of the stipulation and puts it in there. That's, that's fine.

COMMISSIONER EDGAR: Then, Mr. Chairman, with those changes, which I'm glad to read through, if necessary, when you are ready, I'd be prepared to make a motion on Issue 33.

CHAIRMAN GRAHAM: I think we're ready for that motion.

COMMISSIONER EDGAR: Okay. Then, Mr. Chairman, I would propose that we approve the stipulation for Issue 33, recognizing the revised numbers under the 2009 capital cost systems and the jurisdictional net of joint owners, and also making the change at the bottom as suggested by SACE, specifying that the term "those costs" refers to the 2009, 2010 CR3 EPU costs.

CHAIRMAN GRAHAM: It's been moved and seconded, that change to Issue 33. Any further discussion? Seeing none, all in favor, say aye.

(Ayes unanimous.)

CHAIRMAN GRAHAM: Any opposed?

(No response.)

By your action, you have approved Issue 33 as stated.

Okay. Mr. Rehwinkel --

MR. MOYLE: Mr. Chairman, just housekeeping. I assume this will be identified and placed into the record so we'll have a copy of what the stipulation was. Is that the intention?

CHAIRMAN GRAHAM: Hopefully.

Mr. Rehwinkel, you were walking us through the stipulation.

MR. REHWINKEL: Yes, Mr. Chairman. Thank you. And I appreciate the vote that you just took. It took some time, but it was worth it because, because of your vote, the remaining items on this list are now possible. Because without those stipulations, we would have had to bring the witnesses forward and have testimony and cross-examination.

So item number 3 is that the parties agree that PEF will not offer Jon Franke's May 2nd direct testimony or his July 5th rebuttal testimony or, and the exhibits related to those testimonies into this proceeding.

MR. YOUNG: Mr. Chairman, before we get there, if we can just go back a second in terms of what Mr. Moyle --

CHAIRMAN GRAHAM: No. I'm sorry. Go ahead.

MR. YOUNG: In terms of what Mr. Moyle said, I think it would be a seamless transaction if we move the stipulation into the record, as he requested, move the stipulation, identify it, mark it, and move it into the record now. Then move with any other witnesses that are going to be excused or proceed with the further, proceed with the hearing.

CHAIRMAN GRAHAM: So when we just now approved Issue 31, 32, 33, now after we approve that, we have to move that into the record?

MR. YOUNG: It's what he requested in terms of moving it into the record, and I think this would be the appropriate time to move it into the record before you proceed with talking about any other witnesses, thus, it will be, I think it would be a more seamless transaction.

CHAIRMAN GRAHAM: Once again, what exactly am I moving into the record?

MR. YOUNG: The proposed stipulation. Proposed stipulation. It's a sheet that you have. And we can identify it as Number 203.

COMMISSIONER EDGAR: Mr. Chairman, this document that --

CHAIRMAN GRAHAM: Wait, wait, wait. Now what I thought we were doing was I was going to let

Mr. Rehwinkel walk us through the proposed stipulation, and then we were going to push it all into the record after he walked us through and made sure that everybody was on board.

MR. YOUNG: I think by your vote today, by your vote just now, everyone is on board. But I would defer to you.

CHAIRMAN GRAHAM: Thank you.

Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. Chairman.

So Mr. Franke's two pieces of testimony and exhibits will, will not be admitted, as I said. The remaining witnesses in the case will be Foster, Elnitsky, and Jacobs. And Mr. Foster will present direct and rebuttal at the same time, but, pursuant to agreement among the parties, he will not be subject to being excused until Mr. Elnitsky has finished his direct testimony.

We have distributed to all the parties a public version of the July 21, 2011, deposition and exhibits of Staff Witnesses Coston and Carpenter. And, with the admission of that deposition and their testimony, those Staff witnesses are stipulated by the parties.

And then the final piece of the stipulation is that the order of witnesses will be Mr. Foster on direct and rebuttal, Mr. Elnitsky on direct, Mr. Jacobs, Dr. Jacobs on direct, and then Mr. Elnitsky on rebuttal. And, as a consequence, Will Garrett, Jon Franke, Sue Hardison, William Coston, Kevin Carpenter, and Jeffery Small are all stipulated and their testimony and any exhibits are admitted into the record without being present at the hearing. Jon Franke's testimony would be his March 1st testimony.

And that is the remainder of the stipulation that is, that is made possible by the Commission's approval of items 1 and 2.

CHAIRMAN GRAHAM: Okay. Let's make sure that everybody is on board with that Attachment 1, those stipulations as stated by Mr. Rehwinkel.

MR. BREW: PCS Phosphate agrees.

MS. WHITE: FEA agrees.

MR. MOYLE: FIPUG agrees.

MR. WHITLOCK: SACE agrees.

MR. BURNETT: And PEF agrees.

CHAIRMAN GRAHAM: Mr. Young?

MS. NORRIS: And Staff agrees as well.

CHAIRMAN GRAHAM: Thank you.

Commission board?

Commissioner Edgar.

COMMISSIONER EDGAR: Mr. Chairman, I think looking at the document that is headed Attachment 1, Proposed Stipulation, that Mr. Rehwinkel has described to us, that by adopting proposed stipulations for Issues 31, 32, and 33, that we have concurred with issue, with items 1 and 2, and at the appropriate time I would suggest that we use the document marked Proposed Stipulations with the changes that we adopted, note it and mark it as Number 203 for the record.

CHAIRMAN GRAHAM: Okay.

(Exhibit 203 marked for identification.)

MR. REHWINKEL: Mr. Chairman, as a housekeeping matter, we should probably identify the stipulated hearing exhibit of the Coston/Carpenter deposition as an exhibit, if now would be the right time for that.

CHAIRMAN GRAHAM: And where is that exhibit? That's this one. Okay. We will mark that as Exhibit 204.

(Exhibit 204 marked for identification.)

And what would be the short title for that exhibit?

MR. REHWINKEL: I think Coston/Carpenter Deposition is, is good.

CHAIRMAN GRAHAM: Okay. We will enter

Exhibits 203 and 204 into the record.

(Exhibits 203 and 204 admitted into evidence.)

Anything else on the proposed stipulations before us? Okay. So we will enter those proposed stipulations into the record.

Now what happens here with Attachment 2, Mr. Young?

MR. YOUNG: Attachment 2, with your vote on Issues 31, 32, and 33, we now move to the remaining highlighted issues.

After the hearing, Staff will write a recommendation on the following highlighted issues, and they're all Levy issues, plus Issues 36 and 37, which is the rate management plan issue, and the amount to, amount to be transferred for collections in the 2012 NCRC factor.

And with that, Mr. Chairman, I think we can proceed with other preliminary matters as we move along.

CHAIRMAN GRAHAM: Okay. So now you're going to have to explain to me what all that means.

MR. YOUNG: Mr. Chairman, that is just for advisement purposes only. It's nothing that you need to enter. It's just letting you know what you voted on and the issues that remain for discussion and cross -- well, for the witnesses to present testimony and cross-examination.

CHAIRMAN GRAHAM: So you're saying that we're ready for opening statements now?

MR. YOUNG: Almost. But before we get to opening statements, Staff has preliminary matters.

CHAIRMAN GRAHAM: Okay. Then you have the floor, Mr. Young.

MR. YOUNG: All right.

The first preliminary matter, Staff Comprehensive Exhibit List that was marked for identification purposes as Exhibit Number 1, Staff will ask that the stipulated exhibits which are included throughout the Comprehensive Exhibit List be entered into the record after opening statements, or at the Chairman's pleasure.

Staff will request also that the comprehensive exhibits that Staff -- excuse me. Staff would request that the comprehensive exhibits and Staff exhibits be marked and numbered in the Comprehensive Exhibit List, and that any other exhibits proffered during the hearing be numbered sequentially following those listed in the Staff Comprehensive Exhibit List, and this is similar to what we did in the FPL's portion of the docket.

CHAIRMAN GRAHAM: Okay.

MR. YOUNG: And those, for identification purposes, Mr. Chairman, is Numbers 174 to 182.

CHAIRMAN GRAHAM: 174 to 182?

MR. YOUNG: Yes, sir.

CHAIRMAN GRAHAM: And we're going to enter that after opening statements?

MR. YOUNG: Yes, sir.

CHAIRMAN GRAHAM: Okay.

MR. YOUNG: As relates to the stipulated witnesses, prefiled testimony and exhibits, Staff recommends that the stipulated witnesses and prefiled testimony and exhibits be taken up in turn as the witnesses are called. And, as Mr. Rehwinkel just mentioned, there are several stipulated witnesses based on the approved stipulations.

At the time Staff would request that the testimony of the stipulated witness be inserted into the record as though read, and the stipulated exhibits of that witness be moved -- and the stipulated exhibits of that witness be moved into the record.

CHAIRMAN GRAHAM: Okay.

MR. YOUNG: Now, Mr. Chairman, I think we are ready for opening statements.

CHAIRMAN GRAHAM: All right.

MR. YOUNG: Staff would note that opening statements, if any, shall not exceed ten minutes per party for PEF's petition.

CHAIRMAN GRAHAM: Now are we ready?

MR. YOUNG: We're ready.

CHAIRMAN GRAHAM: Okay. Progress, please.

MR. BURNETT: Thank you, sir, and good morning.

Commissioners, you have four things that you're charged to decide today in this docket under the governing statute and rules. Number one, the prudence of the Levy 2010 costs; number two, the prudence of the project management contracting and accounting controls; number three, the reasonableness of the Levy 2011 and 2012 estimated and projected costs; number four, the reasonableness of the long-term feasibility analysis for Levy.

The good news is no witnesses challenge any of these, and the evidence on all of these are undisputed. The proof to that? Listen to Dr. Jacobs when we cross-examine him and read the testimony.

Two issues remain for you to decide. The first is legally and factually improper, and the second amounts to nothing more than a series of distractions.

First, the Intervenors improperly ask you to limit PEF's recovery of costs this year to only those costs needed to obtain the combined operating license for the Levy plants. In plain English, they suggest that you should ignore the fact that all of our non-COLA costs this year are undisputedly reasonable and prudent, and instead ask you to arbitrarily limit cost recovery to only those licensing costs. Again, the proof of that? Listen to Dr. Jacobs during his cross and read the testimony.

The simple fact, Commissioners, is while the Intervenors encourage you to limit cost recovery to those COLA only costs, as they call them, in contravention to the *Florida Statutes* and your NCRC rule, that's a distraction for the fact that no witness will testify that one penny of cost sought for recovery is unreasonable or imprudent. Thus, you should reject this request to ignore the controlling law and the facts of this case.

Next, Intervenors will tell you that PEF has no intention to build the Levy units. The problem with that is that the only Intervenor, the only Intervenor witness that will testify in this case cannot prove it. Dr. Jacobs will tell you in cross-examination that he does not dispute the fact that Progress Energy Florida has a present intent to build the Levy plant. Dr. Jacobs will also tell you that he doesn't believe that we should cancel the Levy plant.

This is where the credible evidence ends and the distractions will begin. This is not the first time that the Intervenors have used this tactic of a litany of distractions. We and some of you on the Commission have actually heard these same arguments since the Levy need proceeding and every year after that.

I anticipate you will hear that nuclear plants cost a lot of money. Correct, they do. I anticipate you will hear that nuclear plants take a long time to build. Correct, they do. I anticipate that you will here that the nuclear cost recovery statute is unfair. Not correct, but, again, something that we hear every year. These sound bites, again, are nothing more than distractions.

You heard in the FP&L case several days ago, and may hear again today, that customers will pay money for the Levy plant before a single megawatt of energy is produced. Correct. We have not yet found a way to get megawatts out of plants that aren't built yet.

You will also hear that customers have to pay for the Levy units if they're canceled. Correct. That is an unremarkable proposition that has existed since the beginning of modern regulatory law. There's not been a single project that I'm aware of in Florida ever that has been prudently canceled where the customers didn't pay. Again, unremarkable facts that are a distraction.

The biggest distraction you will hear this year are documents that OPC will show you that they will say contend that we have moved the in-service dates, or at least plan to move the in-service dates for the Levy project to 2026 and 2027. What these documents are are a series of environmental what-if scenarios that the company performed to think about how PEF could potentially respond to a myriad of environmental regulations, and, again, what-if scenarios.

The Levy units play a very small part in this, and, in fact, most of the presentations, all four of them, deal with nonnuclear units, and even units in the Carolinas. What's the proof of that? Read them. OPC will show you some snippets, some tidbits, single pages. That's fine. Read the whole documents, and then see what they look like in context. Read the comments where they say, we're not picking a scenario, we're not planning for this. This is blue sky, what-if scenarios.

Listen carefully to Dr. Jacobs, Mr. Elnitsky, and your own Staff audit report. That evidence will show that the plan of record that Progress Energy Florida has is to put the Levy units in service on schedule for a 2021 and 2022 in-service date.

Dr. Jacobs will not and cannot disagree with that fact. All he will tell you is that these documents show a wavering intent to go forward with the Levy case, but he will not tell you that we have moved the in-service date, nor will he dispute the factual evidence that show that the current in-service date is what's approved by management. Audit Staff acknowledges the same in their report. They, they actually make reference to the March 2011 IPP where our management approved the current in-service date for Levy.

OPC may also try to convince you that why would a utility ever do these sort of planning scenarios unless they had some sort of evil intent, or this was some sort of mischievous plan for Levy. Well, shame on us if we didn't do this, if we put blinders on and said, we're not going to plan for the future and we're not going to do what-ifs, we're just going to go forward and not think about this. Shame on us if we don't do this.

Also, our Ten-Year Site Plan we file every year. The day after we file that we're thinking, okay, what if gas changes, what if carbon changes, what if these units don't come in, what if renewable projects don't show up, what if they do? We're doing what-ifs the day after we file that. Your Staff takes discovery on what-ifs with the Ten-Year Site Plan. In fact, they're doing it right now. That's part of the business. With a business like this, you always plan, but you have your what-if scenarios and then you have your plan of record. So I would commend to concentrate on our plan of record, the only real evidence in this case.

The bottom line, Commissioners, is the four things you must decide this year are undisputed. This Commission does not make decisions on distractions and sound bites, and I'm confident of that. And I'm confident that once you hear the evidence, you'll make a fair determination on that evidence.

Thank you for your time.

CHAIRMAN GRAHAM: Thank you, sir.

Which Intervenor wants to go first?

Mr. Rehwinkel.

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

Public Counsel comes before you today in this phase of the proceeding with two fairly straightforward requests. We are asking you to say no, and then to say no again.

The first no, now that this project has reached the $1 billion spent or obligated to spend level and its prospects for a timely completion, even on the five-year delayed schedule that PEF announced last year, appear dimmer than ever, we ask you to hold the line. Don't approve as reasonable PEF's projected expenditures that are not needed to get the combined license or COL. That's the first no.

The second no, we are also asking you to give a break to the PEF customers who are overpaying this year and let them have a deserved reduction in their bill since they overpaid based on PEF's overestimation in last year's docket. Don't accept PEF's request to replace a $60 million overcharge with a $55 million increase in the rate management plan amortization. That is the second no.

For three years now, ratepayers of PEF have sat helplessly by while the company, with the accommodation of the NCRC process, has become further mired in a project that has a dismal future at best, that is feasible in only the most unlikely of cases, a project with no eager joint venture -- joint owners on the horizon, and a project that without those phantom joint owners will yield unconscionable monthly bills for average customers $70 higher, if PEF still tries to build it.

Under these circumstances, the customers may well be wise today to take their billion-dollar pill, swallow it, and be happy to avoid what could have been.

Remember that the Florida Legislature had every expectation that the utilities upon whom they bestowed this heretofore unheard of privilege of advanced cost recovery would actually build nuclear power plants, not get expensive pieces of certificates. Sure they knew that projects could be abandoned or not enter service, but they fully expected that the lessons of the past would not be repeated and that companies would use the new licensing process, new streamline design, and the benefit of hindsight to avoid the pitfalls of past failures.

So how did Progress respond to the advanced recovery legislation? In the euphoria, they bought 3,100 acres of land in Levy County, hired a relatively green, in the nuclear world, engineering firm to do site characterization work in support of an early NRC authorization, called an LWA, that would let them get a big two-year head start. Despite the crumbling of the global economy in 2008 and in spite of a strong signal in November 2008 from the NRC about the unlikelihood of the LWA being issued, the company quickly submitted their billion-dollar obligation for long-lead materials by a hasty December 31, 2008, execution of the $7.65 billion EPC contract.

Three weeks later, on the eve of the filing deadline for the 2009 NCRC docket, they were notified by the, that the NCR -- NRC had denied them the LWA, jeopardizing the value of that EPC contract and forcing PEF to announce a minimum two-year delay in the Levy project. All optimism was gone at that point. The project started on a tailspin that it has not recovered from.

On the eve of the 2010 filing, PEF announced that the two-year delay would stretch to at least five years, and they hoped to at least get to the combined license while deciding when and if to proceed.

Yes, PEF has responded impressively to minimizing the ill-fated March 2008 long-lead material procurement obligation, but that still leaves the total cost of the project at this point right at $1 billion. And that is going to be true if nothing else happens beyond the NRC issuing a license to build a ghost plant that is never to be built.

Customers will want to know why has this happened. Although PEF can rely for explanation on the past orders from the need determination all the way through the February 2nd order in this docket -- in the NRC process and can rely on Sections 366.93 and 403.519, that will be of little consolation to these customers.

It may well be that the billion dollars is water over the dam in the legal sense, but that doesn't mean that customers should be throwing good money after bad, all for the sake of making it look like the LNP project is going to go online in 2021.

Why do we say this? Well, the answers are found in the testimony of two feature witnesses in this case: Dr. William Jacobs on behalf of the customers, and John Elnitsky on behalf of PEF. Both men are nuclear engineers with impressive credentials. Dr. Jacobs has 30-plus years of experience in the nuclear -- mostly in the nuclear electric power industry, and Mr. Elnitsky has a distinguished career on behalf of his country in the nuclear Navy. There is no dispute as to the expertise and credentials of either.

You will hear from John Elnitsky that PEF has a plan of record and that it supports the company's insistence that they possess a present intent to build Levy in 2021.

Dr. Jacobs, on the other hand, is the Georgia PSC's official monitor on the Vogtle project, and he knows what a project that is under construction looks like. He will tell you why PEF's plan of record may have less actual realistic significance due to several factors. He lists six, including some that you have heard in past years, such as a lack of joint owners.

However, there is one factor that the customers ask you to take a very close look at, and that is the highly confidential scenario planning that senior executives in Progress Energy concluded on the day before last year's NCRC hearing began. This was not a frivolous manager's team building exercise at some retreat, but a months' long process that was designed to narrow focus and choices and allow the senior executives at PEF and Progress Energy to reach a useful conclusion.

You'll be shown the results of this process in unredacted but confidential form. Look at the way it is structured and decide if you think it supports PEF's program of record in light of all the conditions facing the company. You have that right, you have that obligation, and you are faced with -- as you are faced with requests for new types of costs from PEF.

We are asking that the Commission recognize what the company is truly planning for, a world without Levy before 2027, if at all. We ask that as a result of the evidence that you will hear that you exercise your oversight that the Legislature expects and authorized. Don't deem as reasonable costs not absolutely needed to obtain a COL. That means no more land buying for transmission, no transmission studies, no more transmission design and construction costs, no cost of full notice to proceed.

The OPC disputes that there was any Commission decision that authorized these specific costs in 2010. You did authorize a go slow COL receipt approach. You agreed that PEF wouldn't be able to build the plant any sooner than 2021, but you didn't make any ruling that the company would actually meet that date. And in so ruling, you didn't know that all the while PEF was taking a look at a 2027 COD, or commercial operation date, for Levy.

Other than PEF projecting costs that would be needed in the very unlikely event they would actually be trying to meet 2021 COD, these costs are speculative at best, and though relatively minor compared with the billion dollars, the customers should be spared them.

We urge that you take the initiative that the Legislature said you have in approving or disapproving unspent estimated or projected dollars as being reasonable or not. Please say no.

Finally, as to the rate management plan, you said that PEF could collect on a five-year deferred basis $273 million plus carrying costs. Absent the overcollection of about $61 million in 20 -- during 2011, primarily related to the overestimation of long-lead material procurement costs, the customers would be getting what the company calls in their testimony a refund. Unfortunately, PEF wants you to let them offset this elusory refund that the customers should get by piling onto the already assumed $60 million of amortization from that rate management plan another $55 million.

We say enough is enough. Customers are weary of shouldering costs for nuclear energy that is not being received, from CR3 to the CR3 uprates to a vanishing LNP, zero for three, and on top of that, another $55 million to cruelly snatch away the refund that they would be getting in 2012. Again, please say no.

PEF will get their money from the rate management plan. We ask you to make 2012 a time when customers get a little bit of a break. Say no twice, please. Thank you very much.

CHAIRMAN GRAHAM: Thank you, sir.

Mr. Brew.

MR. BREW: Thank you. Good morning, Chairman, Commissioners.

A little background on why we are here. PCS operates a manufacturing and mining complex on about 100,000 acres in Hamilton County. We are one of the largest power users on the Progress Energy Florida system, and typically have requirements that are comparable to the electric needs of a city of about 800 -- 80,000 people.

Most of our load is served on an interruptible basis. That means that Progress Energy does not plan generating capacity to serve our load. It also means that Progress can and does disrupt service to our process so that it can avoid service disruptions to thousands of other consumers and businesses.

We also have invested substantially in renewable energy. We've invested in substantial amounts for equipment to recapture heat from our manufacturing process, which is exothermic, in order to generate about 20 megawatts of energy without any incremental carbon emissions at all.

A big reason why PCS has invested in generating power from recaptured heat and agreed to take service at a lesser quality is because we operate in globally competitive commodity markets. Given our energy intensity, competitive power prices are critical to economic competitiveness.

Now with respect to Levy, we have said from the beginning that the proposed project would be unaffordable for consumers and would only become more so given inevitable slippages in schedule and rising costs. The expected costs, even in a best-case scenario, are too high, and Progress's customer base is too small to support an investment of this magnitude.

Now as we discussed last year, apart from the three basic stated functions of these NCRC proceedings, which are to audit the project costs, make prudence determinations, and determine ongoing long-term feasibility of completing the plant, a basic function in these dockets is to address the rate and bill impacts associated with the dollars authorized for recovery.

In the very first NCRC proceeding in 2008 the Commission approved $418 million for recovery, and then Progress later asked for and received permission to split that over a period of years. In 2009, the Commission approved the rate management plan, which, as Mr. Rehwinkel mentioned, allowed for recovery over five years of 273 million of the 444 million that was authorized for recovery in that period.

Last year, which we spent a lot of time discussing, the company moved to its go-slow approach in large part to mitigate near-term rate impacts for consumers.

I wanted to go through these pieces of the NCRC history because the notion of rate mitigation is soon going to disappear or change dramatically once Progress receives its construction, construction license from the NRC. And let me explain.

It's essential to, to look at and fully take in the magnitude of the ratemaking train wreck that we're headed for. For 2012, Progress has proposed a nuclear cost recovery factor of about $4.50 a month for the average residential customer. Once Progress receives a COL, that factor goes up in multiples. By 2016 it's going to be four times larger -- the revenue requirement impact of proceeding with Levy is going to result in a factor that's four times larger than the proposed factor for this year. It's five times bigger in 2017, 17 times bigger after that, and 20 -- 10 times bigger later.

In round numbers, for the years 2016 and 2020, your average residential customer is going to be paying $400 a year more to support the Levy investment. For an energy intensive user like PCS, that amount is going to go into the millions.

Plus, at that point -- and all of this information are in the company's exhibits, there's nothing confidential about it at all -- most of the clause recovery that you're going to be asked to act on will be driven by carrying costs on construction additions. These will not be procurement that could be slipped or moved around. We will be locked in. Progress will be financing billions of dollars to support the project in one year and even more in the next.

So you will not see proposals to mitigate rate impacts on consumers. You will instead hear demands for cost recovery now, driven by cash flow requirements just to cover the interest on this massive amount of debt. On top of that, once we've already recovered $8 billion or thereabouts from consumers, you're then going to have to deal with a base rate case to add another $14 billion to rate base.

Given these frightening figures, the logical question is what can be done about it? Well, once they start, there's only two ways to really control the cost. One is to actually lower the cost of construction. That's not going to happen. The only other way to do it is to share those costs with other entities through joint owners. And what we've heard over the past several years and heard today are either vague possibilities or missed opportunities. Last year we saw that Seminole, which had originally targeted an interest in Levy, dropped that out of its Ten-Year Site Plan and decided to build peakers instead. This month, Florida

Municipal Power Agency announced its intention to acquire a portion of the new V.C. Summer unit in South Carolina, which is also a Westinghouse AP1000 plant that's designed to go into service in 2016 and 2019, or roughly the dates that Levy was originally proposed for.

With the continuing adverse trends that are addressed in Mr. Jacobs' testimony, other folks are likely to remain on the fence or not go here at all, which leaves Progress Energy Florida customers back on the sole ownership track and bearing all of those costs.

That leads us to really another realization, that Levy, as Mr. Rehwinkel mentioned, may already be a phantom, a project for which we'll spend a billion dollars of ratepayer money to get a ticket to nowhere, a construction license for a facility that will never break ground.

Given all of this, PCS has only two requests in this year's docket. The first, we strongly agree with OPC that the Commission, that the Commission should not approve Progress's proposal to backfill in its overspending on the, its disposition of procurement by adding $55 million to the rate management plan for the 2012 factor. Given the economy and the tenuous nature of this project, those costs should be spread out further, they shouldn't be accelerated. And we strongly encourage the Commission to reject that proposal.

Second, we do think that more assertive Commission action is required concerning joint ownership. And, no, I don't mean that we're asking the Commission to get entangled in those negotiations. But I do think the Commission needs to make clear now, before you get to the COLA, that it is not going to authorize that massive spin up in spending, absent secure joint ownership participation that will mitigate rate impacts for Florida consumers. Once we're on that track, it's going to be, it's going to be a terrible annual battle over what to do because the costs are going to be unaffordable.

Finally, I'd like to close with a statement made by John Rowe, the retiring CEO of Exelon, the utility with the largest nuclear fleet in the country, at an American Nuclear Society conference in Hollywood, Florida, yesterday that he entitled My Last Nuclear Speech. In his keynote address to that nuclear group, he said, "We cannot pray for the future we want and hope that it will happen. We are a business and must make rational economic decisions based on the cold hard facts at hand. I do not purport to know what the exact future of our sector will be, but I do know that if we don't pay attention to the grim economic facts, we, our customers, and our shareholders will get burned."

PCS simply asks that the Commission take a cold hard look at the facts and take actions accordingly.

Thank you.

CHAIRMAN GRAHAM: Thank you, sir.

Ms. White.

MS. WHITE: Good morning again, Commissioners.

I'm not going to restate what I said last week about why FEA is here. We're still here. Although we have a somewhat smaller federal presence because it's a somewhat smaller territory, we still have the same very large concerns about the financial situation both that the project seems to be facing and also that our budgets face on a regular basis. So we're still here and we still care very much that this project will give the benefits that were promised to customers, including the federal customers, who rely very much on this Commission to look at the, as my colleague Mr. Brew says, the cold hard facts of this case.

I thank you for your work on this. I know that it's not an easy decision to make, and I'm glad that I'm not sitting in that chair. So I thank you for your work on this, and that's all I have to say for this morning. Thanks.

CHAIRMAN GRAHAM: Thank you.

Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman, members of the Commission.

Vicki Kaufman was here last week on behalf of FIPUG, and I just wanted to start by indicating that FIPUG, Florida Industrial Power Users Group, has a lot of companies operating in Florida that use electricity 24/7. It's a variable cost. A lot of the companies compete in a global marketplace, as Mr. Brew said. You know, it's a tough economy. Things that increase costs are ones that everybody is trying to hold down. And you have an opportunity today, I think, to send a message to Progress about what's been called a rate train wreck coming forward. And as you hear the testimony, I would urge you to consider that.

Companies that cool groceries, big warehouse facilities that cool food that needs to be frozen, phosphate companies, companies in the pulp and paper business, cement companies, companies in the chemical business, there are a lot of users in Florida that can be severely impacted by rates that would have to be incurred should Progress move forward with this, with this effort.

You're going to hear a lot. You have very talented witnesses with engineering degrees. They're going to be talking a lot about issues. You're going to be getting into a lot of, a lot of details. But when it really comes down to it, you know, what is this case about? I think Mr. Elnitsky says this, and we'll talk about this, but it's really about judgment. It's about what is the right judgment to make. And you have facts. Progress is making a judgment currently that you are charged with reviewing. The consumers are advocating for a judgment that is different from that sought by Progress, but ultimately it's your call, both as set forth in the statute and in your, and in your rule.

And I thought it would be instructive just to quote the rule that gives you the ability to make a judgment. It says -- this is the nuclear cost recovery rule, 25-6.0423(5)(c)(5), but it says, "By May 1 of each year, along with required filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long-term feasibility of completing the project."

So you will have information in front of you, you'll have some detailed facts that can be measured and quantified, and then you'll also have some that are hard to measure and quantify. They're called enterprise risk. And we'll talk with Mr. Elnitsky about enterprise risk, and I think he'll admit that enterprise risk ultimately, you know, they're a judgment call. And Progress is making a particular judgment. You will have to look at the facts and decide whether, whether that is the right judgment.

The, the consumers, who Progress in its testimony says that this project is in the best interest of Progress, of the company and the customers, I think we have a little bit of a disagreement whether it's in the best interest of the customers, just given the fact that I'm the fourth lawyer representing consumers to go and express concerns about the direction this is heading. So I think if it was truly in the best interest of customers, you may not have as many Intervenors up here raising, raising concerns with you.

But the Intervenors do have a lot of concerns, the project has a lot of uncertainty. You're going to hear about uncertainty related to the joint ownership. We think there's price uncertainty. We think there's timing uncertainty. The economic conditions present a lot of uncertainties. Progress has said, well, we're not growing like we used to. That's a, that's a material change that I think needs to be taken into consideration. The public support and acceptance seems to be waning.

So, as, as we move forward with this hearing, I think you're going to hear some discussions, some facts, some evidence as to the uncertainty associated with, with this project, not the least of which is execution. These nuclear power plants are obviously a tough thing to execute on. We're not getting into Crystal River 3, the uprates today, but that repair has been tough to, to execute.

Mr. Burnett in his opening statement, a lawyer who I respect a great deal, talked about, well, you know, the evidence is undisputed, and the evidence will say this. Well, with all due respect, we haven't had evidence yet. I mean, we're having opening statements. The evidence will start coming in when people take the stand and raise their hand and they're subjected to cross-examination, and I intend to ask Mr. Elnitsky about the intent to move forward.

While he may say, yes, that's the intent, I think you'll get the sense that it's an intent with a small "i". It's a very soft intent. You know, they had to make a decision about, well, what do we do with this thing? Do we, do we, you know, cancel it, do we move full speed ahead, or do we sort of take a middle ground and suspend it and kind of see how it goes? And they, they selected the middle ground or suspending it. Well, you know, it'll be interesting to see how you make, how you reconcile a decision to suspend with intent to move forward.

We think, the consumers think that there's an opportunity for you all to send a signal to Progress that this path that they're heading down is treacherous, it's difficult, it's going to have a real negative impact on consumers. And rather than just kicking the nuclear can down the road, we would hope that you all would take this opportunity, after hearing the evidence about all of the uncertainties, about the impacts on ratepayers going forward, that you would send a strong signal to, to them that maybe, maybe their judgment is not 100% spot on with respect to the, to the Levy nuclear, nuclear plant.

So thank you for the opportunity to share, share those thoughts with you.

CHAIRMAN GRAHAM: Thank you, Mr. Moyle.

Mr. Whitlock.

MR. WHITLOCK: Thank you, Mr. Chairman, members of the Commission.

Progress stands before the Commission today requesting advanced cost recovery from its ratepayers, neighborhood of about $135 million, in addition to the hundred of millions that it's already recovered, for its proposed Levy nuclear project, a project that, due to the ever increasing uncertainty and risks that are associated with new nuclear -- with the development of new nuclear generation, the cold facts, as I think Mr. Brew referred to this uncertainty and risk as, but what -- the problem is, is that Progress is in violation of two Commission-established canons, for lack of a better word, of ratepayer protection.

The first, Mr. Moyle just talked about, long-term feasibility. The Commission has to review and approve the long-term feasibility analysis that Progress has submitted this year. And based on that analysis, on its face, despite what Progress might conclude from it, the Levy nuclear project is not feasible of being completed in the long term. And, again, that's evidenced by their own feasibility analysis, and I think that'll come out in the evidence.

The second canon that Progress is in noncompliance with of ratepayer protection is the statute -- is the intent to construct. And I talked about this in detail in my, my opening last week with FPL and won't revisit it, but PEF simply has not met its burden to demonstrate that it actually intends to ever construct the LNP. It might say it does, but I'd ask you to listen to the evidence.

The fact that Progress is in noncompliance with these, with these requirements probably comes as little surprise to the Commission. It certainly is no surprise to the Intervenors, as Mr. Rehwinkel discussed in some detail. The Levy nuclear project has been fraught with, with problems and schedule slippages, delays, and corresponding cost increases ever since the Commission issued an affirmative determination of need for the project.

So, based on this lack of showing of long-term feasibility as well as the lack of a real demonstrated intent to actually construct the Levy nuclear project, both of which are required by the Commission to protect the ratepayers, I would respectfully submit that this is the year the Commission needs to put an end to the bleeding of the Progress ratepayers, to hold the line, as I think Mr. Rehwinkel said. These ratepayers are unfairly, unjustly, and unreasonably being asked to pay to preserve an option, not a certainty, the option that this plant might be built one day. It's not a certainty. And, in fact, for the past couple of years they've been asked to pay hundreds of millions of dollars for nothing more than a piece of paper from the NRC.

The Commission can do this and should do this by denying any further cost recovery relating to the Levy nuclear project for 2011 or 2012 or, at the very least, limiting cost recovery to what is absolutely necessary for Progress to support the possible issuance of a combined operating license from the NRC.

Going back to the first canon of ratepayer protection, I'm not going to read the rule, Mr. Moyle just did that, on long-term feasibility. In Order Number PSC-08-0518, the Commission, after setting out specific, specific guidance for what Progress needs to do to demonstrate long-term feasibility, stated, "We will review the continued feasibility of Levy units 1 and 2 during the annual nuclear cost recovery proceedings, thus providing the appropriate checks and balances to ensure that the construction of the nuclear units continues to be in the best interest of PEF's ratepayers."

PEF's feasibility analysis submitted this year does not show the construction of the LNP, or perhaps more aptly the continued pursuit of their combined operating license -- there's very little talk about construction -- continues to be in the best interest of Progress ratepayers. From a qualitative perspective, all of the major enterprise risks are trending unfavorably for Progress. Their demand is down, there's no cost of carbon, there's no greenhouse gas legislation, the price of natural gas is extremely depressed, and there's just simply not the robust public or the robust policy support that's necessary for the development of new nuclear generation.

Quantitatively, Progress's updated CPVR shows nuclear being cost-effective only in the most unlikely combination of projected scenarios, such as scenarios combining a high cost of carbon and a high, and a high cost of natural gas. That's not the reality today. And even in the scenarios where it is -- in these scenarios where it is shown as cost-effective, it's still trending unfavorably from past CPVRRs submitted by Progress, and I would ask that the Commission look at those trends and consider them.

In regards to the second canon of ratepayer protection, the intent to actually construct the LNP. This intent must be evidenced by more than just empty statements; it must be backed up by the evidence. As Mr. Moyle said, it's an intent with a small "i", and I think you'll get that out of Mr. Elnitsky's testimony.

PEF simply has not met the standard to demonstrate the intent to actually construct the Levy nuclear project, and therefore they're not even eligible for cost recovery under Section 366.93 of the *Florida*

Statutes, as determined by the Commission last year.

Much like FPL, as we talked about last year, the only thing that Progress has demonstrated an intent to do is to try and obtain a COL and create the option to construct the Levy nuclear project.

It's not a matter of when to build, it's a matter of whether to build. And this distinction is crucial to the Commission's determination of whether or not PEF has the intent to actually build the LNP. You'll hear a lot about their present intent, their program of record, but this must be considered in light of the fact that it's an issue of whether to build, not when to build.

So in conclusion, it's time for the Commission to rein in spending on the Levy nuclear project. While Progress apparently would like to think so, statutory and regulatory scheme for advanced cost recovery in Florida does not create -- provide a blank check for the utility. And until the Commission sends a strong signal to Progress, its ratepayers are the ones who are going to continue to bear the burden of paying for a project that is not feasible and one that, that Progress has not demonstrated a real intent to actually construct.

Put simply, they've not met the requirements of the statute or the rule. And as a result, the

Commission should deny all further cost recovery relating to the Levy nuclear project, or again, at the very least, limit that recovery to what the ratepayers are actually paying for, and that's a piece of paper from the NRC. Thank you.

CHAIRMAN GRAHAM: Thank you all for your opening statements.

Mr. Young, we have a list of things that need to be entered.

MR. YOUNG: Yes, sir. The first Staff would like to enter is exhibits, the Staff exhibits on the, and it's Numbers 174 through 182 on the Comprehensive Exhibit List.

CHAIRMAN GRAHAM: We will enter 174 through 182 into the record, if there's no objections. Seeing none.

(Exhibits 174 through 182 admitted into evidence.)

MR. YOUNG: And I think this is the appropriate time to enter the Witnesses Garrett, Henderson [sic] direct testimony into the record, if --

MS. HUHTA: Yes. Will Garrett was the first witness listed in the Prehearing Order, and he has been stipulated based on the stipulation we discussed earlier. We would move that Mr. Will Garrett's

March 1st, 2011, direct testimony be entered into the record as though read, as well as his Exhibits WG-1, WG-2, WG-3, which are Staff comprehensive exhibits 135, 136, and 137.

CHAIRMAN GRAHAM: Do I hear any objections to that? No. So we will enter Mr. Garrett's testimony into the record as though read. And we'll also enter Exhibits 135, 36, 37 into the record.

(Exhibits 135, 136, and 137 admitted into evidence.)

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 110009

DIRECT TESTIMONY OF WILL GARRETT

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Will Garrett. My business address is 299 First Avenue North, St. Petersburg, FL 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. What are your responsibilities in that position?

A. As legal entity Controller for Progress Energy Florida ("PEF" or "the Company"), I am responsible for all accounting matters that impact the reported financial results of this Progress Energy entity. I have direct management and oversight of the employees involved in PEF Regulatory Accounting, Property Plant and Materials Accounting, and PEF Financial Reporting and General Accounting. In this capacity, I am also responsible for the Levy County Nuclear Project ("LNP") and Crystal River Unit 3 ("CR3") Uprate Project Cost

Recovery True-Up filings, made as part of this docket, in accordance with Rule 25-6.0423, Florida Administrative Code (F.A.C.).

Q. Please describe your educational background and professional experience.

A. I joined the Company as Controller of PEF on November 7, 2005. My direct relevant experience includes the position of Corporate Controller for DPL, Inc. and its major subsidiary, Dayton Power and Light, headquartered in Dayton, Ohio. Prior to this position, I held a number of finance and accounting positions for 8 years at Niagara Mohawk Power Corporation, Inc. (NMPC) in Syracuse, New York, including Executive Director of Financial Operations, Director of Finance and Assistant Controller. As the Director of Finance and Assistant Controller, my responsibilities included regulatory proceedings, rates, and financial planning. I provided testimony on a variety of matters before the New York Public Service Commission. Prior to joining NMPC, I was a Senior Audit Manager at Price Waterhouse (PW) in upstate New York, with 10 years of direct experience with investor owned utilities and publicly traded companies. I am a graduate of the State University of New York in Binghamton, with a Bachelor of Science in Accounting and I am a Certified Public Accountant in the State of New York.

Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Nuclear Cost Recovery?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval, the actual costs associated with PEF's LNP and CR3 Uprate activities for the period January 2010 through December 2010. Pursuant to Rule 25-6.0423, F.A.C., PEF is presenting testimony and exhibits for the Commission's determination of prudence for actual expenditures and associated carrying costs. Pursuant to Commission Order No. PSC-11-0095-FOF-EI, deferring consideration of the CR3 Uprate project 2009 costs, I will also be presenting for Commission review and approval the actual costs associated with PEF's CR3 Uprate project for the period January 2009 through December 2009.

Q. Are you sponsoring any exhibits in support of your testimony on 2009 CR3 Uprate project costs?

A. Yes. I am sponsoring sections of the following exhibits, which were prepared under my supervision:

2009 Costs:

- Exhibit No. ___ (WG-1), consisting of Schedules T-1 through T-7B of the Nuclear Filing Requirements (NFRs) and Appendices A through C, which reflect PEF's retail revenue requirements for the CR3 Uprate Project from January 2009 through December 2009; however, I will only be sponsoring Schedules T-1 through T-6 and Appendices A through C. Jon Franke will be co-sponsoring Schedules T-4, T-4A, T-6 and Appendix B and sponsoring Schedules T-6A through T-7B.

These exhibits are true and accurate.

Q. *What are Schedules T-1 through T-7B and the Appendices?*

A.
- Schedule T-1 reflects the actual true-up of total retail revenue requirements for the period.
- Schedule T-2 reflects the calculation of the site selection, preconstruction, and construction costs for the period.
- Schedule T-3A reflects the calculation of actual deferred tax carrying costs for the period.
- Schedule T-3B reflects the calculation of the actual construction period interest for the period.
- Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule T-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule T-5 reflects other recoverable O&M expenditures for the period.
- Schedule T-6 reflects actual monthly capital expenditures for site selection, preconstruction, and construction costs for the period.
- Schedule T-6A reflects descriptions of the major tasks.
- Schedule T-6B reflects capital expenditure variance explanations.
- Schedule T-7 reflects contracts executed in excess of $1.0 million.
- Schedule T-7A reflects details pertaining to the contracts executed in excess of $1.0 million.

- Schedule T-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Appendix A reflects a comparison of 2006 to 2009 revenue requirements.
- Appendix B reflects a comparison of 2006 to 2009 actual capital expenditures.
- Appendix C (CR3 Uprate) reflects various Uprate in service project revenue requirements.

Q. What is the final true-up amount for the CR3 Uprate project for which PEF is requesting recovery for the period January 2009 through December 2009?

A. PEF is requesting approval of a total over-recovery amount of $244,764 for the calendar period of January 2009 through December 2009. This amount, which can be seen on Line 9 of Schedule T-1 of Exhibit No. __ (WG-1), represents the carrying costs on construction cost balance, CCRC recoverable O&M, and deferred tax asset carrying cost associated with the CR3 Uprate, as well as the revenue requirements associated with the various in service projects, and was calculated in accordance with Rule 25-6.0423.

Q. What is the carrying cost rate used in Schedules T-2.1, T-2.2, and T-2.3?

A. The carrying cost rate used on Schedules T-2.1, T-2.2, and T-2.3 is 8.848 percent. It is explained in detail at footnote "A" of these schedules, and it is based on the approved Allowance for Funds Used During Construction ("AFUDC") rate pursuant to Order No. PSC-05-0945-S-EI in Docket No. 050078-EI.

Q. Are you sponsoring any exhibits in support of your testimony on 2010 LNP and CR3 Uprate costs?

A. Yes. I am sponsoring sections of the following exhibits, which were prepared under my supervision:

2010 Costs:

- Exhibit No. ___ (WG-2), consisting of Schedules T-1 through T-7B of the NFRs and Appendices A through D, which reflect PEF's retail revenue requirements for the LNP from January 2010 through December 2010; however, I will only be sponsoring Schedules T-1 through T-6 and Appendices A through D. Sue Hardison will be co-sponsoring portions of Schedules T-4, T-4A, T-6 and Appendix D and sponsoring Schedules T-6A through T-7B.
- Exhibit No. ___ (WG-3), consisting of Schedules T-1 through T-7B of the NFRs and Appendices A through D, which reflect PEF's retail revenue requirements for the CR3 Uprate Project from January 2010 through December 2010; however, I will only be sponsoring Schedules T-1 through T-6 and Appendices A through D. Jon Franke will be co-sponsoring Schedules T-4, T-4A, T-6, and Appendix D and sponsoring Schedules T-6A through T-7B.

These exhibits are true and accurate.

Q. What are Schedules T-1 through T-7B and the Appendices?

A.
- Schedule T-1 reflects the actual true-up of total retail revenue requirements for the period.
- Schedule T-2 reflects the calculation of the site selection, preconstruction, and construction costs for the period.

- Schedule T-3A reflects the calculation of actual deferred tax carrying costs for the period.
- Schedule T-3B reflects the calculation of the actual construction period interest for the period.
- Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule T-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule T-5 reflects other recoverable O&M expenditures for the period.
- Schedule T-6 reflects actual monthly capital expenditures for site selection, preconstruction, and construction costs for the period.
- Schedule T-6A reflects descriptions of the major tasks.
- Schedule T-6B reflects capital expenditure variance explanations.
- Schedule T-7 reflects contracts executed in excess of $1.0 million.
- Schedule T-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule T-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Appendix A reflects support for beginning balances.
- Appendix B (Levy) reflects individual components of Site Selection, Preconstruction, and the PSC approved deferral.
- Appendix B (CR3 Uprate) reflects various Uprate in-service project revenue requirements.
- Appendix C reflects a comparison of 2006 to 2010 revenue requirements.

- Appendix D reflects a comparison of 2006 to 2010 actual capital expenditures.

Q. What is the source of the data that you will present in your testimony and exhibits in this proceeding?

A. The actual data is taken from the books and records of PEF. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, provisions of the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC"), and any accounting rules and orders established by this Commission.

Q. What is the final true-up amount for the LNP for which PEF is requesting recovery for the period January 2010 through December 2010?

A. PEF is requesting approval of a total over-recovery amount of $60,743,424 for the calendar period ending December 2010. This amount, which can be seen on Line 9 of Schedule T-1 of Exhibit No. __ (WG-2), represents the site selection, preconstruction, carrying costs on construction cost balance, CCRC recoverable O&M, and deferred tax asset carrying cost associated with the LNP and was calculated in accordance with Rule 25-6.0423.

Q. What is the final true-up amount for the CR3 Uprate Project for which PEF is requesting recovery for the period January 2010 through December 2010?

A. PEF is requesting approval of a total under-recovery amount of $108,602 for the calendar period of January 2010 through December 2010. This amount, which can be seen on Line 9 of Schedule T-1 of Exhibit No. __ (WG-3), represents the carrying

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costs on construction cost balance, CCRC recoverable O&M, and deferred tax asset carrying cost associated with the CR3 Uprate, as well as the revenue requirements associated with the various in service projects, and was calculated in accordance with Rule 25-6.0423.

Q. What is the carrying cost rate used in Schedules T-2.1, T-2.2, and T-2.3?

A. The carrying cost rate used on Schedules T-2.1, T-2.2, and T-2.3 is 8.848 percent. It is explained in detail at footnote "A" of these schedules, and it is based on the approved AFUDC rate pursuant to Order No. PSC-05-0945-S-EI in Docket No. 050078-EI.

III. CAPITAL COSTS INCURRED IN 2010 FOR LEVY NUCLEAR PLANT

Q. What are the total costs PEF incurred for the LNP during the period January 2010 through December 2010?

A. Total preconstruction capital expenditures, excluding carrying costs, were [redacted] million, as shown on Schedule T-6.2, Line 8 and 21. Total construction capital expenditures, excluding carrying costs, were [redacted] million, as shown on Schedule T-6.3, Line 10 and 25.

Q. How did actual Preconstruction Generation capital expenditures for January 2010 through December 2010 compare with PEF's actual/estimated costs for 2010?

A. Schedule T-6B.2, Line 6 shows that total preconstruction Generation project costs were [redacted] million, or [redacted] million lower than estimated. By cost category, major

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cost variances between PEF's projected and actual 2010 preconstruction LNP Generation project costs are as follows:

License Application: Capital expenditures for License Application activities were [redacted] million or [redacted] million lower than estimated. As explained in the testimony of Sue Hardison, this variance is primarily attributable to lower than estimated NRC fees and related licensing and consulting fees.

Engineering & Design: Capital expenditures for Engineering & Design activities were [redacted] million or [redacted] million lower than estimated. As explained in the testimony of Sue Hardison and John Elnitsky, this variance is primarily attributable to the deferral of an estimated one-time Long Lead Equipment ("LLE") disposition cost to 2011 based on continuing LLE negotiations with the Consortium.

Q. How did actual Preconstruction Transmission capital expenditures for January 2010 through December 2010 compare with PEF's actual/estimated costs for 2010?

A. Schedule T-6B.2, Line 11 shows that total preconstruction Transmission project costs were [redacted] million or [redacted] million lower than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2010 preconstruction LNP Transmission costs are as follows:

Substation Engineering: Capital expenditures for Substation Engineering activities were [redacted] million or [redacted] million lower than estimated. As explained in the testimony of Sue Hardison, this variance is primarily attributable to deferral of the Crystal River Energy Center work due to the Crystal River 3 plant outage schedule adjustments.

Q. How did actual Construction Generation capital expenditures for January 2010 through December 2010 compare with PEF's actual/estimated costs for 2010?

A. Schedule T-6B.3, Line 8 shows that total construction Generation project costs were [redacted] million, or [redacted] million greater than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2010 construction LNP Generation project costs are as follows:

Real Estate Acquisition: Capital expenditures for Real Estate Acquisition activities were [redacted] million or [redacted] million greater than estimated. As explained in the testimony of Sue Hardison, this variance is primarily attributable to the transfer of responsibility and payment for the state lands easement related to the Barge Slip from Levy Transmission to Generation.

Power Block Engineering: Capital expenditures for Power Block Engineering activities were [redacted] million or [redacted] million greater than estimated. As explained in the testimony of Sue Hardison, this variance is attributable to payments to the Consortium for earlier than scheduled completion of partial milestones.

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Q. How did actual Construction Transmission capital expenditures for January 2010 through December 2010 compare with PEF's actual/estimated costs for 2010?

A. Schedule T-6B.3, Line 15 shows that total construction Transmission project costs were [redacted] million or [redacted] million lower than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2010 construction LNP transmission costs are as follows:

Real Estate Acquisition: Capital expenditures for Real Estate Acquisition were [redacted] million or [redacted] million lower than estimated. As explained in the testimony of Sue Hardison, this variance is primarily attributable to the shift in the LNP schedule and the transfer of responsibility and payment for the state lands easement related to the Barge Slip from Levy Transmission to Generation.

Q. What was the source of the separation factors used in Schedule T-6?

A. The jurisdictional separation factors are calculated based on the January 2010 sales forecast, using the Retail Jurisdictional Cost of Service methodology that was approved in Order No. PSC-10-0131-FOF-EI in PEF's base rate proceeding in Docket No. 090079-EI.

IV. O&M COSTS INCURRED IN 2010 FOR THE LEVY NUCLEAR PLANT

Q. How did actual O&M expenditures for January 2010 through December 2010 compare with PEF's actual/estimated costs for 2010?

A. Schedule T-4A, Line 15 shows that total O&M costs were $2.9 million or $1.3 million lower than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2010 LNP O&M costs are as follows:

Corporate Planning: O&M expenditures for Corporate Planning were $0.2 million or $0.1 million lower than estimated. As explained in the testimony of Sue Hardison, this variance was primarily attributable to lower corporate planning internal labor hours than anticipated due to the project schedule shift.

Legal: O&M expenditures for Legal were $1.2 million or $0.3 lower than estimated. As explained in the testimony of Sue Hardison, this variance was primarily attributable to lower than expected outside legal counsel services.

Project Assurance: O&M expenditures for Project Assurance were $0.2 million or $0.1 million lower than estimated. As explained in the testimony of Sue Hardison, this variance was primarily attributable to lower project assurance internal labor hours than anticipate due to the project schedule shift.

Nuclear Generation: O&M expenditures for Nuclear Generation were $0.9 million or $0.6 million lower than estimated. As explained in the testimony of Sue Hardison, this variance was primarily attributable the deferral of Operational Readiness activities due to the LNP schedule shift.

V. CAPITAL COSTS INCURRED IN 2009 FOR CR3 UPRATE PROJECT

Q. What are the total Construction costs incurred for the CR3 Uprate Project for the period January 2009 through December 2009?

A. Schedule T-6.3, Line 12 shows that total Construction capital expenditures gross of joint owner billing and excluding carrying costs were $118.1 million.

Q. How did actual capital expenditures for January 2009 through December 2009 compare to PEF's actual/estimated costs for 2009?

A. Schedule T-6B.3, Line 10 shows that total project costs were $0.6 million higher than estimated. By cost category, major cost variances between PEF's projected and actual 2009 Construction costs are as follows:

License Application: Capital expenditures for License Application activities were $20.0 million or $3.7 million greater than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to higher than originally anticipated costs for preparation of the License Amendment Request ("LAR") because of the need for additional, more detailed engineering information for the Extended Power Uprate ("EPU") to meet evolving Nuclear Regulatory Commission ("NRC") requirements for EPU LAR submittals.

Project Management & Power Block Engineering: Capital expenditures for Project Management activities were $21.2 million or $18.5 million less than estimated while capital expenditures for Power Block Engineering activities were $71.2 million, or $18.7 million greater than estimated. As explained in the testimony of Jon Franke, these variances offset one another and are primarily attributable to using a new method to assign costs to these two categories in actuals compared to the general assumptions used for categorizing costs in the Estimated/Actual filing.

Permitting: Capital expenditures for Permitting activities were $0.9 million or $0.7 million greater than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to the need for environmental permits to support the project and temporary facilities that were not originally anticipated in the estimated facilities plan.

On-Site Construction Facilities: Capital expenditures for On-Site Construction Facilities were $1.2 million or $3.0 million less than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to a revision in the way costs are assigned to this category in actuals compared to the Estimated/Actual filing.

Non-Power Block Engineering, Procurement, etc.: Capital expenditures for Non-Power Block Engineering, Procurement, etc. activities were $3.6 million or $1.0 million less than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to scope and schedule changes associated with the Point of Discharge/Cooling Tower work for the project.

Q. Has PEF billed the CR3 joint owners for their portion of the costs relative to the CR3 Uprate and identified them in this filing?

A. Yes. Construction expenditures shown on Schedule T-6.3, Line 12 are gross of Joint Owner Billings but construction expenditures have been adjusted as reflected on Schedule T-6.3, Line 15 to reflect billings to Joint Owners related to CR3 Uprate expenditures. Due to this, no carrying cost associated with the Joint Owner portion of the Uprate are included on Schedule T-2.3. Total Joint Owner billings were $9.2 million for 2009.

Q. What was the source of the separation factors used in Schedule T-6?

A. Order No. PSC-05-0945-S-EI established appropriate jurisdictional separation factors as part of PEF's last base rate case. In Order No. PSC-07-0922-FOF-EI, these jurisdictional separation factors were approved as reasonable for costs to be recovered in 2009.

VI. CAPITAL COSTS INCURRED IN 2010 FOR CR3 UPRATE PROJECT

Q. What are the total Construction costs incurred for the CR3 Uprate Project for the period January 2010 through December 2010?

A. Schedule T-6.3, Line 12 shows that total Construction capital expenditures gross of joint owner billing and excluding carrying costs were $45.5 million.

Q. How did actual capital expenditures for January 2010 through December 2010 compare to PEF's actual/estimated costs for 2010?

A. Schedule T-6B.3, Line 10 shows that total project costs were $20.8 million lower than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2010 Construction costs are as follows:

License Application: Capital expenditures for License Application activities were $3.3 million or $1.7 million greater than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to the additional, more detailed engineering information needed for the EPU to meet evolving NRC requirements for EPU LAR submittals, which is a continuation of the cost variance for the 2009 License Application costs.

Project Management: Capital expenditures for Project Management activities were $5.2 million or $4.6 million lower than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to shifting resources due to changes in the next planned refueling outage for CR3 and, therefore, the schedule for EPU phase work.

Power Block Engineering & Procurement: Capital expenditures for Power Block Engineering & Procurement activities were $32.7 million or $10.3 million lower than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to the deferral of contract milestone payments.

Non-Power Block Engineering, Procurement, etc.: Capital expenditures for Non-Power Block Engineering, Procurement, etc. activities were $4.2 million or $7.0 million lower than estimated. As explained in the testimony of Jon Franke, this variance is primarily attributable to scope and schedules changes due to the extended plant outage.

Q. Has PEF billed the CR3 joint owners for their portion of the costs relative to the CR3 Uprate and identified them in this filing?

A. Yes. Construction expenditures shown on Schedule T-6.3, Line 12 are gross of Joint Owner Billings but construction expenditures have been adjusted as reflected on Schedule T-6.3, Line 15 to reflect billings to Joint Owners related to CR3 Uprate expenditures. Due to this, no carrying cost associated with the Joint Owner portion of the Uprate are included on Schedule T-2.3. Total Joint Owner billings were $3.4 million for 2010.

Q. What was the source of the separation factors used in Schedule T-6?

A. The jurisdictional separation factors are calculated based on the January 2010 sales forecast, using the Retail Jurisdictional Cost of Service methodology that was approved in the Order No. PSC-10-0131-FOF-EI in PEF's base rate proceeding in Docket No. 090079-EI.

VI. O&M COSTS INCURRED IN 2010 FOR THE CR3 UPRATE PROJECT

Q. How did actual O&M expenditures for January 2010 through December 2010 compare with PEF's actual/estimated costs for 2010?

A. Schedule T-4A, Line 15 shows that total O&M costs were $1.0 million or $0.3 million lower than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2010 CR3 Uprate O&M costs are as follows:

Legal: O&M expenditures for Legal were $0.3 million or $0.1 million lower than estimated. This variance was primarily attributable to lower than anticipated outside legal counsel services.

Nuclear Generation: O&M expenditures for Nuclear Generation were $0.5 million or $0.2 million lower than estimated. As explained in the testimony of Jon Franke, this variance was primarily attributable to lower than anticipated obsolete inventory expense.

VI. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT

Q. Please describe all accounting and costs oversight controls PEF has implemented for the LNP and CR3 Uprate Project.

A. The project accounting and cost oversight controls that PEF utilizes to ensure the proper accounting treatment for the LNP and CR3 Uprate project have not substantively changed from 2009. These controls were found to be reasonable and prudent in Docket No. 100009-EI.

PROJECT ACCOUNTING CONTROLS

Project Set-Up

The first part of project set up is the Major Projects - Integrated Project Plan ("IPP") Approval and Authorization. Per corporate policy, all projects equal to or exceeding $50 million require completion of an IPP which must be approved by a Project Review Group, the Senior Management Committee, and the Board of Directors.

The next part of PEF's project accounting controls involves project set up, specifically approval and authorization of projects. Projects are determined to be capital based upon the Company's Capitalization Policy and are documented in PowerPlant or in documents prepared in accordance with the Company's Project Governance Policy. The justifications and other supporting documentation are reviewed and approved by the Financial Services Manager, or delegate, based on input received from the Financial Services or Project Management Analyst to ensure that the project is properly classified as Capital, eligibility for AFUDC is correct and that disposals/retirements are identified. Supporting documentation is maintained within Financial Services or with the Project Management Analyst. Financial Services personnel, and selected other personnel (including project management analysts), access this documentation to set-up new projects in Oracle or make changes to existing project estimates in PowerPlant. The Oracle and PowerPlant system administrators review the transfer and termination information provided by Human Resources each pay period and take appropriate action regarding access as outlined in the Critical Application Access Review Process Policy.

An analyst in Property Accounting must review and approve each project set up before it can receive charges. All future status changes are made directly in PowerPlant by a Property Accounting analyst based on information received by the Financial Services Analyst or the Project Management Analyst.

Finally, to ensure that all new projects have been reviewed each month, Financial Services Management reviews a report of all projects set up during the month prior to month-end close for any project that was not approved by them in the system at set up.

Project Monitoring

The next part of the Company's project controls is project monitoring. First, there are monthly reviews of project charges by responsible operations managers and Financial Services Management for the organization. Specifically, these managers review various monthly cost and variance analysis reports for the capital budget. Variances from total budget or projections are reviewed, discrepancies are identified and corrections made as needed. Journal entries to projects are prepared by an employee with the assigned security and are approved in accordance with the Journal Entry Policy. Accruals are made in accordance with Progress Energy policy.

The Company uses Cost Management Reports produced from accounting systems to complete these monthly reviews. Financial Services may produce various levels of reports driven by various levels of management, but all reporting is tied back to the Cost Management Reports which are tied back to Legal Entity Financial Statements.

Finally, the Property Accounting unit performs a monthly review of sample project transactions to ensure charges are properly classified as capital. Financial Services is responsible for answering questions and making necessary corrections as they arise to ensure compliance.

Q. Are there any other accounting and costs oversight controls that pertain to the LNP and the CR3 Uprate Project?

A. Yes, the Company has also implemented disbursement services and regulatory accounting controls.

Q. Can you please describe the Disbursement Services Controls?

A. Yes. A requisition is created in the Passport Contracts module for the purchase of services. The requisition is reviewed by the appropriate Contract Specialist in Corporate Services, or field personnel in the various Business Units, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition.

The contract requisition then goes through the bidding or finalization process. Once the contract is ready to be executed, it is approved online by the appropriate levels of the approval matrix pursuant to the Approval Level Policy and a contract is created.

Contract invoices are received by the Account Payable Department. The invoices are validated by the project manager and Payment Authorizations approving payment of the contract invoices are entered and approved in the Contracts module of the Passport system.

Q. Can you please describe the Regulatory Accounting Controls?

A. Yes. The journal entries for deferral calculations, along with the summary sheets and the related support, are reviewed in detail and approved by the Manager of Regulatory & Property Accounting, per the Progress Energy Journal Entry policy. The detail review and approval by the Manager of Regulatory & Property Accounting ensure that recoverable expenses are identified, accurate, processed and accounted for in the appropriate accounting period. In addition, transactions are reviewed to ensure that they qualify for recovery through the Nuclear Cost Recovery Rule and are properly categorized as O&M, Site selection, Preconstruction, or Construction expenditures.

Analysis is performed monthly to compare actuals to projected (budgeted) expenses and revenues for reasonableness. If any errors are identified, they are corrected in the following month.

For balance sheet accounts established with Regulatory & Property Accounting as the responsible party, a Regulatory Accounting member will reconcile the account on a monthly or quarterly basis. This reconciliation will be reviewed by the Lead Business Financial Analyst or Manager of Regulatory & Property Accounting to ensure that the balance in the account is properly stated and supported and that the reconciliations are performed regularly and exceptions are resolved on a timely basis. The review and approval will ensure that regulatory assets or liabilities are recorded in the financial statements at the appropriate amounts and in the appropriate accounting period.

Q. Describe the review process that the Company uses to verify that the accounting and costs oversight controls you identified are effective.

A. Our assessment of the effectiveness of our controls is based on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). This framework involves both internal and external audits of our accounting and cost oversight controls.

With respect to internal audits, all tests of controls were conducted by the Audit Services Department, and conclusions on the results were reviewed and approved by both the Steering Committee and Compliance Team chairpersons. Based on these internal audits, Progress Energy's management has determined that Progress Energy maintained effective internal control over financial reporting and identified no material weaknesses within the required Sarbanes Oxley controls during 2010.

With respect to external audits, Deloitte and Touche, Progress Energy's external auditors, determined that the Company maintained effective internal control over financial reporting during 2010. Refer to Item 9A of 2010 Progress Energy Form 10-K Annual Report.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. YOUNG: Mr. Chairman, at this time I think for, for the record, Exhibits Numbers 138, 139, 140, 141, 142, 143, 144, 145, 146, 147, and 148 will not be entered into the record. Am I correct?

MS. HUHTA: I believe that that is incorrect. Mr. Franke's March 1st, 2011, testimony will be entered into the record, so that will be his Exhibits 138 through 144.

MR. YOUNG: Okay.

MS. HUHTA: Mr. Franke's Exhibits 145 through 148 on the Comprehensive Exhibit List will not be entered into the record. So if I may proceed with that, Mr. Young?

MR. YOUNG: Yes, ma'am.

MS. HUHTA: Thank you.

Chairman, we would move that Jon Franke's March 1st, 2011, testimony be entered into the record as though read, along with his Exhibits JF-1 through JF-7. Those are Staff comprehensive exhibits 138 through 144.

CHAIRMAN GRAHAM: Do we have any objections to those? Seeing none, we will enter Mr. Franke's testimony into the record as though read. And we'll also enter Exhibits 138, 39, 40, 41, 42, 43, and 44 into the record.

(Exhibits 138, 139, 140, 141, 142, 143, and

144 admitted into evidence.)

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 110009

DIRECT TESTIMONY OF JON FRANKE

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Jon Franke. My business address is Crystal River Nuclear Plant, 15760 West Power Line Street, Crystal River, Florida 34428.

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

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") in the Nuclear Generation Group and serve as Vice President – Crystal River Nuclear Plant.

Q. What are your responsibilities as the Vice President at the Crystal River Nuclear Plant?

A. As Vice President – Crystal River Nuclear Plant, I am responsible for the safe operation of the nuclear generating station. The Plant General Manager, Engineering Manager and Training sections report to me either directly or indirectly. Additionally, I have responsibilities in oversight of major project activities at the station. Through my management team I have about 420 employees that perform the daily work required to operate and maintain the station and provide engineering, training, and other support to the station.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor's degree in Mechanical Engineering from the United States Naval Academy at Annapolis. I have a graduate degree in the same field from the University of Maryland and a Masters of Business Administration from the University of North Carolina at Wilmington.

I have over 20 years of experience in nuclear operations. I received training by the U.S. Navy as a nuclear officer and oversaw the operation and maintenance of a nuclear aircraft carrier propulsion plant during my service. Following my service in the Navy, I was hired by Carolina Power and Light and have been with the company through the formation of Progress Energy. My early assignments involved engineering and operations, including oversight of the daily operation of the Brunswick nuclear plant as a Nuclear Regulatory Commission ("NRC") licensed Senior Reactor Operator. I was the Engineering Manager of that station for three years prior to assignment to Crystal River as the Plant General Manager in 2002. Almost two years ago, in April of 2009, I was promoted to my current position.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My direct testimony supports the Company's request for cost recovery pursuant to the nuclear cost recovery rule for costs incurred in 2010 for the Crystal River 3 ("CR3") Extended Power Uprate ("EPU") project ("CR3 Uprate") and the Company's request for a prudence determination of the costs incurred for the EPU project in 2010.

I will also provide testimony regarding PEF's 2010 project management, contracting, and oversight controls policies and procedures that are designed to manage project costs and maintain the project schedule and explain why they are reasonable and prudent.

In addition, pursuant to Commission Order No. PSC-11-0095-FOF-EI, issued on February 2, 2011, my testimony will also support a request for a determination of prudence of PEF's CR3 Uprate 2009 costs and 2009 project management, contracting and oversight controls policies and procedures. In this Order, the Florida Public Service Commission ("FPSC" or the "Commission") deferred the determination of the prudence of PEF's 2009 CR3 Uprate costs and 2009 project management, contracting and oversight controls policies and procedures to the 2011 nuclear cost recovery clause ("NCRC") proceeding to investigate the management of the License Amendment Request ("LAR") development process and ascertain the impacts, if any, that it had on actual 2009 CR3 Uprate costs.

Q. Do you have any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No.___ (JF-1), Work Authorization No. 84 between PEF and AREVA;
- Exhibit No. ___ (JF-2), Review Standard for Extended Power Uprates (RS-001);
- Exhibit No. ___ (JF-3), Excerpts from 2010 Commission Staff Audit Report applicable to the CR3 Uprate Project;

- Exhibit No. ___ (JF-4), EPU Expert Panel November 6, 2009 Management Debrief;
- Exhibit No. ___ (JF-5), Breakdown of 2009 Project Management and License Application Cost;
- Exhibit No. ___ (JF-6), Change Order 23 to Work Authorization No. 84; and
- Exhibit No. ___ (JF-7), Index of 2010 Revised and New Project Management Policies and Procedures.

These exhibits were prepared by me or the Company under my direction and control, or they are documents regularly used by the Company in the normal course of business, and they are true and correct.

I am also sponsoring the cost portions of Schedules T-4, T-4A, T-6, T-6A through T-7B, and Appendix B (2009) and Appendix D (2010) of the Nuclear Filing Requirements ("NFRs") for the 2009 and 2010 CR3 Uprate project costs respectively, which are included as part of the exhibits to Will Garrett's testimony. Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the 2009 and 2010 period. Schedules T-4A reflects CCRC recoverable O&M expenditure variance explanations for the 2009 and 2010 period. Schedule T-6.3 reflects the construction expenditures for the project by category. Schedules T-6A.3 reflect descriptions of the major cost categories of the expenditures and Schedules T-6B.3 reflect explanations for the significant variances between these expenditures and previously filed estimates for 2009 and 2010. Schedules T-7 are lists of the contracts executed in excess of $1.0 million for 2009 and 2010. Schedules T-7A reflect details pertaining to the contracts executed in excess of $1.0 million for 2009 and 2010. Schedules T-7B reflect contracts executed in excess of $250,000, but less than $1.0 million for 2009 and 2010. All of these schedules are true and accurate.

Q. Please summarize your testimony.

A. PEF requests a prudence determination and approval of the recovery of its 2009 and 2010 actual CR3 Uprate project costs. The Company's 2009 actual CR3 Uprate costs were determined to be reasonable and PEF was permitted to recover them as a result of the Commission's order in the 2010 NCRC proceeding. The Commission deferred, however, the determination of the prudence of PEF's 2009 actual CR3 Uprate project costs to the 2011 NCRC proceeding to address issues that were raised with respect to PEF's management of the LAR development process in 2009.

These LAR development costs represent a small fraction of the total CR3 Uprate project costs in 2009. The bulk of those costs were incurred for the work that was performed during the CR3 refueling outage in 2009 and for engineering analyses that supported the LAR. These costs were necessary for CR3 Uprate project work and they were reasonably and prudently incurred. In fact, there was no issue with respect to the reasonableness and prudence of these costs in the 2009 NCRC proceeding. As a result, the Commission should find the balance of the 2009 CR3 Uprate project costs for the Balance of Plant ("BOP") phase work and the engineering analyses for the LAR, including related project management costs, prudent pursuant to the nuclear cost recovery rule.

The LAR development costs in 2009 were also prudent. Problems with the quality and completeness of the initial draft LAR document were corrected by AREVA at no additional cost to PEF and its customers. Further, the cost for more engineering and analytical work in support of the revised LAR document, for example, to meet evolving NRC expectations for EPU LARs, would have been the same or higher if it was performed before rather than after the draft LAR document was reviewed by the expert panel in June-July 2009. The need for more engineering analyses and a new LAR format template due to evolving NRC expectations coincided with the expert panel reviews. As a result, devoting more management and other resources to this work before the expert panel reviews would have resulted in the same or likely an increase in the costs to PEF and its customers for the preparation of the draft LAR document. In summary, PEF and its customers paid no more than they should have paid to complete the EPU LAR draft document consistent with the evolving NRC expectations for EPU LAR submittals.

PEF also incurred CR3 Uprate project costs in 2010 in preparation for phase 3, the EPU phase of the project, during the Company's next re-fueling outage for CR3. The majority of these costs were incurred for necessary engineering analyses for the engineering change packages for the phase 3 work, for long lead item payments, and for related licensing and project management work. PEF took appropriate steps under its project management, contracting, and oversight policies and procedures to ensure that the 2010 CR3 Uprate project costs were reasonable and prudent, and that all of these costs were necessary for completion of the CR3 Uprate project. Accordingly, the Commission should approve PEF's 2010 CR3 Uprate project costs as reasonable and prudent pursuant to the nuclear cost recovery rule.

III. STATUS OF CR3 UPRATE PROJECT.

Q. Please explain the status of the CR3 Uprate project.

A. The CR3 Uprate project is a three-phase project involving the engineering, design, equipment procurement, and equipment installation necessary to generate an additional, estimated 180 MWe of efficient nuclear power at the Company's existing nuclear unit. The work necessary for this project was divided into three phases to be performed during separate, planned re-fueling outages at CR3. The first phase of the work was successfully completed during the 2007 CR3 refueling outage and it was brought online in January, 2008, providing PEF and its customers with an additional 12 MWe of nuclear energy generation.

The second phase of the work, primarily BOP work, was performed during the 2009 CR3 refueling outage and was successfully installed on schedule and at projected costs for the R16 outage with no major issues with the BOP work. When CR3 returns to service the BOP phase work will yield an additional 4 MWe nuclear energy production and supports the final EPU phase to be installed in R17.

PEF is currently performing the engineering and design analyses and is identifying and procuring the material and equipment necessary to complete the third and final phase of the CR3 Uprate. This is called the EPU work phase because, upon completion of the EPU work and NRC approval of the LAR for the power uprate, the Company will be able to increase the power generated at CR3 by an additional 164 MWe. The EPU work will be completed during the next refueling outage for CR3. The next refueling outage is scheduled for April 2013 (because of the extended outage of the CR3 unit). PEF expects the EPU phase of the CR3 Uprate project to be successfully completed in 2013. When phase 3 is complete, the CR3 Uprate will, in total, provide the Company with an estimated, gross additional 180 MWe nuclear energy production.

IV. COSTS INCURRED IN 2009 FOR THE CR3 UPRATE PROJECT.

A. COMMISSION DECISION IN DOCKET NO. 100009-EI.

Q. What did the Commission determine regarding PEF's 2009 CR3 Uprate Project costs and project management?

A. In Order No. PSC-11-0095-FOF-EI in Docket No. 100009-EI, the Commission determined that PEF's 2009 CR3 Uprate costs and 2009 project management, contracting, and oversight control policies and procedures were reasonable and allowed PEF to recover its actual 2009 CR3 Uprate costs. The Commission, however, decided to defer a decision on the prudence of the CR3 Uprate 2009 costs and 2009 project management, contracting, and oversight control policies and procedures to the 2011 NCRC proceeding.

Q. Did the Commission make any finding with respect to the prudence of PEF's 2009 CR3 Uprate project costs in its Order?

A. No. The Commission stated that it was deferring the prudence of PEF's 2009 CR3 Uprate costs and 2009 project management, contracting, and oversight controls to the 2011 NCRC proceeding to allow the parties "the opportunity to fully investigate and present the facts and circumstances surrounding the management of the CR3 Uprate LAR development process." The Commission expressly stated that the reason it was providing the parties this opportunity was to "ascertain the impacts [the CR3 Uprate LAR development process] had on actual 2009 costs, if any." See Order No. PSC-11-0095-FOF-EI, Docket No. 100009-EI, p. 39. The Commission expressed that there was insufficient information in the record in Docket No. 100009-EI to determine whether the Company's 2009 CR3 Uprate costs were negatively affected by PEF's management actions concerning the LAR development. Id. The Commission did not, however, make any finding that any of PEF's actual 2009 CR3 Uprate costs were imprudently incurred. Instead, the Commission deferred the consideration of this limited issue into this year's NCRC docket.

Q. What was the issue with respect to PEF's management of the CR3 Uprate LAR development process?

A. The issue was PEF's management of the preparation of the draft LAR document submittal in 2009. To obtain NRC approval for the CR3 EPU, PEF must submit a LAR to the NRC for review and approval. The LAR document includes a substantial technical report outlining the impact on and changes to plant systems and associated analyses, a set of proposed changes to the plant's technical specifications (detailed operational controls), and various other technical reports. This EPU Technical Report (Attachment 5 of the LAR document) is supported by extensive engineering studies and analyses that are used to develop the information in the Technical Report or included in other parts of the LAR document. Neither the Commission nor any of the parties raised any issues with the engineering work on the studies and analyses that were necessary to obtain the information required for the LAR document. In fact, the only issue last year that was deferred for consideration this year was PEF's management of the preparation of the LAR document itself.

Q. Who was the contractor who prepared the LAR document?

A. PEF contracted with AREVA to perform engineering work and draft portions of the LAR document in Work Authorization 84 in 2007 after obtaining the need determination from the Commission for the CR3 Uprate. See Exhibit No. ___ (JF-1) to my testimony. PEF contracted with AREVA to perform this work because AREVA is the successor to Babcock & Wilcox ("B&W"), the original Nuclear Steam Supply System ("NSSS") vendor of the CR3 plant. AREVA owns licenses to perform certain of the critical analyses as well as other technology rights and is the most experienced and knowledgeable vendor with respect to B&W plants like CR3. AREVA, therefore, was a necessary vendor for the power uprate work at CR3. Other portions of the LAR are the responsibility of PEF.

Q. What was the issue with AREVA's work on the draft LAR document?

A. AREVA commenced work on the necessary engineering analyses and studies to support the LAR document development in 2007 and prepared draft documents for PEF review in 2008 and 2009. PEF and AREVA provided the draft LAR document to an expert panel that PEF established to review the draft application.

The expert panel reviewed the draft document and found that the level of detail included in the draft likely would not meet acceptance review approval at the NRC. The expert panel reached this conclusion because the draft LAR document included poor quality work, incomplete work, and work that did not meet the evolving NRC standards for LAR draft submittals. PEF documented these short-comings in PEF's corrective action system, investigated the circumstances and contributing causes, and prepared an adverse conditions report as required by our Quality Assurance and Project Controls Programs. This report concluded that PEF did not devote adequate management resources to the management of the LAR draft document to ensure that a quality draft was completed as scheduled. PEF's management of the preparation of this draft is the LAR development issue that the Commission deferred to this proceeding.

Q. What questions did the Commission identify with respect to the deferral of the LAR development issue to the 2011 NCRC proceeding?

A. The Commission acknowledged that PEF's management, contracting, and oversight controls policies and procedures on the CR3 Uprate project -- which included the expert panel review of the draft LAR document -- provided the mechanisms for PEF to identify the issues with respect to the draft LAR document and correct them. The Commission, therefore, did not question the quality of the Company's project management and oversight controls mechanisms. Instead, the Commission questioned the timing of PEF's implementation of these mechanisms with respect to PEF's and AREVA's work on the draft LAR document. Order No. PSC-11-0095-FOF-EI, Docket No.

100009-EI, pp. 17-18. Specifically, the Commission questioned whether PEF had a process or the resources to timely redirect work under the AREVA contract due to evolving NRC expectations to potentially avoid performing superseded and, thus, unnecessary work on the draft LAR document. Id. at p. 18. The Commission further questioned whether the need for additional resources was apparent at any time before the expert panel review of the draft LAR document and whether PEF engaged in any mitigation strategies to augment the actual level of resources devoted to the development of the draft LAR document. Id. In summary, the Commission questions: (1) whether PEF's costs for the draft LAR document could have been reduced if PEF devoted additional management resources to the draft LAR document work prior to the first expert panel review; and (2) whether PEF incurred management or other costs for work on the draft LAR document that was unnecessary because of evolving NRC expectations. As a result of these two questions, the Commission concluded that it could not determine from the record last year whether customer costs were negatively affected by PEF's management of the development of the draft LAR document. Id.

B. 2009 CR3 UPRATE DRAFT LAR DOCUMENT DEVELOPMENT PROCESS AND COSTS.

Q. Addressing the first of the two remaining Commission questions, would PEF have reduced its costs for the draft LAR document if PEF had devoted additional resources to manage work on the draft LAR document prior to the first expert panel review?

A. No, because the timing of the additional management resources did not negatively impact customer costs for the draft LAR document. If PEF devoted the same additional management resources to the AREVA and PEF work on the draft LAR document prior to the first expert panel review in June-July 2009 that PEF devoted after this review, the costs to customers for the draft LAR document would have been the same or higher than they were. As a result, PEF's customers were not adversely impacted by PEF's management of the draft LAR document development prior to the first expert panel review.

Q. Why would the cost to customers for the draft LAR document have been the same or higher then they ended up being had PEF dedicated more management resources to the project prior to the first expert panel review in June-July 2009?

A. As I will explain later in more detail, the summary answer to this question is that (1) the problems with the quality and completeness of the initial AREVA draft LAR document were corrected by AREVA at no additional cost to PEF, and (2) the cost for more engineering work in the original draft, and more engineering analyses and a new LAR document template to meet evolving NRC expectations for EPU LAR submittal applications, would have been the same or higher if it was performed <u>before</u> rather than <u>after</u> the draft LAR document was submitted to the expert panel for review, because the need for more engineering analyses and a new LAR document template due to evolving NRC expectations coincided with the expert panel reviews.

Q. What resources were devoted to the draft LAR document preparation?

A. PEF and AREVA devoted experienced licensing and engineering staff to the draft LAR document preparation. PEF and AREVA LAR licensing and engineering staff were experienced nuclear professionals with prior licensing and engineering experience on nuclear projects. PEF and AREVA's licensing and engineering staff had prior experience on similar, technical issues on other nuclear projects they had worked on that were reviewed or approved consistent with NRC standards.

PEF also used the NRC's express guidelines for EPU projects to develop the CR3 Uprate draft LAR document. These guidelines were published by the NRC in 2003 explicitly for EPU projects. The guidelines are called the "Review Standard for Extended Power Uprates (RS-001)." These guidelines outline the NRC's expectations for an EPU project. See Exhibit No. ___ (JF-2) to my testimony.

In addition, the first plant to submit an EPU LAR based on RS-001 was the R.E. Ginna nuclear power plant in 2005. Ginna received a Safety Evaluation report ("SE") from the NRC in 2006 indicating the NRC's approval of the Ginna LAR document submittal. The NRC indicated to PEF that the Ginna LAR document provided a good model for future EPU LAR document submittals. As a result of the NRC staff's tacit approval of the Ginna LAR as a model EPU LAR and the NRC's ultimate approval of the Ginna EPU LAR submittal, PEF used the Ginna LAR document as a model for the CR3 EPU LAR document. AREVA was provided both the RS-001 and Ginna LAR document as a guide for the development of the CR3 EPU LAR inputs.

As a result, PEF was reasonably assured that the quality of its draft LAR document resources at PEF and AREVA were adequate. These resources included licensing and engineering staff at both PEF and AREVA that had prior experience on nuclear projects subject to review or approval under NRC standards. These resources were also provided the existing NRC and industry guidelines at that time for the preparation of EPU LAR documents.

Q. Did PEF take other steps to manage the work on the CR3 EPU draft LAR document?

A. Yes. The management of the AREVA and PEF work on the CR3 EPU draft LAR document was subject to the same project management and oversight controls and procedures that applied to all PEF major capital projects like the CR3 Uprate project. These are the same project management and oversight controls and procedures that I described in my testimony in the 2009 NCRC proceeding that were determined by the Commission to be reasonable and prudent in Order No. PSC-09-0783-FOF-EI in Docket No. 090009-EI. See Order No. PSC-09-0783-FOF-EI, p. 24 ("Therefore, we find that during 2008, PEF's project management, contracting, and oversight controls were reasonable and prudent for the CR3 Uprate project."). I provided testimony updating these same project management, contracting, and oversight controls in my testimony in the 2010 NCRC proceeding and I provide similar testimony below in this NCRC proceeding.

These project management, contracting, and oversight controls include mechanisms and procedures for the management of vendor work like AREVA on the CR3 Uprate project, and they provide for the auditing of that management and work as a matter of nuclear oversight by personnel independent from the Uprate project managers. As a result, PEF did not just accept the draft LAR document or its own management of that work. Both were subject to further review in accordance with project management, contracting, and oversight mechanisms PEF established for the CR3 Uprate project.

This further review included the expert panel review followed by the investigation of the expert panel findings that produced the adverse condition report and recommendations. As I explained in my rebuttal testimony last year, PEF established a team of industry experts, including outside experts, to critically review the draft LAR for completeness, correctness, clarity and conformance with industry best practices at the time of their review. They were specifically directed to review and critique the draft LAR document. PEF's decision to have an expert panel review the LAR document was consistent with best industry practices and, therefore, prudent project management.

Similarly, the subsequent, independent adverse conditions report regarding the quality of PEF's management of the work on the draft LAR document also reflected critical oversight and prudent project management, as I also explained last year. These independent external and internal critical reviews were and are necessary to any prudent project management process. The fact that PEF had them in place and that they were implemented on the CR3 Uprate project with respect to the LAR document development process demonstrates PEF's prudent project management, contracting, and oversight controls over this aspect of the work on the Uprate project in particular, and on the CR3 Uprate project in general. This review process ensured that the LAR document work was reviewed, that any work that was not up to par was corrected, and that a LAR document that was sufficient and consistent with the standards at the time of the review for LAR document submittals was prepared. The Commission audit staff agreed in the 2010 NCRC proceeding that the expert panel performed an important role in insuring a complete and thorough LAR submittal to the NRC. See Exhibit No. ___ (JF-3), 2010 Staff Audit Report, p. 40. The Commission further agreed that this process represented a prudent project management process. Order No. PSC-11-0095-FOF-EI, pp. 17-18.

Q. Did the expert panel include members with experience on other EPU projects?

A. Yes. All members of the expert panel that conducted the first review of the draft LAR document in June-July 2009 and in subsequent time periods extending into early 2010 were experienced nuclear professionals with prior NRC EPU or similar NRC experience. One of the two Progress Energy members of the expert panel reviews of the CR3 Uprate EPU draft LAR document had worked on the EPU at the Progress Energy Brunswick nuclear power plant. The other Progress Energy member of the expert panel was previous to his employment with Progress Energy the licensing lead on the Waterford nuclear power plant EPU. The others had contributed to other EPUs or other similar projects.

Q. Would placing those Progress Energy members of the expert panel reviews on the CR3 Uprate project to help manage the draft LAR development work

prior to the first expert panel review have resulted in lower costs to customers?

A. No. As I testified earlier, if these expert panel members were employed by PEF to manage the draft LAR document prior to the expert panel review --- or if PEF employed the additional resources PEF added after the expert panel review to manage the draft LAR document prior to the expert panel review --- the costs to PEF's customers would have been the same or higher than they were. Changing the quality or quantity of the management resources on the draft LAR document prior to the expert panel review would not have reduced the customer costs for the LAR document. In fact, adding to the quality or quantity of the management of the development of the draft LAR document prior to the expert panel reviews likely would have increased the costs to customers of the ultimate LAR document that was prepared and ready for NRC submittal consistent with the known NRC standards for EPU LAR submittals at the time of the expert panel reviews.

Q. Why would increasing the quality or quantity of the LAR management resources for the work on the draft LAR document prior to the expert panel reviews have likely resulted in the same or increased costs for the draft LAR document?

A. There are several reasons, all related to the nature of the expert panel and adverse condition report recommendations for improving the draft LAR document that was provided to the expert panel to review. First, one issue with the initial draft LAR document was the quality and completeness of the work consistent with the RS-001 and Ginna model guidelines at the time this draft was prepared. In essence, the expert panel determined that the draft LAR document lacked the level of detail or quality necessary to meet these guidelines in certain sections of the draft LAR document. The expert panel also determined that certain sections were incomplete in that they did not incorporate sufficient engineering information or analysis when compared to the pre-existing guidelines that AREVA and PEF used for the preparation of the EPU draft LAR document. This did not mean that this engineering analysis had not been done or the engineering information was not developed by AREVA. Rather, it meant that AREVA had not included this engineering information or analyses in the draft LAR document consistent with the RS-001 and Ginna EPU LAR submittal model guidelines.

As I testified in last-year's proceeding, the correction of these issues with the draft LAR document by AREVA was performed <u>at AREVA's cost</u>. PEF paid AREVA <u>no additional funds</u> to re-do or re-write unchanged LAR document sections to improve the quality or add additional engineering information or analysis that had already been performed for the LAR document consistent with the RS-001 and Ginna EPU LAR submittal model guidelines. As I further testified last year, PEF, therefore, addressed the expert panel and internal adverse condition report recommendations concerning the quality and completeness of the draft LAR document at no additional cost to customers. Because these issues were corrected at no additional cost to customers anyway, adding more and more experienced licensing and engineering staff to manage the draft LAR document work prior to the expert panel review would not have resulted in any change in the cost to customers. Adding these additional resources to manage the draft LAR document work prior to the expert panel review may have led to the correction of these issues earlier, but having these corrections earlier than June-July 2009 would not have saved PEF's customers any money. Said another way, if PEF had deployed the expert panel the first day work began to review each page of the draft LAR document as soon as it was completed, PEF's customers would not have saved one penny over what they are being charged now. Granted, this hypothetical process would have likely avoided AREVA having to do re-work on the LAR document to correct issues, but as I have made clear, all costs of the correction work that AREVA had to do did not cause any delay costs and that work was performed solely at AREVA's cost.

Q. How do you know PEF did not pay AREVA twice for the same work on the quality and completeness of the draft LAR document?

A. AREVA was paid a flat fee of [redacted] to write the draft LAR document sections reviewed by the expert panel in June-July 2009 using the RS-001 and Ginna LAR draft submittal document as guides. These payments are identified at line items 8.28, 8.28 revised, and Note 2 in the "Deliverable Section" on page 4 of Work Authorization No. 84 between PEF and AREVA for design and engineering work to support the CR3 Uprate project, including the work to support the LAR document and draft the LAR document. These line items demonstrate that AREVA was paid [redacted] for LAR inputs and draft comment responses and that AREVA was paid another [redacted] when the LAR document was ready for submittal to the NRC. See Exhibit No. ___ (JF-1) to my testimony. That is all AREVA will be paid for the initial draft LAR document work. After the expert panel issued its report and recommendations, AREVA corrected their quality and completeness issues and re-wrote the LAR document sections at AREVA's own cost.

As I testified last year, PEF met with AREVA prior to AREVA submitting each invoice under Work Authorization No. 84 and related changes orders. That is why the costs for work to re-write portions of the LAR document do not show up in subsequent AREVA invoices to PEF. AREVA did, however, correct the portions of the draft LAR document that did not meet the quality or completeness standards of the RS-001 and Ginna LAR model guidelines. Subsequent expert panel reviews confirmed that these corrections were made. See, e.g., Exhibit No. ___ (JF-4) to my testimony. PEF, however, paid no additional compensation for that work. The Commission agreed that, in reviewing the record in the NCRC proceeding last year, it found no instance where work performed by AREVA under the original contract or change orders was shown to be unneeded. See Order No. PSC-11-0095-FOF-EI, Docket No. 100009-EI, p. 18.

Q. You testified there were other reasons adding additional management resources to the LAR document development prior to the expert panel review would have resulted in the same or higher costs to customers, what are they?

A. One of the expert panel criticisms was that PEF and AREVA had not done enough work on the draft LAR document at the time it was submitted to the expert panel for review in June-July 2009. The expert panel concluded that the draft LAR document did not provide sufficient design and engineering detail for the EPU equipment and modifications to plant operations for the NRC to accept the LAR document for review and approval. This required additional design and engineering detail that had not yet been performed. In sum, then, the expert panel found that PEF had not incurred the costs and performed the work necessary to that point to prepare a draft LAR document that was capable of NRC acceptance review.

PEF accepted the expert panel comments and recommendations and invested the money in the design, engineering, and analysis work necessary to complete the design and engineering work for the EPU modifications described in the draft LAR document to improve the LAR submittal to the NRC. Subsequent expert panel reviews confirmed that PEF adequately addressed these expert panel comments and recommendations to prepare a LAR document that was acceptable for NRC acceptance review. See, e.g., Exhibit No. ___ (JF-4) to my testimony. The Commission audit staff further noted last year that PEF had to expend resources to strengthen the EPU LAR submittal to meet the NRC's acceptance review. See Exhibit No. ___ (JF-3), 2010 Staff Audit Report, p. 59.

The fact that PEF had to expend additional costs on additional resources for the design, engineering, and procurement work to enhance the EPU draft LAR document demonstrates that these costs would have been incurred in any event to produce the same end LAR document work product. In other words, the same work required to produce a draft LAR document that met NRC submittal requirements at the time the expert panel concluded they were met in early 2010 would have to be done and the costs for that work incurred no matter when that work took place. The timing of the costs for this additional, required design and engineering work recommended by the expert panel was different but the work and costs required were essentially the same.

Q. **Did the difference in the timing of these costs cause customers to bear more costs than they otherwise would have?**

A. No, because the timing difference was a matter of months -- from early 2009 to mid-to-late 2009 and early 2010 -- and the costs for engineering work that might have been performed at the beginning compared to the costs of the same work that was performed at the end of this relatively short period of time did not change. In other words, PEF moved quickly to perform the additional, required engineering work in response to the recommendations of the expert panel and, as a result, there were no delays in performing this additional work that resulted in additional costs to customers.

Q. **In what way could adding additional management resources to the LAR document development prior to the expert panel review have resulted in higher costs to customers?**

A. Another expert panel recommendation was that the draft LAR document needed to conform to evolving NRC expectations for LAR document submittals. These evolving NRC expectations resulted in additional engineering work as well as the development of a new template for the LAR document. In fact, PEF and AREVA developed an updated template for its LAR document, after the expert panel review in June-July 2009, consistent with the evolving NRC standards to replace the Ginna model as a guideline for LAR document submittals to the NRC.

If PEF had added more and more experienced licensing and engineering staff to the management of work to develop the draft LAR document prior to the expert panel review, then, the cost to perform the additional engineering work and develop a new LAR submittal template to meet evolving NRC expectations would have been higher for PEF's customers. The reason is that any additional management resources employed on the draft LAR document work <u>before</u> the first expert panel review would have followed the same LAR submittal format for the scope of work for the draft LAR document that PEF followed. The RS-001 and Ginna LAR submittal were the only guidelines available at that time. The generalized need for additional engineering work for and work on a new template for the LAR document submittal due to evolving NRC expectations was not apparent at that time. As a result, had PEF prematurely added more and/or more experienced licensing and engineering staff to manage the draft LAR document work prior to the first expert panel review PEF would have incurred more costs for these additional management resources, but PEF could not and would not have improved the draft LAR document submittal to meet evolving NRC expectations for EPU LAR submittals that were not known at that time.

Q. When did PEF first become aware of evolving NRC expectations for EPU LAR submittals that indicated PEF needed additional engineering work and a new template for its EPU LAR submittal document?

A. PEF became aware that the Ginna EPU LAR submittal may no longer be an acceptable model for LAR document submittals in mid to late 2009, after reviewing the NRC's Requests for Additional Information ("RAIs") to Point

Beach regarding its EPU LAR document submittal to the NRC. Point Beach submitted its EPU LAR document to the NRC for acceptance review in April 2009. The NRC commenced RAIs to Point Beach regarding its EPU LAR document submittal in late April to early May 2009, and these RAIs continued in number and complexity over the course of the summer and into the fall of 2009. In October of 2009 the NRC issued a non-acceptance to Point Beach stating that Point Beach should supplement its LAR application or withdraw it.

Q. Why was the Point Beach EPU LAR submittal an indication of evolving NRC requirements for EPU LAR application submittals to the NRC?

A. Point Beach is a Westinghouse Pressurized Water Reactor ("PWR"). CR3 is also a PWR. The Point Beach PWR is a similar PWR design to the Ginna nuclear power plant. As a result, the Point Beach LAR submittal was similar to the Ginna LAR submittal that had been accepted and approved by the NRC and that PEF was using as a model for its CR3 EPU LAR submittal with the tacit approval of the NRC staff.

Point Beach submitted its EPU LAR document to the NRC for acceptance review and, by the end of April to early May 2009, Point Beach began receiving numerous, detailed RAIs from the NRC. During the period from mid to late 2009, it became increasingly clear from reviewing the NRC RAIs and the Point Beach RAI responses that NRC expectations for EPU LAR submittals had changed. The scope, extent, and nature of the Point Beach RAIs suggested a more stringent NRC review of EPU LAR submittals and more stringent requirements for the design and engineering analyses to be performed for or submitted in the EPU LAR document.

The level of detailed engineering analysis and information required by the Point Beach EPU LAR NRC RAIs demonstrated that the level of detail included in the Ginna LAR document submittal was inadequate for NRC acceptance review and, therefore, that the Ginna LAR document was no longer an acceptable model for EPU LAR submittals. This view was confirmed when the NRC wrote Point Beach in October 2009 indicating that it was not accepting the Point Beach LAR submittal --- which was based on the same Ginna LAR submittal that PEF was using as a model --- and that Point Beach could either supplement its LAR submittal or withdraw it.

Q. Did the Point Beach EPU LAR review experience at the NRC mean that PEF incurred costs that were unnecessary for its draft EPU LAR submittal document?

A. No. All PEF and AREVA work on the draft EPU LAR document for the CR3 Uprate prior to the Point Beach LAR RAIs and RAI responses was necessary to meet the known LAR document submittal requirements at that time. PEF and AREVA were using the RS-001 and Ginna LAR submittal document that had been approved by the NRC and indicated by NRC staff as a useful guide for EPU LAR submittals. Prior to the Point Beach EPU LAR RAIs and RAI responses, then, PEF and AREVA work on the CR3 EPU LAR draft document was based on the known and knowable LAR submittal requirements at that time.

It is important to remember too that one of the expert panel's criticisms of the PEF and AREVA EPU LAR document work was that PEF did not have sufficient resources devoted to this work prior to the expert panel review. PEF likewise reached a similar conclusion that more licensing and engineering staff was needed for the LAR submittal work following a routine Nuclear Oversight Organization audit in early 2009. This audit was performed in accordance with PEF's project management and oversight policies and procedures. This audit recommended employing additional licensing and engineering staff for the CR3 EPU LAR submittal. In response to this audit recommendation, PEF revised the LAR submittal schedule to provide for a later September 2009 target date for LAR submittal to the NRC to give PEF more time to develop the LAR submittal. PEF also firmed up the expert panel review commencing in the summer of 2009 to determine where the draft LAR document stood in terms of the engineering analysis and work that was being done and that needed to be done for the EPU LAR submittal. As a result, PEF did not have excess resources devoted to the EPU LAR document work before PEF became aware of the evolving NRC requirements for such submittal documents.

Finally, the most significant impact of the evolving and more stringent NRC requirements for the LAR submittal following the Point Beach RAIs and RAI responses was the identification of more – not less – engineering and other, related work that needed to be performed for the LAR submittal document to meet NRC acceptance review. PEF had to add licensing and engineering resources and incur more costs to meet the evolving NRC standards for EPU LAR documents. If these additional LAR submittal requirements were known earlier --

which was not the case -- the same costs would have been incurred to meet these requirements earlier that were incurred to meet them after they were known to PEF.

Q. Did PEF's management of the LAR document development process in 2009 actually benefit PEF's customers?

A. Yes. PEF took a reasonable and prudent approach to the need for additional LAR application licensing and engineering support in 2009 when it determined that such additional resources were necessary. PEF planned to employ its existing oversight plan involving the expert panel review of the draft EPU LAR document to identify where additional licensing and engineering resources were necessary to support the LAR document development process. The most efficient way to add additional resources to support the development of the LAR submittal was to first evaluate the draft AREVA work product and determine what resources were needed and where the resources were needed. The expert panel reviews provided PEF with an existing independent mechanism to timely review the draft EPU LAR document and determine where to most efficiently add licensing and engineering resources.

The timing of the expert panel review also provided PEF the opportunity to efficiently incorporate the evolving NRC standards for EPU LAR submittals into the CR3 draft EPU LAR submittal. The expert panel reviews coincided with the development of the additional NRC requirements for EPU LARs as a result of the Point Beach EPU LAR NRC RAIs and RAI responses from mid 2009 to late October 2009. As a result, the expert panel reviews provided a timely mechanism to incorporate these evolving NRC standards into the expert panel recommendations for the CR3 EPU LAR submittal application. This is in fact what the expert panel did when they made their recommendations to PEF to improve the CR3 EPU LAR draft document.

As a result, the LAR development work in 2009 for the CR3 EPU LAR draft document was valuable. The addition of licensing and engineering resources to assist with the draft LAR submittal work and incorporate evolving NRC standards for such applications as recommended by the expert panel reviews ultimately provided a necessary and efficient mechanism to add resources and meet the changing EPU LAR submittal requirements at that time. This saved PEF's customers money. PEF's customers paid no more than what they should have paid for the EPU LAR draft document work by AREVA and PEF in 2009.

Q. Should PEF have been aware of the evolving NRC standards prior to the NRC review of the Point Beach EPU LAR submittal?

A. No. As I previously testified, the first indication of a general increase in the NRC requirements for EPU LAR submittals was the Point Beach NRC RAIs and RAI responses because this LAR submittal was also for a PWR plant and the EPU LAR document was similar to the Ginna LAR submittal document that PEF was using as a guide for its EPU LAR document. There was one earlier relevant EPU LAR submittal to the NRC, but this submittal was for a Boiling Water Reactor ("BWR"), not a PWR plant, and it involved a more limited set of LAR issues. Thus, this earlier EPU LAR submittal did not indicate a more general increase in the requirements for EPU LAR submittals to the NRC. Nevertheless, PEF followed this EPU LAR submittal at the NRC and incorporated applicable changes in its EPU draft LAR work where such changes were indicated.

Q. **Can you explain what this prior EPU LAR submittal was and how PEF responded to it with its own EPU draft LAR document?**

A. Yes. In late June 2008 the Monticello nuclear power plant withdrew its EPU LAR submittal in response to a NRC letter indicating that the EPU LAR was inadequate with respect to three, limited EPU issues. As I indicated earlier, the Monticello nuclear power plant is a BWR, which is a very different design from the PWR plants like CR3. Also, Monticello had followed a different format for its EPU LAR submittal. Monticello used a series of General Electric Topical Reports on EPU as the basis for its EPU LAR. These reports were very different from the Ginna EPU LAR document that PEF was using at the time as its model application and contained far less information than the Ginna EPU LAR document. These circumstances made the Monticello EPU LAR submittal distinguishable from the CR3 EPU LAR draft document and, thus, of limited value to PEF as PEF worked with AREVA on the draft CR3 EPU LAR document.

As a result of these differences, the narrow issues identified by the NRC for determining the Monticello EPU LAR submittal inadequate were of limited application to the CR3 EPU LAR submittal document. For example, the NRC questioned the Steam Dryer Integrity in the Monticello EPU LAR submittal. PWRs like CR3 do not have Steam Dryers. Nevertheless, based on the NRC's expressed interest in this area, PEF did determine if it had any applicability to the

CR3 EPU LAR and, as a result, PEF established a more thorough vibration monitoring plan for its EPU LAR than PEF originally planned.

Also, the NRC had questioned the instrumentation setpoints for the Monticello BWR EPU in the LAR submittal document. This issue did not impact the CR3 EPU LAR document because no instrumentation setpoints were being changed at that time.

The third and final EPU LAR issue identified by the NRC with respect to the Monticello EPU LAR was the Environmental Qualification ("EQ"). EQ is a standard design requirement for all nuclear power plants. It basically requires the licensee to demonstrate through testing that components required to mitigate accidents can withstand a normal operating environment and the environment during related accidents. Previously, all utility EPU LAR submittals planned to complete their EQ work after LAR submittal but prior to EPU implementation. Starting with the Monticello EPU LAR submittal, the NRC required that EQ impacts be completed prior to LAR submittal and incorporated into the EPU LAR submittal. As a result of the NRC response to the EQ analysis in the Monticello EPU LAR submittal, and confirmation of the changing expectation through direct communications with the NRC, PEF moved up its EQ work activities and included the EQ analysis in its draft LAR document. The expert panel reviews raised no concerns with PEF's EQ analysis in the draft EPU LAR document for CR3.

As I have demonstrated here, PEF responded to the limited NRC issues identified with the very different Monticello EPU and EPU LAR submittal when a response was in any way indicated for the CR3 EPU LAR submittal. There was no indication from this limited NRC review of the Monticello EPU LAR, however, that the NRC was going to generally expand the requirements for all EPU LAR submittals to include substantially more and different engineering information and analysis in the EPU LAR document.

Q. Did PEF have appropriate processes in place to identify and timely redirect EPU LAR licensing and engineering work if the redirection of that work was necessary?

A. Yes. PEF did have a proper process in place to timely redirect work if redirection of the EPU LAR work was in fact necessary. This process included (i) AREVA and PEF participation in the industry working group that developed the EPU guidance, (ii) AREVA and PEF involvement in the review of other EPU LAR submittals, (iii) PEF participation with other utility EPU licensing managers in discussions regarding EPU LAR submittal requirements, and (iv) PEF involvement in following and participating in NRC public reviews of EPU LAR submittals. PEF's decision to re-direct EQ work for its EPU LAR submittal following information gleaned from this process regarding the Monticello EPU LAR submittal that I just described demonstrates that PEF's process to redirect EPU LAR licensing and engineering efforts worked when the information indicating the need to re-direct work existed.

Q. Did the issues with AREVA's work on the draft LAR document have an impact on the CR3 Uprate project?

A. Yes, but no impact that cost PEF's customers more money than they would otherwise have paid. When PEF had to add additional licensing and engineering resources for the draft LAR work PEF did miss its targeted September 2009 EPU LAR submittal date. Missing this target for the EPU LAR submittal to the NRC, however, did not result in any additional cost to ratepayers and it did not delay EPU LAR approval beyond the planned implementation of the CR3 power uprate at that time.

The September 2009 EPU LAR submittal deadline was an aggressive target date for the CR3 EPU LAR submittal. This target date provided approximately twenty-four months to complete the EPU LAR submittal review process prior to the then-planned November 2011 refueling outage for the phase 3 EPU work. The NRC licensing process performance indicators is based on fourteen months from the date the EPU LAR is submitted to the NRC for approval to obtain a SE report from the NRC approving the EPU LAR submittal. PEF therefore had approximately ten months of float in the EPU LAR schedule based on the initial September 2009 target EPU LAR submittal date. As a result, even if the November 2011 refueling outage at CR3 was not extended, PEF had until August 2010 to submit its EPU LAR document for NRC approval in time for the original planned completion of the phase 3 EPU work and the power uprate. The Commission audit staff agreed that PEF had substantial float in its initial EPU LAR submittal schedule. See Exhibit No. ___ (JF-3), 2010 Staff Audit Report, p. 38.

Although PEF had established a September 2009 target for submittal of the EPU LAR document to the NRC, the priority for PEF engineering resources in

2009 was correctly focused on the R16 outage work in the fall of 2009. That was why the original EPU LAR submittal date was June 2009 (before the R16 outage), then shifted to September 2009 (right before the R16 outage), before being moved to March 2010 (after the scheduled R16 outage). These shifts in the targeted EPU LAR submittal date provided the additional time necessary to address the expert panel and adverse conditions report recommendations while ensuring that the additional licensing and engineering work required to comply with these recommendations did not interfere with the engineering work for the R16 outage. Because PEF had substantial float in its EPU LAR schedule, PEF was able to perform the additional licensing and engineering work recommended by the expert panel and internal audit for the EPU LAR document without adversely impacting the timing for submittal of the EPU LAR to the NRC for approval. The delay in preparation of the EPU LAR document for submittal to the NRC from June 2009 to March 2010 therefore did not result in any additional ratepayer costs.

Q. What project management costs were incurred in 2009 for the AREVA draft LAR document development management and oversight?

A. PEF incurred $110,261 in project management costs for direct oversight of the EPU LAR document development process from January to June 2009, as referenced in the footnotes in Exhibit No. __ (JF-5) to my testimony.

Q. Did Commission Order No. PSC-11-0095-FOF-EI identify a broader range of potential cost impacts due to the draft LAR document development process?

A. Yes. The Commission noted that potential cost impacts, if any, due to PEF's management of the LAR document development process range from $0 to over $40 million, with the higher range based solely on intervenor arguments -- not the evidence -- in the 2010 NCRC proceeding, as I explain in more detail below. Order No. PSC-11-0095-FOF-EI, Docket No. 100009-EI, p. 39. The Commission further determined that all of PEF's 2009 CR3 Uprate costs were reasonable, but deferred finding that they were prudent to the 2011 NCRC proceeding. The total CR3 Uprate 2009 costs included capital costs of $118,140,493, operation and maintenance ("O&M") expenses of $821,773, carrying charges of $14,351,595, and a base revenue requirement of $396,018. Thus the vast majority of the CR3 Uprate 2009 costs have nothing to do with the CR3 Uprate LAR development process that was identified as an issue for the 2011 NCRC proceeding by the Commission. The Commission recognized this, noting "that beyond those items identified in the issues above [the LAR development process issues], no other concerns where [sic] identified with the 2009 final costs and final true-up amount for the CR3 Uprate project." Order No. PSC-11-0095-FOF-EI, Docket No. 100009-EI, p. 39. In fact, as I testified earlier, the actual 2009 PEF management costs for the development of the draft EPU LAR document is a very small fraction of the potential cost range identified by the Commission based on the parties' arguments in the 2010 NCRC proceeding and an even smaller percentage of the total 2009 CR3 Uprate costs.

Q. Where did the identified range of potential cost impacts come from in Order No. PSC-11-0095-FOF-EI?

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A. The low end of the range, or $0, represents PEF's testimony and document evidence in the 2010 NCRC proceeding that the issues with the draft EPU LAR document that led to the expert panel and adverse conditions report recommendations resulted in no additional costs to PEF's customers. For the reasons I explained earlier, PEF's customers paid no more than they should have paid for the development of the EPU LAR document for submittal to the NRC.

The high end of the range, $40 million, was first identified in the Office of Public Counsel's ("OPC") post-hearing brief in the 2010 NCRC proceeding. It simply represents the total of all Licensing Application and Project Management costs incurred in 2009 for the entire CR3 Uprate project. PEF obviously did not spend all of its 2009 Licensing Application and Project Management costs on the management of the EPU LAR draft document by AREVA.

PEF incurred [redacted] for EPU LAR document development work by AREVA and a total of $132,059 for PEF internal project management oversight and associated PE Company labor costs for the LAR document development work from January to June of 2009. To illustrate this point, I have provided a line-by-line breakdown of the $40 million in License Application and Project Management actual costs incurred in 2009 in Exhibit No. ____ (JF-5) to my testimony. As this exhibit demonstrates, the vast majority of the 2009 CR3 Uprate License Application and Project Management costs were not incurred in connection with the EPU LAR document development. Most of the $20,016,839 in License Application costs in 2009 for the CR3 Uprate project was incurred for the extensive engineering work under WA 84 including the fuels analysis, safety analysis, and system and program reviews. Most of the $21,154,156 in 2009 CR3

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Uprate Project Management costs were incurred for the management oversight of the BOP phase engineering work that was completed during the R16 CR3 refueling outage in 2009.

Q. Can you please explain how you calculated the costs for the 2009 AREVA and PEF LAR document development work in Exhibit No. ___ (JF-5)?

A. Yes. The NSSS contract WA 84 with AREVA was approved on February 27, 2007. WA 84 provided the basis for all engineering and accident safety analysis work required to support the EPU LAR submittal and the work required to draft the EPU LAR document. WA 84 is attached as Exhibit No. ___ (JF-1) to my testimony. As I testified earlier, line items 8.28, 8.28 revised, and Note 2 totaling [redacted] show the fixed price amount PEF contracted with AREVA to draft sections of the initial EPU LAR document. Two additional items are added to the 2009 EPU LAR development costs. The first work item was change order number 23 to WA 84, executed in December 2009 (Rev 1) in the amount of [redacted]. See Exhibit No. ___ (JF-6) to my testimony. Of this total change order amount, [redacted] was incurred in 2009 for LAR document development activities (the remaining change order amount was incurred in 2010). See Exhibit No. ___(JF-5). The second work item is the inclusion of internal Company labor for the management oversight and work on the LAR document development in 2009. As I indicated previously, for January to June 2009, PEF costs for the management oversight and associated PEF labor costs for the draft LAR document development process was $132,059.

Q. Why was Change Order Number 23 necessary for the LAR development work?

A. This change order was for the work necessary to re-write the original EPU LAR document in 2009 to comply with the revised EPU LAR template to meet evolving industry standards and NRC expectations. Change Order Number 23 expressly states the LAR re-write effort was to re-write sections of the LAR document to comply with the revised template and other new scope activities. It was not payment to AREVA to re-write poorly drafted LAR sections identified in the June-July 2009 expert panel review of the AREVA draft LAR document. Indeed, Change Order Number 23 further expressly states that the expert panel "comment incorporation is considered part of the original scope of activities and is not included in this scope of work." See Exhibit No. ___ (JF-6) to my testimony. Under this Change Order, AREVA was entitled to more compensation for more work to conform the LAR document to meet the additional EPU LAR document requirements based on evolving industry standards and NRC expectations. These evolving industry and NRC expectations for EPU LAR documents required more detailed engineering analyses and documentation of that analyses to be included in the EPU LAR document than was the previous industry standard.

C. CR3 UPRATE 2009 CAPITAL AND OTHER COSTS.

Q. What were the other 2009 CR3 Uprate project costs?

A. PEF incurred costs in 2009 related to the last two phases -- the BOP and EPU phases -- of the CR3 Uprate project. In fact, PEF completed the work necessary to install the BOP phase work during the R16 refueling outage in 2009. The total capital expenditures for 2009, gross of joint owner billing and exclusive of carrying cost, were $118,140,493. These costs were incurred for (i) license application costs, (ii) project management costs, (iii) permitting costs, (iv) on-site construction facility costs, (v) power block engineering, procurement and related construction costs, and (vi) non-power block engineering, procurement, and related construction costs. Schedule T-6A attached as Exhibit No. ___ (WG-1) to Mr. Garrett's testimony provides further details regarding these costs.

PEF also incurred O&M expenses in 2009 for the CR3 Uprate project in the amount of $821,773. These expenses were incurred for Administrative and General ("A&G") expenses and other, related project overhead costs in 2009. Schedules T-4 and T-4A attached as Exhibit No. ___ (WG-1) to Mr. Garrett's testimony provides further details regarding these costs.

Q. You mentioned that PEF completed the installation of the BOP phase work in 2009, did this work account for a significant portion of PEF's 2009 CR3 Uprate project costs?

A. Yes. The Company incurred $71,243,000 for Power Block Engineering, Procurement, and related construction cost items. Most of the costs incurred in this category in 2009 were associated with the R16 outage scope of work for the BOP phase of the Uprate project, which included:

- Installation of 4 Moisture Separator Reheaters
- Installation of 2 Secondary Cooling Heat Exchangers
- Installation of 2 Moisture Separator Reheater Shell Side Drain Heat Exchangers
- Installation of 4 Turbine Bypass Valves and Mufflers

- Modification of the Turbine Generator Electrical Output Bus Duct Cooling System
- Installation of 2 Condensate Heaters
- Replacement of the Turbine Generator Exciter
- Turbine Generator Electrical Stator Rewind
- Rescaled Integrated Control System
- Installation of a fiber optic "backbone" to interface with new turbine monitoring equipment
- Installation of 2 Secondary Cooling Pumps and Motors
- Installation of a Turbine Lube Oil Cooler
- Installation of Heater Drain Valves
- Plant computer updates
- Facilities

PEF's 2009 Power Block Engineering and Procurement costs were necessary for the timely completion of the CR3 Uprate BOP phase work during the 2009 R16 refueling outage. PEF also incurred On-Site Construction Facilities costs of $1,203,995 for the labor costs associated with mobilizing and maintaining temporary facilities to house the extra personnel needed to implement the BOP phase of the CR3 Uprate project during the R16 refueling outage in 2009. Finally, PEF incurred Project Management costs related to the management of the BOP phase work performed during the R16 outage in 2009.

As I testified earlier, the BOP phase work was performed during the 2009 R16 refueling outage on schedule and on budget. These costs were reviewed by the parties and Commission audit staff in the 2010 NCRC proceeding and no issues with respect to these costs were identified. Commission audit staff reviewed and verified that the project remained on schedule with minor variances and confirmed that no major issues were identified during the work. See Exhibit No. ___ (JF-3), 2010 Staff Audit Report, p. 37. The Commission staff auditors further confirmed that the BOP phase work during the R16 outage was completed as scheduled and at projected costs for the R16 outage. Id.

Q. What were the Company's 2009 Project Management costs for the CR3 Uprate project?

A. The Company incurred Project Management costs of $21,154,156. As reflected on Exhibit No. __ (JF-5), the Company's Project Management costs included the following Project Management activities performed for the CR3 Uprate project, but primarily for the BOP phase work that was completed in 2009:

(1) project administration, including project instructions, staffing, roles and responsibilities, and interface with accounting, finance, and senior management;

(2) contract administration, including status and review of project requisitions, purchase orders, and invoices, contract compliance, and contract expense reviews;

(3) project controls, including schedule maintenance and milestones, cost estimation, tracking and reporting, risk management, and work scope control;

(4) project management, including project plans, project governance and oversight, task plans, task monitoring plans, lessons learned, and task item completions;

(5) project training, including the uprate project training program, training of personnel in accordance with the training program, and maintaining training records; and

(6) management of CR3 Uprate licensing work.

Each activity was conducted under the Company's project management and oversight controls policies and procedures. Such costs were necessary to ensure that the BOP scope of work was adequate to achieve the uprate project objectives, that the engineering and construction labor, material, and equipment provided by

PEF or outside vendors for the BOP phase of the project was available when needed at a reasonable cost, and that the project schedule was maintained.

Q. Did PEF incur other CR3 Uprate project costs in 2009?

A. Yes. PEF incurred permitting costs of $882,003 for permitting needs for 2009. These costs were necessary for the permitting activities to support the BOP phase construction work in 2009. PEF also incurred permitting costs to develop the environmental report associated with the EPU LAR and to obtain environmental permits for facilities and other construction activities.

PEF also incurred Non-Power Block Engineering, Procurement and related construction costs in the amount of $3,640,540 in 2009. These costs were associated with the studies the Company completed on the effects of the increased heat at the Point of Discharge ("POD"). These costs were necessary for the project because PEF will not be able to complete the full uprate without analyzing and accommodating the higher water temperature in the discharge canal.

Q. Were there variances between the actual 2009 CR3 Uprate project capital expenditures and PEF's actual/estimated costs for 2009?

A. Yes. As I explained in the 2010 NCRC proceeding, there were variances in actual 2009 costs compared to PEF's actual/estimated capital expenditures in 2009. These variances were primarily driven by the additional EPU LAR preparation costs that I previously described and permitting activity costs, but they were partially off-set by Non-Power Block Engineering work, as described in more detail below. To begin with though, there was a change in the assignment of costs on the CR3 Uprate project that impacted the variances in 2009 actual and actual/estimated project costs. As I explained last year, at the time of the Actual/Estimated filing in 2010, the assigning of costs into the filing categories was based on general assumptions that were determined to be the most appropriate guidelines to assign costs to the categories at that time. As the project has matured and a more detailed task structure has been implemented, the Company established a new and more accurate method for assigning costs to the various categories. This change did not affect the total project cost or the total capital expenditure variance, but did affect variances within individual categories, particularly in Project Management, Power Block Engineering, and On-Site Construction Facilities. With this background, the variances include:

License Application:

The 2009 License Application capital expenditures on the T-6 schedule were $20,016,839 with a total estimate of $16,277,263, resulting in a variance of $3,739,576. This variance is attributable to additional, more detailed information for the EPU LAR document, the necessary acceleration of engineering work scope to create the information, and the creation and implementation of a revised template for the EPU LAR document, for all the reasons I explained earlier in my testimony.

Project Management:

Project Management capital expenditures were $21,154,156. The original estimate was $39,666,137, resulting in a variance of ($18,511,981). This variance is primarily driven by the new method for assigning costs to cost categories that I described above.

Permitting:

Permitting capital expenditures were $882,003. The original estimate was $151,463, resulting in a variance of $730,540. The variance was primarily due to the need for environmental permits to support the project and temporary facilities that were not originally anticipated in the projected facilities plan.

On-Site Construction Facilities:

On-Site Construction Facilities capital expenditures were $1,203,955. The original estimate was $4,223,713, resulting in a variance of ($3,019,758). This variance is primarily driven by actuals only capturing the labor to manage facilities work due to the change in method for assigning costs to the categories as described above. All costs to mobilize, rent, and maintain the temporary facilities needed to house the additional personnel for the EPU Phase 2 implementation that were estimated for this category are being appropriately captured in the Power Block Engineering category.

Power Block Engineering:

Power Block Engineering capital expenditures were $71,243,000. The original estimate was $52,560,048, resulting in a variance of $18,682,952. This variance is also primarily driven by the new method for assigning costs to categories that I explained above.

Non-Power Block Engineering, Procurement, etc.:

Non-Power Block Engineering, Procurement, etc. capital expenditures were $3,640,540. The original estimate was $4,658,928, resulting in a variance of ($1,018,388). This variance is primarily driven by scope and schedule changes associated with POD/Cooling Tower work. As the engineering evaluation of the New Forced Draft Cooling Tower progressed, the location of the tower was changed. The new location relieved the project of relocating a warehouse, thus reducing the project cost for 2009. Also in 2009, the recirculation line work that was scheduled to start was put on hold for further evaluation and rescheduled.

Q. Were all of PEF's 2009 CR3 Uprate project costs reasonably and prudently incurred?

A. Yes. For all the reasons I have provided, PEF reasonably and prudently incurred the 2009 CR3 Uprate project costs. These costs were necessary for completion of the BOP phase work for the CR3 Uprate project in 2009 and the continuation of work for the EPU phase during the Company's next planned refueling outage for CR3. The Commission, in fact, reviewed the Company's 2009 CR3 Uprate project costs and determined that they were reasonably incurred in Order No. PSC-11-0095-FOF-EI. The Commission also determined, based on the record evidence in the 2010 NCRC proceeding, that no concerns other than the management of the LAR development process in 2009 were identified for PEF's 2009 CR3 Uprate project costs. Order No. PSC-11-0095-FOF-EI, Docket No. 100009-EI, p. 39. As I have explained earlier, PEF's management of the development of the EPU LAR document by AREVA in 2009 did not result in any unnecessary or duplicative costs and, therefore, did not result in additional costs to PEF's customers that should not have been incurred. All of PEF's 2009 CR3 Uprate project costs were reasonably and prudently incurred.

V. ACTUAL COSTS INCURRED IN 2010 FOR THE CR3 UPRATE PROJECT.

Q. What costs did PEF incur for the CR3 Uprate project in 2010?

A. PEF incurred construction costs related to the last phase of the CR3 Uprate project in 2010. The total capital expenditures for 2010, gross of joint owner billing and exclusive of carrying cost, were $45,544,492. These costs cover (i) license application, (ii) project management, (iii) permitting, (iv) on-site construction facilities, (v) power block engineering, procurement and related construction, and (vi) non-power block engineering, procurement, and related construction. Schedule T-6 in Exhibit No. ___ (WG-3) to Mr. Garrett's testimony further details these costs.

Q. Please describe the total License Application costs incurred and explain why the Company incurred them.

A. The License Application costs reflected on the T-6.3 Schedule were $3.3M. These costs were incurred for continued work on the EPU LAR submittal document into 2010 to address evolving industry and NRC expectations for EPU LAR submittals as I explained earlier. These activities included fuels analysis, safety analysis and system and program reviews.

Q. Please describe the total Project Management costs incurred and explain why the Company incurred them.

A. The Company incurred Project Management costs of $5.2M. The Company's Project Management costs include the following Project Management activities for the EPU phase of the CR3 Uprate project:

(1) project administration, including project instructions, staffing, roles and responsibilities, and interface with accounting, finance, and senior management; (2) contract administration, including status and review of project requisitions, purchase orders, and invoices, contract compliance, and contract expense reviews; (3) project controls, including schedule maintenance and milestones, cost estimation, tracking and reporting, risk management, and work scope control; (4) project management, including project plans, project governance and oversight, task plans, task monitoring plans, lessons learned, and task item completions; and

(5) overall management of CR3 Uprate licensing work.

Each activity was conducted under the Company's project management and oversight control policies and procedures.

Q. Please describe the total Permitting costs incurred and explain why the Company incurred them.

A. Permitting costs incurred were ($10,607) for permitting needs for 2010. This credit in actual costs incurred is due to an adjustment to reclassify costs from environmental permitting to licensing.

Q. Please describe the total On-Site Construction Facilities costs incurred and explain why the Company incurred them.

A. On-Site Construction Facilities costs incurred were $164,692. This represents the labor costs associated with demobilizing and maintaining temporary facilities to house the extra personnel needed to implement Phase 3 of the CR3 Uprate project.

Q. Please describe the total costs incurred for the Power Block Engineering, Procurement and related construction cost items and explain why the Company incurred them.

A. The Company incurred $32.7M for Power Block Engineering, Procurement, and related construction cost items. The majority of the costs incurred in this category in 2010 were associated with the preparation of design changes for the phase 3 scope and for procurement of long lead time equipment. Over thirty Engineering Change (EC) packages were initiated and progressed to different levels in support of the Phase 3 scope. These 2010 Power Block Engineering and Procurement costs were necessary for the implementation of the CR3 Uprate work during the next refueling outage.

Q. Please describe the total costs incurred for the Non-Power Block Engineering, Procurement and related construction cost items and explain why the Company incurred them.

A. These costs total $4.2M. The majority of the costs incurred in this category in 2010 were associated with the POD portion of the EPU Project. The major contributors to these costs were payments for Helper Cooling Tower (HCT) design, a discharge canal cooling study, and delivered HCT equipment. These costs are necessary for the project because PEF will not be able to complete the full uprate without mitigation of the higher water temperature in the discharge canal.

Q. How did actual capital expenditures for January 2010 through December 2010 compare to PEF's actual/estimated costs for 2010?

A. PEF's actual capital expenditures for the CR3 Uprate project in 2010 were lower than PEF's actual/estimated costs for 2010 by $20.8M. This variance is primarily due to the deferral of funds for Uprate project work from 2010 to 2011 and 2012. These deferrals were required as a result of rescheduling milestone payments and the extended outage at CR3. I will explain the reasons for the major (more than $1.0 million) variances below:

License Application:

The 2010 License Application capital expenditures on the T-6 schedule were $3.3M with a total estimate of $1.6M, resulting in a variance of $1.7M. This variance is primarily attributable to invoice timing on carry-over AREVA work-scope under Change Order No. 23. This additional, more detailed engineering information was needed for the EPU LAR draft document to meet evolving NRC requirements for EPU LAR submittals, which is a continuation of the cost variance for the 2009 License Application cost I described earlier. It is also noted that some AREVA Change Orders were inappropriately charged to License Application and a re-classification to move these charges to Engineering will be made in the first quarter of 2011.

Project Management:

Project Management capital expenditures were \$5.2M. The original estimate was \$9.7M, resulting in a variance of (\$4.6M). This variance is due to the reallocation of project management resources during 2010 because of the extended CR3 outage and the associated delay of the R17 refueling outage.

Power Block Engineering:

Power Block Engineering, Procurement and related construction costs capital expenditures were \$32.7M. The original estimate was \$43.0M, resulting in a variance of (\$10.3M). This variance is due to the deferral of contract milestone payments from 2010 to 2011 because of the extended CR3 outage and the associated delay of the R17 refueling outage.

Non-Power Block Engineering:

Non-Power Block Engineering capital expenditures were \$4.2M. The original estimate was \$11.3M, resulting in a variance of (\$7.0M). This variance is primarily driven by scope and schedule changes associated with POD/Cooling Tower work, which is a result of the extended CR3 R16 outage and the associated delay of the R17 refueling outage, as well as pending and emerging environmental regulations which would impact the fossil units at Crystal River. The POD project has been placed on hold until such time that the impact of these changes can be appropriately assessed.

Q. Did PEF incur O&M costs in 2010 for the CR3 Uprate project?

A. Yes. PEF incurred necessary O&M costs to support the continuation of the CR3 Uprate project work in 2010. These O&M costs are identified and included in Schedule T-4 in Exhibit No. ___ (WG-3) to Mr. Garrett's testimony.

Q. How did actual O&M expenditures for January 2010 through December 2010 compare with PEF's actual/estimated O&M expenditures for 2010?

A. Schedule T-4A, Line 15, on Exhibit No. ___ (WG-3) to Mr. Garrett's testimony shows that total O&M costs were $1,000,181, or $345,037 less than estimated. By cost category, major cost variances between PEF's actual/estimated and actual 2010 CR3 Uprate O&M costs are as follows:

Legal: O&M expenditures for Legal were $281,116 or $139,871, less than projected. This variance was due to lower than anticipated outside legal counsel services.

Nuclear Generation: O&M expenditures for Nuclear Generation were $538,893 or $236,025 less than projected. This variance was primarily attributable to identification of less obsolete inventory than expected.

Q. Were all of PEF's 2010 CR3 Uprate project costs reasonably and prudently incurred?

A. Yes. PEF reasonably and prudently incurred the 2010 CR3 Uprate project costs. These costs were necessary for the continuation of work for the EPU phase during the Company's next planned refueling outage for CR3, as I have just described.

All of PEF's 2010 CR3 Uprate project costs were reasonably and prudently incurred.

VI. ALL COSTS INCLUDED FOR THE CR3 UPRATE ARE "SEPARATE AND APART FROM" THOSE COSTS NECESSARY TO RELIABLY OPERATE CR3 DURING ITS REMAINING LIFE

Q. Are the CR3 Uprate project costs included in this NCRC docket for recovery separate and apart from those that the Company would have incurred to operate CR3 during the extended life of the plant?

A. Yes, PEF has only included for recovery in this proceeding those costs that were incurred solely for the CR3 Uprate project. In other words, the Company only included project costs that would not have been incurred but for the CR3 Uprate project.

VII. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Does the Company have project management and cost control oversight policies and procedures that it utilizes for its capital projects?

A. Yes. The Company has several project management and cost oversight control policies and procedures that it employs for all of its capital projects fleet-wide. Each year the Company will review and revise its policies and procedures as necessary. These policies and procedures, existing, new, and as revised, that are applicable to the 2009 CR3 Uprate project were produced to the Commission Staff auditors in Data Request One ("DR -1") for 2010 in Bates range 11PMA-DR1CR3-9A-000001 through 000330 and 11PMA-DR1Levy-12A-000001 through 002553 and 11PMA-DR1Levy-12B-000001 through 000080 (a few of the CR3 procedures listed were inadvertently omitted from this production and will be produced in a supplemental DR production). See Index of 2010 Revised and New Project Management Policies and Procedures attached hereto as Exhibit No. ___ (JF-7) to my testimony. These are the same Company-wide capital project policies and procedures that are applicable to the Levy Nuclear Project ("LNP") and that have been approved as reasonable and prudent three straight years for the LNP and in the 2008 NCRC proceeding, Docket No. 090009-EI, for the CR3 Uprate project.

Q. Can you please provide an overview of the Company's 2009 and 2010 project management and cost oversight policies and procedures?

A. Yes. The CR3 Uprate project is being undertaken by the Company consistent with its Project Management Manual, which the Company has used to manage capital projects since early in this decade. Additionally, because the CR3 Uprate project is a major capital project for the Company, the project must comply with the Company's Major Capital Projects – Integrated Project Plan ("IPP") procedure that was issued in 2009. The CR3 Uprate is also being undertaken by the Company consistent with the project standards established and implemented by Progress Energy's Project Management Center of Excellence organization ("PMCoE"). These standards are based on principles from the internationally recognized Project Management Institute Project Management Body of Knowledge and establish a standardized project management approach that spans tools, templates and processes; training and qualification programs; and adoption of best practices. The CR3 Uprate project was also approved in accordance with the Company's Project Evaluation and Authorization Process. This evaluation and project authorization process has been in place at the Company for many years. The CR3 Uprate project is subject to the Progress Energy Project Governance Policy, which also has been in place for many years.

Along with these general procedures the Company utilizes several specific project management and cost oversight procedures as listed on Exhibit No. __ (JF-7) to my testimony. These procedures are reviewed on a continuous basis for changing business conditions and to incorporate improvements, lessons learned, and clarifications.

Q. **Have PEF's project management and cost oversight controls substantially changed between 2009 and 2010?**

A. No, however the Company continuously reviews and revises policies and procedures based on changing conditions, lessons learned, and best industry practices.

Q. **Does the Company have any policies or procedures in place to assess and mitigate project risks?**

A. Yes. The Company routinely assesses various project risks and assigns each risk with a probability of occurrence and level of importance in terms of effect on project schedule and cost using its CR3 Uprate Risk Register. The risk register facilitates monitoring and controlling risk by providing a tool to document risk probability, impact, response plans, ownership, triggers, and expected monetary value. It also provides the ability to document risk mitigation opportunities for the project.

Q. Are employees involved in the CR3 Uprate Project trained in the Company's project management and cost control policies and procedures?

A. Yes, they are. PEF's project management team for the CR3 Uprate project has been trained in these Company policies. There are also formal Project Manager qualification requirements for projects of various sizes as well as for other roles within the Project Team (Designated Representative, Field Lead, etc.).

Q. What polices and procedures does the Company utilize to ensure that its selection and management of outside vendors is reasonable and prudent?

A. First, a requisition is created in the Passport Contracts module for the purchase of services. The requisition is reviewed by the appropriate Contract Specialist in Corporate Services, or field personnel on the CR3 Uprate project, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition.

The contract requisition then goes through the bidding or finalization process. Once the contract is ready to be executed, it is approved online by the appropriate levels of the approval matrix pursuant to the Approval Level Policy and a contract is created. Contract invoices are received by the CR3 Uprate project managers. The invoices are validated by the project managers and

Payment Authorizations approving payment of the contract invoices are entered and approved in the Contracts module of the Passport system.

When selecting vendors for the CR3 Uprate project, PEF utilizes bidding procedures through a Request For Proposal ("RFP") process when possible for the particular services or materials needed to ensure that the chosen vendors provide the best value for PEF's customers. When an RFP cannot be used, PEF ensures that the contracts with the sole source vendors contain reasonable and prudent contract terms with adequate pricing provisions (including fixed price and/or firm price, escalated according to indexes, where possible). When deciding to use a sole source vendor, PEF must provide a sole source justification for not doing an RFP for the particular work.

Q. Does the Company verify that the Company's project management and cost control policies and procedures are followed?

A. Yes, it does. PEF uses internal audits to verify that its program management and oversight controls are being implemented and are effective in practice. During the first quarter of 2009, an audit was conducted to review financial controls related to the Nuclear Cost Recovery Rule for the CR3 Uprate project. These processes were found effective. On July 2, 2009, an audit was completed regarding the effectiveness of project management and cost management for the CR3 Uprate project. Areas needing improvement were risk management, earned value analysis and KPI reporting, and improvements have since been made consistent with the audit recommendations. The Financial Controls Internal Auditing Program, financial status reporting, and information and process management were found effective. As a result of the audit, observations and recommendations were provided for improvement. The Company implemented the recommended action plans, and action items are completed.

For 2010, the Company conducted the Florida Nuclear Plant Cost Recovery Rule Compliance Monitoring Review on March 12, 2010. These processes were found effective.

Q. Are the Company's project management and cost control policies and procedures on the CR3 Uprate project reasonable and prudent?

A. Yes, they are. These project management policies and procedures reflect the collective experience and knowledge of the Company across the fleet. These policies and procedures have also been tested by the Company on other capital projects. Any lessons learned from those projects have been incorporated in the current policies and procedures. Moreover, in 2009 the project management policies and procedures in place successfully recognized issues with project resources and realigned work on the EPU LAR submittal exactly as intended. We believe, therefore, that our project management policies and procedures are consistent with best practices for capital project management in the industry and are reasonable and prudent.

VIII. <u>CONCLUSION.</u>

Q. Will the CR3 Uprate project be successfully completed at a reasonable and prudent cost to the Company and its customers?

A. Yes. As I explained above, we are well on the way to successfully completing the CR3 Uprate project and achieving the power uprate benefits, albeit on a longer schedule than originally anticipated due to the extended CR3 outage. There is no indication that the CR3 Uprate project cannot be successfully completed and NRC approval of the EPU LAR obtained at a reasonable cost to PEF and its customers.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. HUHTA: Finally, I believe we have Ms. Hardison, who is also part of the stipulation. We would move that her March 1st, 2011, testimony as well as her May 2nd, 2011, testimony be entered into the record as though read. And Ms. Hardison has no exhibits.

CHAIRMAN GRAHAM: We will enter Ms. Hardison's March 31 -- I'm sorry, March 1st and May 2nd testimony into the record as though read.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 110009

DIRECT TESTIMONY OF SUE HARDISON

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Sue Hardison. My business address is 100 East Davie Street, TPP 19, Raleigh, NC 27601.

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

A. I am currently employed by Progress Energy Carolinas ("PEC") in the capacity of General Manager – EnergyWise Program Office. I assumed this position with PEC on February 11, 2011.

Q. Did this change in employment affect your responsibilities for the Levy Nuclear Project in 2010?

A. No. In 2010 I was the General Manager-Corporate Development Group ("CDG") Business Services. In this role I was accountable for the financial reporting, business, and project controls for CDIG-managed major projects, including the Levy Nuclear Project ("LNP"). I will continue to provide support as needed for the LNP in 2011.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor of Arts degree in both Economics and Accounting from North Carolina State University. I am a licensed Certified Public Accountant in the State of North Carolina. I have been with Progress Energy – and formerly Carolina Power & Light -- for nearly 24 years. I have held various accounting, business management and support services roles in several departments in the Company including Treasury, Accounting, Nuclear Generation, Energy Delivery, and Plant Construction. I have been a manager in the Company since 1995. Prior to joining the Company, I spent five years in public accounting holding staff positions in both a local firm and a 'Big 8' accounting firm.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports the Company's request for cost recovery and a prudence determination, pursuant to the Nuclear Cost Recovery Rule, Rule 25-6.0423, F.A.C., for the Company's LNP generation and transmission costs incurred from January 2010 through December 2010. I will also explain the major variances between actual LNP costs and actual/estimated costs included in the Company's April 30, 2010 filings in Docket No. 100009-EI. John Elnitsky will also provide additional detail regarding status of LNP work and reasons for the costs incurred.

Q. Do you have any exhibits to your testimony?

A. No. I will, however, be co-sponsoring portions of Schedules T-4, T-4A, T-6, and Appendix D of the Nuclear Filing Requirements ("NFRs"), which are included as part of the exhibits to Will Garrett's testimony, Exhibit No. ___(WG-2). I am also sponsoring Schedules T-6A through T-7B. Schedule T-6A is a description of the major tasks. Schedule T-6B reflects capital expenditure variance explanations. Schedule T-7 is a list of the contracts executed in excess of $1.0 million and Schedule T-7A provides details for those contracts. Schedule T-7B reflects details pertaining to contracts executed in excess of $250,000, but less than $1.0 million.

All of these schedules are true and accurate.

Q. Please summarize your testimony.

A. PEF requests a prudence determination and approval of the recovery of its 2010 actual LNP costs. These 2010 LNP costs were incurred in connection with licensing application activities to support the Levy Combined Operating License Application ("COLA") to the Nuclear Regulatory Commission ("NRC"), engineering and procurement activities in support of the COLA, and for continuation of PEF's Engineering, Procurement and Construction ("EPC") contract and disposition of Long Lead Equipment ("LLE") Purchase Orders ("PO") for the LNP. In addition, costs were incurred for Levy Transmission strategic land acquisition activities. PEF took adequate steps to ensure that the 2010 LNP costs were reasonable and prudent and that all of these costs were necessary to the LNP for the completion and operation of Levy Units 1 and 2.

REDACTED

Accordingly, the Commission should approve PEF's 2010 costs as reasonable and prudent pursuant to the nuclear cost recovery rule.

III. CAPITAL COSTS INCURRED IN 2010 FOR THE LNP.

Q. What was the total overall difference between PEF's actual 2010 costs and PEF's actual/estimated costs for 2010?

A. Overall LNP costs, inclusive of transmission and generation costs, were [redacted] or [redacted] less than PEF's actual/estimated costs for 2010. The reasons for this variance are described below and [redacted] of this variance is related to one item also discussed further in Mr. Elnitsky's March 1, 2011 testimony.

A. <u>GENERATION.</u>

Q. Can you please describe the work and activities that were performed for the LNP in 2010 to generate these costs?

A. Yes. PEF performed work on the following activities for the LNP in 2010: Licensing; Engineering, Design and Procurement; Project Management; Real Estate Acquisition; and Power Block Engineering and Procurement. The work on these activities for the LNP in 2010 resulted in preconstruction and construction costs.

Q. Can you explain what licensing work was done for the LNP in 2010?

A. Yes. Throughout 2010, the Levy New Generation Programs and Projects ("NGPP") group continued to provide responses to NRC Requests for Additional

Information ("RAIs") on safety and environmental issues. As a result of this work, the Draft of the Environmental Impact Statement, which is part of the COLA process, was issued by the NRC on August 13, 2010, and public hearings were held to discuss this document on September 23, 2010. The NGPP group further worked on Revision 2 to the Levy COLA, which was submitted to the NRC on October 6, 2010.

On July 8, 2009, the Atomic Safety and Licensing Board ("ASLB") ruled to admit parts of three contentions that were filed by the Nuclear Information and Resource Service ("NIRS"), the Ecology Party of Florida ("EPF"), and the Green Party of Florida ("GPF") in response to the Levy COLA. In 2010, the NGPP developed a process to disclose and provide all documents related to the contentions, and has continued in 2010 to work on and submit responsive documents to the ASLB on a monthly basis.

The NGPP group further provided information needed by the U.S. Army Corps. of Engineers ("USACE") to complete the Jurisdictional Determination of wetlands by USACE. The NGPP group responded to the USACE comments regarding the Least Environmentally Damaging Practicable Alternative ("LEDPA") analysis. The NGPP group also initiated detailed environmental engineering studies required to support the Wetland Mitigation Plan implementation for the Florida Department of Environmental Protection ("FDEP"). The Wetland Mitigation Plan was submitted on April 29, 2010, and FDEP questions regarding this plan were subsequently addressed in 2010. The Wetland Mitigation Plan was administratively approved by FDEP on November

8, 2010. The NGPP group completed the following additional, required Conditions of Certification Reports for FDEP:

- Barge Canal & Withlacoohee River Monitoring Plan
- Crystal Bay Surface Water Monitoring
- Discharge Monitoring Plan
- Floodplain Compensation Plan

Finally, the NGPP group has continued to participate in industry groups including NuStart and the AP1000 Owner's Group ("APOG"). The NGPP group continues the work necessary to support the joint efforts of these industry groups. Throughout 2010, NGPP provided support to NuStart for review of documents in the development of AP1000 DCD Revision 18 and Revision 19 and the Reference COLA ("R-COLA") and to APOG for joint licensing and operational program development.

Q. What engineering work was done for the LNP in 2010?

A. In 2010, PEF conducted engineering activities in support of its COLA for the LNP. This included ongoing engineering support to assist the licensing activities in response to NRC RAIs. In 2010, PEF completed all engineering, reporting activities, and RAIs related to the Offset Boring Program. PEF also completed a site specific Soil-Structure Interaction Analysis ("SSI") for the proposed AP1000 Nuclear Island in response to NRC RAIs. PEF further developed the Roller Compacted Concrete ("RCC") Mix Design and Specialty Testing Programs in response to NRC RAIs and began the laboratory portion of the RCC Mix Design Program. Finally, PEF engineers developed the conceptual drilled shaft foundation design concept for the non-safety related structures (Turbine Building, Radwaste Building and Annex Building).

In the beginning of 2010, PEF's engineering team also completed multiple document reviews in support of the partial suspension of the EPC contract for the LNP. These reviews were primarily related to ensuring that the site-specific engineering work performed to date was properly documented in order to allow the work to continue with minimal interruption when the partial suspension is lifted. PEF engineering personnel also participated in multiple NuStart Management and Design Review meetings and provided engineering support for the joint APOG efforts in Engineering Program development.

Q. Can you generally describe the project management work on the LNP in 2010?

A. Yes. On March 25, 2010, PEF and the Consortium executed Amendment 3 to the EPC contract. This amendment to the EPC agreement set the stage for the Company's revised schedule for the LNP. Throughout 2010, baseline schedules and costs estimates were completed for the LNP based on the new in-service date as defined in revision 2 of the Levy IPP dated April 28, 2010. Project control metrics were established which included metrics for cost, schedule, safety, compliance, and risk. Work also continued to update the EPC Change Order review and approval process procedure to ensure compliance with NGG contracting procedures. The procedure was utilized to authorize incremental work scopes during the partial suspension period. The work scopes were evaluated and appropriate Change Orders were issued.

Members of the Levy EPC project team also worked to evaluate the impacts and options on Long Lead Equipment (LLE) based on the estimated shift in the in-service dates. PEF conducted the evaluation of options based on information received from the Consortium and its vendors. PEF continues to work with the Consortium and its vendors to negotiate the selected LLE PO disposition paths. The disposition of the LLE POs is discussed in more detail in the March 1, 2011 testimony of John Elnitsky.

PEF also finalized the Levy Estimate in March of 2010 and created a Readiness Requirements document that provides an outline of the major activities and key decisions that support a Full Notice to Proceed (FNTP) for the LNP. The activities described in the document work in concert with the Levy Readiness Requirements Timeline to provide additional clarity regarding the time frames of the key activities and decision points.

i. <u>Preconstruction Generation Costs Incurred.</u>

Q. Did the Company incur any Generation preconstruction costs for the LNP in 2010?

A. Yes. As reflected on Schedule T-6.2, the Company incurred preconstruction costs in the categories of License Application and Engineering, Design, and Procurement.

Q. For the License Application costs, please identify what those costs are and why the Company had to incur them.

REDACTED

A. As reflected on Line 3 of Schedule T-6.2, the Company incurred License Application costs of [redacted] in 2010. The costs incurred were for the licensing activities supporting the LNP COLA that I previously described.

Q. For the Engineering, Design and Procurement costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 4 of Schedule T-6.2, the Company incurred Engineering, Design, and Procurement costs of [redacted] in 2010. The costs incurred related to: (1) AP1000 design finalization royalty milestone payments of [redacted] pursuant to PEF's contractual obligations under the partial suspension terms in the EPC contract; (2) [redacted] in contractual payments to the Consortium for project management, quality assurance, PO disposition support, and other Home Office Services such as Accounting and Project Controls; (3) [redacted] under the EPC agreement; and (4) [redacted] of PGN labor, expenses, indirects and overheads for general project management, project scheduling and cost estimating, legal, and other support services that were necessary for the LNP.

Q. How did Generation preconstruction actual capital expenditures for January 2010 through December 2010 compare to PEF's estimated/actual costs for 2010?

A. LNP preconstruction generation costs were [redacted], or [redacted] less than PEF's actual/estimated costs for 2010. The reasons for the major (more than $1.0 million) variances are provided below.

REDACTED

License Application: License Application capital expenditures were [redacted], which was [redacted] less than the actual/estimated License Application costs for 2010. This variance is primarily driven by a shift in the NRC COL review schedule which resulted in lower than estimated NRC fees and related licensing and consultant fees, as well as the associated contingency, internal staffing and expenses and outside legal counsel costs that were related to the NRC review schedule shift.

Engineering, Design & Procurement: As I previously indicated, Engineering, Design & Procurement capital expenditures were [redacted], which was [redacted] less than the actual/estimated Engineering, Design & Procurement costs for 2010. This variance is driven primarily by the deferral of the 2010 estimated [redacted] for one-time LLE PO disposition cost to 2011 based on the continued negotiations with the Consortium and its vendors regarding the LLE PO dispositions in 2010. The status of the LLE PO disposition and the reason for this variance are also discussed in more detail in the March 1, 2011 testimony of John Elnitsky. The remaining [redacted] variance is related to lower than anticipated payments for engineering and design work, associated project management and development, PO disposition support, Home Office Services, and PGN labor, expenses, indirects and overheads and [redacted] under the EPC agreement.

REDACTED

ii. **Construction Generation Costs Incurred.**

Q. Did the Company incur any Generation construction costs for the LNP in 2010?

A. Yes. As reflected on Schedule T-6.3, the Company incurred generation construction costs in the categories of Real Estate Acquisitions and Power Block, Engineering and Procurement.

Q. For the Real Estate Acquisition costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 3 of Schedule T-6.3, the Company incurred Real Estate Acquisition costs of [redacted] in 2010. Costs incurred related to land acquisitions for the LNP, including [redacted] for the purchase of state lands for the LNP Barge Slip easement and [redacted] for the Inglis Island Bike Trail.

Q. For the Power Block Engineering and Procurement costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 8 of Schedule T.6-3, the Company incurred Power Block Engineering and Procurement costs of [redacted] in 2010. These costs were for EPC milestone payments for certain LLE items including the: [redacted]

REDACTED

Q. How did actual generation construction capital expenditures for January 2010 through December 2010 compare to PEF's actual/estimated costs for 2010?

A. LNP construction generation costs were [redacted], or [redacted] greater than PEF's estimated projection costs for 2010. The reasons for the major (more than $1.0 million) variances are provided below.

Real Estate Acquisition: Real Estate Acquisition capital expenditures were [redacted] which was [redacted] greater than the actual/estimated Real Estate Acquisition costs for 2010. This variance is primarily driven by the transfer of funding responsibility and payment for state lands Barge Slip easement from Levy Transmission to Generation. The transfer was reflected in cost management reports after the April 30, 2010 actual/estimated cost filings.

Power Block Engineering and Procurement: Power Block Engineering and Procurement capital expenditures were [redacted], which was [redacted] greater than the actual/estimated Power Block Engineering and Procurement costs for 2010. This variance is driven primarily by payments to the Consortium under the EPC contract for the earlier than scheduled completion of partial milestones for certain items of LLE -- including the [redacted]

B. <u>TRANSMISSION.</u>

Q. Can you describe what transmission work and activities were performed in 2010 for the LNP?

A. Yes. At the beginning of the year, responsibility for any active Levy Transmission activities was re-assigned to the NGPP Licensing organization. Primary activities for 2010 included review and closeout of transmission activity contracts, project management reviews related to adjusting entries for the Levy portion of the road widening construction project along Sunshine Grove Road completed by Transmission Operations in 2010, and minimal strategic right-of-way ("ROW") acquisition work in the 500kV common corridor. The work focus was on strategic acquisition and planning for the new Transmission Study scheduled to start in the fourth quarter of 2011. Further transmission activities were suspended due to the partial work suspension for the LNP and the schedule for the revised in-service dates for the Levy nuclear units.

i. <u>**Preconstruction Transmission Costs Incurred**</u>.

Q. Did the Company incur transmission-related preconstruction costs for this transmission work and activity for the LNP in 2010?

A. Yes, as reflected on Schedule T-6.2 the Company incurred transmission-related preconstruction costs in the categories of Line Engineering, Substation Engineering, Clearing, and Other.

Q. For the Line Engineering costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 17 of Schedule T-6.2, the Company incurred Line Engineering costs of [redacted]. These costs included the residual trailing charges from 2009 to complete payments for contracted design and engineering, wetlands delineation, survey and mapping, and other general environmental services from the Patrick Energy Services and Golder & Associates contracts.

Q. For the Substation Engineering costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 18 of Schedule T-6.2, the Company incurred Substation Engineering costs of [redacted] This decrease results from a true-up of residual charges from 2009 to complete adjusting entries to transfer responsibility for the Levy Central Florida South substation projects to Transmission Operations.

Q. For the Clearing costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 19 of Schedule T-6.2, Clearing costs were [redacted]. These costs reflect accounting entries for the Levy portion of the road widening construction project along Sunshine Grove Road completed by Transmission Operations in 2010.

Q. For the Other costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 20 of Schedule T-6.2, the Other costs were [redacted]. These costs included [redacted] for PGN labor and related expenses, indirects and overheads to perform general project management, project scheduling and cost estimating activities, and costs for external relations and legal services necessary for the transmission aspects of the LNP. These costs were offset by a negative

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[redacted] of remaining residual project indirect costs to complete the true-up of the transfer of the Levy Central Florida South substation projects to Transmission Operations.

Q. How did actual transmission-related preconstruction capital expenditures for January 2010 through December 2010 compare to PEF's actual/estimated costs for 2010?

A. LNP preconstruction capital transmission costs were [redacted] or [redacted] less than PEF's actual/estimated transmission-related preconstruction capital costs for 2010. The reasons for the major (more than $1.0 million) variances are provided below.

Substation Engineering: As I previously indicated, Substation Engineering capital expenditures were [redacted] which was [redacted] less than the actual/estimated costs. This variance is mainly driven by the deferral of Crystal River Energy Center ("CREC") switchyard design engineering and environmental permitting work for the LNP due to Crystal River 3 plant outage schedule adjustments and coordination with planned completion of environmental licensing activities.

ii. <u>Construction Transmission Costs Incurred.</u>

Q. Did the Company incur any transmission-related construction costs for the transmission work and activities you identified for the LNP in 2010?

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A. Yes, as reflected on Schedule T-6.3, the Company incurred transmission-related construction costs in the categories of Real Estate Acquisition, Line Construction, Substation Engineering, Substation Construction, and Other.

Q. For the Real Estate Acquisition costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 21 of Schedule T-6.3, the Company incurred Real Estate Acquisition costs of [redacted]. These costs included survey and title services for minimal strategic ROW acquisition in the Levy 500kV common corridor.

Q. For the Line Construction costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 22 of Schedule T-6.3, the Company incurred Line Construction costs of [redacted]. These costs were for the Levy portion of the road widening construction project along Sunshine Grove Road completed by Transmission Operations in 2010.

Q. For the Substation Engineering costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 20 of Schedule T-6.3, the Company incurred Substation Construction costs of [redacted]. These costs were the remaining adjusting entries to complete the transfer of responsibility for the Levy Central Florida South substation projects to Transmission Operations.

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Q. For the Substation Construction costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 23 of Schedule T-6.3, the Company incurred Substation Construction costs of [redacted]. These costs were final contractor payments and material inventory credit adjustments for work to complete the installation of three new 500kV switches at the Levy CREC switchyard.

Q. For the Other costs, please identify what those costs are and why the Company had to incur them.

A. As reflected on Line 24 of Schedule T-6.3, the Company incurred Other costs of [redacted]. These costs included labor and related expenses, indirects and overheads to perform general project management activities, and the Levy portion of indirect and overhead costs related to the road widening construction project along Sunshine Grove Road completed by Transmission Operations in 2010.

Q. How did actual transmission-related construction capital expenditures for January 2010 through December 2010 compare to PEF's actual/estimated 2010 costs?

A. LNP construction transmission costs were [redacted], or [redacted] less than PEF's actual/estimated construction transmission costs for 2010. I will explain the reasons for the major (more than $1 million) variances below.

Real Estate Acquisition: Real Estate Acquisition capital expenditures were [redacted], which was [redacted] less than the actual/estimated Real Estate Acquisition costs for 2010. This variance was primarily driven by the shift in the Levy Project schedule. The land acquisition plan was re-evaluated in light of the schedule shift changes and resulted in a significant reduction of actual strategic ROW land acquisition and siting expenditures in 2010. Also included in the variance above was the transfer of funding responsibility and payment for the state lands Barge Slip easement from Levy Transmission to Generation. The transfer was reflected in cost management reports after the April 30, 2010 actual/estimated filings.

IV. O&M COSTS INCURRED IN 2010 FOR THE LEVY NUCLEAR PLANT.

Q. Did the Company incur any Operation & Maintenance ("O&M") costs for the LNP in 2010?

A. Yes, as reflected on Schedule T-4 the Company incurred O&M expenditures in the amount of $2.9M for internal labor and expenses, legal costs, and the NuStart Energy Development, LLC program that were necessary for the LNP. The explanations for major variances are provided below:

Corporate Planning: O&M expenditures for Corporate Planning were $0.2M, or $0.1M lower than the actual/estimated costs. This variance is primarily due to fewer corporate planning internal labor hours than anticipated due to the project shift.

Legal: O&M expenditures for Legal were $1.2M, or $0.3M lower than the actual/estimated costs. This variance is primarily due to lower than expected outside legal counsel services.

Project Assurance: O&M expenditures for Project Assurance were $0.2M, or $0.1M lower than the actual/estimated costs. This variance is primarily due to fewer project assurance internal labor hours than anticipated due to the project shift.

Nuclear Generation: O&M expenditures for Nuclear Generation were $0.9M, or $0.6M lower than actual/estimated costs. This variance is primarily due to the deferral of operational readiness activities due to the LNP schedule shift.

Q. To summarize, were all the costs that the Company incurred in 2010 for the LNP reasonable and prudent?

A. Yes, the specific cost amounts for the LNP contained in the NFR schedules, which are attached as exhibits to Mr. Garrett's testimony, reflect the reasonable and prudent costs PEF incurred for LNP work in 2010. All of these costs were necessary for the LNP.

V. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Are the LNP Project Management and Cost Control Oversight policies and procedures the same in 2010 as they were for 2008 and 2009?

A. Yes, they are essentially the same. There have been no substantial changes to the LNP project management and cost oversight controls since I described the process in my March 1, 2010 testimony last year in Docket No. 100009-EI. However, the Company continues to review policies, procedures, and controls on an ongoing basis and makes revisions and enhancements based on changing business conditions, organizational changes, and lessons learned, as necessary. This process of continuous review of our policies, procedures, and controls is a best practice in our industry and is part of our existing LNP project management and cost control oversight.

Q. Can you please provide an overview of the Company's applicable LNP project management and cost control oversight policies and procedures?

A. Yes. The Company maintains an Integrated Project Plan ("IPP") procedure to provide guidance regarding evaluation and funding authorization for major projects, including the LNP. The Company adheres to this procedure, along with numerous other policies, procedures, and controls to effectively manage the LNP. In March of 2011, Progress Energy senior management will review an IPP update for the LNP (Revision 3 to the Levy IPP). This IPP update will confirm funding approval for 2011 through 2013 on the LNP consistent with the Company's March 2010 decision to continue with the LNP on a slower pace and defer significant capital investment until after the LNP Combined Operating License ("COL") is obtained. This decision benefits PEF's customers by reducing the near-term project costs during the immediate recessionary period. A 2012 IPP annual update is scheduled for mid-year 2012. The 2012 mid-year IPP will provide cost estimates leading up to FNTP, which is anticipated in conjunction with the receipt of the Levy COL estimated for early 2013.

The LNP is also being undertaken by the Company consistent with the applicable project standards established and implemented by Progress Energy's Project Management Center of Excellence organization ("PMCoE"). These standards are based on principles from the internationally recognized Project Management Institute Project Management Body of Knowledge and establish a standardized project management approach that spans tools, templates and processes, training and qualification programs, and adoption of best practices.

The LNP work also continues to be performed under Nuclear Generation Group ("NGG") and Corporate procedures as well. These procedures are reviewed on a continuous basis for changing business conditions and to incorporate improvements, clarifications, and other administrative changes. Other corporate tools are used to support the management of the LNP work. The Oracle Financial Systems/Business Objects reporting tool provides monthly corporate budget comparisons to actual cost information, as well as detailed transaction information. This information, along with other financial accounting data, allows PEF to regularly monitor the costs of the LNP work compared to budgets and projections. The project schedule is maintained in the Primavera scheduling tool. Detailed schedules for near term work are developed and reviewed on a bi-weekly basis and updated and refined as appropriate.

During the partial suspension period, the Company meets quarterly with the Consortium to review the status of approved work. Financial Services personnel prepare monthly Cost Management Reports that include all contracts, labor, equipment, material and other project cost transactions recorded to the LNP. These reports are regularly reviewed by the LNP management team. Project Controls and Business Services issue a combined monthly report which provides current status of cost, completed and upcoming schedule milestones, Level 1 schedules, major contract status, and the current risk matrix, which first appears in the December report.

Q. Can you describe some of the enhancements to the Company's project management and cost control policies or procedures that were made in 2010?

A. Yes. As the partial suspension period continues for the Levy project, there is limited field activity for both LNP generation and transmission work. As a result, the Company's oversight and management plan for contractors did not change in 2010, but PEF has implemented several enhancements to continuously improve the oversight and management of contractors for the LNP. Corporate and nuclear contract procedures were further reviewed and revised in 2010. Overall sixty-nine (69) corporate, nuclear, and EPC procedures were revised and eight (8) new procedures were created. Of these eight new procedures, five (5) were new PMCoE procedures issued in 2010. Most of these were minor revisions or updates to existing policies and procedures so I will describe a few of the more substantive revisions or updates to our policies and procedures for the LNP.

In 2010, CDIG Business Services implemented improvements to the LNP Contract Administration function. Vendor invoice audits were completed at Shaw and the Joint Venture Team ("JVT") in 2010. These audits looked at vendor time, expense, and subcontract procedures and verified invoices were being billed according to contract terms and conditions. A Vendor Audit Schedule was also approved for 2011. Other improvements include issuance of the CDIG Contract Change Order Management procedure which provides Project Teams and Program Managers with a standard Contract Change Management approach and formal procedure to process change orders in accordance with PMCoE standards. Also in 2010, the contract language was strengthened for all JVT COLA Contract Work Authorizations to better define the change order process in each of the contracts.

Q. Can you explain how the Company ensures that its selection and management of outside vendors is reasonable and prudent?

A. Yes. When selecting vendors for the LNP, PEF utilizes bidding procedures through a Request for Proposal ("RFP") when possible for the particular services or materials needed to ensure that the chosen vendors provide the best value for PEF's customers. Once proposals are submitted by potential vendors, formal bid evaluations are completed and a final selection is determined and documented. When an RFP cannot be used, PEF ensures that contracts with sole source vendors contain reasonable and prudent contract terms with adequate pricing provisions (including fixed price and/or firm price, escalated according to indexes, where possible). When deciding to use a single or sole source vendor, PEF documents a single or sole source justification for not doing an RFP for the particular work. Both Corporate and Nuclear Generation contracting procedures contain guidance on what justifies using a sole source or single source vendor. The Company requires that all sole or single source contract activity must be justified on the contract requisition and must be approved by the appropriate management level for the dollar value of the contract. This justification for the sole or single source vendor must describe in detail why a sole or single source vendor approach is being taken.

The contract development process starts when a requisition is created in the Passport Contracts module for the purchase of services. The requisition is reviewed by the appropriate Contract Specialist in Corporate Services and appropriate technical and management personnel on the Levy project, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition. Once the contract is ready to be executed, it is approved online by the appropriate levels of the management approval matrix as per the Corporate Approval Level Policy, and a contract is created. Contract invoices are received by the LNP Support Services. The invoices are validated by the project managers and Support Services Team. Payment Authorizations approving payment of the contract invoices are entered and approved.

Q. Does the Company verify that the Company's project management and cost control policies and procedures are followed?

A. Yes, it does. PEF uses internal audits, self assessments, benchmarking, and quality assurance reviews and audits to verify that its program management and oversight controls are in place and being implemented. Internal audits are also conducted on outside vendors. During 2010 the Florida Nuclear Plant Cost Recovery Rule Compliance Monitoring Review Audit was conducted. This internal audit did not have any findings and did not require any corrective action. Two internal audits are scheduled for 2011. An internal Nuclear Oversight Organization ("NOS") assessment N-NP-10-01, was conducted in September

2010. It identified one finding and four recommendations. The finding was related to the process and procedures for the identification and evaluation of industry Operating Experience and Construction Experience as it applies to new nuclear plant activities. This finding was entered into the Progress Energy Corrective Action Program as Nuclear Condition Report 425609 for investigation and resolution. The corrective actions for this finding included revising existing fleet procedures to include the identification of new nuclear plant operating and construction experience for screen and evaluation. A due date for corrective action is in early 2011.

From November 30, 2010 through December 2, 2010 PEF completed an audit of the JVT Invoice Process to ensure invoice compliance with contract terms. PEF concluded that appropriate controls are in place for the invoice process. On January 29, 2010, PEF completed an audit of EPC Monthly Invoice # 927917-R8-00361. The audit focused on two areas: 1) engineering deliverables associated with authorized design tasks included on the invoice and the reference letter, and 2) a review of project controls utilized by the Consortium for the actual T&M hours invoiced. PEF concluded that appropriate controls are in place for the invoice process.

In addition, the NRC performed an inspection of the Progress Energy Nuclear Quality Assurance Program, processes, and procedures as they applied to the LNP from April 12-16, 2010. During this inspection, the NRC did not identify any violations or non-conformances with program implementation associated with the LNP.

Q. Are these project management and costs control oversight procedures described applicable to both transmission and generation projects?

A. Yes. The generation and transmission projects associated with the LNP are subject to the same overall Company management.

Q. Were the Company's Project Management and Cost Control Oversight policies and procedures for the LNP independently reviewed?

A. Yes. In both 2009 and 2010 PEF hired independent expert Gary Doughty of Janus Management Associates, Inc. to review the reasonableness and prudence of the project management and control systems in place to manage the LNP. Mr. Doughty concluded in both 2009 and 2010 that PEF's LNP project management and project controls were reasonable and prudent. In addition, Office of Public Counsel ("OPC") expert witness Dr. William Jacobs, Jr. also reviewed the LNP project management and cost oversight controls in the 2009 and 2010 NCRC proceedings. He expressed no opinion in either proceeding that the Company's LNP project management and cost oversight controls were unreasonable or imprudent. In fact, he testified in the 2010 NCRC hearings that he expressed no opinion regarding the prudence of the Company's LNP project management, contracting, and oversight controls because he reviewed them in 2009 and did not see any significant concerns with them. (Docket 10009-EI Hearing Trans. pp. 730-731). Mr. Doughty has not been retained this year to review the LNP project management and oversight controls because there have been no substantial changes since his review in 2010.

Q. Has the Commission previously determined that these LNP project management and cost oversight controls were reasonable and prudent?

A. Yes. In Order No. PSC-09-0783-FOF-EI, issued Nov. 19, 2009, and No. PSC-11-0095-FOF-EI, issued Feb. 2, 2011, the Commission determined that the LNP project management and cost oversight controls were reasonable and prudent for 2008 and 2009. The Company's 2010 LNP project management and cost oversight controls are substantially the same as they were in 2008 and 2009.

Q. Are the Company's LNP project management and cost control oversight policies and procedures reasonable and prudent?

A. Yes, they are. These project management policies and procedures reflect the collective experience and knowledge of the Company and have been vetted, enhanced, and revised over several years to reflect industry leading best project management and cost oversight policies, practices, and procedures. The culmination of these policies, practices, and procedures in the LNP project management and cost control oversight measures have been independently reviewed by third party experts in 2009 and 2010 and by the Commission and they were found to be reasonable and prudent. We believe, therefore, that our project management policies and procedures are consistent with best practices for capital project management in the industry and are reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 110009

DIRECT TESTIMONY OF SUE HARDISON

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sue Hardison. My business address is 100 East Davie Street, TPP 19, Raleigh, NC 27601.

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

A. I am currently employed by Progress Energy Carolinas ("PEC") in the capacity of General Manager – EnergyWise Program Office. I assumed this position with PEC on February 11, 2011.

Q. Did this change in employment affect your responsibilities for the Levy Nuclear Project?

A. No, not at this time. In 2010 I was the General Manager-Corporate Development Group ("CDG") Business Services. In this role I was accountable for the financial reporting, business, and project controls for CDIG-managed major projects, including the Levy Nuclear Project ("LNP"). I will continue to provide support as needed for the LNP in 2011.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor of Arts degree in both Economics and Accounting from North Carolina State University. I am a licensed Certified Public Accountant in the State of North Carolina. I have been with Progress Energy – and formerly Carolina Power & Light – for nearly 24 years. I have held various accounting, business management and support services roles in several departments in the Company including Treasury, Accounting, Nuclear Generation, Energy Delivery, and Plant Construction. I have been a manager in the Company since 1995. Prior to joining the Company, I spent five years in public accounting holding staff positions in both a local firm and a 'Big 8' accounting firm.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the Company's request for cost recovery pursuant to the Nuclear Cost Recovery Rule, for the costs it incurred for the LNP. My testimony supports the Company's actual/estimated and projected costs for 2011 and 2012.

Q. Have you previously filed testimony in this docket?

A. Yes, I filed testimony on March 1, 2011 in support of the actual costs incurred in 2010 for the LNP.

Q. Do you have any exhibits to your testimony?

A. No, however, I am sponsoring portions of the schedules attached to Thomas G. Foster's testimony. Specifically, I am co-sponsoring portions of Schedules AE-4, AE-4A, and AE-6 and sponsoring Schedules AE-6A through AE-7B of the Nuclear Filing Requirements ("NFRs"), included as part of Exhibit No. __ (TGF-1) to Thomas G. Foster's testimony. I will also be co-sponsoring portions of Schedules P-4 and P-6 and sponsoring Schedules P-6A through P-7B included as part of Exhibit No. ___ (TGF-2) to Mr. Foster's testimony, and co-sponsoring Schedules TOR-4, TOR-6, and TOR-6A which is Exhibit No. ___ (TGF-3) to Mr. Foster's testimony. A description of these Schedules follows:

- Schedule AE-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule AE-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule AE-6 reflects actual/estimated monthly expenditures for site selection, preconstruction and construction costs for the period.
- Schedule AE-6A reflects descriptions of the major tasks.
- Schedule AE-6B reflects annual variance explanations.
- Schedule AE-7 reflects contracts executed in excess of $1.0 million.
- Schedule AE-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule AE-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.

- Schedule P-4 reflects CCRC recoverable O&M expenditures for the projected period.
- Schedule P-6 reflects projected monthly expenditures for preconstruction and construction costs for the period.
- Schedule P-6A reflects descriptions of the major tasks.
- Schedule P-7 reflects contracts executed in excess of $1.0 million.
- Schedule P-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule P-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Schedule TOR-4 reflects CCRC recoverable actual to date and projected O&M expenditures for the duration of the project.
- Schedule TOR-6 reflects actual to date and projected annual expenditures for site selection, preconstruction and construction costs for the duration of the project.
- Schedule TOR-6A reflects descriptions of the major tasks.

These schedules are true and accurate.

Q. Please summarize your testimony.

A. In 2011 and 2012, PEF has incurred and will continue to incur reasonable costs for work on its Combined Operating License Application ("COLA") to the Nuclear Regulatory Commission ("NRC") and work related to environmental permitting and implementation of the conditions of certification for its Site Certification Application ("SCA"), which was approved by the Governor and

Cabinet sitting as the Siting Board. This work is necessary to obtain the required licenses and permits for the LNP.

In addition, under its Engineering, Procurement, and Construction Agreement ("EPC Agreement") entered into with Westinghouse and Shaw, Stone and Webster (the "Consortium"), PEF incurred and will continue to incur costs for Long Lead Equipment ("LLE") items, associated support costs, and purchase order management and disposition. PEF will also prepare for and commence negotiations of necessary amendments to the EPC Agreement to efficiently end the current partial suspension of the LNP and continue with the LNP work on the anticipated LNP schedule as discussed in the testimony of Mr. John Elnitsky filed in this docket.

In 2011, PEF will begin work on an updated transmission study given the anticipated in-service dates for the LNP. In 2012, PEF will commence work related to detailed transmission design packages. In 2011 and 2012, PEF will continue activity associated with strategic land acquisitions for transmission lines.

As demonstrated in my testimony and the NFRs filed as exhibits to Mr. Foster's testimony, PEF took adequate steps to ensure that the costs it incurred were reasonable and prudent. PEF has also provided reasonable projections for costs to be incurred during the remainder of 2011 and all of 2012. The costs of this work are necessary for the LNP and therefore reasonable.

Q. Please briefly describe the Levy Nuclear Project ("LNP").

A. The LNP involves the planned construction of two state-of-the-art Westinghouse AP1000 Advanced Passive nuclear power plants in Levy County, Florida and associated transmission facilities to meet the Company's generation capacity needs. The LNP will provide needed base load generation from a clean, carbon-free generation resource that enhances the Company's fuel diversity and reduces PEF's and the State of Florida's dependence on fuel oil and natural gas to generate electricity.

III. 2011 ACTUAL/ESTIMATED AND 2012 PROJECTED PERIODS

Q. Can you generally explain what the LNP costs are for 2011 and 2012?

A. Yes. As I indicated above, the LNP costs for 2011 and 2012 reflect the Company's decision to focus work on obtaining the Combined Operating License ("COL") from the NRC. PEF will continue work related to the conditions for its SCA, work on environmental surveys for the transmission routes and environmental permitting work for the LNP, work on strategic land acquisitions for transmission lines, and will continue work in support of LLE disposition, while deferring most of the capital investment in the project until after the COL is obtained.

More specifically, for 2011 and for 2012, PEF will incur costs related to: (1) continuing COLA activities with the NRC, which includes completion of the Roller Compacted Concrete ("RCC") mix design and specialty testing programs and the submission of structural, seismic, and other Requests for Additional

Information ("RAI") responses for the NRC site specific review of the LNP COLA; (2) completing environmental surveys for the transmission routes and the work on and submittal of the United States Army Corps of Engineers ("USACE") Section 404 permit for the LNP; (3) completing annual LNP COLA update and preparations for the ASLB hearings; (4) continuing work associated with obtaining the Final Environmental Impact Statement ("FEIS") from the NRC and the USACE; (5) completing all LLE change orders to approve the final disposition of LLE purchase orders; (6) commencing the preparations for, and the negotiations of, the EPC Agreement amendment(s) necessary for the Full Notice to Proceed ("FNTP"); (7) continuing AP1000 design support and work; and (8) benchmarking and monitoring of licensing activities at other plants. All of this work is necessary to the LNP under the current management decision and LNP schedule.

The overall scope of the transmission activities planned for the LNP have not materially changed, but PEF will move forward with an updated transmission study. This study is necessary because the state-wide transmission system that the LNP will connect with is not static, but instead changes with PEF and other electric utility resource and transmission system additions. The initial transmission study for the LNP was performed for the Levy units based on in-service dates of 2016 and 2017. As discussed in the testimony of Mr. Elnitsky filed in this docket, now that the Levy units are expected in-service in 2021 and 2022, an updated transmission study must be performed to determine the transmission system impacts of the LNP given the revised in-service dates for

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Levy Units 1 and 2 and the changes in the state-wide transmission system. PEF will begin preparations for the updated transmission study in 2011. It is expected that a new transmission study will be completed by late 2012. In 2012, PEF will commence work related to detailed transmission design packages. In 2011 and 2012, PEF will continue activity associated with strategic land acquisitions for transmission lines. This transmission work scope supports PEF's decision to defer most of the transmission activities past receipt of the COL and to reschedule work based on the expected in-service dates for the LNP.

A. <u>Generation.</u>

Q. Does PEF have nuclear generation preconstruction costs?

A. Yes. PEF has 2011 actual/estimated and 2012 projected preconstruction costs for the LNP. Schedule AE-6 of Exhibit No. ___ (TGF-1) to Mr. Foster's testimony, shows actual/estimated generation preconstruction costs for 2011 in the following categories: License Application development costs of [redacted] and Engineering, Design & Procurement costs of [redacted] Schedule P-6 of Exhibit No. __ (TGF-2) to Mr. Foster's testimony breaks down the 2012 projected generation preconstruction costs into the following categories: License Application costs of [redacted] and Engineering, Design & Procurement costs of [redacted]

Q. Please describe what the License Application costs are, and why the Company has to incur them.

A. The License Application costs are necessary to support the on-going licensing, environmental, and permit activities for the LNP. This includes the COLA pending before the NRC, the conditions of certification under the LNP SCA, and additional, necessary environmental and other permits required for the LNP.

As discussed in the May 2, 2011 testimony of Mr. Elnitsky filed in this docket, the NRC review includes three parts that lead up to the issuance of the LNP COL: (1) the Final Safety Evaluation Report ("FSER"); (2) the FEIS; and (3) the conclusion of the mandatory hearing and any contested hearing on the LNP COLA before the NRC Atomic Safety and Licensing Board ("ASLB"). The issuance of a FSER is preceded by NRC review of the LNP COLA and the NRC's issuance of an Advanced Safety Evaluation Report ("ASER") with no open items. The current NRC milestone for issuance of the ASER is September 2011. The ASER will be reviewed by the Advisory Committee on Reactor Safeguards ("ACRS"). The NRC milestone for the ACRS review and report is January 2012. The ACRS review and report is followed by NRC review and the issuance of a FSER. The NRC milestone target to issue the FSER for the LNP COLA is April 2012. PEF will continue to incur costs to support the NRC SER review before issuance of the FSER for the LNP.

The draft Environmental Impact Statement ("EIS") for the LNP was issued in August 2010 and the public comment period ended on October 27, 2010. The NRC staff responses to the public comments on the LNP draft EIS are due

November 2011. The current NRC milestone for the FEIS is April 2012. PEF will continue to incur costs to support issuance of the FEIS for the LNP.

The ASLB allowed three groups to intervene in PEF's NRC LNP COLA docket and admitted parts of three contentions to the LNP COL. Some of these contentions were subsequently dismissed, but the remaining contentions will go to a final hearing before the ASLB. The Company currently anticipates that the ASLB hearings will start in October 2012. PEF will reasonably incur costs in 2011 and 2012 to prepare for and participate in these hearings.

As discussed in more detail by Mr. Elnitsky, due to regulatory schedule uncertainty at the NRC with respect to the LNP COLA review, we now expect issuance of the LNP COL in mid-2013. PEF will continue to reasonably incur costs in 2011 and 2012 to support the NRC's review and issuance of the FSER, FEIS, and the COL for the LNP.

PEF will also complete environmental surveys for the transmission routes, work supporting submittal of the USACE Section 404 permit, and other conditions of certification and environmental permitting activities for the LNP. PEF will further provide the NRC with its annual LNP COLA update.

These License Application costs are necessary for the LNP. PEF developed the preconstruction License Application cost estimates on a reasonable licensing and engineering basis, using the best available information to the Company, and consistent with utility industry and PEF practices. For the costs associated with the COLA review and other permit processes, PEF used the terms of its existing contracts as well as updated forecasts, which are provided on a monthly basis by the contractors, to estimate the costs they will incur for the technical and engineering support necessary for these license and permit review processes. In addition, PEF based its projections on known project milestones necessary to obtain the requisite approvals. Because PEF is using actual or expected contract costs, NRC estimates, and its own experience including industry lessons learned, PEF's cost estimates for the preconstruction License Application work are reasonable.

Q. Can you please describe the reasons for the difference between the system projected amount for 2011 and the system actual/estimated amount for LNP License Application costs?

A. Yes. On April 30, 2010 I filed testimony in Docket No. 100009-EI, including a projection of License Application costs in 2011 of [redacted]. The actual/estimated costs, as described above, are [redacted], a variance of [redacted] The variance is primarily attributable to additional costs and activities in support of providing the NRC responses to open structural, seismic, and other RAIs such as, completing activities for the RCC mix design and specialty testing programs, completing site specific Soil-Structure Interaction ("SSI") and other seismic/structural analyses and costs incurred in support of foundation design calculation revisions.

Q. Please describe what the Engineering, Design & Procurement costs are, and explain why the Company has to incur them.

A. PEF must incur certain Engineering, Design & Procurement costs in 2011 and 2012 to move forward with the LNP. Key work scope in 2011 and 2012 by the Consortium and the Company includes completing all LLE negotiations and related change orders, as well as execution, implementation, and oversight of the LLE terms and conditions as described in each approved change order.

As discussed in the testimony of Mr. Elnitsky, the majority of the outstanding LLE information needed for final LLE disposition was provided by the Consortium to PEF on February 1, 2011. Following the receipt of this information, PEF completed its reviews and made its final disposition of all outstanding LLE purchase orders. PEF and the Consortium are in the process of executing change orders to implement PEF's disposition options for the LLE.

In addition to the LLE work, there will be shared module program development work and defined Project Management Organization ("PMO") activities. Also, PEF will commence preparations for, and the negotiations of, the EPC Agreement amendment(s) necessary to terminate the partial suspension terms and establish the basis for a FNTP to move the LNP forward on a schedule with the expected in-service date for Levy Unit 1 in 2021 and Unit 2 in-service eighteen (18) months later in 2022.

PEF developed the preconstruction Engineering, Design & Procurement cost estimates on a reasonable engineering basis, using the best available information. To develop the costs, PEF utilized cost information from the EPC

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Agreement and information obtained through negotiations with the Consortium. Because PEF is using actual or expected contract costs and a documented detailed qualitative and quantitative analysis to disposition LLE purchase orders, PEF's cost estimates for the preconstruction Engineering, Design & Procurement work are reasonable.

Q. Can you please describe the reasons for the difference between the system projected amount for 2011 and the system actual/estimated amount for Engineering, Design & Procurement costs?

A. Yes. On April 30, 2010 I filed testimony in Docket No. 100009-EI, including a projection of Engineering, Design & Procurement costs in 2011 of [redacted]. The actual/estimated costs, as described above, are [redacted], a variance of [redacted] This variance is attributable mainly to the deferred estimated one-time LLE purchase order disposition costs for the [redacted], offset by lower LLE purchase order disposition and PMO support costs, lower PGN labor, expenses, indirects and overheads

Q. Does PEF have generation construction costs?

A. Yes. PEF will have 2011actual/estimated and 2012 projected construction costs for nuclear generation for the LNP. Schedule AE-6 of Exhibit No. __ (TGF-1) to Mr. Foster's testimony breaks down the 2011 actual/estimated generation construction costs into the following categories: Real Estate Acquisition costs of

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[redacted] and Power Block Engineering and Procurement costs of [redacted]. Schedule P-6 of Exhibit No. __ (TGF-2) to Mr. Foster's testimony breaks down the 2012 projected generation construction costs into the following categories: Real Estate Acquisition costs of [redacted] and Power Block Engineering and Procurement costs of [redacted].

Q. Please describe what the Real Estate Acquisitions costs are, and explain why the Company has to incur them.

A. For 2011, real estate acquisition costs will be incurred for residual costs to record fees related to the LNP barge slip easement payment made in December 2010. Costs will be incurred in 2012 for a portion of the remaining barge slip easement acquisition. Costs will also be incurred in 2012 to convey the bike trail state lands easement, and to acquire a portion of the Blowdown pipeline easement.

The NGPP Real Estate Governance Document (REI-NPDF-00001) provides guidance for the acquisition of land needed for PEF's nuclear plant development. This document identifies participants; outlines the acquisition procedure and payment process; outlines document tracking, approval, filing, reporting and document management and retention procedures. It was developed to define and formalize the management and execution of acquiring land and land rights and to provide for cost oversight and management concerning land acquisition. This document was updated in December 2010 to incorporate NGPP organization changes and payment process refinements. Utilizing these procedures, PEF developed these construction Real Estate Acquisition cost

REDACTED

estimates on a reasonable basis, using the best available information, consistent with utility industry and PEF practice.

Q. Please describe what the Power Block Engineering and Procurement costs are, and explain why the Company has to incur them.

A. Power Block Engineering and Procurement costs in both 2011 and 2012 are for contractual milestone payments and incremental storage and shipping, insurance, and warranty costs on select LLE items and associated support work from the Consortium. For example, in 2011, these LLE contract milestone payments include [redacted] which were executed by EPC Agreement Change Order No. 23 and EPC Change Order No. 22, respectively. Final disposition on other LLE items will be documented in forthcoming change orders. As previously discussed, as a result of these final LLE purchase order dispositions, PEF and the Consortium are executing change orders to implement PEF's LLE disposition options for the remaining LLE items described in Exhibit JE-3 to Mr. Elnitsky's May 2, 2011 testimony.

PEF developed these cost estimates utilizing cost information from the EPC Agreement and from information obtained directly through extensive negotiations with the Consortium. PEF's cost estimates for the construction Power Block Engineering and Procurement work are reasonable.

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B. <u>Transmission.</u>

Q. Does PEF have transmission-related preconstruction costs?

A. No.

Q. Does PEF have transmission-related construction costs?

A. Yes. PEF will have 2011 actual/estimated and 2012 projected construction costs for the LNP. Schedule AE-6 of Exhibit No. ___ (TGF-1) to Mr. Foster's testimony shows transmission construction costs for 2011 actual/estimated in the following categories: Real Estate Acquisition costs of [redacted] and Other costs of [redacted] Schedule P-6 of Exhibit No. __ (TGF-2) to Mr. Foster's testimony breaks down the 2012 projected transmission construction costs into the following categories: Real Estate Acquisition costs of [redacted] and Other costs of [redacted]

Q. Please describe what the Real Estate Acquisition costs are, and why the Company has to incur them.

A. In 2011 and 2012, Real Estate Acquisition activity for the LNP includes ongoing costs related to strategic Right-of-Way ("ROW") acquisition for the transmission lines during the partial suspension period. These costs are necessary to ensure that the ROW and other land upon which the transmission facilities will be located are available for the LNP.

Q. Please describe what Other costs are, and why the Company has to incur them,

A. For 2011 and 2012, these costs include labor and related indirect costs, overheads and contingency in support of strategic transmission ROW acquisition activities. They also include general project management, project scheduling and cost estimating, legal services and external community relations outreach to local, state, and federal agencies. These construction costs are necessary for the transmission project work in support of the LNP.

Q. Please describe briefly how the transmission construction cost estimates were prepared.

A. PEF developed these Real Estate Acquisition and Other transmission construction cost estimates on a reasonable engineering basis, in accordance with the Association for the Advancement of Cost Engineering International ("AACEI") standards, using the best available construction and utility market information at the time, consistent with utility industry and PEF practice. Real estate costs within the project estimates are based on an expected dollar per acre amount based on the type and location of the property using current route selection analysis. The management and indirect costs within the project estimates were developed based on the project schedule and staffing requirements. Costs include PGN labor and related overheads and indirect costs, contingency and escalation related to the inherent risk associated with a conceptual and preliminary design.

These estimates reasonably reflect the necessary LNP transmission project work for 2011 and 2012.

IV. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the LNP since the testimony you filed on March 1, 2011?

A. No, there have been no substantial changes to the LNP project management and cost oversight controls since I described the process in my March 1, 2011 testimony in Docket No. 110009. However, there are two additional updates to provide.

First, on March 1, 2011, the project team completed a true-up of the 2010 baseline estimate to reflect actual 2010 costs incurred and to incorporate completed LLE purchase order disposition costs for certain components. Based upon this true-up, there was no change to the overall expected project cost of the LNP, and the estimate approved in 2010 was maintained by the project team.

Second, on March 29, 2011, Progress Energy senior management reviewed an Integrated Project Plan ("IPP") update for the LNP (Revision 3 to the Levy IPP). This IPP was intended to confirm annual spending for 2011 through mid-2012 for the Levy partial suspension and provide an update related to the decision to continue the partial suspension. Management approved the IPP update and confirmed funding for 2011 through mid-2012 on the LNP consistent with the

Company's March 2010 decision to continue with the LNP on a slower pace and defer significant capital investment until after the LNP COL is obtained.

With regard to the Company's policies and procedures discussed in my March 1, 2011 testimony, the Company continues to review policies, procedures, and controls on an ongoing basis and makes revisions and enhancements based on changing business conditions, organizational changes, and lessons learned, as necessary. This process of continuous review of our policies, procedures, and controls is a best practice in our industry and is part of our existing LNP project management and cost control oversight.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. HUHTA: Progress's next witness is Mr. Thomas G. Foster, and based on stipulation of the parties, we're going to take up his direct and rebuttal at the same time, but he will not be excused until Mr. Elnitsky's direct testimony is complete. And Mr. Foster has not been sworn, Chairman.

CHAIRMAN GRAHAM: Are we going to, or have we -- we've already entered Coston and Carpenter?

MR. YOUNG: Mr. Chairman, he will be taken up -- well, I guess we can do it right now.

At this time Staff would request that Mr. -- the prefiled direct testimony of William Tripp Coston and Kevin Carpenter be entered into the record as though read. Also, the pre, that's, also his exhibits, their joint prefiled exhibits be entered into the record, and that's Number 171.

CHAIRMAN GRAHAM: Okay. We'll enter Coston and Carpenter direct testimony into the record as though read today. And Exhibit 171.

(Exhibit 171 admitted into evidence.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT JOINT TESTIMONY OF WILLIAM COSTON AND KEVIN CARPENTER

DOCKET NO. 110009-EI

JULY 11, 2011

Q. Mr. Coston, please state your name and business address.

A. My name is William Coston. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By whom are you employed?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Government Analyst II, within the Office of Auditing and Performance Analysis.

Q. What are your current duties and responsibilities?

A. I perform reviews and investigations of Commission-regulated utilities, focusing on the effectiveness of management and company practices, adherence to company procedures, and the adequacy of internal controls. Mr. Carpenter and I jointly conducted the 2011 review of Progress Energy Florida Inc.'s (PEF) project management internal controls for the Extended Power Uprate (EPU) project at the Crystal River Unit 3 and Levy Nuclear Project.

Q. Please describe your educational and relevant experience.

A. I earned Bachelor of Arts and Master of Public Administration degrees from Valdosta State University in 1993 and 1995, respectively. I have worked for the Commission for eight years conducting operations audits and investigations of regulated utilities. Prior to my employment with the Commission, I worked for six years at Bank of America in the Global Corporate and Investment Banking division.

Q. Have you filed testimony in any other dockets before the Commission?

A. Yes. I filed similar testimony in Docket No. 090009-EI and 100009-EI. This testimony concerned the audits of PEF's project management internal controls for the nuclear plant uprate at the Crystal River Unit 3 and Levy Nuclear Project for the years 2009 and 2010. Additionally, in 2005 I filed testimony in Docket No. 050078-EI. The testimony addressed an audit of distribution electric service quality for PEF's vegetation management, lightning protection, and pole inspection processes.

Q. Mr. Carpenter, please state your name and business address.

A. My name is Kevin Carpenter. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By whom are you employed?

A. I am employed by the FPSC as a Regulatory Analyst II, within the Office of Auditing and Performance Analysis.

Q. What are your current duties and responsibilities?

A. I perform reviews and investigations of Commission-regulated utilities, focusing on the effectiveness of management and company practices, adherence to company procedures, and the adequacy of internal controls. Mr. Coston and I jointly conducted the 2011 review of PEF's project management internal controls for the nuclear plant uprate at the Crystal River Unit 3 and new construction underway at the Levy site.

Q. Please describe your educational and relevant experience.

A. I earned a Bachelor of Science in Business Administration degree from Concord University in 1981. I am currently enrolled as a graduate student at Florida State University, seeking a Masters degree in Applied American Politics and Policy. My background includes experience with the West Virginia State Tax Department and the Florida Department of Business and Professional Regulation. I also worked as an Accountant with a public accounting firm in Orlando, FL.

Q. Have you filed testimony in any other dockets before the Commission?

A. Yes. I filed similar testimony in Docket No. 100009-EI. This testimony concerned the 2010 audit of PEF's project management internal controls for the nuclear plant uprate at the Crystal River Unit 3 and Levy Nuclear Project.

Q. Please describe the purpose of your testimony in this docket.

A. Our testimony presents the attached audit report entitled ***Review of Progress Energy Florida Inc.'s Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects*** (Exhibit CC-1). This review was requested by the Commission's Division of Economic Regulation to assist with the evaluations of nuclear cost recovery filings. The report describes key project events and contract activities completed during mid-2010 through May 2011 for the Crystal River 3 Uprate project and the Levy Nuclear Project. The report also presents descriptions of the current project management internal controls employed by PEF.

Q. Please summarize the areas examined by your review.

A. The Office of Auditing and Performance Analysis conducted a review of the internal controls and management oversight of the nuclear projects underway at PEF. This is an ongoing annual review that examines the organizations, processes, and controls being used by the company to execute the Extended Power Uprate of Unit 3 at the Crystal River Energy Complex and the construction of Levy Nuclear Plant Unit 1 and Unit 2. This is the fourth review of the company's controls for its nuclear construction projects. The previous reviews were filed in the 2008, 2009, and 2010 Nuclear Cost Recovery Clause Dockets before the Commission.

The primary objective of this review was to document project key developments, along with the organization, management, internal controls, and oversight that PEF has in place or plans to employ for these projects. The internal controls examined were related to the following key areas of project activity: planning, management and organization, cost and schedule controls, contractor selection and management, and auditing and quality assurance.

Q. Are you sponsoring any exhibits?

A. Yes, our audit report is attached as Exhibit CC-1.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN GRAHAM: And since we're here, could we also take Jeffery Small's?

MR. YOUNG: Yes, sir.

Also at this time, Mr. Chairman, Staff would request that the prefiled direct testimony of Jeffery A. Small be entered into the record as though read, and his exhibits be entered into the record, and those are Numbers 172 and 173.

CHAIRMAN GRAHAM: Any objections for those exhibits? Okay. We will enter Mr. Small's record -- testimony into the record as though read today and Exhibits 172 and 173.

(Exhibits 172 and 173 admitted into evidence.)

DIRECT TESTIMONY OF JEFFERY A. SMALL

Q. Please state your name and business address.

A. My name is Jeffery A. Small, and my business address is 4950 West Kennedy Blvd, 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 Division of Regulatory Compliance.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission (FPSC) since January 1994.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Science degree in Accounting from the University of South Florida. 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.

Q. Please describe your current responsibilities.

A. Currently, I am a Professional Accountant Specialist with the responsibilities of planning and directing the most complex investigative audits. Some of my past audits include cross-subsidization issues, anti-competitive behavior, and predatory pricing. I am also responsible for creating audit work programs to meet a specific audit purpose and integrating Electronic Data Processing applications into these programs.

Q. Have you presented expert testimony before this Commission or any other regulatory agency?

A. Yes. I testified in the Southern States Utilities, Inc. rate case, Docket No. 950495-WS, the transfer application of Cypress Lakes Utilities, Inc., Docket No. 971220-WS, and the Utilities, Inc. of Florida rate case, Docket No. 020071-WS.

Q. Have you provided testimony before the Commission in a prior Nuclear Cost Recovery Clause (NCRC) docket?

A. Yes, I provided testimony in the Progress Energy Florida, Inc., Nuclear Cost Recovery Clause filings, Docket Nos. 080009-EI, 090009-EI and 100009-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of PEF which addresses the Utility's application for nuclear cost recovery in 2010. The audit report was issued April 15, 2011, and addressed the pre-construction and construction cost as of December 31, 2010, for Levy County Units 1 & 2. This audit report is filed with my testimony and is identified as Exhibit JAS-1.

Q. Was the audit prepared by you or under your direction?

A. Yes, the audit was prepared by me.

Q. Please describe the work you performed in the Levy Units 1&2 audit.

A. We reconciled the Company's filing to the general ledger and verified that the costs incurred were appropriate and were recorded in the correct accounts.

We reconciled and recalculated a sample of the monthly jurisdictional recovery accruals displayed on Schedule T-1 to the supporting schedules in the Company's 2010 NCRC filing.

We reconciled the monthly site selection and pre-construction carrying cost balances displayed on Schedules T-2.2 and T-2.3, respectively, to the supporting schedules in the Company's 2010 NCRC filing. We recalculated the schedule and reconciled the Allowance for Funds Used During Construction rates applied by the Company to the rates approved in Order No. PSC-05-0945-FOF-EI, issued September 28, 2005.

We reconciled the monthly site selection and pre-construction deferred tax carrying cost accruals displayed on Schedules T-3A.2 and T-3A.3, respectively, to the supporting schedules in the Company's 2010 NCRC filing. We recalculated a sample of the monthly carrying cost balances for deferred tax assets based on the equity and debt components established in Order No. PSC-05-0945-FOF-EI.

We recalculated a sample of the monthly recoverable O&M expenditures displayed on Schedule T-4 of the Company's 2010 NCRC filing. We sampled and verified the O&M cost accruals and traced the invoiced amounts to supporting documentation. We verified company salary expense accruals and recalculated the respective overhead burdens the Company applied. We reconciled the jurisdictional factors applied by the Company to the eligible carrying cost to the factors approved in Order No. PSC-06-0972-FOF-EI, issued November 22, 2006, in Docket No. 060007-EI and in Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI.

We recalculated a sample of monthly jurisdictional nuclear construction accruals displayed on Schedules T-6.1, T-6.2 and T-6.3 of the Company's 2010 NCRC filing. We sampled and verified the generation and transmission cost accruals and traced the invoiced amounts to supporting documentation. We verified a sample of Company salary expense accruals and recalculated a sample of the respective overhead burdens that the Company applied. We reconciled the jurisdictional factors applied by the Company to the eligible carrying cost to the factors approved in Order Nos. PSC-06-0972-FOF-EI and PSC-10-0131-FOF-EI.

Q. Were there any audit findings in the audit report, Exhibit JAS-1, which address the 2010 pre-construction and construction cost for Levy County Units 1 & 2?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

(Transcript continues in sequence with Volume 10.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 19th day of August, 2011.

Linda Boles

LINDA BOLES, RPR, CRR
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