BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause. DOCKET NO. 120009-EI

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VOLUME 4

Pages 467 through 731

PROCEEDINGS: HEARING

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

DATE: Monday, September 10, 2012

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

REPORTED BY: LAURA MOUNTAIN, RPR
Wilkinson & Associates
(850) 224-0127

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

P R O C E E D I N G S

(The transcript follows in sequence from Volume 3.)

CHAIRMAN BRISE: We're going to go ahead and reconvene at this time. We are at Commissioner questions, and -- okay, Commissioner Brown?

COMMISSIONER BROWN: Thank you, and good morning -- good afternoon, Mr. Elnitsky. I only have two questions for you. Regarding moving the COLA to late 2014, I know we talked about that; how does that further shift the in-service dates?

THE WITNESS: Good afternoon, Commissioner. That currently would not have an impact on the updated in-service dates of '24 and '25. The driver there is we have to have that COLA in place before we do diaphragm wall construction, which will be in about '18 on the current schedule. So provided that we have that license in place before that 2018 period, we have adequate time to pursue the project for a 2024 in-service.

COMMISSIONER BROWN: Okay. And in your direct testimony I think I read somewhere that the estimated life of the leading units in your feasibility analysis was 60 years?

THE WITNESS: That's correct.

COMMISSIONER BROWN: What is the typical life of a nuclear power plant?

THE WITNESS: Currently they -- the current operating fleet was licensed for 40 years and most plants have been extended for 20 years beyond that to 60 years. There's even some discussion today about whether another round of license extensions is reasonable or even feasible to do for the existing fleet.

The Levy Plant, the AP1000 design is specifically designed to be able to operate for 60 years. But per the current license arrangement it would initially be licensed at 40 years and then the expectation would be you'd come in later for a license extension for that next 20 years.

COMMISSIONER BROWN: So that's the basis for your 60 years?

THE WITNESS: Yes, ma'am.

COMMISSIONER BROWN: And then your depreciation life, I think, you have as 40 years on your exhibit --

THE WITNESS: I think that's correct. I think that's correct, yes, ma'am.

COMMISSIONER BROWN: Can you elaborate, the distinction between 40 years and 60 years again?

THE WITNESS: For the depreciation or for the --

COMMISSIONER BROWN: The depreciation.

THE WITNESS: I think just from a modeling perspective -- and I think, as I recall, it's the way the strategist model works that we use in that feasibility analysis. It actually is somewhat limited, but we basically depreciate during a 40-year period just because of some of the limits of the way that model works.

COMMISSIONER BROWN: Okay, thank you.

THE WITNESS: Thank you, ma'am.

CHAIRMAN BRISE: Commissioner Balbis?

COMMISSIONER BALBIS: Thank you, Mr. Chairman. I have a few questions. Welcome, Mr. Elnitsky.

THE WITNESS: Thank you, sir.

COMMISSIONER BALBIS: You answered a question from Mr. Moyle that I'd like you to explain because I'm not sure I heard you correctly, and it's concerning the shelf life of a combined operating license.

Could you explain your answer again? Because I think you answered there was no shelf life, and I just want to make sure I know what that means.

THE WITNESS: Yes, sir, I'll be happy to. Technically there is no shelf life on a combined operating license. There is nothing in the rules right now or the regulatory guides that says you can't have a license and then basically set it aside for whatever period of time you choose before you start construction.

What I will say is from a practical standpoint, you know, it's likely that there may in the future be some guidance that comes out from NRC around that. When the Part 52 Rule was put in place, I don't think it was envisioned that you would get these licenses and let them sit for 20 or 30 years before you started construction. I don't think that was their intent.

But technically -- and that's why I answered Mr. Moyle the way I did -- technically there is no current requirement that says at some period your license is no longer valid.

COMMISSIONER BALBIS: Okay, thank you. And you indicated in your testimony that the delay in the Levy projects of a year was in the best interests of the customers. Does this delay increase the project costs? And if so, how much, if you can answer.

THE WITNESS: Yes, sir. So the delays -- maybe if I can expand a little bit, the delays in the project in general have increased the cost of the project but those costs are primarily a result of escalation. So the scope of work as we envision it and the elements that would be part of the actual project haven't changed.

What has changed is what we have to assume for escalation when you think about what are labor costs going to be, commodity costs, et cetera, for a plant that you don't start construction on now effectively until 2016. That's substantially different than the original plan.

In terms of the year, from what we testified to last year to this year, last year we had a 2012 in-service. We had an expected case, and you may remember from last year, we provided a band around that based on a classified estimate. The expected case was 17.6 billion.

We went back to that estimate based on '24 in-service, recalculated our expectations around escalation rates, and, again, what those things like commodities and labor would cost us on a revised schedule for 2024, and that now expected case is 18.8 billion. So there's a $1.2 billion change as a result.

COMMISSIONER BALBIS: Okay. But those escalation factors, those are true costs. I mean, you would expect a project of the same scope, et cetera, constructed one year later, you apply the escalation factor so the customers will be paying $1.2 billion more, or expect to pay $1.2 billion more, is that correct?

THE WITNESS: Yes, sir, those are true costs, but just as we would expect, you know, anything we construct in the future, there's going to be some escalation factor that's going to have to be applied to those costs.

COMMISSIONER BALBIS: So how would delaying the project by one year and having the customers pay $1.2 billion more be in their best interests?

THE WITNESS: Well, sir, it wasn't a one-year delay, that was based on the three-year delay, from 2021 to 2024.

COMMISSIONER BALBIS: Okay. Well, then, the same question with the three-year delay, then.

THE WITNESS: Well, and the rationale there, sir, is when you look at the Levy project compared to the alternative portfolio of an all gas type portfolio, when we do that side-by-side comparison over the life of the project, it's still to the benefit of the customers in terms of the avoided fuel costs in the future.

But, you know, admittedly, it is an increased cost to the customer on the front end to complete that project.

COMMISSIONER BALBIS: But the project is cost effective, correct?

THE WITNESS: Yes, sir, that's our assessment.

COMMISSIONER BALBIS: And it is still needed, correct?

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: So, again, I'm struggling with why delay a project that is needed and is cost effective by three years when the result is a $1.2 billion additional cost.

THE WITNESS: My best answer to that, sir, is that that cost increase -- you know, when we looked at near term economic conditions in Florida, when we looked at what we were seeing in terms of our load growth, what we were seeing in near term fuel and carbon costs, it did not make sense to us to continue to proceed on that 2021 schedule, given those factors, as compared to the 2024 plan, and that was why the company made that decision around delaying the project.

COMMISSIONER BALBIS: Well, were they based more -- the IPP, was it based more on the enterprise risk factors?

THE WITNESS: Yes, sir, more on the enterprise risk factors. Again, I described that in my testimony and in the IPP, but if you look at those things in the near term -- and somewhat consistent, then, with what we, you know, provided as input from the project to the team that was doing the settlement discussions, that just seemed in the near term to be better for the customers, even though we recognize that any time you delay a project it does result in a cost increase. So, you know, we looked at that very hard in terms of what was the best near term actions to take.

COMMISSIONER BALBIS: But at some point, if, again, every delay increases the cost, based on those factors, I mean, at some point you could delay the project to where it's no longer cost effective, is that correct?

THE WITNESS: I think it depends. And the reason I say that is, again, it's a little bit of comparing to what. So if we are not going forward with the Levy nuclear project, there's some other base load generation that would have to be constructed, whether that's part of that all gas portfolio or something else.

And the fact is, those other generation sources increase in their costs, as well. They're driven by the same escalation factors that the nuclear plant is. So what we really end up doing is a side-by-side comparison of those two portfolios. And when you take that block of time that the Levy Plant operates and you slide it forward, you're looking at other alternatives in those same windows, and their costs are going up, as well.

So, yes, every time you delay a project, in general, it costs more. But I think you have to compare that to what the alternatives are that you would construct if you don't go forward with the Levy Project, and that's what we do in that feasibility analysis study.

COMMISSIONER BALBIS: Okay. Let me change gears a little bit. In the executive summary of JE-1 --

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: -- and you don't have to refer to it -- but basically the statement is made that the cost effectiveness remains favorable in more cases than not, and that is the determination, I guess, in that IPP --

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: -- that it's cost effective. At what point is it not cost effective? Is it when there's more that are not favorable than favorable? Is there a hard line cutoff where the company would decide it's not cost effective?

THE WITNESS: You know, Commissioner, I think it's hard to draw a hard line that says, you know, if it's more or less, you know whatever the numbers are. I think you have to, our assessment, look at that feasibility analysis. What we're trying to do is provide a range of potential future outcomes, whether you believe a scenario that says fuel is not only low but it's going to continue to go lower, or whether you're at the other end of the spectrum in terms of high fuel and high carbon.

We really think that somewhere in the middle is probably where we end up; that you have some sort of mid fuel case with some sort of carbon that we're going to have in the future. So really we're trying to look at all those cases and say is this really in the best interest. And I don't think it's as simple as just counting, because to some extent what you're saying is for the benefits of fuel diversity are we willing to take some amount of risk that maybe that fuel forecast doesn't play out exactly the way we anticipated in the CPVRR, or maybe the carbon doesn't.

But at the other end of the spectrum, if we move forward with new nuclear, and, in fact, fuel prices do go up and in fact we do have some amount of carbon, and we do want to continue fuel diversity in Florida and we do want to continue to reduce our dependence on fossil fuels, then that's a good project to have.

So, again, we're trying to provide some context to have that discussion, but I don't think it's as simple as just saying, well, we're going to count boxes and, you know, when more are unfavorable than not, then it's not the right time to go forward, or that we shouldn't go forward.

COMMISSIONER BALBIS: Okay, yeah, I just wanted you to clarify that, because at least in the executive summary that was the only justification, the cost effectiveness, so I was just curious as to --

THE WITNESS: We use that in the executive summary sort of to provide a context, but it's not, you know, if you have nine it's good, if you have 20 -- it's not that cut and dried.

COMMISSIONER BALBIS: Okay. And I just have a few more, Mr. Chairman. There's also a comment made in JE-1, page five, on how it's consistent with, quote, Progress Energy's balance solution. With the Duke merger, how does -- does Duke have a similar strategic plan, if you will, and is this consistent with Duke's plan?

THE WITNESS: Yes, sir, the best of my understanding, it is still consistent. You know, Duke Energy, as a whole, has talked about the need to have, you know, alternate alternatives, you know, including renewables, including efficiency programs, including new nuclear and other new generation. So the language they use is a little bit different, but I think the concept of a balanced solution where you bring multiple things to the table in terms of providing reliable and affordable and increasingly clean energy for our customers is part of their strategy -- part of our strategy now, as well.

COMMISSIONER BALBIS: Okay. So I just want to make sure that that statement still has relevance.

THE WITNESS: Yes, sir. Yes, sir.

COMMISSIONER BALBIS: Okay. And one more question on the JE-1. And just talking about different enterprise risks, which are more qualitative risks that are listed in the IPP, have you factored in the new EPA regulations, especially the carbon rule, which may limit new coal facilities being constructed, and would that be an increased enterprise risk or decreased enterprise risk if you were to include it?

THE WITNESS: We have included that globally as part of the concept of what does carbon legislation look like going forward, and we've kind of watched what the EPA has been trying to do around other regulations on fossil plants as an indicator of what's going to be the viability of those other fuel sources in the future.

In general, I would say, as you see increased regulation around fossil fuel sources, it does tend to improve the favorability of nuclear. But again, we've sort of bucketed that in the broader category of is there going to be a common strategy around carbon in general.

COMMISSIONER BALBIS: Okay. And I guess the point of my question is, you've used the fact that there isn't a carbon tax, for example, as an elevated enterprise risk that supports delaying the project until, I assume, a carbon tax is put in place. But the EPA's proposed rule is a clear limit on carbon production for facilities, that coal facilities cannot meet that limit without carbon sequestration, which in Florida has not been demonstrated on that scale.

So being that those EPA rules came out pretty close to the time of the filing, does that rule make nuclear production in Florida more favorable or less favorable, or more likely or less likely?

THE WITNESS: I would say in general it makes it more favorable, more likely, and the way that that manifested itself in the feasibility analysis is, you know, we looked at what were going to be new generation sources, what you start getting yourself cornered into is you're either building a gas-based portfolio, which is the only way to meet some of these new EPA requirements, and retiring your older coal plants, or you're building nuclear generation.

So that's why that CPVRR analysis, if you kind of look through the register of plants that are constructed, the only thing in the future in that alternate portfolio are really gas-type plants. And it's, again, back to that EPA constraints on coal plants.

COMMISSIONER BALBIS: Okay. And then I just have one question on JE-2, page 17.

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: In each of these scenarios it shows Crystal River 3 being back in service on November, 2014, and then the uprate being completed in 2015. Given the uncertainty of Crystal River, that obviously the decision has not been made to repair versus retire, how does that affect the strategic optimization scenario?

THE WITNESS: Let me just make sure I'm -- which scenario were you pointing at, sir?

COMMISSIONER BALBIS: All of them include --

THE WITNESS: Oh, all these.

COMMISSIONER BALBIS: -- CR3 coming back in service. What happens if it doesn't come back into service?

THE WITNESS: Well, there's -- you know, our assessment is, really, as we think about not only Crystal River 3 but also the impact of EPA rules around maximum achievable toxicity standards on Crystal River 1 and 2, there is an impact there in terms of this resource portfolio. So the resource portfolio that we used in the feasibility analysis did, to your point, assume that Crystal River 3 comes back in service, for lack of an alternate decision at this point.

If it doesn't, then that generation either is replaced with something else, a gas portfolio, or it's replaced with a nuclear based portfolio. And again, that's a decision that we'd have to evaluate at that point, as well.

COMMISSIONER BALBIS: And I guess that may be the point that I'm trying to make, is that there's a lot of uncertainty with EPA MATS rules and other rules. Crystal River 3, the decision has not been made. But couldn't, theoretically, if Crystal River 3 is not returned to service, obviously the uprate project can't move forward, Crystal River 1 and 2 may be affected, that the delay the Levy Units 1 and 2 maybe shouldn't have been made?

THE WITNESS: I would say it this way: We have not precluded the possibility of moving faster. What we have said is a project -- you know, a program record or project plan that has us marching to that 2024 plan, there are potential to move that schedule back if, in fact, some of these other factors, such as Crystal River 3, change.

There's other things that could drive that kind of thought, too; if all of the sudden we saw a big change in fuel prices or we saw some other regulation move forward, I would think -- well, I don't think -- we would as a company reevaluate whether we could move the schedule faster.

To some extent, as we've described in Commissioner Brown's question, there is a limitation from a licensing perspective, but there is the capability to move the project on a faster schedule, if that is ultimately what is needed. So we haven't precluded that option, we've just laid out, hey, here's a plan, because we have to have a plan, and it's better to have that plan and change it than to not have a plan at all. But it doesn't preclude us from moving faster if we had to.

COMMISSIONER BALBIS: But if Progress or Duke or whomever cancels the EPC contract, at some point you're going to lose that ability to move faster, are you not?

THE WITNESS: Canceling the EPC contract doesn't, in itself, preclude us from moving faster. It means we've got to put another contract mechanism in place. The reason we've kind of kept that cancellation path viable is to preserve to some extent our ability to negotiate more favorable terms.

By the time we would mobilize to the field in 2016, we would have two plants completed in China, two AP1000 plants in China at the Sanmen site. We would be close to completing the first Vogtle site. So we would like to think, from a Duke Energy perspective, that we should be able to get much better certainty around ultimate project cost and move more portions of the project from that time and material firm category into a fixed category.

And that's why we thought keeping that option available to cancel the contract, if we need to, and renegotiate a new approach, is a good thing. And we'd start that work, you know, as early as needed to support the planned project schedule.

COMMISSIONER BALBIS: Okay. And then I think this may be my last question, but you mentioned project costs and cost estimates. And in the IPP you mentioned that you're using a level five cost estimate, but I believe you spent hundreds of millions of dollars in work in obtaining the COLA, and why are you still using a level five and not a more detailed cost estimate?

THE WITNESS: The reason for that is until we have locked up -- in my mind, until we have locked up the contract for full notice to proceed and we drive in some of that certainty I was just talking about, from a experience base from the other projects, I think there is still some variability in that cost estimate, up and down.

I mean, you'll notice that band, you know, has gotten a little bit bigger from last year on the negative side and the plus side. And because we're still pretty far away from mobilization, you know, the uncertainty associated with those things, like I talked about, around labor rates and productivity rates and some of these commodity costs, I think, is still there.

So although we have a good insight into the project, we spent a lot of time doing bottoms-up estimating, I think, just because we're still pretty far in the future yet in terms of mobilization. I don't feel comfortable yet saying it's a tighter band on that cost estimate.

COMMISSIONER BALBIS: Okay, and I probably should have started with this question, but were you involved with the decision to delay the Levy projects by three years?

THE WITNESS: Oh, yes, sir. Most definitely.

COMMISSIONER BALBIS: Okay, thank you. That's all I have.

CHAIRMAN BRISE: All right. Then I think I may have maybe one or two questions for you. There's been some discussion about the COL and the shelf life and so forth. My question is really is there any benefit to the consumer to have the COL sort of on the shelf?

THE WITNESS: From the perspective of the flexibility to move forward. You know, I kind of think about it this way, Commissioner: We've been involved in a very extensive front-end development effort for this project. For a project of this scale and this size, that's very necessary. It really drives ultimately the success and certainty of the project as it goes forward.

And as you've seen over the couple of years here now, there's things that continue to kind of perturbate that plan to get to a license. So personally I think having that license in hand is a real big risk mitigator. It puts behind the regulatory uncertainly associated with a final environmental impact statement which we now have for the first greenfield site in the country. It puts behind us the regulatory uncertainty associated with the design of the AP1000. You know, that's done. It really gives us a clear path to move forward with the project, and, you know, we stay committed to the plan we have, that is to do that.

If factors -- as we continue to evaluate and we come in front of this Commission, if, you know, our joint decision here is that the project shouldn't move forward right now, I think that license still has value for those same reasons. It then really just becomes a question of when is the right time to go forward with the project.

CHAIRMAN BRISE: You touched on the second issue, the license having value. Let's say that at some point down the road it becomes not a viable option. Who benefits from the value? Does the consumer benefit from the value?

THE WITNESS: You know, Commissioner, I'd say if the project doesn't go forward, then that license, unfortunately, doesn't have a lot of value in and of itself. It really is about its connection to a project. It provides an option in the future, potentially. But without actually putting concrete and steel on the ground that generates carbon-free electricity, then the license, by itself, I would argue, is not in itself a valuable asset other than that option it gives you to go forward and construct.

CHAIRMAN BRISE: Would you agree that the license is valuable on the market?

THE WITNESS: Yes, sir. Certainly the -- having a greenfield site in a favorable location with good, you know, good site characteristics, is a very valuable commodity, I think, and certainly something that potentially others would be interested in.

CHAIRMAN BRISE: Okay. So what I'm really trying to get at is the investment that has been made by consumers up to this point, is it a valuable investment for the consumer just to have the option available?

THE WITNESS: Yes, sir, I think we think it is.

CHAIRMAN BRISE: Okay. Thank you. Any further questions, Commissioners? Okay, seeing none, redirect?

REDIRECT EXAMINATION

BY MR. WALLS:

Q Very briefly. Mr. Elnitsky, do you recall the question you were asked by Mr. Whitlock regarding the customer rate impact in 2018?

A Yes, I do.

Q And I believe you indicated as part of your response that the issue of customer rate impacts was a company decision that would have to be made, right?

A I think the question was around levelization and I said, yes, that's a decision to be made at a company level.

Q Okay. And can you tell the Commission who the person is who could probably respond better on behalf of the company today regarding customer rate impacts?

A I think Mr. Lyash can provide a good perspective on that.

MR. WALLS: No further questions.

THE WITNESS: Not to put my boss on the spot.

CHAIRMAN BRISE: Exhibits.

MR. WALLS: Yes, we would move in evidence Mr. Elnitsky's Exhibits JE-1 through JE-7 as Exhibits 10 through 16 of Staff's comprehensive exhibit list.

CHAIRMAN BRISE: Okay, seeing no objections, we'll move in Exhibits 10 through 16.

(Exhibits 10 through 16 admitted in evidence.)

MS. BENNETT: I believe SACE had several exhibits, 117, 125, and 126?

MR. WHITLOCK: That's correct, Mr. Chairman. We'd move those at this time.

CHAIRMAN BRISE: Okay, seeing no objections, we will move in 117, 125 and 126.

(Exhibits 117, 125 and 126 admitted in evidence.)

MS. BENNETT: And Mr. Chairman, as a matter of oversight, we forgot to admit some of Staff's exhibits into the record. At this time I would ask -- these have been stipulated by the parties. For the Progress side we would ask that Exhibits 28, 29 and 30 be moved into the record.

CHAIRMAN BRISE: Okay, at this time, seeing no objections, we will move into the record -- what were those numbers again?

MS. BENNETT: 28, 29 and 30.

CHAIRMAN BRISE: 28, 29, and 30 into the record.

MS. BENNETT: Thank you.

(Exhibits 28, 29 and 30 admitted in evidence.)

CHAIRMAN BRISE: Okay. Are there any other exhibits that need to be moved in associated to this witness or at this point? Okay, seeing none --

MR. WALLS: Mr. Chairman, we'd like to ask if Mr. Elnitsky can be excused from the proceeding. He has no rebuttal testimony.

CHAIRMAN BRISE: Okay, Mr. Elnitsky, we will excuse you from the hearing.

THE WITNESS: Thank you, sir.

MR. WALLS: And at this time we'll call Mr. Lyash.

Thereupon,

JEFF LYASH

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

DIRECT EXAMINATION

BY MR. WALLS:

Q Would you please introduce yourself to the Commission and provide your business address.

A Yes, my name is Jeff Lyash. My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q And have you already been sworn as a witness?

A I have.

Q And who did you work for and what was your position at the time you filed your prefiled direct testimony in April of 2012?

A I was employed by Progress Energy and my position was Executive Vice-President of Energy Supply.

Q And has your title or position changed since the merger with Duke Energy?

A No, it has not.

Q Have your job responsibilities with respect to the Levy Nuclear Project stayed the same or have they changed since the merger?

A They've remained the same.

Q And have you filed prefiled direct testimony on April 30th of 2012 in this proceeding?

A I have.

Q And do you have that with you?

A I do.

Q Do you have any changes to make to your testimony?

A Yes, I'd like to raise just one item, and it's on page 11 of the testimony, and it's identical to the issue raised by Mr. Elnitsky, and that is that in my testimony I state 2013 as the COL issuance for Levy, and we now view that as not likely. It is likely 2014 is the correct date.

Q Other than that change, Mr. Lyash, if I ask you the same questions asked in your prefiled direct testimony today, would you give the same answers?

A I would.

MR. WALLS: We request that the April 30th, 2012 prefiled direct testimony of Mr. Lyash be moved in evidence as if it was read in the record today.

CHAIRMAN BRISE: Okay, we will move Mr. Lyash's direct filed testimony into the record as though read.

(Whereupon, the prefiled testimony was inserted.)

IN RE: NUCLEAR COST RECOVERY CLAUSE
BY PROGRESS ENERGY FLORIDA
FPSC DOCKET NO. 120009-EI

DIRECT TESTIMONY OF JEFF LYASH

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Jeff Lyash. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am currently employed by Progress Energy, Inc. ("Progress Energy") as the Executive Vice President-Energy Supply. I assumed my current position on June 1, 2010. Prior to this appointment, I was employed by Progress Energy as the Executive Vice President of Corporate Development. I also held the position of President and Chief Executive Officer ("CEO") of Progress Energy Florida, Inc. ("PEF" or the "Company") from 2006 until July 6, 2009. In this role, I had overall responsibility for the operations of PEF.

Q. What is your role with respect to the development of the Levy nuclear power plants?

A. As the Executive Vice President-Energy Supply for Progress Energy, I have senior management oversight responsibility for the Levy nuclear power plant project ("LNP") and program. The LNP program oversight and enterprise governance charter provides program execution oversight, including ongoing review of performance and decision making on the LNP. John Elnitsky, as Vice President- New Generation Programs and Projects ("NGPP"), leads the Levy Nuclear Power Plant Project and quarterly Levy Program Performance Reviews. The Levy Program Performance Review includes the following functional areas with respect to the LNP: transmission planning; finance; regulatory; external relations; communications; and nuclear operations, safety, and quality. In terms of this governance and execution oversight role, John Elnitsky continues to report to me as the Executive Sponsor of the Levy Program. As a result, I have direct line accountability for the LNP development. Also, I am a member of the Senior Management Committee ("SMC"), which has senior management responsibility for the LNP. I have briefed the SMC and participated in the SMC's decisions with respect to the LNP, and I have briefed the Progress Energy Board regarding the LNP.

Q. Please describe your educational background and professional experience.

A. I graduated with a bachelor's degree in mechanical engineering from Drexel University in 1984. Prior to joining Progress Energy, I worked with the Nuclear Regulatory Commission ("NRC") in a number of capacities. While with the NRC, I served as a senior resident inspector, a project manager, a project engineer, and a section chief. In 1993, I joined Progress Energy, and spent eight years at the Brunswick Nuclear Plant in Southport, North Carolina, ultimately becoming Director of Site Operations. In January 2002, I assumed the position of Vice President of Transmission/Energy Delivery in the Carolinas. On November 1, 2003, I was promoted to Senior Vice President of Energy Delivery-Florida. On June 1, 2006, I was promoted to President and CEO of PEF. On July 6, 2009, I was appointed the Executive Vice President of Corporate Development for Progress Energy. As I indicated above, I assumed my current position as the Executive Vice President-Energy Supply on June 1, 2010, which is the position I currently hold.

II. PURPOSE AND SUMMARY OF DIRECT TESTIMONY.

Q. Can you explain the purpose of your direct testimony and summarize it for the Commission?

A. Yes. The purpose of my direct testimony is to explain the Company's decision to shift the expected in-service dates for the Levy nuclear power plants to 2024 and 2025. This decision was made by the SMC. This decision reflects the Company's prudent management of the LNP in the best interests of the Company and its customers.

The decision to shift the executed in-service dates for Levy Unit 1 to 2024 and Levy Unit 2 to 2025 mitigates the current uncertainty and increased near term enterprise risks while preserving the long-term benefits of nuclear energy generation for PEF, its customers, and the State of Florida. This decision provides additional time for Florida economic conditions to improve for PEF and its customers, for natural gas demand and supply to align in fuel markets, and for more certainty with respect to environmental emission costs, including carbon costs, as a result of developing energy and environmental legislation and regulation, before PEF must decide to commence construction of the LNP. There is no fundamental change in these enterprise risks that prevent this risk mitigation strategy from being successful. The LNP remains the preferred future base load generation resource decision for the Company. The Company still intends to build the LNP and place the Levy nuclear power plants in service in 2024 and 2025.

III. PRUDENCE OF PEF MANAGEMENT LNP IMPLEMENTATION DECISION.

Q. Did the Company make a decision this year that affects implementation of the LNP?

A. Yes. The Company decided to place the Levy nuclear units in service in 2024 and 2025. This decision means that the Company will continue work to obtain the Combined Operating License ("COL") from the NRC for the LNP, but the Company will not commence construction of the LNP next year. Instead, the Company will continue with work on the LNP to commence construction in time to place the first Levy nuclear unit in service in 2024 and the second Levy unit in service eighteen-months later, in 2025. This is the best project implementation decision for PEF and its customers and retains the flexibility to commence construction earlier if enterprise risks and economic conditions warrant.

Q. Why is this decision the best LNP implementation decision for PEF's customers?

A. Completion of the LNP will still furnish the Company and its customers the long term benefits that additional base load nuclear generation provides. The LNP will provide customers long-term fuel savings benefits from a relatively low-cost, fuel source. Nuclear is still the lowest cost fuel source to produce electrical energy, even now with historically low natural gas prices in the utility industry. Nuclear is a clean emission fuel source. The production of energy from the LNP will always be essentially carbon free energy generation. The LNP will also enhance fuel diversity for the Company and the State of Florida. Fuel portfolio diversity will always be a long term benefit of the LNP. The addition of the LNP to PEF's system will reduce PEF's reliance on fossil fuels, especially fossil fuels from foreign sources, for energy production. The reduction in the reliance on fossil fuels for energy generation will always be a benefit for PEF and the State. The LNP will further provide PEF and its customers unparalleled base load energy generation. These long-term benefits of nuclear generation still exist for PEF, its customers, and the State of Florida. There has been no fundamental change in the benefits of nuclear generation.

Also, completion of the LNP is still feasible, whether the Company commences construction of the LNP next year or decides, as it did at this time to commence construction later, in order to complete the Levy nuclear units in 2024 and 2025. From both a qualitative and quantitative feasibility perspective, as explained in detail in Mr. Elnitsky's direct testimony in this proceeding, the Company can complete the LNP.

Near term, however, there is greater uncertainty and, therefore, increased near term enterprise risks associated with the commencement of construction of the LNP next year. Florida economic conditions for customers and the Company have not significantly improved, near term natural gas prices reflect these economic and current over supply conditions, and the economic conditions affect the near term development of clear legislative climate control and greenhouse gas ("GHG") emission policy and regulation at the federal and state government levels. These circumstances represent greater near term uncertainty and, thus, increased enterprise risk with the commencement of construction of the LNP next year.

Under such circumstances, prudent project management requires a strategy to mitigate the increased near term enterprise risks. The only meaningful way for the Company to mitigate the increased near term uncertainty and enterprise risks is to extend the time to commence construction of the LNP. This decision provides the Company additional time prior to commencement of construction for economic conditions in Florida to improve for PEF's customers and the Company, for natural gas markets to respond to current over supply conditions, and for energy and environmental legislative and regulatory policy to develop with respect to climate control and GHG emissions.

Q. When will the Company commence construction of the LNP?

A. One of the benefits of the Company's decision to build the LNP later is that the decision provides the Company the near term flexibility to determine the best time to commence construction. The Company has the flexibility to advance construction if near term uncertainty improves and the enterprise risks diminish. The Company also has the flexibility to extend the construction date until sometime later in order to complete the LNP by 2024 and 2025.

Q. Does the Company expect the current uncertainty and increased enterprise risks associated with the development of new nuclear generation to change?

A. Yes. Continued uncertainty and thus increased enterprise risks over the long term evaluation period for new nuclear generation realistically cannot be expected. We emphasized when we petitioned this Commission for the need determination for the LNP that this was a long-term project, requiring up to a decade to site, license, design, engineer, and construct two base load nuclear power plants, that will generate electrical energy for PEF and its customers for an estimated sixty years. The Company takes into account the long-term nature of this project when it makes management decisions affecting implementation of the LNP. Near term uncertainty and increased enterprise risk must be evaluated in light of the time it takes to develop, construct, and operate the LNP.

The current uncertainty and increased near term enterprise risks associated with the LNP cannot realistically be expected to continue over the extended period of time required to build and operate the LNP. Economic conditions in Florida will not remain stagnant forever, but must begin to improve, as they nascent appear to be doing now. Natural gas prices cannot remain depressed. Near term, historic low natural gas prices will increase as suppliers and purchasers in the market respond to the historic low prices resulting from low demand and oversupply and capacity storage conditions.

The market response to current gas prices will lead to higher demand, diminished oversupply, and reduced storage conditions and, thus, higher, long term natural gas prices. Eventually too, there must be increased certainty in energy and environmental legislative and regulatory policy. Some form of legislation or regulation of fossil fuel emissions that benefits nuclear generation is inevitable. The current trend and pace of regulation in fact is toward more, not less, constraints on fossil fuel emissions and, thus, increased costs to generate electrical energy with fossil fuels.

For all these reasons, the Company reasonably believes that there is no long term fundamental shift in the enterprise risks associated with the development of new nuclear generation in Florida. The current uncertainty and increased enterprise risks reflect transient economic and fuel market conditions and a transitional period in the economy and energy and environmental policy. Current economic and fuel market conditions will change, economic growth will return, and uncertain environmental policy affecting generation decisions in the utility industry will end. For these reasons, over the long-term, the Company expects economic and fuel market conditions and energy and environmental policy to favor the development of new nuclear generation in Florida.

Q. Is the Company still committed to the development of new nuclear generation?

A. Yes. The development of new nuclear generation is part of the Company's Balanced Solution Strategy. Our Balanced Solution Strategy is a comprehensive plan to change the way we generate electrical energy and meet our customers' future energy demands. This is a three-pronged corporate strategy designed to deliver reliable, clean, and affordable power to our customers in the future. The corporate strategy includes the development of energy efficiency and Demand-Side Management Programs, the development of alternative and renewable energy, and the development of a state-of-the-art power system to meet future customer energy demands.

Nuclear generation is a key component of our strategy to develop a state-of-the-art power system. The cost to produce energy from power plants using fossil fuels is increasing for the Company and our customers. Electrical energy generation from fossil fuels faces growing emission regulations. The Environmental Protection Agency ("EPA") has issued increasingly stringent regulations to reduce nitrous oxide ("NOx"), sulfur dioxide ("SO2"), mercury, and particulate emissions from fossil-fueled power plants. These regulations adversely impact the cost to produce electrical energy from power plants using fossil fuels. The Company must install emissions controls and continue to invest in fleet modernization projects to meet the current and expanding emission regulations. Additionally, all fossil-fuel power plants emit GHG, including carbon. Today, nuclear energy generation is the only technology capable of producing carbon-free electricity on a utility scale, twenty-four hours a day, for continuous, base load operation. Nuclear power plants also produce electrical energy without NOx, SO2, mercury, particulate or any other emissions associated with the production of energy from fossil-fueled power plants. For these reasons, nuclear energy generation is an important element of our Balanced Solution Strategy.

Under our Balanced Solution Strategy, the LNP is the Company's preferred future base load generation resource in its future generation resource plan. The Company's current LNP implementation decision does not change the Company's preference for the LNP in its future resource plan. The Company still intends to build the LNP. The Company simply plans to build the LNP later by shifting the expected in-service dates for the Levy nuclear power plants to 2024 and 2025.

Q. Does the development of new nuclear generation still benefit the State of Florida?

A. Yes, it does. The long-term benefits of nuclear generation were recognized by the Florida Legislature. The Commission was specifically required to consider these benefits -- fuel portfolio diversity, reduced reliance on fossil fuels and fossil fuels from foreign sources, reduced air emission compliance costs, and long-term, electric grid reliability -- in need determinations for nuclear power plants. These benefits are the reason the Florida Legislature wanted to encourage utility investment in nuclear power plants. The alternative cost recovery provisions for nuclear power plant costs were established to encourage utility investment in nuclear power plants to achieve these benefits for the State and its residents. The legislative policy has not changed. The Florida Legislature remains committed to the legislation recognizing the long-term benefits of new nuclear generation in Florida for the benefit of the State and its residents.

Q. What was the status of the LNP when PEF made its current implementation decision?

A. The Company focused LNP work on obtaining the COL for the LNP from the NRC after its decision in 2010 to proceed with the LNP on a slower pace. This 2010 decision continued the project by extending the partial suspension that was implemented when the NRC did not issue the Limited Work Authorization ("LWA") for the LNP in 2009. The Company extended the partial suspension of the Engineering, Procurement, and Construction ("EPC") Agreement for the LNP through an amendment to the EPC Agreement that focused work on obtaining the LNP COL. The Commission agreed this decision was reasonable in Order No. PSC-11-0095-FOF-EI in Docket No. 100009-EI. As a result of this decision, the Company planned to commence construction of the LNP after the licensing of the Levy nuclear power plants is complete.

Q. Does the Company still expect to complete the licensing of the LNP in 2013?

A. Yes. The Company expects to obtain the LNP COL from the NRC in the second quarter of 2013. There is no reason to believe that the Company will not receive the COL for the LNP from the NRC. The NRC has nearly completed all three parts to the NRC's review of the LNP Combined Operating License Application ("COLA"). These parts are the environmental review, the safety review, and the hearing process. With respect to the environmental review, the LNP draft environmental impact statement ("DEIS") was issued, the public comment period has concluded, and the NRC has completed its review of the public comments to the LNP DEIS. PEF also completed its responses to U.S. Army Corps of Engineers ("USACE") information requests for the USACE review for the final environmental impact statement ("FEIS"). The LNP FEIS is expected to be issued on April 27, 2012.

The NRC Staff completed its safety review of the LNP COLA when the NRC Staff issued its Advanced Safety Evaluation Report ("ASER") with no open items in

September 2011. The Advisory Committee on Reactor Safeguards ("ACRS") completed its review of the ASER early this year. Upon completion of the ASER review and report all that remains to complete the safety review for the LNP COLA is the NRC review and issuance of the Final Safety Evaluation Report ("FSER"). Issuance of the LNP FSER is expected by September 2012.

The NRC will also complete the formal hearing process for the LNP COLA this year. This is the last step prior to the NRC's issuance of the LNP COL. There is a contested hearing process before the NRC's Atomic Safety Licensing Board ("ASLB") to resolve the one remaining contention at issue in the LNP COLA. All other admitted contentions have been dismissed by the ASLB. The ASLB hearing is scheduled for October of 2012. There is also a mandatory hearing before the NRC that focuses on the adequacy of the NRC Staff review of the LNP COLA. This mandatory hearing process also will be conducted later this year, possibly extending into early 2013. The completion of this hearing process will complete the NRC's LNP COLA review. The Company still expects the NRC to issue the LNP COL in the second quarter of 2013.

Q. Does the Fukushima event in Japan last year cast doubt on the NRC's expected issuance of the COL for the LNP?

A. No. The Fukushima events in Japan delayed issuance of the LNP FSER from April to later this year to allow time for the Company to address the Fukushima Near Term Task Force recommendations in the LNP COLA, but we do not expect the incorporation of these recommendations into the LNP COLA to adversely impact the

FSER for the LNP or the LNP COL. The impact of these recommendations on the LNP COLA is explained in more detail in Mr. Elnitsky's direct testimony in this proceeding; however, the Company expects to address these recommendations in a timely fashion to permit the NRC to issue the FSER in September and the LNP COL in the second quarter of 2013. Addressing these task force recommendations is just a natural extension of the Company's consistent practice of incorporating operating experience ("OE") from around the world into the Company's best practices. The Company has already taken steps to incorporate the OE from the Fukushima events in Japan last year in the management and operation of its existing and planned nuclear power units. The incorporation of the Fukushima Near Term Task Force recommendations is just another step in this on-going process. We fully expect to incorporate these recommendations into the LNP COLA to the NRC's satisfaction and to obtain the LNP COL from the NRC next year.

Q. Why are you confident that the NRC will issue the LNP COL next year?

A. The NRC did not abandon or delay the NRC's AP1000 license reviews as a result of the Fukushima event in Japan last year. The Fukushima Near Term Task Force did not recommend that the NRC abandon or delay its on-going AP1000 license reviews. The incorporation of lessons learned from the Fukushima event last year and the continuing OE at the affected Japanese nuclear reactors since that event occurred is already an essential aspect of the NRC's regulatory review of the existing and planned nuclear power plants in the United States and the nuclear industry's best practices. As a result, there was no reason for the NRC to abandon or delay its AP1000 license reviews. In fact, the NRC completed the AP1000 Design Control Document ("DCD") review and issued the final rule approving the AP1000 nuclear reactor design in December last year, subsequent to the Fukushima event in Japan. The NRC also issued the reference COL for the Georgia Power Vogtle AP1000 nuclear power plant site and the COL for the SCANA V.C. Summer nuclear power plant site early this year. Additionally, the NRC is continuing its review of the LNP COLA with the issuance of the LNP FEIS expected to be completed this April, the planned issuance of the FSER in September 2012, and the planned hearing process scheduled for this year. This is an expected result of the existing NRC regulatory process for the U.S. nuclear power industry. There is no reason to think that the OE from the Fukushima event and the task force recommendations will not be successfully incorporated into the LNP COLA and that the NRC will complete its review and issue the LNP COL next year.

Q. If the Company still expects to obtain the NRC license for the LNP in 2013 why has the Company decided not to commence construction of the LNP next year?

A. The ability to obtain the LNP COL is just one factor in the Company's decision to commence construction of the LNP. As I explained above, other factors must be considered in the exercise of the Company's management judgment of the best course of action on the LNP for the Company's customers and the Company. Among these factors are the qualitative and quantitative enterprise risk factors employed each year by the Company to determine if completion of the Levy nuclear power plants is feasible. The ability of the Company to license the LNP is just one of the qualitative enterprise risk factors. Other qualitative enterprise risk factors must be evaluated as well to determine if it is feasible to build the LNP and to further determine the best implementation schedule if it is feasible. This requires the Company to consider both the short- and long-term costs and benefits of nuclear generation. The Company must evaluate all these factors to determine the best implementation of the LNP for the Company and its customers. This year, the Company concluded as a result of this evaluation that the commencement of construction of the LNP next year is not in the best interests of the Company and its customers. The Company's judgment is that the Company should build the LNP, but later, with a projected in-service date for the Levy nuclear units in 2024 and 2025.

Q. What must Company management do to implement its decision?

A. The Company does not need to take any immediate management action to implement its decision. As I explained above, there currently is a partial suspension of the EPC Agreement until the LNP COL is obtained from the NRC. As I also explained above, the LNP COL is not expected until the second quarter of next year. As a result, the Company does not need to take any action at this time to implement its decision. The Company will continue with the work necessary to obtain the LNP COL this year and next year and the Company will continue to evaluate the project to determine at what point it should commence construction of the LNP.

IV. CONCLUSION.

Q. Do you believe the decision to build the LNP later, with in-service dates for the Levy nuclear units in 2024 and 2025, is a prudent Company decision?

A. Yes. For all the reasons explained in my direct testimony, the Company's decision mitigates the near term uncertainty and increased enterprise risks associated with commencement of LNP construction next year while at the same time preserving the long-term benefits of nuclear generation for the Company, its customers, and the State of Florida. The LNP will provide PEF and its customers fuel savings benefits from a relatively low cost fuel source, and reliable, around-the-clock, base load energy generation without the operational and environmental costs associated with fossil-fuel energy generation. The LNP will enhance fuel portfolio diversity for the Company and the State and it will reduce reliance by the Company and the State on fossil fuels, especially from foreign sources, for electrical energy generation. The LNP is a clean source of energy generation for PEF and its customers. As a result, the LNP is an important element of the Company's Balanced Solution strategic plan to deliver reliable, clean, and affordable power to the Company's customers in the future. The Company intends to build the LNP and plans to build the Levy nuclear power units and expects to place them in service in 2024 and 2025.

Q. Does this conclude your testimony?

A. Yes.

By MR. WALLS:

Q Mr. Lyash, do you have a summary of your prefiled direct testimony?

A Yes, I do.

Q And will you provide the Commission the summary at this time?

A I will. Good afternoon, Commissioners. My direct testimony explains the company's decision to build the Levy Nuclear Power Plants and place them in service in 2024 and 2025. I'm here to answer any questions you may have regarding this decision and the Levy Nuclear Plant. That concludes my opening remarks.

MR. WALLS: We tender Mr. Lyash for cross.

CHAIRMAN BRISE: Okay, OPC?

MR. REHWINKEL: Mr. Chairman, as with the prior witness, with respect to the settlement agreement, we have no cross.

CHAIRMAN BRISE: Okay. Mr. Brew?

MR. BREW: Mr. Chairman, PCS has no questions for this witness.

CHAIRMAN BRISE: Okay. Mr. Moyle?

MR. MOYLE: We have questions on behalf of FIPUG.

CROSS EXAMINATION

BY MR. MOYLE:

Q Good afternoon, Mr. Lyash.

A Good afternoon, Mr. Moyle.

Q Just one brief point, I guess, so that the record is completely clear on the correction that was made on your testimony on page 11, line 11. It should now read the company expects to obtain the LNP COL from the NRC in the fourth quarter of 2014?

A I would say late 2014. It's not clear whether it would be third or fourth quarter, but if I take the Staff requirements memorandum from the Commission at its face and presume the Staff comes in at but not ahead of the two-year window, then I would expect third or fourth quarter.

Q Okay. And I want to just ask you some general questions. You're in the senior management team at -- you were at Progress and you're in the senior management team at Duke, correct?

A Yes.

Q And the senior management team is the team that ultimately made the decision to suspend or delay or defer the Levy Project for the three years that we've talked about with Mr. Elnitsky, correct?

A Yes, in consultation with our Board of Directors.

Q Okay. The shelf life issue has been discussed, and I had a follow-up related to that as it relates to the license. If you get the license, do you have an understanding as to whether additional requirements that the

NRC or others may impose would be required to be met if you had that license on the shelf or would you be grandfathered in, or do you know?

A Yes, I can provide some general information on this. Nuclear license lives are typically or kind of legislatively beginning at 40 years with the provision to extend them in 20-year increments. The AP1000 is a 60-year design. Once the license is issued, there is no specific provision for it to sunset. The term used is shelf life. In that context it has an indefinite shelf life.

Although the license must be maintained, which means as regulations change the Commission would evaluate whether those regulations should be applied in some way to existing licenses and license holders, and then the Levy license would need to be evaluated and amended, if necessary, to maintain it current with the -- with the continuing regulation of operating reactors.

Q Okay, and you --

A But its fundamental design and licensing basis would have been set at the point of issuance.

Q Okay. And you worked at the NRC for a number of years, isn't that right?

A That's correct.

Q So if I understood your answer, it would be that, no, it's not grandfathered in, but that to keep it current, to the extent that additional regulations are put in place, you would have to evaluate and more likely than not meet the additional requirements; is that fair?

A Yes, if they were applicable to that specific design they would need to be evaluated and incorporated.

Q Okay. And then Mr. Elnitsky was asked some questions about the value of a license. Do you agree that the license would have market value, even if Progress Energy decided not to move forward with the Levy Project?

A Yes, I agree. The prime value -- I also agree with Mr. Elnitsky's statement that the prime value here is acting on the license and constructing the plant so that you can begin to garner the fuel savings and environmental benefits of the plant.

If circumstances arose where you obtained the license and didn't proceed immediately to construction, I believe it has value in terms of providing a more rapid path forward, if circumstances were to change in that instance, and drive you toward construction.

Licenses are generally transferable, as property is, so it's conceivable that the project could be sold or transferred, although I don't want to go too far down that path because it's not something we've looked at very specifically or deliberately.

Q Are you aware of anywhere in the nuclear environment currently whether anyone is looking at doing merchant nuclear facilities?

A I am not.

Q And that potentially would be one way in which a license would have value, if you transferred it to a third party, either a merchant or another investor-owned utility, is that correct?

A That would be one way, yes.

Q And in terms of the Levy Project, you make a comment on page five, line nine -- I just have some questions related to fuel diversity.

Let me just read it to you for the record: Fuel portfolio diversity will always be a long-term benefit of the LNP. The addition of the LNP to PEF's system will reduce PEF's reliance on fossil fuels, especially fossil fuels from foreign sources for energy production. Right?

A I see that, yes.

Q Okay. Currently Progress doesn't make use of many fuels from foreign sources, if you define foreign as outside the United States, is that right?

A We use oil and coal and from time to time some of those supplies do come internationally. For example, we have imported Venezuelan coal to our Crystal River facilities for consumption there in the past.

Q If you had to just ballpark it with respect to the percentage of fuel that comes in from, you know, outside of the country, could you do that for me?

A No, I wouldn't want to venture a guess at that presently.

Q But currently most of your fleet is natural gas fired, is that correct?

A Were you asking about our fleet or Progress domestically?

Q Progress.

A Okay, I'm sorry, I didn't hear -- I didn't know you were being that specific. It's a relatively small percentage in the present -- the present time.

Q Okay, we may be talking past each other. You were -- the question -- I was asking you about ballparking the percentage of fuel coming in from foreign sources as it relates to Progress, and you said it's not a big percentage, is that right?

A It's a very small percentage presently, yes.

Q Okay. And then I moved on and asked you with respect -- I want to ask you some questions about portfolio diversity. And I guess you would agree that one of the selling points of Levy is that it would provide a fuel diversity, is that correct?

A Yes, Levy would provide significant fuel diversity.

Q Okay. And as we sit here today, can you -- again, not to, you know, the decimal point level, but just generally describe the generation mix of the Progress portfolio.

A Well, if I look forward to 2014, my estimate right now is that 70 percent of the megawatt hours generated by Progress Energy Florida in '13 will come from natural gas. The remainder of that, absent Crystal River 3, comes from a combination of coal and oil.

Q And do you know if you are the most dependent investor-owned utility on natural gas in the state or not?

A I'm not comfortable citing numbers to you. I think we are -- Progress Energy Florida is highly dependent on natural gas, as is Florida Power & Light. I'm not up to date on their specific number.

Q Okay. And with respect to fuel diversity, are you aware of any study or metric or any intellectual academic information that speaks to the level of diversity with respect to fuel?

A No, I can't cite you a specific study at the present time, although over the years much has been written about the value of diversity in any portfolio in general, and specifically about the value of diversity in a fuel system for maintaining stability and reducing volatility.

Q And diversity, you would agree, is another qualitative factor that it's very difficult, you know, as we sit here today to measure the value diversity, of fuel diversity?

A I would agree that it's a very important qualitative factor. And I would also agree that its specific dollar value is difficult to measure outside of a scenario that you might postulate. However, if we were to postulate a scenario, for example, 70, 80, 90 percent dependence on natural gas, and look at the price change at the customer level for a dollar or a two dollar or a five dollar change in gas, that could be quantified. I don't have the number at hand.

Q You would have to make certain assumptions about future prices of natural gas compared to nuclear cost. I guess it could be done if you made certain assumptions, correct?

A Yes, as you always do in scenario planning, that is correct.

Q Okay. And the Levy Project, how many megawatts is associated with it?

A Roughly 2,300 megawatts.

Q So each one is roughly a 1,150?

A Generally, yes.

Q And the projected cost of the Levy Project is 20 billion, is that fair, if you include the AFUDC number?

A 18.8 is our most likely estimate, absent AFUDC.

Q So what would it be with AFUDC?
A It depends on what the cash flow looks like, and so, yeah, a reasonable number might be 21 to 22 billion dollars, with AFUDC, perhaps a little more, perhaps a little less, depending on what the specific cash flow is.
Q Okay. And do you know, as we sit here today -- again, ballpark -- what it would cost to do a thousand -- let's say 1,100 megawatts of a natural gas fired facility?
A I'm sorry, can you say that again, what you're asking for?
Q Sure. 1,100 megawatts of state of the art natural gas, my information is it would be a little north of a billion dollars. I was just curious as to whether you had an estimate as to what it would cost to do, you know, a thousand megawatts of natural gas.
A Okay, I understand, yes. What I was curious about is were you looking at just the up-front construction cost or were you looking at the life cycle cost of the plant? If you just focus on the up-front construction cost, which is the smaller component of the life cycle of a gas-fired combined cycle plant, a thousand megawatts, a billion dollars, perhaps higher, a billion one, a billion two, for a thousand.
Q Okay. I don't know if you followed the recent need determination in the Power & Light case for the Port Everglades case, but I think that number was about a billion

two for a thousand megawatts. Do you generally have that understanding?

A I haven't followed the Florida Power & Light, but we've got multiple gas-fired combined cycle plants under construction currently, so I'm relying on that for my response.

Q And where I want to go with this is wouldn't it seem to make sense, you know, just intuitively, that if you can do for -- you know, let's call it a billion dollars, a thousand megawatts of gas, you know, two billion dollars for 2,000 megawatts of gas, that compared to a $20 billion figure for 2,000 megawatts of nuclear, that the better prospect is to, you know, maybe go a little heavy on gas?

A No, I don't agree with that.

Q And you don't agree with it because the future cost projections, we're not sure what the price of natural gas is going to do; is that primarily the reason?

A No, that's not primarily the reason. Would you like me to explain?

Q Sure.

A Okay. These are long-term decisions, so we're talking about a 40, 60, or 80-year decision. There are a number of complex issues in here, some of them easily quantifiable, some of them not. You raised one already: Fuel diversity, environmental impact and price of carbon, NOX, SOX, Mercury, et cetera, the price of fuel, itself, the operating cost of the plants over its lifetime.

And so in order to answer that question I think you must compare the alternatives of those two portfolios, construction of additional natural gas and the way that plays into the portfolio, as well as construction in nuclear. This is really the prime focus of the feasibility study. And so, as I look at the feasibility study for Levy, the mid-gas curve in that study is really the nominal view of the way gas prices are more likely than not going to play out.

And in that scenario, with any price on carbon, the nuclear construction over its lifetime provides a positive net present value to the customer, absent the other qualitative values, such as fuel diversity.

So, Mr. Moyle, I would not generically answer the question, what's better, natural gas or nuclear. You have to answer that question in the context of this sort of assessment. And what the feasibility study tells us, at this point, is the project still feasible, and the project under the most likely scenarios has significant present value to the customer.

Q Would you agree with me that given those two choices, doing a couple thousand megawatts of gas as compared to a couple thousand megawatts of nuclear, that if it was hypothetically posed to a grandparent in your service territory, say, you know, 65, 70 years old, that the answer that they would be likely give would be I'd rather have the, you know, natural gas, given that, you know, the projected life of somebody who is 65, 75, they're not going to be there to see the benefits of the nuclear project, more likely than not, correct?

A I'm sorry, was there a question? I'm trying to get to the question.

Q Yeah, I'm trying to understand. You're familiar with inter-generational transfers?

A I am.

Q And when you do your economic analysis, you're assuming the nuclear plant is going to last for 60 years, correct?

A Yes.

Q Okay. And in order to have those savings, you have to look out 60 years. For somebody who is not going to make it out 60 years, wouldn't you agree that the economic situation would be different?

A No, because fundamentally I don't agree with the premise of your question. I will admit that the nuclear plant is a long-term investment. And because of that it has -- it has a negative value up until it goes into service and then it quickly flips and becomes a year by year positive value to the then customers.

I will admit that because of the length of these projects and their construction and because of the length of their life, both their costs and their benefits can be multi-generational. That is not unlike many other plants. It takes us ten years -- has taken us -- is taking us today ten years to build a coal plant. Even with a gas plant it can take us five, six years to develop it.

Customers move into our service territory; they move out. People are born; they die. Energy is such a critical investment that making decisions that appropriately balance the near term with the long term, even inter-generational impacts, is important.

And to your original very specific question, I have asked seniors their view on this and gotten a wide range of responses. My experience, personal experience, is generally more supportive than against.

Q We'll let you get away with the hearsay reference there --

A You asked me --

Q -- and I won't ask you how many of them are related to you, either. But, anyway, let me move on and ask you this question. Over the years we've had conversation about partners, with respect to Levy. Can you give us an update?

Do you have any partners that have signed up or that are looking at defraying the expense to the extent that the risk can be shared with partners in the Levy Project?

A The situation with respect to partners in the project, I don't think, has really materially changed recently. We have from the beginning had a number of potential partners who expressed significant interest in the project. They continue to express significant interest in the project. We keep them apprised of its progress, but we have not reached the point with any of those potential partners where they have committed to close on an ownership share plan.

Q Okay, thank you. And with respect to the change that you're here testifying about now, which is the pushing the project out to 2024, 2025, and increasing the cost by $1.2 billion, without including AFUDC, you would agree with that, right? Those facts are correct?

A Yes.

Q What -- and this is a hard question, admittedly -- but what degree of confidence do you have that Levy will be operational and on line in 2024 and 2025, as you are suggesting, and cost the projected $18.8 billion?

A Confident. I can characterize the basis for it, if you'd like, but I'd say a reasonable level of confidence.

Q And that's a hard question. It's like a lawyer being asked am I going to win in front of a jury. I mean, you can say, well, it's hard to nail down. But, you know, it's a lot of money, and I just was wanting to understand and would think a board member might ask you something like that.

How confident are you in these numbers, or do you think it's more likely than not that they will change again?

A I'm confident in the schedule and the numbers. And if I might just take a minute, the price of the Levy Project really has only changed from its original 14.2 billion, I think, with the Certificate of Need, to the current 18.8 billion

The driver for that, as was questioned earlier, is the escalation as you move the project out with the passage of time. So what we haven't seen on the project are significant changes in scope, significant changes in design approach, that would drive units -- yards of concrete, feet of pipe, or productivity rates. So while we still hold this as a Class 5 estimate, the cost basis for the plant as we move through time has been fairly consistent.

What's gotten more clear over time is the licensing and permitting risk, and I think that has generally subsided, with the waste competence issue being a recent exception to that. And so that's part of the basis for my confidence. The AP1000 design was certified, the Vogtle license was issued, the Scana license was issued; they're under construction. The Chinese are well along. The Part 52 licensing process is being exercised very effectively.

The Levy project has really no substantial deviations from that. It should follow in its footsteps. I see no reason why it shouldn't. So I'm confident of our ability to license it. And with that construction experience, as that proceeds, my confidence in our ability to construct it and our ability over time to sharpen the schedule and cost rises.

Now, what I can't be -- what I can't be as confident about, Mr. Moyle, is the broader set of risks. What will we see for environmental regulation, and will it become more urgent or less urgent, more impactful or less impactful.

How will the market come back into balance around natural gas. I believe it will. How quickly will it. Those I have less confidence in our ability to predict, and it's why we must monitor them closely.

Q Okay. And I didn't ask you that yes-no question because there's a possibility we may come back and revisit this at some future point, as you may imagine, depending on things down the horizon. So let me move on and ask you a few more questions, if I could.

And this question was touched on by Commissioner Balbis, but the balance solution strategy, now that the merger has taken place, is that still in effect today, you know, if it's called by a different name, what has been previously termed the balance solution strategy that you reference in your testimony --

A Yes.

Q -- if you can just give me a yes or no?

A Yes, it is.

Q So Duke has adopted it?

A Yes, Duke had a similar strategy prior to the merger. The two were very complementary.

Q Okay. And you had talked about carbon a little bit, and I want to -- I want to ask you some questions about carbon and environmental issues. And in response to a question from Commissioner Balbis, Mr. Elnitsky said that he believed that the EPA rule related to emissions from coal plants would help the prospects of Levy. Did you understand that to be his answer to the question posed by Commissioner Balbis?

A Yes, I did.

Q Okay. But wouldn't you agree that to the extent that the government is addressing carbon through a mechanism such as a tough rule that reduces carbon, that that would make it less likely that legislation imposing a carbon tax would take place?

A No, I don't.

Q So you think that in addition to doing a tough rule that it's more likely than not that Congress would act to put in place a carbon tax or a cost of carbon?

A Well, it's a bit hard to predict this, but a rule that disadvantages coal, while it might slow the increase in greenhouse gases, it does not really make material progress at addressing the reduced greenhouse objectives that are embedded in most of the scientific studies.

So a rule or a series of rules for the EPA can nudge things in the right direction, or at least slow the assent. But my personal opinion -- I think that's what you're asking me -- is that it will take carbon legislation if we're to meet, say, the Kyoto protocol objectives.

Q Okay. And with the merger, now, Duke is the biggest utility in the country, correct?

A By several measures, yes.

Q Okay. And you all have not only internal governmental affairs folks, you hire outside lobbyists to advance positions of Duke in state legislatures and at the Capitol, correct?

A Yes.

Q Okay. So to the extent that one of the key drivers for the advancement of the Levy Project is a carbon tax or monetizing carbon, it would follow logically in my mind that Duke would support a carbon tax. Do you agree with that? I guess, first of all, do you agree with the logic?

A Not entirely. Generally, yes, but not entirely. Let me just explain. We, as a company, are in favor of addressing carbon as a national and international issue. And so the company has been supportive of carbon regulation because we believe it's the right thing environmentally and nationally.

However, we feel very keenly our responsibility to balance the interest -- that interest -- with the interests of our customers who will ultimately bear the price impact of that. And so we are supportive of carbon legislation but only if it materializes in a way that's equitable for the customers and minimizes the cost impact on the customers for the results you're trying to achieve.

Q And you would also agree that that rationale you just described is probably equally applicable to the analysis as to whether to move forward with Levy?

A Yes.

MR. MOYLE: I think that's all I have, if I can just have one quick minute.

CHAIRMAN BRISE: Say that again?

MR. MOYLE: If I can just have one minute to check my notes. Sorry.

CHAIRMAN BRISE: Okay. I thought I heard that's all you have.

MR. MOYLE: I think it is. That is all I have.

Thank you, Mr. Lyash, I appreciate it.

THE WITNESS: You're welcome.

CHAIRMAN BRISE: Thank you, Mr. Moyle. Lieutenant Colonel Fike?

LT. COL. FIKE: No questions, Mr. Chairman.

CHAIRMAN BRISE: Okay. Mr. Whitlock?

MR. WHITLOCK: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WHITLOCK:

Q Good afternoon, Mr. Lyash.

A Good afternoon.

Q Mr. Elnitsky answered a lot of my questions today as far as the overlap between you all's testimony, but I suppose that's probably his job, right, to make your job easier?

A That is his job, I would agree with that, among other things.

Q I want to focus on just one or two parts of your testimony. On page four, line seven, you state the company still intends to bill the LNP and place the Levy Nuclear Power Plants in service in 2024 and 2025. Is that an accurate representation of your testimony?

A Yes.

Q Okay. There's been a lot of talk over the past half hour to an hour or so, some good questions from the

Commissioners about the shelf life of a COL, the value of a COL, the COL as an option. And based on that, wouldn't it be a more honest assessment of the company's intent to say that the company, Duke Progress, intends to get a COL for the LNP and then reassess the increased risk and uncertainty that we talked about with Mr. Elnitsky that you discussed in your testimony and make a decision at that point in time of whether or not to build the LNP?

A No, I wouldn't agree with that characterization.

Q How so?

A Well, we've made a decision to build Levy and that decision was made at the outset when we filed the Certificate of Need. You know, that was the passing of our judgment on the item under consideration at the time, and the Commission weighed in on that, as well.

So what has transpired as we've moved through the project is a prudent management approach that evaluates the project, itself, the landscape, emergent items that either were not or could not have been anticipated to reaffirm that that decision should stand either unaltered or should be adjusted in some way, given the circumstance.

So I don't consider Levy an option, at all. I consider Levy a decision that's been made.

Q And so I'm clear, the decision to build Levy has been made?

A That's correct, when we filed the Certificate of Need.

Q Okay. And post-merger, the decision to build Levy still stands?

A Yes.

Q So you're willing to go on the record today and tell the Commission Levy will be built?

A I said the decision to build Levy has been made. Any prudent approach to project management, given that decision, will systematically evaluate the progress and status of the project, the alternates, the regulatory situation, the economy, to decide whether the course of executing on that decision should be altered. It can be altered to accelerate it, to slow it, to change its trajectory, because there are choices to be made over the life of the project.

And as a matter of fact, I would say that the Part 52 licensing process, as well as this proceeding, are about ensuring that we continue to take on board all that information and make choices about whether to alter the course of the project or proceed with our present intent, which is to build the Levy Plant.

Q So the decision has been made to build Levy, but the decision would be made moving forward to essentially make a new decision, which is to not build Levy. Is that what you're saying, basically?

A It could be, and that is the purpose of the feasibility study and the evaluation of enterprise risk and the purpose of coming here each year to discuss this. You would not and the Commission would not want us to make a decision by what appears to be your definition that is a single decision, inalterable, irreversible. That would be an imprudent way to approach a project. We need to make a decision, understand our intentions, and then evaluate that decision in light of circumstance, as things unfold.

Q Well, I guess, if I'm making it sound like that's my, quote, unquote, definition of the decision, it's not. I simply just want to know if the company has made the decision to build Levy, and your answer is yes.

A Yes, as demonstrated by the Certificate of Need and our feasibility study that we've done on an annual basis.

Q Were you present before this Commission when the Duke CEO, Mr. Rogers, testified in early August?

A I was not.

Q Okay. Are you familiar with his testimony?

A I haven't reviewed it.

Q Okay. Do you know how he characterized the Duke's intent as to Levy at that time?

A No.

Q So you don't know if your characterization of the intent today is consistent with what Mr. Rogers said?

A Because I haven't reviewed his specific testimony here, I'm not.

Q Okay. Have you spoken with Mr. Rogers about the status of Levy since the merger?

A Yes.

Q What can you tell the Commission about those discussions?

A I'm not sure how to respond other than that we've talked about our construction projects and our operating and generation plan as a routine matter of business. And I think Mr. Rogers understands the status of the Levy Project. He is generally, and I think on the record, is being supportive of nuclear as a part of the balance solution. I mean, if you have something more specific, I'd be happy to be responsive.

MR. MOYLE: I don't. I don't. Mr. Lyash, those are all my questions. Thank you.

CHAIRMAN BRISE: Mr. LaVia.

MR. LaVIA: No questions, Mr. Chairman.

CHAIRMAN BRISE: Staff? Ms. Bennett?

MS. BENNETT: No questions.

CHAIRMAN BRISE: All right, Commissioners. Commissioner Balbis?

COMMISSIONER BALBIS: Thank you, Mr. Chairman. Welcome, Mr. Lyash. I should have apologized to the previous witness, as well. I reserved these technical questions for this setting rather than Mr. Rogers, so you're making his job easier at this point.

THE WITNESS: This is my job.

COMMISSIONER BALBIS: I'm going to bounce around a little bit here, and a lot of the questions I'm going to ask are similar to the ones asked by the previous witness and hopefully you were -- you were in the room for that.

You indicated several times in answering questions, to Intervenor questions, about a feasibility study. And I want to make sure, what is this study? Because you have the CPVRR update report and then you have the integrated project plan. Is that where you indicate -- I mean, is that the feasibility study? Is there another study?

THE WITNESS: No, those are what I'm referring to. We annually -- we're constantly evaluating the project and the circumstances that affect it, but at least annually we do a quantitative and a qualitative feasibility analysis. The quantitative portion of it is the CPVRR analysis you're referring to.

The qualitative analysis has to do with an assessment of all of the other risks related to the project: Environmental regulation, the current state of the economy, and the customers' ability to support the project, the long-term growth rates for power consumption in Florida, what we think of as long-term fuel prices, licensing risk.

So we take these qualitative assessments of enterprise risk, pair them up with a quantitative CPVRR study, and that's what I'm referring to as our feasibility study, that leads us to a conclusion.

COMMISSIONER BALBIS: Okay. Thank you, I just wanted to make sure there wasn't another report out there that we didn't have. Let's talk a little bit about the quantitative results. Do you agree that the Levy Nuclear Project is still cost effective and economically viable?

THE WITNESS: Yes.

COMMISSIONER BALBIS: Okay. On page eight of your testimony you indicate that some form -- starting with line four -- some form of legislation or regulation of fossil fuel is inevitable. And you answered a question, I believe, from Mr. Moyle, that there was some uncertainty about carbon tax, if you will, or monetizing carbon. Do you believe, again, what's indicated in your testimony, that it's inevitable?

THE WITNESS: I do. What I see as very uncertain is the time frame. You know, the issues that we have around the environmental impact of fossil fuels, I think, are very real, cumulative, and long lasting. And when I say inevitable, I mean that we will -- it's my belief and the company's belief and we will address these, they will need to be addressed legislatively.

In the near term, the political climate makes it very uncertain as to when, and exactly what form they will take.

COMMISSIONER BALBIS: Okay. And any form of legislation would likely make the project more favorable, correct?

THE WITNESS: That's correct.

COMMISSIONER BALBIS: Okay. And that's what I'm struggling with. We have the quantitative results indicates it's cost effective, you have some form of legislation, as you testified, is likely coming that will make it more favorable; then why delay the project by three years and incur a $1.2 billion additional cost?

THE WITNESS: Well, let me give you two thoughts, two of the bases here. It is true by delaying the project three years, under the assumptions that we've made, the project might escalate $1.2 billion, although there are factors that might mitigate against that cost pressure, or it might exacerbate it. So it's a nominal estimate. It is purely a result of the escalation that comes from the passage of time.

The option against which you're comparing it is also escalating with the passage of time. So the relative -- delaying the project doesn't change its relative standing against alternatives.

Now, your fundamental question, which is, then, why delay, the answer here is embedded in the evaluation, qualitatively, of enterprise risk. Will -- when will customer and load growth return in Florida and how aggressive will that growth be? When will the Florida economy begin to show signs of recovery and unemployment come down?

That affects two things. It affects people's consumption, which is very correlated with disposable income of the product, electricity. It also bears on their ability to pay up front or early for a long-term, very positive benefit.

What will -- what legislation will develop on the environment and what actions will be required for it. And so our assessment was that given all that uncertainty and risk, along with the fact that there are plants being built and we're gaining construction and operating experience, the right balance is to delay.

If it were purely the CPVRR that was driving the decision, you would move more quickly. But we've said from the very first on this that that's an important consideration, but it's not the only consideration.

COMMISSIONER BALBIS: Okay, and you touched on a couple of the enterprise risks. And if I could, Mr. Chairman, I'd like to go just quickly through each one of those enterprise risks and what the effect of the delay -- how that affects those individual risks. You discuss the economic conditions and load growth in the nexus customer impacts. Could you discuss the enterprise risks and how customer impacts are affected by delaying the project?

THE WITNESS: We're sensitive to the fact that when the economy -- these are related risks -- so with the economy and with growth in the condition it's currently in in Florida, moving aggressively on a project like this that by its nature is going to add a burden to the customer's bill in the near term is the risk we're talking about there.

And so we feel as though it is better if we have the alternative to continue to move the project forward, but try to push as much of the high level of spending a little further down the road as we can to give the Florida economy and the customer, himself, the time to get in a stronger position.

COMMISSIONER BALBIS: Okay, so the delay doesn't make the impact any less, it actually makes it greater and just pushes it out some. Is that a fair assessment?

THE WITNESS: Yes.

COMMISSIONER BALBIS: Okay. The next one is state and Federal policy. And Federal policy you discussed; again, I guess, proposed carbon legislation. But none of that legislation will suddenly make the project cheaper, will it?

THE WITNESS: No, but it will -- it will -- to the extent carbon policy moves forward, it adds significant present value to the project. In other words, if it is certain that there is a carbon tax, for example, and we know how the carbon tax is going to wrap up, then you can adjust your construction schedule to optimize it against the phase-in of the carbon tax, considering the plan is a broader portfolio.

So the more certain Federal policy is in both its cost and its scheduled implementation, the more strongly it argues -- well, perhaps I don't want to put it that way -- the better able you are to optimize the project construction schedule around capturing the most value.

COMMISSIONER BALBIS: And also would you agree that it would make carbon producing generation more expensive so therefore nuclear is more cost effective?

THE WITNESS: It would. It would. And the change here from last year is that even at this point last year there was more comprehensive carbon legislation moving through the Legislature in Washington. A year later, particularly in this lead-up to the election, there really is no motion on that, other than some rulemaking at the EPA, which I think is not trivial, but not at the heart of the matter.

COMMISSIONER BALBIS: Okay. And then shifting to the state, state legislation and policy, you mention in your testimony that there's been several or numerous attempts to repeat the nuclear cost recovery clause. Are you aware that some of the criticisms on the nuclear cost recovery clause are the fact that the nuclear plants may never be built?

THE WITNESS: I am. That has been a criticism from the outset, yes.

COMMISSIONER BALBIS: So wouldn't delaying the project add additional uncertainty as to whether or not the plants will ever be built?

THE WITNESS: It could, yes.

COMMISSIONER BALBIS: Okay, that's all I had on the enterprise risks. And just real quick, on comparing the nuclear plant to traditional fossil fuels, I think a gas plant, I think Mr. Moyle compared it to a combined cycle plant. And there's obviously the opportunity for parties to halt the permitting process of a nuclear plant and challenge it. And would you agree that even with a combined cycle plant that is perhaps -- or is cheaper up-front costs -- can still be challenged by parties?

THE WITNESS: Oh, absolutely, yes, sir.

COMMISSIONER BALBIS: Okay, that's all I had. Thank you.

CHAIRMAN BRISE: Commissioner Brown?

COMMISSIONER BROWN: Thank you. I just have one question, and it's kind of a different version of what Commissioner Balbis previously asked you regarding Progress's current trajectory pushing Levy out to 2024, 2025. How did Progress determine that pushing out Levy by three years was the best alternative? Was there a shorter time frame that was evaluated?

THE WITNESS: Yes, we evaluated continuing the project on its then current schedule, which was '21, '22 in service. We evaluated various delays, including the three-year delay, and as we do every year, we evaluate, based on the feasibility, should we continue the project, is there a reason that we ought -- that it would be prudent to stop the project.

And these are subjective, to a large extent, so we do quantitative assessment, the CPVRR. But the way we reach the conclusion, really, is looking at those enterprise risks and our detailed understanding of the, you know, Federal, the state legislative landscape, and what's happening in the industry. And so this is a judgment that on balance the best course of action was to move the schedule three years to 2024, 2025.

COMMISSIONER BROWN: I understand, I understand all that, I just wanted to understand why you chose the three years versus, say, one year; to allow, I guess, more flexibility on the part of Progress?

THE WITNESS: No. You know, our -- I want to give a short answer.

COMMISSIONER BROWN: You can give a long one.

THE WITNESS: You know, we were aware -- there were certain things pushing out the COL absent the waste confidence. We were still confident we would be getting it in '13. There were some issues, including, you know, working through the Fukushima responses, which we've got a clear path on, that we felt would push the license out for some period of time. We were aware that this waste confidence issue was being challenged in court and we needed to look at that.

As we looked at what has changed in the last year, in terms of the Florida economy and what trajectory a real recovery might look like here in Florida, and perhaps most significantly looking at the impact of shale gas on gas price, the over-supply of gas that currently exists, gas capacity that currently exists in a down economy, and how long might it take for that to rationalize itself -- and we believed it would -- all these things led us to say let's -- the best course here is a three-year delay, realizing that we have the alternative to reaccelerate that schedule in a window if circumstances change.

COMMISSIONER BROWN: Okay, thank you.

CHAIRMAN BRISE: Commissioners, any further questions? All right, seeing none, redirect?

MR. WALLS: No redirect.

CHAIRMAN BRISE: All right, let's deal with the exhibits.

MR. WALLS: Mr. Lyash has no exhibits.

CHAIRMAN BRISE: All right, very good.

MR. WALLS: We would ask that Mr. Lyash be excused from the proceeding, as he has no rebuttal testimony.

CHAIRMAN BRISE: All right, Mr. Lyash, you are excused.

THE WITNESS: Thank you, Mr. Chairman. Thank you, Commissioners.

CHAIRMAN BRISE: All right, thank you. We are going to go ahead and move out of order and go to the

Staff witnesses, and so if Ms. Bennett can --

MS. BENNETT: Thank you. I would call William Coston and Jerry Hollinstein to the stand. This is a panel of witnesses.

Thereupon,

WILLIAM COSTON

JERRY HALLENSTEIN

were called on behalf of Florida Public Service Commission Staff, having been previously duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. BENNETT:

Q Good afternoon, gentlemen.

A (By Mr. Hallenstein) Good afternoon.

A (By Mr. Coston) Good afternoon.

Q Have you previously been sworn in?

A (By Mr. Coston) Yes.

A (By Mr. Hallenstein) Yes.

Q Let's start with, would you state your name, each one of you state your name and your business address.

A (By Mr. Coston) Yes, my name is William Coston. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32301.

A (By Mr. Hallenstein) My name is Jerry Hallenstein. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32301.

Q And would you state by whom you are employed and in what capacity.

A (By Mr. Coston) I'm employed by the Florida Public Service Commission as a Government Analyst II.

A (By Mr. Hallenstein) I am also employed by the Florida Public Service Commission as a Government Analyst II.

Q And, gentlemen, have you jointly prefiled testimony consisting of four pages in this case as it related to Progress Energy Florida?

A (By Mr. Coston) Yes.

A (By Mr. Hallenstein) Yes.

Q If I were to ask you those same questions today as were in your prefiled testimony, would your answers be the same?

A (By Mr. Coston) Yes.

A (By Mr. Hallenstein) Yes.

MS. BENNETT: Mr. Chairman, at this time we ask that the joint prefiled testimony of Mr. William Coston and Mr. Jerry Hallenstein -- Hallenstein be entered into the record as though read.

CHAIRMAN BRISE: All right, we will enter the joint direct testimony of Mr. Coston and Mr. Hallenstein into the record as though read.

(Whereupon, the prefiled testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT JOINT TESTIMONY OF

WILLIAM COSTON AND JERRY HALLENSTEIN

DOCKET NO. 120009-EI

JUNE 19, 2012

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 audits 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. Hallenstein and I jointly conducted the 2012 audit 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. I have worked for the Commission for nine 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, 100009-EI, and 110009-EI. This testimony addressed the audits of PEF's project management internal controls for the nuclear plant uprate at the Crystal River Unit 3 and the Levy Nuclear Project for the years 2009 through 2011. 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. Hallenstein, please state your name and business address.

A. My name is Jerry Hallenstein. 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 Government Analyst II, within the Office of Auditing and Performance Analysis.

Q. What are your current duties and responsibilities?

A. I perform audits 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 2012 audit 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 Finance from Florida State University in 1985. I have worked for the Commission for twenty-two years conducting operations audits and investigations of regulated utilities. Prior to my employment with the Commission, I worked for five years at Ben Johnson Associates, a consulting firm that specializes in providing economic and research services to state regulatory commissions.

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

A. Yes. I filed testimony in Docket 981488-TI, with an audit I conducted regarding the billing and sales practices of Accutel Communications, a reseller of telecommunications services.

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 CH-1). This audit 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-2011 through April 2012 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 an audit 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. The previous reviews were filed in the 2008, 2009, 2010, and 2011 Nuclear Cost Recovery Clause dockets before the Commission.

The primary objective of this audit was to document key project 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 CH-1. The audit report's conclusions are summarized in the Executive Summary chapter for both the Extended Power Uprate project and the Levy Nuclear Project.

Q. Does this conclude your testimony?

A. Yes.

BY MS. BENNETT:

Q And, gentlemen, did you have one exhibit attached to your testimony as it relates to Progress Energy, Florida, which is the Project Management Internal Controls Audit relating to Progress Energy Florida's nuclear plant uprate and construction projects?

A (By Mr. Coston) Yes.

A (By Mr. Hallenstein) Yes.

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

A (By Mr. Coston) No.

A (By Mr. Hallenstein) No.

MS. BENNETT: Mr. Chairman, I'd ask that Exhibit CH-1, which is marked as Number 25 on the comprehensive exhibit list, be identified as such.

CHAIRMAN BRISE: Okay, we've identified it.

MS. BENNETT: Thank you.

BY MS. BENNETT:

Q Have you prepared a summary for today's hearing?

A (By Mr. Coston) Yes, we have.

Q Would you please present that summary.

A (By Mr. Coston) Yes. Good afternoon, Commissioners. Our testimony presents a management audit review of the project management internal controls that Progress Energy Florida uses in managing its CR3 extended power uprate project and the construction of its new -- new Levy Nuclear Units.

To develop our conclusions for our review, our office, at the directive of the Commission Technical Staff, has annually conducted an independent assessment of the internal controls used by the company for the project management and its methodology.

The primary focus of our review was to document and assess the key project management developments for both projects since the 2011 Nuclear Cost Recovery Hearing. Specifically, our review examines company project controls in the following areas: Project planning, management and organizational structure, cost and scheduling, contractor selection and oversight, internal and external auditing and quality assurance.

Our team conducted interviews with key company project management personnel for both projects. In addition, we issued extensive document and data requests related to project management and oversight, project development, and project implementation.

Items our team reviewed and evaluated include management reports, contracts, scope change control documents, invoices, quality assessments, and audit reports. These documents and interview responses form the basis of our overall assessment of the status and effectiveness of project management controls that the company employed for the two projects.

Based upon our review, we have no specific recommendations concerning the company's project management internal controls employed by both projects for the current period. This concludes our summary and we're available for any questions.

MS. BENNETT: We would make the witnesses available for cross examination.

CHAIRMAN BRISE: All right. Office of Public Counsel?

MR. REHWINKEL: I have three questions, Mr. Chairman.

CHAIRMAN BRISE: Sure.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q Good evening -- afternoon.

A (By Mr. Hallenstein) Good afternoon.

Q To the panel, did you evaluate 2011 CR3 Uprate costs in light of the delay caused for the CR3 delaminations in March and July of 2011?

A (By Mr. Coston) No, our particular scope looks at the project management process that the company has employed for these -- for that project specifically.

Q Okay. So accordingly, I would expect you to say that you also did not make any judgment about whether any delay in the uprate project was due to the CR3 delamination evaluation and the repair or retired decision-making?

A No.

Q So the answer is correct, that the answer is no?

A Correct. Thank you.

Q And finally, I take it from your first answer that such an analysis was not within the scope of your audit?

A That would be correct, yes.

MR. REHWINKEL: Thank you. Thank you, Mr. Chairman. That's all I have.

CHAIRMAN BRISE: All right. Mr. Brew?

MR. BREW: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. BREW:

Q Good afternoon, gentlemen. Mr. Coston and I have talked before, but is it Hallenstein or Hallenstein?

A (By Mr. Hallenstein) It's Hallenstein, but my wife calls me worse.

Q I'm not going to go there at all. This is going to jump around a little bit. In your testimony on page three, line 11, there's the statement that the report describes key project events and contract activities completed during mid 2011 through April, 2012 for the uprate project. Do you see that?

A (By Mr. Coston) If I could have you repeat that line to make sure --

Q Page three of your testimony, lines 11 and 12, the sentence that begins the report describes.

A (By Mr. Coston) Yes, I see that.

Q Okay. So that period that's described in your report, throughout that entire period the unit has been out subject to the most recent containment delamination, is that right?

A (By Mr. Coston) Yes.

Q Okay. Did you include in your study of key project events the status of insurance recovery through NEIL?

A No, we did not. Again, our scope looks at the project management internal controls. And the project management process is a very defined process within the organization. The events that revolve around the delamination issue and the operational viability of the plant would fall outside of that project management scope.

Q They would fall outside the scope of your review. So along the same lines, the strategic decision as to whether or not to attempt to repair the unit also falls out beyond the scope of your review?

A Yes, it would.

Q Okay. Did the scope of your review include how the company was performing planning for the uprate in light of the delays in the decision whether to repair the unit or not?

A Yes. Our review, when we looked at the project management process that the company has in place, a directive has been given by the business unit or the management team that is directing the project's initiative. We look at what the project team was informed, how they were informed, and what the going-forward tasks they were given during this interim period, and we did evaluate that.

We did not evaluate the decision process or the decision process that the business unit made in determining in light of the outage, extended outage.

Q So decisions relating to this -- more simply stated, the decisions relating to their actual decisions fall outside the scope of your review; decisions relating to following their own established process for making decisions is what you reviewed?

A Yes, as well as the project team taking the initiative or what the business unit has directed them to go and get moving on a going-forward basis. We looked at that.

Q All right. And finally, the other issues relating to delay in the decision such as Duke performing an independent study of the repair or retire decision, is that also beyond the scope of your analysis?

A Yes, that would be outside of the scope.

Q If I could refer you to your actual report, page six begins the heading 1.4.2 Crystal River 3 extended power uprate.

A Okay.

Q Now, you describe the changes in the cost estimate of the project from 461 million to 617 million at the bottom of page six, right?

A Yes.

Q Okay. Does your analysis form any conclusion as to the reasonableness of the current cost estimate?

A Our analysis looks at how the company developed the additional cost estimates based on what requirements created that cost, how the company identified it, how the company embedded those issues, as well as the approval process that was necessary for them to be included in the overall project, additional project scope that was identified.

Q But if I were to ask you do you think 617 million is a good number, your answer would be that's beyond the scope of my analysis?

A Correct, that would be outside of the scope.

Q If I could refer you farther on to page 31 of that report. Are you there?

A Yes.

Q On the bottom of page 30 you have a heading Risk

Evaluation Performed. Do you see that?

A Yes.

Q And on 31, there's the second paragraph talks about the other high risk concern is the potential for the containment repair being completed ahead of schedule. Do you see that?

A I do.

Q In the context of -- you're referring here to risk assessments performed by Progress, right?

A By the Progress -- by the Progress project management team, yes.

Q Okay. It's not a risk assessment that you performed, right?

A Correct.

Q Okay. And this risk assessment assumed the repairs of the unit being accomplished over what, a 35-month repair -- repair period?

A Within 2014, I believe, is the time frame they were given, so looking at 2011 now, that sounds roughly accurate, yes.

Q Okay. Based on what you know or do you have any opinion as to whether or not the repair would be realistically achievable any time before the end of 2014?

A We were not looking at making an assessment on what the repair timeline is. This is looking at what the company determines -- was looking at when it was determining what the moving forward schedule -- moving the schedule forward within the EPU project and how that may tie into the current extended power outage repair timeline.

Q   So when they're talking about this element of the risk matrix, the company was only looking at, for planning purposes, whether or not they would finish the uprate before it became a critical path item on the overall outage?

A   Correct. It was a scheduling issue.

Q   Did the company's risk analysis consider at all the risk that the unit not be repaired?

A   Within the project management risk analysis that we looked at, that was not a factor. I'm not saying the company wasn't looking on it as a business decision but within the project management process that was not a particular line item.

Q   So within the context of the scope of the review you did --

A   Correct.

Q   -- that was not considered.

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

CHAIRMAN BRISE: FIPUG?

MR. MOYLE: No question.

CHAIRMAN BRISE: All right. FEA?

LT. COL. FIKE: No questions, Mr. Chairman.

CHAIRMAN BRISE: SACE?

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

CHAIRMAN BRISE: All right. FRF?

MR. LaVIA: No questions, Mr. Chairman.

CHAIRMAN BRISE: Progress?

MR. WALLS: No questions.

CHAIRMAN BRISE: Commissioners?

COMMISSIONER BALBIS: Well, fine, I'll ask a question, then. I do have one question for the Staff that I was going to pass on, but I'll ask it. In Section 2.2.4 you discuss PEF's Levy risk review meetings for COLA and near-term non-COLA work. If I can get a little more clarification. You discuss that they hold these monthly meetings and then you jump, on page 17, that to mitigate near-term risk the LNP project management extended the project suspension, et cetera, et cetera. Did you audit the decision-making process in general, or for that specific decision?

WITNESS HALLENSTEIN: The answer is yes, we audited the process in general, the decision-making process in general, not for that specific decision.

COMMISSIONER BALBIS: Were there any other decisions made that you're aware of as a result of those monthly risk assessment meetings?

WITNESS COSTON: Yeah, the risk assessment process that the Levy project management team uses is with these monthly meetings they update the risk registry or look at and they identify what may be a new risk based on where they are at that point in time in the process, whether it be on an issue with the COLA or non-COLA issue.

They go in there, and based on our understanding and our discussions with the team, is that they vet out whether that is an actual risk, and, if so, then they include it onto the process. And then we followed the process on how they choose to identify and mitigate or create contingencies for that risk.

When we look at the risk matrix, we look at how the company has assigned that risk to a particular individual within the company or in the project team and how they are working to resolve that to their expectations and their process standards to feel comfortable that they can move forward with that, move forward with the project based on than risk rating.

COMMISSIONER BALBIS: Okay, then a real quick question on the last page of your report, Appendix B, you have the non-COLA risk matrix, which again you said they're updated in the monthly risk meetings. And just so I understand it -- and I know that it's confidential, but the bottom table, the total risk exposure, does that mean that if all of those risk factors occur that that is the dollar impact, total dollar impact?

WITNESS COSTON: Yes, the company assigns, based when they do the risk assessments and look at these risk meetings on a monthly level, they assign what they believe would be a cost estimate or a cost factor to each of those risks, if the risk was triggered. And these are the amounts that the company has internally assigned to those risks, if each of them were triggered in a way and they had to respond to them.

COMMISSIONER BALBIS: Okay. And then any risk mitigation strategy would be to minimize that total dollar amount cost?

WITNESS COSTON: Correct. Minimize or reduce the ability of that risk to actually be triggered.

COMMISSIONER BALBIS: But that total risk exposure is the maximum amount? I mean, any mitigation would be less than that, correct?

WITNESS COSTON: Correct, based on their estimates.

COMMISSIONER BALBIS: Okay, that's all I have. Thank you.

CHAIRMAN BRISE: Thank you, Commissioner Balbis. Redirect?

MS. BENNETT: No redirect. We would ask that if it's appropriate Exhibit Number 25 be entered into the record.

CHAIRMAN BRISE: Okay, at this time we'll enter Exhibit Number 25 into the record, seeing no objections.

(Exhibit 25 admitted in evidence.)

MS. BENNETT: And Mr. Chairman, may these witnesses be excused?

CHAIRMAN BRISE: Sure. Gentlemen, you may be excused. Thank you.

MS. BENNETT: Thank you for taking them out of order.

CHAIRMAN BRISE: Okay, at this time we'll go back to Progress.

MR. WALLS: Progress would call Mr. Franke, Jon Franke. Before Mr. Franke proceeds, just a point of clarification, I believe, with OPC, and to put on the record here is that it's my understanding that Mr. Jacobs is not going to take the stand and we're going to enter his direct testimony, so we would be entering Mr. Franke's rebuttal testimony at this time, as well.

MR. REHWINKEL: That is correct.

CHAIRMAN BRISE: Okay.

Thereupon,

JON FRANKE

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

DIRECT EXAMINATION

BY MR. WALLS:

Q Mr. Franke, will you please introduce yourself to the Commission and provide your business address.

A Yes, my name is John Franke. My business address is 15760 West Power Line Street, Crystal River, Florida, 34428.

Q And have you already been sworn as a witness?

A Yes, I have.

Q Who did you work for and what was your position at the time of your prefiled direct testimony and rebuttal testimony in this proceeding?

A At the time of my testimony I was the Site Vice-President for Crystal River 3 Nuclear Plant working for Progress Energy Florida.

Q Has your title changed since your merger with Duke Energy?

A No, it has not.

Q So have your job responsibilities with respect to the Crystal River Unit 3 uprate project stayed the same or have they changed since the merger?

A They have remained the same.

Q And have you prefiled direct testimony on March 1, 2012 and April 30, 2012 and rebuttal testimony on July 9th, 2012 in this proceeding?

A Yes, I have.

Q And do you have a copy of your testimony with you?

A I do.

Q Okay. Do you have any changes to make to your testimony?

A I have none.

Q Okay. And so if I asked you the same questions asked in your prefiled testimony today, would you give the same answers?

A I would provide the same responses.

MR. WALLS: We request that the March 1, 2012, April 30, 2012 and July 9, 2012 rebuttal testimony be introduced or moved into evidence as if it was read in the record today.

CHAIRMAN BRISE: Okay, we will move into the record Mr. Franke's direct and rebuttal testimony into the record as though read.

(Whereupon, the direct and rebuttal testimony was inserted.)

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA, INC.

FPSC DOCKET NO. 120009-EI

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 more than 400 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 22 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. 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 2011 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 CR3 Uprate project in 2011.

I will also provide testimony regarding PEF's 2011 project management, contracting, and oversight controls policies and procedures that are designed to manage project costs and schedule and explain why they are reasonable and prudent.

Q. ***Do you have any exhibits to your testimony?***

A. No. I am however sponsoring Schedules T-6A, T-6B, T-7, T-7A and T-7B and co-sponsoring the cost portions of Schedules T-4, T-4A, and T-6 and Appendix D of the Nuclear Filing Requirements ("NFRs") for the 2011 CR3 Uprate project costs, which are included as part of Exhibit No. __(WG-2) to Will Garrett's testimony. Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the 2011 period. Schedules T-4A reflect CCRC recoverable O&M expenditure variance explanations for the 2011 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 2011. Schedules T-7 are lists of the contracts executed in excess of $1.0 million for 2011. Schedules T-7A reflect details pertaining to the contracts executed in excess of $1.0 million for 2011. Schedules T-7B reflect contracts executed in excess of $250,000, but less than $1.0 million for 2011. 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 2011 actual CR3 Uprate project costs. PEF incurred CR3 Uprate project costs in 2011 in preparation for Phase 3, the EPU phase of the project. The majority of these costs were incurred for necessary engineering analyses for the engineering change packages for the Phase 3 work, for long lead equipment payments, and for related licensing work on the Company's EPU License Amendment Request ("LAR") to the NRC, and associated project management work. PEF took appropriate steps under its project management, contracting, and oversight policies and procedures to ensure that the 2011 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 2011 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 an additional 12 MWe of nuclear energy generation. The second phase of the work, primarily

Balance of Plant ("BOP") work, was performed during the 2009 CR3 16R refueling outage and was successfully installed. When CR3 returns to service the BOP phase work will yield an additional 4 MWe nuclear energy production and support the final EPU phase. PEF is currently performing the engineering and design analyses, licensing, and material procurement necessary to complete the third and final phase of the CR3 Uprate, the EPU phase. 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.

IV. ACTUAL COSTS INCURRED IN 2011 FOR THE CR3 UPRATE PROJECT.

Q. What costs did PEF incur for the CR3 Uprate project in 2011?

A. PEF incurred construction costs related to the last phase of the CR3 Uprate project in 2011. The total capital expenditures for 2011, gross of joint owner billing and exclusive of carrying cost, were $49.0 million. These costs cover (1) license application, (2) project management, (3) permitting, (4) on-site construction facilities, (5) power block engineering, procurement and related construction, and (6) non-power block engineering, procurement, and related construction. Schedule T-6 in Exhibit No. ___ (WG-2) 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 $2.8 million. These costs were incurred for activities related to the finalizing and submittal of the EPU LAR to the NRC.

PEF submitted the EPU LAR to the NRC on June 15, 2011. The next step in the NRC review process is referred to as Acceptance Review. During the Acceptance Review process, the NRC technical branches reviewed the submittal to confirm that adequate information was available to complete their review without passing judgment on approval. The NRC completed its Acceptance Review on November 21, 2011. Throughout 2011, PEF worked with the NRC to address Requests for Additional Information ("RAIs") to support NRC submittal acceptance. Feedback from the NRC staff and management during this phase of the review was very positive. PEF is confident that the NRC will approve the EPU LAR in time to support restart from the current extended outage.

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

A. The Company incurred Project Management costs of $3.8 million. The Company's Project Management costs include the following Project Management activities for the CR3 Uprate project in 2011:

(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 and LAR work.

Each activity was conducted under the Company's project management and oversight control policies and procedures I will discuss in more detail below.

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

A. Permitting costs incurred were $19,650 for permitting needs for 2011. These costs were incurred for revisions to the EPU LAR environmental report.

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 $37,791. These costs were incurred for erection of tent storage for components and tools, temporary lavatory facilities, and rental costs for trailers housing CR3 Uprate project personnel.

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 $42.4 million for Power Block Engineering, Procurement, and related construction cost items. The majority of the costs incurred in this category in 2011 were associated with the preparation of design changes for the Phase 3 scope and for procurement of long lead time equipment.

Engineering developed the Engineering Change ("EC") packages for the EPU Phase 3 to various levels of design completion in 2011. Overall to date design completion is estimated at 70 percent. Engineering did not reach 100 percent completion in 2011 as previously estimated because of a slow down and reprioritization of work based on the containment repair schedule impacts on EPU installation schedule and plant in-service dates. Phase 3 ECs completed and approved by management in 2011 included:

- EC 68886 – Add Feedwater Heat Exchangers ("FWHE") 1 (De-aerator Bypass Line)
- EC 79352 – High Pressure Injection Modification
- EC 74873 – Safety Related Motor Operated Valves Specification
- EC 73351 – Feedwater Booster Pump & Feedwater Valve-14/15 Change Out Specification
- EC 73932 – Low Pressure Injection ("LPI") Crosstie Installation Specification
- EC 73907 – Atmospheric Dump Valve Specification
- EC 78022 – Main Feedwater Pump Specification

- EC 80348 – FWHE 3A/B Feedwater Heater Replacement Specification
- EC 77337 – Inadequate Core Cooling Mitigation System ("ICCMS") Specification
- EC 80137 – ICCMS Core Exit Thermocouple Conduit & Cable Routing
- EC 73794 – Low Pressure Turbine ("LPT") Implementation
- EC 74980 – Replace (2) LPTs
- EC 73917 – Replace FWHE 2A/2B
- EC 74526 – Replace Condensate Pump/Motor/Head/Valves/Recirculation ("CDP") 1A/1B
- EC 74980 – Replace High Pressure Turbine ("HPT")
- EC 75004 – Reconcile/Adjust Replacement Once Through Steam Generator ("ROTSG") (ROTSG Orifice Plate)
- EC 75659 – Add Make Up Tank ("MUT") Injection Line Bypass 1
- EC 76095 – Modify Safety Related Main Steam ("SR MS") Supports/Restraints
- EC76339 – Heavy Haul Path Evaluation
- EC 76344 – Add Vibration (Pipe Vibration Monitoring System)
- EC 77901 – Modify Turbine Building for FWHE 2A/2B Removal

In addition, contract payments were made for major components including the Feedwater Heaters 3A/3B and 2A/2B, the Analog Actuation and Control System, Atmospheric Dump Control Valves, Condensate Motors, Booster Pumps, and the In-Core Detector Assemblies. These 2011 Power Block Engineering and Procurement costs were necessary for the implementation of the CR3 Uprate work.

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 $40,457. The majority of the costs incurred in this category in 2011 were associated with transport, storage, and maintenance of the Point of Discharge ("POD") helper cooling tower parts. As a result of pending and emerging environmental regulations that could impact the fossil units at Crystal River, and due to the schedule shift from the extended 16R outage, the POD portion of the EPU project remained on hold until such time that the impact of these changes can be properly assessed and recommendations presented to senior management.

Q. Please explain how the approval of the Motion for Deferral in Docket No. 110009-EI in the 2011 NCRC proceeding affects your testimony regarding true-up of the 2011 CR3 Uprate costs.

A. On August 10, 2011, the Commission approved PEF's Motion for Deferral of 2011 and 2012 projected CR3 Uprate construction expenditures and deferred review of PEF's 2011 costs to this docket. As a result of this ruling, PEF filed revised NFR AE schedules – attached to Mr. Thomas G. Foster's revised August 12, 2011, testimony as Exhibit No. ___(TGF-4). PEF had previously filed NFR AE Schedules on May 2, 2011 reflecting its best available estimate at the time for actual/estimated 2011 CR3 Uprate costs. As noted in my May 2, 2011 testimony in Docket No. 110009-EI, these schedules were prepared prior to the March 14, 2011 delamination at CR3.

In preparing my current testimony the variances described below are based on PEF's actual expenditures for 2011 compared to the AE Schedules attached to Mr. Foster's May 2, 2011 testimony, which reflected actual/estimated 2011 CR3 Uprate costs prior to the March 2011 delamination.

Q. How did actual capital expenditures for January 2011 through December 2011 compare to PEF's actual/estimated costs for 2011?

A. PEF's actual capital expenditures for the CR3 Uprate project in 2011 were lower than PEF's actual/estimated costs for 2011 by $45.2 million. This variance is primarily due to the extended outage at CR3 and the Company's decision to postpone CR3 Uprate project construction work. I will explain the reasons for the major (more than $1.0 million) variances below:

License Application:

The 2011 License Application capital expenditures on the T-6 Schedule were $2.8 million with a total estimate of $1.2 million, resulting in a variance of $1.6 million. This variance is primarily due to AREVA engineering support costs associated with PEF responses to NRC RAIs for the EPU LAR being budgeted in engineering but invoiced to licensing.

Project Management:

Project Management capital expenditures were $3.8 million. The original estimate was $8.5 million, resulting in a variance of ($4.7 million). This variance is due to reallocation of project management resources based on the deferral of construction activities for Phase 3 of the CR3 Uprate project because of the extended CR3 outage.

Power Block Engineering, Procurement and related construction costs:

Power Block Engineering, Procurement and related construction costs capital expenditures were $42.3 million for 2011. The original estimate was $76.5 million, resulting in a variance of ($34.2 million). This variance is due to the Company's decision to defer construction activities on the CR3 Uprate project because of the extended CR3 outage and to align such activities with the containment repair estimated schedule. Approximately 50 percent of the variance to budget is attributed to deferral of equipment/material payments; approximately 25 percent of the variance to budget is attributed to under-runs in Engineering, Project Management, Health Physics, and Administrative support; and approximately 25 percent of the variance to budget is attributed to deferring 2011 contingency funds.

Non-Power Block Engineering, Procurement, and related construction cost items:

Non-Power Block capital expenditures were $40,457. The original estimate was $7.7 million, resulting in a variance of (approximated $7.7 million). This variance is driven by deferral of the POD/Cooling Tower construction work, which is a result of pending and emerging environmental regulations that could impact the fossil units at Crystal

River, and the schedule shift from the extended 16R outage. The POD construction portion of the EPU project remained on hold in 2011 until such time that the impact of these changes can be properly assessed and recommendations presented to senior management.

Q. Did PEF incur O&M costs in 2011 for the CR3 Uprate project?

A. Yes. PEF incurred necessary O&M costs to support the CR3 Uprate project work in 2011. These O&M costs are identified and included in Schedule T-4 in Exhibit No. ___ (WG-2) to Mr. Garrett's testimony.

Q. How did actual O&M expenditures for January 2011 through December 2011 compare with PEF's actual/estimated O&M expenditures for 2011?

A. Schedule T-4A, Line 15, on Exhibit No. ___ (WG-2) to Mr. Garrett's testimony shows that total O&M costs were $0.5 million or $18,000 less than estimated. Schedule T-4A shows the variance explanations for the O&M costs categories. There were no major cost variances.

Q. Were all of PEF's 2011 CR3 Uprate project costs reasonably and prudently incurred?

A. Yes. PEF reasonably and prudently incurred the 2011 CR3 Uprate project costs. These costs were necessary for the continuation of work for the EPU phase. All of PEF's 2011 CR3 Uprate project costs were reasonably and prudently incurred.

V. 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.

VI. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. What project management and cost control oversight policies and procedures does PEF utilize for its capital projects?

A. The Company has several project management and cost oversight control policies and procedures that it employs for all of its capital projects on a fleet-wide basis. 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 in previous years NCRC proceedings. PEF continually reviews these policies, procedures, and controls and issues new procedures as necessary based on changing business conditions, organizational changes, and project schedules.

Q. Were the CR3 Uprate project Management and Cost Control Oversight policies and procedures the same in 2011 as they were for 2009 and 2010?

A. Yes, they are essentially the same. There have been no substantial changes to the project management and cost oversight controls since the process was described most recently in my direct testimony in Docket No. 110009-EI.

Q. Can you please provide an overview of the Company's 2011 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, which provides guidance regarding evaluation and funding authorization for major projects. 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. The Company also utilizes several specific project management and cost oversight Nuclear Generation Group ("NGG") and Corporate procedures.

Q. Have PEF's project management and cost oversight controls substantially changed between 2010 and 2011?

A. No, however the Company continuously reviews and revises policies and procedures based on changing conditions, lessons learned, and best industry practices and makes changes as necessary and appropriate. PEF revised more than 75 of its policies and procedures in 2011, and created 13 new policies and procedures since April of 2011. In addition, in late first quarter of 2011, Project Management Controls implemented three revised cost reports that have provided project management a more detailed view of project cost information. The reports include a Variance Report by Project and Work Breakdown Structure ("WBS"), a Contract Summary Report, and a Labor Report.

Q. What policies or procedures are in place to assess and mitigate project risks?

A. 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. In addition monthly risk management meetings are held and risk management reports are generated that are the basis for the continuous updates to the overall CR3 Uprate Risk Register.

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 policies 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.

In addition, CR3 EPU contractor oversight and management, including external vendors, has been a continuous project focus in an effort to improve schedule adherence, vendor deliverables, and process efficiencies. Policies and procedures for contractors are revised and updated on an ongoing basis to include lessons learned. For 2011, changes included (1) establishment and implementation of new EPU Organization and EPU Engineering Charts; (2) the addition of scheduling resources; and (3) establishing quarterly management review meetings to discuss scope and resources for vendors.

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. Quality assurance reviews and audits of external vendors are also conducted.

On March 23, 2011, the Florida Nuclear Plant Cost Recovery audit was completed and issued. This audit involved testing a sample of invoices for compliance with the Nuclear Plant Cost Recovery Rule related to the CR3 Uprate project. The overall audit was effective and no specific observations or recommendations were identified or resulted from the audit.

In addition, the Nuclear Oversight Organization ("NOS") conducted an assessment of the Nuclear Upgrades Section (across the NGG fleet) during the period April 5, 2011 through May 26, 2011. This was a multi-site assessment which included the EPU project. This assessment has been completed and overall assessment was needs improvement, but generally solid performance. The review team noted two findings for the CR3 Uprate project. These findings related to adverse condition and quality assurance documentation and reporting. These finding have been resolved and closed.

Several contractor and quality assurance evaluations were also performed in 2011 including at the Scientech facility and at the Siemens regional and international facilities and a NUPIC Joint Utility Audit of Enertech – Curtiss Wright Flow Control Corporation at its California facility. The results of the Siemens facilities reviews were satisfactory with no open items. The Scientech audit concluded Scientech had an effective quality assurance program and identified minor variant conditions which were corrected through the vendor's internal processes. The NUPIC audit concluded Enertech had an effective quality assurance program and issued three finding that were administrative in nature.

Q. Has the Commission previously determined that these CR3 Uprate 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 Order No. PSC-11-0547-FOF-EI, issued Nov. 23, 2011, the Commission determined that the CR3 Uprate project management and cost oversight controls were reasonable and prudent for 2008, 2009, and 2010 respectively. As I discussed above, the Company's 2011 CR3 Uprate project management and cost oversight controls are substantially the same as they were in 2008, 2009, and 2010.

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. In addition, as I discussed, PEF's policies and procedures are reviewed and revised on a continuous basis as necessary and have been approved as reasonable and prudent by the Commission. 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, INC.

FPSC DOCKET NO. 120009-EI

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 15760 W. Powerline St., Crystal River, FL 34442.

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 job responsibilities?

A. As Vice President I am responsible for the safe operation of the nuclear generating station. The Plant General Manager, Site Support Services and Training sections report to me. Additionally, I have responsibilities in oversight of major project activities at the station. Through my management team I have more than 400 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 25 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 U.S. 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. In April 2009, I was promoted to my current position.

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 replacement and modification of equipment at the Crystal River 3 ("CR3") nuclear power plant in connection with Phase 3, the Extended Power Uprate ("EPU") for the CR3 Uprate project ("CR3 Uprate"). My testimony supports the Company's actual/estimated and projected costs for 2012 and 2013, respectively, and explains why these CR3 Uprate costs are reasonable. Finally, my testimony explains why the CR3 Uprate project is feasible, pursuant to Rule 25-6.0423(5)(c)5, Florida Administrative Code ("F.A.C.").

Q. Have you previously filed testimony in this docket?

A. Yes, I filed testimony on March 1, 2012 in support of the actual costs incurred in 2011 for the CR3 Uprate project.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (JF-1), NRC acceptance review letter for the EPU License Amendment Request ("LAR") for the CR 3 Uprate project;
- Exhibit No. ___ (JF-2), Integrated Project Plan ("IPP") Interim Approval 3A (Short Form) for the CR3 Uprate project;

- Exhibit No. ___ (JF-3), a description of the engineering scope changes for the EPU phase work and a schedule identifying the phased work scope to successfully implement the power uprate for the CR3 Uprate project;
- Exhibit No. ___ (JF-4), the Company's updated cumulative present value revenue requirements ("CPVRR") analysis for the CR3 Uprate project; and
- Exhibit No. ___ (JF-5), February 2012 EPU Options Update.

Also, I am co-sponsoring portions of Schedules AE-4, AE-4A, AE-6.3 and sponsoring Schedules AE-6A.3 through AE-7B and Appendix B of the Nuclear Filing Requirements ("NFRs"), included as part of Exhibit No. __ (TGF-4) to Mr. Thomas G. Foster's testimony. I will also be co-sponsoring portions of Schedules P-4 and P-6.3; sponsoring Schedules P-6A.3 through P-7B of Exhibit No. ___ (TGF-5) to Mr. Foster's testimony; co-sponsoring Schedules TOR-4 and TOR-6; and sponsoring TOR-6A and TOR-7 of Exhibit No. _____(TGF-6) 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 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.
- Appendix B reflects the reconciliation of the beginning construction work in progress ("CWIP") balance for those assets placed into rate base that are not yet in service as detailed on AE-2.3.
- Schedule P-4 reflects CCRC recoverable O&M expenditures for the 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-6 reflects actual to date and projected annual expenditures for preconstruction and construction costs for the duration of the project.
- Schedule TOR-6A reflects descriptions of the major tasks.
- Schedule TOR-7 reflects initial project milestones in terms of costs, budget levels, initiation dates, and completion dates.

These exhibits, schedules, and appendices are true and accurate.

Q. Please summarize your testimony.

A. PEF is committed to completion of the EPU phase of the CR3 Uprate project for the benefit of the Company and its customers. The current project plan is to complete the EPU phase during the current, extended CR3 16R outage. The Company performed a quantitative and qualitative feasibility analysis of completing the EPU phase of the CR3 Uprate project. Completion of the EPU phase is feasible from a technical and regulatory perspective. Completion of the EPU phase of the CR3 Uprate project is also economically feasible. The EPU phase of the CR3 Uprate project will provide PEF and its customers substantial operational and carbon cost compliance savings. PEF's customers will benefit from additional fuel savings and potential carbon cost savings from completion of the EPU phase of the CR3 Uprate project when CR3 returns to commercial service.

The Company is providing the Florida Public Service Commission ("PSC" or the "Commission") with its 2012 actual/estimated and 2013 projected CR3 Uprate project costs with this filing in accordance with the Commission's nuclear cost recovery rule. The 2012 actual/estimated and 2013 projected CR3 Uprate project costs reflect the current plan to implement the EPU phase of the CR3 Uprate project in the current, extended CR3 re-fueling outage and reflect the best available information the Company currently has with respect to the CR3 Uprate project costs. These costs are reasonable, subject to true-up under the Commission's rule next year.

The CR3 Uprate project is still in the best interests of PEF and its customers. It provides PEF and its customers additional carbon-free, fuel savings from clean nuclear energy generation while improving the Company's fuel diversity and reducing the Company's reliance on fossil fuels to generate electricity for PEF's customers. The current, 2012 and 2013 CR3 Uprate project costs to achieve these benefits are reasonable. For this reason, the Company requests that the Commission determine that PEF is entitled to recover its prudent and reasonable CR3 Uprate project costs.

III. 2012 ACTUAL/ESTIMATED AND 2013 PROJECTED PERIOD COSTS.

A. <u>CR3 Uprate Project Status.</u>

Q. Does the Company plan to complete the CR3 Uprate project?

A. Yes, PEF currently plans to repair the CR3 containment building and complete the EPU phase of the CR3 Uprate project.

Q. What is the current CR3 Uprate project schedule?

A. PEF plans to complete the EPU phase of the CR3 Uprate project during the current, extended CR3 16R re-fueling outage. Under this schedule, PEF plans to start EPU construction in June 2013 and complete implementation of the EPU in June 2014 with an expected return of CR3 to commercial service in November 2014 and the EPU expected in service in December 2014. The Company's actual/estimated 2012 and projected 2013 CR3 Uprate costs are based on the Company's current schedule to complete the EPU phase during the CR3 16R extended re-fueling outage.

Q. Is the Company's current schedule consistent with the Company's plan last year to complete the CR3 Uprate project?

A. Yes. In early 2011, the Company planned to complete the EPU phase in the next CR3 re-fueling outage. That next CR3 re-fueling outage, R17, was planned for Spring 2013 with the expected return of CR3 to commercial service in 2011 upon completion of the repairs to the CR3 containment building. The Company had re-scheduled the CR3 Uprate project work in late 2010 and early 2011 to meet this project plan. Accordingly, the Company already planned to perform EPU phase construction work in 2013 when the second delamination occurred in March 2011. As a result of that event, the EPU project management team evaluated the EPU phase work and schedule to provide the Company the flexibility to continue to meet this EPU implementation schedule if that proved to be the prudent course of action. The extended CR3 R16 re-fueling outage further provided the Company the opportunity to gain schedule and cost efficiencies because the EPU phase work in 2013 no longer had to be completed during the limited timeframe of a typical re-fueling outage, but instead could be implemented over the course of the year. The current EPU phase work schedule and costs reflect these efficiencies.

Q. Is the Company's current EPU phase schedule consistent with the Company's current repair plan for the CR3 containment building?

A. Yes. The Company's current CR3 Uprate project schedule aligns completion of the EPU phase of the CR3 Uprate project with the current plan to repair the CR3 containment building. The Company currently plans to repair the CR3 containment building and return CR3 to commercial service in November 2014.

Q. Has the Company commenced repairs to the CR3 containment building?

A. No, not at this time. Last year, based on an initial review and analysis, the Company determined that the CR3 containment building should be repaired, selected a repair option, and developed a preliminary cost estimate for the repair. The Company moved forward systematically with additional, detailed engineering analyses and designs to develop a final repair plan. The engineering design process of the final CR3 containment building repair plan is still under way. The Company expects to complete that process later this year. A number of factors might affect the current CR3 containment building repair plan, the estimated November 2014 commercial in-service date, or the estimated repair costs, including the ultimate work scope, engineering designs, testing, weather, and regulatory reviews, among other potential developments. Currently, however, the Company intends to repair the CR3 containment building and complete the EPU phase of the CR3 Uprate project.

Q. Why is the Company proceeding with work on the EPU phase of the Uprate project when the Company has not yet commenced repairs of the CR3 containment building?

A. Completion of the CR3 Uprate project during the current extended, CR3 re-fueling outage is in the best interests of PEF and its customers. Completion of the EPU phase of the CR3 Uprate project in the current CR3 re-fueling outage provides fuel savings benefits to PEF's customers. To obtain these benefits the Company must continue with EPU phase work in 2012 and 2013 to complete the CR3 Uprate project when CR3 returns to commercial service under the current plan to repair the CR3 containment building. As I explained above, the Company currently plans to repair CR3, absent some unforeseen risk, design, engineering, or licensing impediment to repairing the CR3 containment building, and return CR3 to commercial service in November 2014.

The Company has, however, developed an alternative plan to complete the EPU phase of the CR3 Uprate project in the next planned CR3 re-fueling outage, in the event that the Company's current plan to repair the CR3 containment building is delayed or unforeseen risks or other impediments require the Company to complete the EPU phase in the CR3 R17 re-fueling outage. As I explain later, the Company evaluated this alternative project plan in its economic feasibility analysis and determined that it is cost-effective for the Company and its customers. Current project costs in 2012 are virtually identical whether the Company performs the EPU phase work in the current outage or in the next planned re-fueling outage. As a result, PEF has maximum flexibility this year to continue with the EPU phase without adding additional work scope or cost prior to the CR3 repair plan being finalized this year as currently expected.

B. <u>EPU Phase Work in 2012 and 2013.</u>

Q. What does the Company's EPU phase work plan include in 2012 and 2013?

A. The EPU phase work plan includes: (1) engineering design work for the EPU phase; (2) engineering and licensing support work for the EPU LAR review by the NRC; and (3) payments for Long Lead time Equipment ("LLE") items for the EPU phase of the CR3 Uprate project. The EPU phase work plan further includes project management of these EPU phase work activities in 2012 and 2013.

Schedule AE-6.3 of Mr. Foster's Exhibit No. __ (TGF-4) contains the total 2012 actual/estimated construction costs for these EPU phase work activities in the following categories: (1) License Application costs estimated at $2.8 million; (2) Power Block Engineering, Procurement, and related construction costs estimated at $45.4 million; (3) Non-Power Block Engineering, Procurement and related construction costs estimated to be $0.2 million; and (4) Project Management costs estimated at $3.2 million.

Schedule P-6.3 of Mr. Foster's Exhibit No. __ (TGF-5) reflects the 2013 projected construction costs for these EPU phase work activities in the following categories: (1) License Application costs estimated at $2.4 million; (2) Power Block Engineering, Procurement, and related construction costs estimated at $101.5 million; (3) Non-Power Block Engineering, Procurement and related construction costs estimated at $0.1 million; (4) On-Site Construction Facilities costs estimated at approximately $0.6 million; and (5) Project Management costs estimated to be $5.7 million.

Q. How did PEF estimate the 2012 and 2013 License Application costs for the CR3 Uprate project?

A. PEF developed the License Application cost estimates using utility industry standard cost estimation practices, with the best available information at this time, including its engineering judgment and experience, and the incorporation of "lessons learned" on its EPU LAR and other utility LARs, in its estimates of the cost to work with the NRC during the EPU LAR review process at the NRC. The License Application costs for 2012 and 2013 reasonably reflect the cost of the work necessary to obtain NRC approval of the EPU LAR.

Q. What is the status of the EPU LAR?

A. PEF submitted the EPU LAR to the NRC on June 15, 2011. The next step in the NRC review process is referred to as Acceptance Review. During the Acceptance Review process, the NRC technical branches reviewed the submittal to confirm that adequate information was available to complete their review of the EPU LAR. The NRC completed its Acceptance Review on November 21, 2011 and determined that the EPU LAR satisfied the Acceptance Review. <u>See</u> the NRC acceptance review letter for the EPU LAR for the CR 3 Uprate project attached as Exhibit No. ___ (JF-1) to my testimony.

The NRC is now reviewing the EPU LAR for LAR approval. For 2012 and 2013, the Company's License Application costs include the work necessary to support the NRC's review of the EPU LAR. The NRC has indicated that up to eighteen (18) technical branches will be actively involved in the review. The NRC approval review process involves Requests for Additional Information ("RAIs") from the NRC technical branches to obtain information necessary for the NRC review and approval of the EPU LAR. PEF is working with the NRC to address RAIs. To date, most of these branches have completed their review sufficiently to request some level of additional information from PEF and PEF has responded to more than half of the branches. Remaining RAIs from the NRC branches cover some of the more technically complex areas of the review. PEF has scheduled a pre-review workshop with the NRC to discuss some of the distinctive features of the CR3 plant, its safety analyses, and EPU impacts. PEF expects to work on the responses to the remaining RAIs from the NRC branches throughout 2012 and into 2013. PEF's Licensing Application costs for 2012 and 2013 reflect the Company's engineering and licensing work to respond to the NRC RAIs for the NRC technical branch review of the EPU LAR.

Q. Does PEF expect the NRC to approve the EPU LAR for the CR3 Uprate?

A. Yes. Feedback from NRC staff and management during the NRC review of the EPU LAR is very positive. PEF is confident that the NRC will approve the EPU LAR in time to support re-start of CR3 from the current extended 16R outage as currently planned. Based on the feedback from NRC with respect to the NRC review schedule, PEF believes the NRC will approve the EPU LAR in 2013.

Q. Please describe the Power Block Engineering, Procurement and related construction cost activities for the CR3 Uprate project in 2012 and 2013.

A. The Power Block Engineering, Procurement, and related construction activities for the CR3 Uprate project include continued engineering design work to reach an optimal design completion percentage in time for implementation of the engineering change ("EC") packages for the EPU phase work and continued progress payments based on pre-existing contractual commitments for the LLE necessary for the EPU phase of the CR3 Uprate project.

The EC packages contain the detailed engineering design instructions for the EPU modifications for implementation or installation by the construction contractor for the EPU phase work. The EPU EC packages are approximately 70 percent complete. The remaining work to complete the EC packages for the EPU modifications will be completed in 2012 and 2013. PEF also expects to award the EPU phase construction contract early in 2013 under the current EPU phase schedule. Under that schedule, in 2013 PEF will begin to mobilize construction resources, perform constructability reviews, receive equipment and materials, begin pre-fabrication activities, and continue to perform vendor oversight for the EPU phase work.

PEF will continue to make necessary progress payments on the LLE necessary for the power uprate in 2012 and 2013. Last year, PEF reviewed each contract and change order for EPU phase work and no contract or change order was executed without senior management or project management approval. Approval for new and continued payments on contracts and change orders was based on the determination that the contract or change order was reasonable and necessary to complete the EPU phase work during the current CR3 outage. PEF accordingly continued payments on the critical path LLE items to implement the EPU phase in the current extended CR3 R16 re-fueling outage. Most of these LLE progress payments for 2012 and 2013 reflect pre-existing contractual commitments. Deferral of these payments cannot be accomplished without cancellation or suspension of contracts, which would result in penalties and an uncertain future regarding LLE contract renewals to meet the current EPU phase work schedule. As a result, PEF must continue with LLE progress payments in 2012 and 2013 to complete the EPU phase work during the current extended CR3 R16 re-fueling outage.

Q. Are the Power Block Engineering, Procurement and related construction costs in 2012 and 2013 reasonable?

A. Yes. As I explained, this work scope is necessary to implement the EPU phase of the CR3 Uprate project and achieve the power uprate when CR3 is returned to service under the current Company plan to repair CR3 and return it to commercial service by November 2014. PEF estimated its 2012 and projected its 2013 power block engineering, procurement, and related construction item costs using actual contract figures and project schedule milestones under its current EPU phase work plan and schedule. Actual contractual payment amounts and payment schedule terms are used for the cost estimates and projections and, therefore, the 2012 and 2013 power block engineering, procurement, and related construction item cost projections are reasonable.

Q. Please describe the Non-Power Block Engineering, Procurement and related construction cost activities for the CR3 Uprate project in 2012 and 2013.

A. These activities are for the Point of Discharge ("POD") cooling tower for the CR3 Uprate project. Construction of an additional cooling tower is necessary to mitigate the additional heat generated at CR3 power uprate conditions in the site cooling water discharge canal. The additional cooling tower maintains the cooling water temperature below the permitted maximum temperature at the point of return to the Gulf of Mexico.

The work necessary to permit, design, engineer, and procure and manufacture equipment and material for the additional cooling tower was placed on hold as a result of the extended CR3 outage. The POD work was suspended to provide PEF time to evaluate the need for this work under new and evolving environmental requirements affecting the Company's generation resource options and plans. These environmental regulations may impact operation of the fossil units at Crystal River, and therefore, impact the need for the additional cooling tower to mitigate the additional heat generated by the CR3 power uprate. The extended CR3 outage provides additional time for the Company to evaluate these environmental regulations, some which have only been issued this year. Under the current schedule for the EPU phase work, PEF does not need to commence the POD construction work until April 2014 in order to complete the POD work by April 2015 prior to the first summer of CR3 operation at power uprate conditions. As a result, PEF has additional time to evaluate the evolving environmental regulatory requirements and their impact on the Company's generation operations before commencing with POD construction work for the EPU phase of the CR3 Uprate project.

The cost estimates for the POD work in 2012 and 2013 are for reasonable storage costs for equipment associated with the POD cooling tower. PEF estimates that it will incur approximately $0.2 million and $0.1 million in 2012 and 2013 respectively, for these non-power block engineering, procurement and related construction activities, as reflected in the NFR schedules attached to Mr. Foster's testimony.

Q. What On-Site Construction Facilities work will be done in 2012 and 2013 for the CR3 Uprate project?

A. These are primarily 2013 costs to install temporary equipment storage and personnel staging facilities for the additional construction personnel in preparation for the EPU phase construction work. PEF developed these on-site construction facilities cost estimates on a reasonable engineering basis, using the best available information and PEF's experience with other construction projects, including completion of phase two of the CR3 Uprate project, consistent with utility industry and PEF practice. These costs are therefore reasonable.

Q. Can you explain the Project Management work in 2012 and 2013 for the CR3 Uprate project?

A. Yes. PEF will continue to incur costs to manage the CR3 Uprate project through the successful completion of the EPU phase of the project. Project management costs, accordingly, are on-going as we continue to prepare for the EPU phase work under the current EPU phase work plan and schedule. PEF's project management costs include the activities conducted pursuant to our project management and cost control oversight policies and procedures necessary to support, supervise, and manage the EPU phase of the CR3 Uprate project. These project management and cost control policies and procedures were generally described in my March 1, 2012 testimony, and in prior testimony in prior nuclear cost recovery clause proceedings.

As I have explained before, consistent with these project management and cost control policies and procedures, the Company's project management work consists of : (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 the CR3 Uprate licensing work. These activities are necessary to ensure that the CR3 Uprate project work scope, schedule, and cost to implement the work scope achieve the CR3 Uprate project objectives.

Consistent with our cost estimation methodologies and past practice on the CR3 Uprate project, the CR3 Uprate project management cost estimates for 2012 and 2013 were developed using the best available information to the Company on the scope of the project management activities, our experience and "lessons learned" from managing the Uprate and other projects, knowledge gained from the industry, and PEF best management practices. As a result, PEF project management costs for 2012 and 2013 are reasonable.

Q. Are the actual/estimated 2012 and projected 2013 costs for the CR3 Uprate project separate and apart from costs that the Company would have incurred to operate CR3 during the extended life of the plant?

A. Yes, they are. PEF only includes for recovery in this proceeding those costs that were incurred or that will be incurred solely for the CR3 Uprate project. No costs are included in the CR3 Uprate project that are needed to continue the operation of the plant for an additional twenty (20) years at power levels prior to the power uprate as a result of the CR3 Uprate project.

IV. TRUE UP TO ORIGINAL COST FILING FOR 2012.

Q. Has the Company filed schedules with the information necessary to true up the original estimates to the actual costs incurred for the CR3 Uprate project?

A. Yes, these schedules are provided in Exhibit No. ___ (TGF-6) to Mr. Foster's testimony, Schedules TOR-1 through TOR-7.

Q. What is the current total project cost estimate, compared to the original estimate for the CR3 Uprate project?

A. The total current CR3 Uprate project cost estimate, exclusive of Allowance for Funds Used During Construction ("AFUDC") and including fully loaded costs, is $617 million ($556 million is applicable to the CR3 Uprate and included in the NFR schedules in this nuclear cost recovery clause ("NCRC") proceeding). The current CR3 Uprate project cost estimate remains unchanged from last year and is included on Schedule TOR-7 in Exhibit No. ___ (TGF-6) to Mr. Foster's testimony.

As I have explained before, this estimate cannot be directly compared to the original estimate provided in the need determination proceeding because the estimate in the need proceeding reflected the estimated direct project costs and not the full "Financial View" or fully loaded project costs. The original CR3 Uprate project cost estimate inclusive of the indirect costs is $439.3 million as presented in Schedule TOR-7. The total project cost approved through IPP Revision 3 for the CR3 Uprate project was $479.4 million, of which $418.6 million was driven by the CR3 Uprate project. In August 2011, IPP Revision 3A (Short Form) was executed to reflect the total financial view budget estimate of $617 million, an increase of $138 million for the CR3 Uprate project, based on the current EPU phase work schedule for completion of the CR3 Uprate project during the current extended CR3 R16 re-fueling outage. See IPP Interim Approval 3A (Short Form) for the CR3 Uprate project attached as Exhibit No. ___ (JF-2) to my testimony.

Q. How was the current total project cost estimate for the CR3 Uprate project developed?

A. The current CR3 Uprate project cost estimate was developed as part of a rigorous analysis last year of the Uprate project needs and costs. It includes EPU phase construction costs based on an estimate from an independent construction contractor, additional ECs for the EPU work necessary to accomplish the full power uprate that are now 70 percent design complete, and the estimates of our CR3 Uprate project management team consistent with PEF's project management and cost control policies and procedures and the Association for the Advancement of Cost Engineering ("AACE") cost estimation guidelines. The current status of the CR3 Uprate project supports an AACE Class 2 estimate, which is accurate between -15 percent and +20 percent, as reflected in the contingency in the current CR3 Uprate total project cost estimate. The current total CR3 Uprate project cost estimate represents the results of the rigorous cost analysis and review that is required to prepare an IPP revision for management approval. The current

CR3 Uprate project cost estimate therefore represents the best information regarding the CR3 Uprate project costs that is available to the Company.

Q. Why have the CR3 Uprate project costs increased from IPP Revision 3 to the Company's current total project cost estimate reflected in IPP Revision 3A?

A. The CR3 Uprate project costs have primarily increased as a result of an increase in the scope of and assessment of the work necessary to successfully implement the full 180 MWe power uprate in the EPU phase of the project work as the EPU phase work has naturally progressed. The increased work scope required for the power uprate is described in the EC packages for material and equipment modifications to the plant. Some of these ECs represent new work scope, some represent revised work scope, and some represent the separation of work scope into its own EC package. A description of these EC packages is included in Exhibit No. ___ (JF-3) to my testimony. The increased scope of EPU phase work represented by some of these ECs and the further assessment of the EPU phase work as the EPU phase naturally progressed led to increases in the engineering, procurement, construction, and project management costs for the Uprate project with the largest increases in the engineering and construction costs for the project.

Q. What are the reasons for the increased work scope and assessment for the EPU phase of the Uprate project?

A. The main reason for the increased work scope and assessment of the EPU phase of the Uprate project was the natural progression of design, engineering, and construction work for this three-phased project. The most efficient means of performing this work was to focus design and engineering work on each phase of work in the order that the phased work was planned. As a result, the completion of the design and engineering work for the EPU phase naturally followed the completion and implementation of the work for phases one and two of the Uprate project. Consequently, the full scope and assessment of the EPU phase work was not known and could not be known earlier in the project when the design and engineering work was focused on completing phases one and two to timely construct and install the material and equipment in those phases during the first two CR3 re-fueling outages when Uprate project work was performed. While design, engineering, and procurement work commenced for all three phases after the need for the project was approved by the Commission, the emphasis of the design, engineering, procurement, and construction work was on each phase of the work in the order that each phase of the Uprate project work was performed.

Q. Why did the Uprate project plan divide the work into three phases in separate CR3 re-fueling outages?

A. This was the CR3 Uprate project plan. It consisted of three phases of modification and efficiency enhancements to the CR3 plant over the course of three separate CR3 re-fueling outages to ultimately increase the power output of CR3 by 180 MWe to about 1,080 MWe. Because the entire CR3 Uprate project work could not be performed during a single re-fueling outage the project was divided into work phases during distinct, successive CR3 re-fueling outages. This plan took advantage of the period of time that CR3 was off-line for re-fueling and maintenance so PEF did not have to take CR3 off-line to perform the CR3 Uprate work. The three-phased Uprate project work plan in successive CR3 re-fueling outages, therefore, benefitted customers by maximizing the fuel savings benefits to customers.

PEF has successfully implemented the Uprate project plan. PEF completed the first phase during the R15 CR3 re-fueling outage that led to a 12 MWe increase in the CR3 power output commencing in 2008. The second phase was installed during the R16 CR3 re-fueling outage in 2009. The current EPU phase work plan calls for installation of the final phase during the current, extended R16 re-fueling outage. When the EPU phase work is complete and CR3 returns to commercial service, customers will receive the fuel savings benefits from an additional 164 MWe in CR3's power output. Consequently, PEF can still complete the CR3 Uprate project when CR3 is off-line as originally planned to maximize the fuel savings from the power uprate for PEF's customers.

Q. What EPU phase work increased as PEF focused on the EPU phase?

A. The development of more detailed engineering design information for the EPU modifications led to increased costs and the identification of necessary changes to EPU modifications. An example is the replacement of booster feed pumps 1A and 1B and the motors with larger feed pumps and motors to increase the head and flow to support the full power uprate. This modification was always a part of the EPU scope for the Uprate project, see the schedule in Exhibit No. ___ (JF-3) to my testimony, however, as a result of the detailed engineering design work in preparation for the final EPU phase work, PEF determined that complete replacement of the pump assembly, including a new oil skid that the pump and motor will sit on, was a necessary change to meet the technical performance objectives associated with the full power uprate. See EC74527 described in Exhibit No. __ (JF-3) to my testimony.

Additionally, the evaluation of system responses and interactions as PEF progressed with more detailed engineering design work for the EPU modifications required additional or enhanced EC modifications that increased the EPU work scope and cost. An example is the Condensate System Modifications in EC74526 described in Exhibit No. __ (JF-3) to my testimony. These modifications also were always part of the EPU phase, however, the original work scope included variable speed digital control for the condensate pumps. As detailed engineering work modeled the system response and interaction to these modifications at the full power uprate, PEF determined that a change from variable speed digital controls to constant speed direct drive pumps with flow control, recirculation valves, and piping was necessary to support an adequate flow and discharge pressure at full power uprate conditions. See Exhibit No. ___ (JF-3) to my testimony.

Q. Were there other reasons the EPU phase work scope and cost increases?

A. Yes. Another reason for the EPU phase work scope and cost increases were changing NRC regulatory requirements. Compliance with the NRC's evolving requirements for the EPU LAR increased the engineering and licensing costs that PEF has incurred beyond what PEF expected to incur for NRC acceptance review and approval. Evolving NRC regulatory requirements also increased the EPU work scope and costs. The principal example is EC76340, representing over ten percent of the total project cost increase, which is summarized in Exhibit No. ___ (JF-3) to my testimony.

Another reason for the increases in the EPU phase costs is that necessary modifications were identified after the Company had the opportunity to evaluate field inspection data obtained during the shutdown of CR3 during the current outage. During re-fueling outages, when CR3 is completely shut down, the Company conducts extensive inspections of all material and equipment and performs maintenance. Data is collected and evaluated regarding the material condition of equipment during these inspections.

This inspection and evaluation process during the current extended R16 re-fueling outage resulted in the identification of additional, necessary EPU modifications to achieve the power uprate. These EPU modifications were assessed, implementation options were considered, and, once an option was selected, the design and engineering work was performed for the modification. An example is EC73917 for the feed water heat exchangers ("FWHE") 2A and 2B. PEF originally planned to re-rate FWHE 2A and 2B for the EPU phase work, but as a result of the internal inspections and dimensional validations of these pieces of equipment during the current CR3 outage, PEF determined that FWHE 2A and 2B cannot be re-rated and need to be replaced for the plant to achieve power uprate conditions. See EC73917 described in Exhibit No. __ (JF-3) to my testimony.

Another example is EC80138, which describes the work scope increase to replace FWHE 3A and 3B. PEF originally planned to keep FWHE 3A and 3B even though the scoping study indicated they were outside industry operating recommendations because the FWHE 3A and 3B issues could be addressed under a monitoring and inspection plan. During the current outage inspections, PEF discovered that there were a number of degraded and plugged tubes in FWHE 3A and 3B. PEF performed a detailed engineering evaluation of these FWHE at power uprate conditions and determined that FWHE 3A and 3B cannot meet efficiency and performance requirements necessary for full uprate conditions although FWHE 3A and 3B can meet efficiency and performance requirements at current power output conditions. As a result, PEF decided to replace FWHE 3A and 3B. This scope increase change in EC80138 is also described in Exhibit No. ___ (JF-3) to my testimony.

Q. Was all of this additional work scope necessary for the EPU phase of the Uprate project?

A. Yes. All the additional work scope identified in the ECs described in Exhibit No. ___ (JF-3) is necessary for PEF to complete the EPU phase work and achieve the full 180 MWe power uprate. This additional work scope was not added to the EPU phase until the Company had fully vetted the need for the work for the power uprate and determined that it was essential to achieve the technical objectives that must be satisfied in order to implement the full power uprate. However, the scope of work for the EPU phase has not always increased. Since the original scope of the EPU phase work was conceptually identified in the feasibility study for the CR3 Uprate project, work scope also has been refined, re-defined, and eliminated from the EPU phase of the project.

To illustrate this point, three of the ECs described in Exhibit No. ___ (JF-3) were always considered part of the EPU work and were identified as additional work scope simply because they were separated from other EPU work into distinct EC packages as the Company completes the ECs for implementation of the EPU phase. These ECs are the vibration monitoring system (EC76344), the heavy haul path requirements for transporting EPU phase components to storage locations on site (EC76339), and the overall EPU design margin work for common engineering analyses, safety analyses, and engineering calculations not covered by existing EPU modifications or associated LAR documents (EC71193). Other ECs for additional work scope represent revisions to previous EPU work scope. These ECs include the feed water booster pumps and motors (EC74527), the condensate pump, motor, valves and recirculation pipe work (EC74526), and the low pressure injection cross tie and hot leg injection modification (EC73934) described in Exhibit No. ___ (JF-3). The work scope for these ECs simply changed and increased over time. See Exhibit No. ___ (JF-3) to my testimony.

EPU phase work scope has also been eliminated as the detailed engineering analyses for the EPU modifications progressed. Several modifications that were initially included or included at one point in the EPU phase work scope were determined to be unnecessary to achieve the technical objectives that must be met to implement the power uprate. The remaining EPU work scope and cost are needed to achieve the technical objectives necessary to obtain the full 180 MWe power uprate.

V. RULE 25-6.0423(5)(c)5, F.A.C.: LONG-TERM FEASIBILITY OF COMPLETING THE CR3 UPRATE PROJECT.

Q. Did the Company evaluate the feasibility of completing the CR3 Uprate project?

A. Yes. The Company performed both a qualitative and quantitative analysis to determine if the CR3 Uprate project remains feasible. The qualitative analysis of the CR3 Uprate project feasibility included a qualitative review of the technical and regulatory capability of completing the EPU phase work. This qualitative analysis is consistent with the Company's CR3 Uprate project qualitative feasibility analysis that was approved as reasonable by the Commission in Order No. PSC-11-0095-FOF-EI. A CPVRR analysis was performed for the quantitative feasibility analysis. This analysis included updated fuel, load, and carbon costs, and was performed in a manner consistent with the Company's quantitative feasibility analysis for the Levy Nuclear Project ("LNP") and the Company's prior CPVRR analyses for the CR3 Uprate project that were previously reviewed and approved by the Commission in prior NCRC proceedings.

Q. Is completion of the CR3 Uprate technically feasible?

A. Yes. The first two phases of the CR3 Uprate project were successfully completed when all equipment and other modifications were installed in a timely manner with no significant issues. The testing of Phase 2 equipment will be completed once the plant returns to service. There is no reason the EPU phase cannot be successfully completed too. The EPU phase includes the installation or implementation of more than twenty-five (25) ECs, including major components such as the Low Pressure and High Pressure Turbines, significant engineering work, and, under the current work plan, installation of a POD cooling tower. PEF's ongoing technical analysis and reviews confirm that the EPU phase work can be successfully completed and the full power uprate achieved. There are no technical impediments to implementation of the full power uprate. Consequently, PEF is confident the EPU phase work can be successfully completed to achieve the full power uprate and obtain for PEF and its customers the fuel-savings benefits of the full 180 MWe increase when CR3 returns to commercial service.

Q. Is the CR3 Uprate project feasible from a regulatory perspective?

A. Yes. All licenses and permits for the CR3 Uprate project can be obtained. There is no reason to believe that the necessary licenses and permits for the EPU phase work will not be obtained. The EPU phase requires a number of permits and license changes to support operation at the higher power level. These include environmental permitting for the currently proposed cooling tower and an EPU LAR from the NRC. The environmental permit approvals can be obtained well in advance of the implementation of the proposed POD cooling tower should PEF determine that it is still necessary after PEF completes its evaluation of the impact of new and proposed environmental regulations on this work. There is no indication that the necessary permits for the POD cooling tower cannot be obtained. The required environmental permits or permit modifications for the POD cooling tower are similar to previously obtained permits and permit modifications that PEF has successfully obtained. PEF fully expects to receive the necessary environmental permits or permit modifications for the cooling towers if PEF determines that completion of the POD work is necessary for the EPU project.

As I explained earlier, the EPU LAR for the CR3 Uprate project can be obtained from the NRC. The EPU LAR was submitted and accepted by the NRC for review in 2011. The NRC has indicated a review period of approximately two years for the EPU LAR. This licensing review is currently underway. PEF does not anticipate any significant impediments to receipt of the EPU LAR well in advance of implementation of the power uprate. PEF expects that the NRC will approve its EPU LAR for the full power uprate.

Q. What was the result of the Company's economic feasibility analysis of the CR3 Uprate project?

A. The updated, quantitative CPVRR analysis demonstrates that the CR3 Uprate project is economically feasible. There are substantial fuel savings for PEF's customers if the EPU phase of the CR3 Uprate project is completed. The results of this economic analysis are included in Exhibit No. ___ (JF-4) to my testimony.

The Company's economic analysis is based on the current, expected EPU schedule with the commencement of construction in June 2013, the completion of construction in June 2014, and the placement of the EPU in service in December 2014. Under this current EPU phase work plan, the EPU phase work is performed in parallel with the current, planned repair to the CR3 containment building with the planned return of CR3 to commercial service in November 2014. The current EPU phase plan (including current project costs) was evaluated in the updated CPVRR analysis against a project cancellation option assuming no further work on the CR3 Uprate project beyond the work already completed in the first two phases of the project. In the event of project cancellation, the system planning models replaced the additional MWe generation from the power uprate as a result of the EPU phase work with additional, natural-gas fired generation available to the Company. The economic feasibility evaluation further considered the benefits of the EPU phase of the CR3 Uprate project with and without carbon cost benefits as a result of future, potential climate control or greenhouse gas ("GHG") emission legislation or regulation.

As shown in Exhibit No. ___ (JF-4) to my testimony, the CPVRR economic evaluation, the current EPU phase plan is economically beneficial to PEF and its customers based on fuel savings alone. Nominal fuel savings without carbon cost benefits are $1.21 billion and the net present value of the total savings is $361 million. When carbon cost benefits are included in the analysis, the economic benefits of completion of the EPU phase during the current extended CR3 re-fueling outage naturally improves. Nominal fuel savings with carbon cost benefits are $1.26 billion and the net present value of the total savings including carbon costs is $650 million. See Exhibit No. ___ (JF-4) to my testimony.

This economic analysis demonstrates that the EPU phase of the CR3 Uprate project is economically feasible when the costs of the project are compared to the fuel savings benefits on a net present value basis. The updated CPVRR analysis demonstrates that the fuel savings benefits exceed the costs to complete the project on a net present value basis. When the carbon cost compliance estimates are included in the economic analysis, the EPU phase of the CR3 Uprate project is even more beneficial on a net present value basis to PEF and its customers.

Q. Did the Company evaluate any other options in its economic analysis of the feasibility of completing the EPU phase of the CR3 Uprate project?

A. Yes. As I discussed above, the Company evaluated an alternative schedule for completion of the EPU phase of the CR3 Uprate project. Under this alternative schedule, completion of the EPU phase of the CR3 Uprate project is deferred to the next planned CR3 re-fueling outage after the CR3 containment building is repaired and CR3 returns to commercial service. The next CR3 re-fueling outage, R17, will be approximately two years after plant start-up. Completion of the EPU phase of the CR3 Uprate project in the next planned CR3 re-fueling outage is also economically feasible.

As demonstrated in Exhibit No. ___ (JF-4) to my testimony, completion of the EPU phase in the R17 CR3 re-fueling outage is economically beneficial to PEF and its customers. Nominal fuel savings without carbon cost benefits are $1.09 billion and the net present value of the total savings is $260 million. When carbon cost benefits are included in the analysis, the economic benefits to PEF and its customers improve. Nominal fuel savings with carbon cost benefits are $1.14 billion and the net present value of the total savings including carbon costs is $513 million. See Exhibit No. ___ (JF-4) to my testimony. There are substantial economic benefits to PEF and its customers if the EPU phase of the CR3 Uprate project is completed in the CR3 R17 re-fueling outage.

Q. Why did the Company evaluate an alternative schedule for completion of the EPU phase of the CR3 Uprate project?

A. The Company prepared and evaluated an alternative schedule to place the EPU phase work in service because it provides the Company project management flexibility to implement the EPU phase of the CR3 Uprate project. In the event the Company's current plan to repair the CR3 containment building is delayed or unforeseen risks or other impediments require the Company to repair the CR3 containment building prior to or ahead of the commencement of the EPU phase work, the Company has an alternative schedule to implement the EPU phase work in the next planned CR3 re-fueling outage and the Company has determined that the alternative EPU phase schedule is economically beneficial to PEF and its customers.

Q. If completion of the EPU phase in the next planned CR3 re-fueling outage is economically feasible why is the Company's current plan to implement the EPU phase in the current CR3 extended outage?

A. Completion of the EPU phase of the CR3 Uprate project in the current CR3 extended re-fueling outage is more beneficial to PEF and its customers. The current 2012 actual/estimated costs for the EPU phase work are the same if the EPU phase work is completed in this re-fueling outage or in the next re-fueling outage because of pre-existing LLE contractual payment commitments and the current, on-going NRC review of the EPU LAR. The EPU phase costs necessarily increase if the construction work is deferred to the next CR3 re-fueling outage and some of the fuel savings benefits to customers are also lost if the EPU power uprate is not placed in service until the next refueling outage. As a result, the fuel savings benefits are greater and commence earlier for PEF's customers if the EPU phase work is completed in the current re-fueling outage and the EPU power uprate is placed in service in December 2014 as opposed to in the next re-fueling outage. Overall, completion of the EPU phase of the CR3 Uprate project in the current extended CR3 re-fueling outage is more beneficial to PEF's customers. See Exhibit No. __(JF-5) to my testimony providing the EPU project management's evaluation of the costs and benefits of completing the EPU phase of the CR3 Uprate project in the current, extended CR3 re-fueling outage or the next planned CR3 re-fueling outage.

Q. Did the Company update its fuel, environmental emission, and load forecasts in the quantitative analysis of the feasibility of completing the EPU phase of the CR3 Uprate project?

A. Yes. The Company performed its updated CPVRR analysis in the same manner that it performed the CPVRR analysis for the LNP with respect to the fuel, environmental emissions, carbon cost compliance, and load forecast estimates. PEF used updated fuel, environmental, carbon dioxide compliance cost, and load estimates consistent with the updated forecasts used in the LNP quantitative economic analysis in the economic feasibility analysis for the Uprate project. The Company further updated its financial forecasts for the economic feasibility analysis for the EPU phase of the CR3 Uprate project.

Q. Last year, the Commission granted PEF's Motion that deferred to this year's docket the review of the long-term feasibility of completing the CR3 Uprate project. Does that decision affect the Commission's review of the Company's current feasibility analysis?

A. No. The Commission granted PEF's Motion for Deferral because the Company expected to update the feasibility analysis filed with the Company's May testimony in the 2011 NCRC docket. The Company has now updated that analysis. My testimony provides the Commission the Company's updated analysis of the long-term feasibility of completing the CR3 Uprate project. Additionally, as this Commission has previously recognized, feasibility is a forward-looking determination. See Order PSC-11-0547-FOF-EI, Docket No.

110009-EI, 2011 WL 5904236, *23, 30, 54, 78 (Fla. P.S.C. Nov. 23, 2011). The Company's prior feasibility analysis filed in the 2011 NCRC docket, therefore, has no bearing on the Commission's review of PEF's updated analysis of the feasibility of completing the CR3 Uprate project in this proceeding.

VI. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the CR3 Uprate project since the testimony you filed on March 1, 2012?

A. The Company has not implemented any additional project management or cost control oversight policies or procedures for the CR3 Uprate since the discussion of these procedures in my March 1, 2012 testimony. The Company continues to utilize the Company policies and procedures described in my March 1, 2012 testimony to ensure that costs for the CR3 Uprate project are reasonably and prudently incurred.

Q. Are these the same policies and procedures that the Commission has previously reviewed for the CR3 Uprate project?

A. Yes. As I explained in my March 1, 2012 testimony, the Commission has previously determined that the CR3 Uprate project management and cost oversight controls were reasonably and prudent. The Company's current CR3 Uprate project management and cost oversight controls policies and procedures are substantially the same as the policies and procedures reviewed and previously determined to be reasonable and prudent by the Commission.

Q. Are these CR3 Uprate project management and cost controls policies and procedures consistent with best practices in the industry?

A. Yes. We believe that our CR3 Uprate project management and cost oversight policies and procedures are consistent with best practices for capital project management in the industry. PEF has employed these project management policies and procedures to successfully implement two phases of the CR3 Uprate project, during two separate plant re-fueling outages, and completed the work scope necessary for the first two phases of the CR3 Uprate project. We believe the project management, contracting, and cost control policies and procedures that we have implemented for the CR3 Uprate project are reasonable and prudent and consistent with industry best practices.

VII. CONCLUSION.

Q. Is completion of the EPU phase of the CR3 Uprate project in the best interests of the Company and its customers?

A. Yes, we continue to believe that completion of the EPU phase of the CR3 Uprate project is in the Company's and customers' best interests. Our updated analysis of the feasibility of completing the EPU phase demonstrates that the EPU phase of the project remains feasible and that it will be economically beneficial to PEF and its customers whether it is completed as currently planned in the current CR3 re-fueling outage or in the next CR3 planned re-fueling outage. The completion of the EPU phase of the CR3 Uprate project will provide PEF and its customers additional carbon-free, clean nuclear energy generation from the lowest cost fuel source available to the Company, it will add to the Company's fuel diversity, and it reduces the Company's reliance on fossil fuels, especially from foreign sources, for energy generation. Implementation of the EPU phase of the CR3 Uprate project remains an important element of Progress Energy's Balanced Solution. As a result, the Company is committed at this time to completion of the EPU phase of the CR3 Uprate project.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 120009-EI

REBUTTAL TESTIMONY OF JON FRANKE

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Jon Franke. My business address is Crystal River Nuclear Plant, 15760 W. Powerline St., Crystal River, FL 34442.

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 ("CR3").

Q. Have you previously filed direct testimony in this docket?

A. Yes, I filed direct testimony on March 1, 2012 and April 30, 2012.

Q. Have you reviewed the intervenor testimony filed in this docket?

A. Yes, I have reviewed the testimony of William R. Jacobs, Jr., Ph.D. ("Jacobs") regarding the CR3 Extended Power Uprate ("EPU") project ("CR3 Uprate") filed on behalf of the Office of Public Counsel ("OPC"). I also reviewed the direct joint testimony of Mr. William Coston and Mr. Jerry Hallenstein ("Audit Staff" witnesses), filed on behalf of the Florida Public Service Commission ("FPSC" or the "Commission"), including portions of the June 2012 Review of Progress Energy Florida, Inc.'s Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects, PA-11-11-004, identified as Exhibit No. ___ (CH-1) to the Audit Staff witnesses' testimony ("Audit Report"), with respect to the CR3 Uprate project.

II. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the recommendations in OPC witness Jacobs' testimony concerning the CR3 Uprate project. Audit Staff includes no findings with respect to the CR3 Uprate project in their Audit Report.

Q. Please provide a brief summary of your rebuttal testimony.

A. I will first address the issues to be decided by the Commission in this proceeding and explain the Company's testimony and exhibits addressing these issues that are uncontested by any witness in this proceeding. In particular, no witness has filed testimony in this proceeding disputing the prudence of any specific cost incurred by PEF on the CR3 Uprate project in 2011 or the reasonableness of any specific actual/estimated or projected cost that PEF has incurred or expects to incur on the CR3 Uprate project in 2012 and 2013. Further, no witness has filed testimony in this proceeding contesting PEF's analysis of the long-term feasibility of completing the CR3 Uprate project. Finally, no witness has filed testimony in this proceeding disputing the prudence of PEF's CR3 Uprate project management, contracting, accounting, and cost oversight controls.

Jacobs recommends that PEF continue the CR3 Uprate project on a different schedule, in his view, to minimize CR3 Uprate project costs until the CR3 containment repair is nearing completion and licensing approval. Jacobs' recommendation will increase, not decrease, the total cost of the project and increase the risk that implementation of the EPU work will delay the return of CR3 to commercial service. As a result, Jacobs' recommendation increases the costs and reduces the benefits of the project to PEF and its customers and should be rejected.

Q. Do you have any exhibits to your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits to my rebuttal testimony:

- Exhibit No. ___ (JF-6), a chart summarizing the PEF projected 2013 CR3 Uprate project costs for the following EPU work: (i) license application; (ii) Long Lead Equipment ("LLE") procurement, contractual progress payments and related vendor contract management and quality control; and (iii) design engineering and related project management work; and
- Exhibit No. ____ (JF-7), the Company's CR3 Uprate project schedule for completion of the EPU work.

These exhibits were prepared by the Company at my direction and under my control and they are true and correct.

III. PEF EVIDENCE UNCONTESTED BY TESTIMONY IN THIS PROCEEDING.

Q. What issues will the Commission decide in this 2012 proceeding?

A. My understanding is that the Commission will determine, pursuant to Section 366.93, Florida Statutes, and Rule 25-6.0423, F.A.C., (1) the prudence of PEF's actual 2011 costs for the CR3 Uprate project; (2) the prudence of PEF's project management, contracting, accounting, and cost oversight controls for 2011 for the CR3 Uprate project; (3) the reasonableness of PEF's actual/estimated 2012 costs for the CR3 Uprate project; (4) the reasonableness of PEF's projected 2013 costs for the CR3 Uprate project; and (5) approval of PEF's analysis of the feasibility of completing the CR3 Uprate project pursuant to Rule 25-6.0423(5)(c)5, F.A.C.

I further understand that the parties have agreed that the Commission should address additional issues related to the prudence of our CR3 Uprate project management decisions in 2011, and the reasonableness of our decisions in 2012, as a result of the evaluation by the Company of the repair of the CR3 Containment Building leading up to a final decision by the Company with respect to that repair. These additional issues further address the prudence of our CR3 Uprate 2011 actual costs and the reasonableness of our CR3 Uprate actual/estimated 2012 and projected 2013 costs.

Q. Have any witnesses asserted in testimony that PEF's actual CR3 Uprate project costs for 2011 are not prudent?

A. No, they have not. Intervenor OPC witness Jacobs specifically says in his testimony that he was asked by OPC to conduct a review and evaluation of PEF's requests for authority to collect historical costs associated with the CR3 Uprate project. (Jacobs Test., P. 3, L.

17-21). Nowhere in his testimony, however, does Jacobs identify any historical 2011 CR3 Uprate project cost that PEF seeks to collect that he finds was imprudently incurred. Audit Staff witnesses reviewed the adequacy of the internal controls and management oversight of the CR3 Uprate project to assist the Commission in its assessment of the Company's cost recovery requests for the CR3 Uprate project. See Audit Staff Test., Exhibit No. ___ (CH-1) at page 1 of 44. Audit Staff witnesses include no findings with respect to the CR3 Uprate project in their Audit Report. No other intervenors presented testimony in this docket regarding the CR3 Uprate project.

Q. Does Jacobs assert that the 2011 CR3 Uprate project management, contracting, accounting, and cost oversight controls are unreasonable or imprudent?

A. No he does not. Jacobs states that he was not asked to focus his efforts in that area in this docket. (Jacobs Test., P. 5, L. 1-5). He therefore offers no opinion regarding the prudence of PEF's 2011 CR3 Uprate project management, contracting, accounting, and cost oversight controls.

Q. Do the Audit Staff witnesses assert that the 2011 CR3 Uprate project management, contracting, accounting, and cost oversight controls are unreasonable or imprudent?

A. No they do not. Audit Staff witnesses state that they "monitored and evaluated the [PEF] project controls in the areas of contract administration, process management and oversight, risk assessment, and organization structure." (Audit Staff Test., Exhibit No. ___ (CH-1) at page 13 of 44). They further state that they "reviewed [PEF's] management reports and negotiated contracts to confirm [PEF's] compliance with its internal procedures." Id. They confirmed "[PEF] continues to monitor and update its project management process and procedures throughout this project." Id. They concluded that there were "[n]o variances in [PEF's] compliance to its EPU procedures [] identified during this review period." Id. There were no findings related to PEF's 2011 CR3 Uprate project management, contracting, accounting, and cost oversight controls in the Audit Report.

Q. Does Jacobs assert in his testimony that PEF's actual/estimated 2012 and projected 2013 costs for the CR3 Uprate project are unreasonable?

A. No. Jacobs does not identify any specific actual/estimated 2012 or projected 2013 CR3 Uprate project cost that he thinks is unreasonable. Again, OPC witness Jacobs says he was asked by OPC to conduct a review and evaluation of PEF's requests for authority to collect projected costs associated with the CR3 Uprate project. (Jacobs Test., P. 3, L. 17-21). Jacobs, however, nowhere identifies any specific actual/estimated 2012 or projected 2013 CR3 Uprate project cost that he claims is unreasonable either because it is not necessary for the CR3 Uprate project or because it is unreasonable in the amount estimated based on the work and/or material involved for the CR3 Uprate project.

Q. Do any witnesses assert that PEF has not demonstrated the long-term feasibility of completing the CR3 Uprate project pursuant to Rule 25-6.0423(5)(c)(5), F.A.C.?

A. No they do not. Audit Staff witnesses conclude that, "[PEF's] current feasibility analysis supports the economic viability of the project." (Audit Staff Test., Exhibit No. ___ (CH-

1), page 42 of 44). And, as I explained above, there are no Audit Staff findings with respect to the CR3 Uprate project. Id. Jacobs does not specifically address the feasibility of the CR3 Uprate project in his testimony. Jacobs, however, nowhere asserts in his testimony that PEF should have cancelled the CR3 Uprate project in 2011 or that PEF should cancel the project now. He agrees that, for the EPU project to continue, "engineering and licensing work must continue and long-lead equipment items must be procured" and presumably paid for (Jacobs Test., P. 12, L. 5-7), and he only argues for the deferral or avoidance of "EPU construction work" until the "success of the repair and NRC acceptance of that repair is assured." (Jacobs Test., P. 12, L. 10-13). Based on these statements and his recommendation, Jacobs apparently believes the CR3 Uprate project is feasible and should be completed, albeit on a different schedule than currently planned by the Company.

IV. OPC WITNESS JACOBS' RECOMMENDATIONS SHOULD BE REJECTED BECAUSE THEY ARE NOT BASED ON ANY EVIDENCE THAT PEF's PROJECTED COSTS ARE UNREASONABLE AND THEY WOULD INCREASE, NOT DECREASE, THE TOTAL PROJECT COST TO PEF'S CUSTOMERS.

Q. Can you explain what OPC witness Jacobs recommends in his testimony?

A. Yes. My understanding of his testimony is that Jacobs generally claims PEF should not recover "avoidable or deferrable" EPU costs that have not already been incurred or committed to for the project. Rather, he claims these costs should be avoided or deferred "until late in the containment repair process when the success of the repair and NRC acceptance of that repair is assured." (Jacobs Test., P. 12, L. 10-13). In his view, these avoidable or deferrable costs are construction contract costs that can be performed during an "outage lasting a few months" and, accordingly, he necessarily proposes that PEF revise its current schedule for the completion of the EPU work during the current CR3 R16 outage to place the EPU construction work at the end of the current outage. (Jacobs Test., P. 12, L. 10-17). He claims that, as a result of his recommendation, "approximately $186,000,000 of planned expenditures of the customers' money will not be spent," according to him, "more than two years early." (Jacobs Test., P. 12, L. 13-20). Based on this recommendation, Jacobs claims that, if PEF "decides to incur avoidable or deferrable [EPU] expenditures," the Commission should withhold any determination of reasonableness and put PEF on notice "that any EPU money spent in 2013 will be held subject to refund until PEF makes an official decision to repair the building and to begin that repair in earnest." (Jacobs Test., P. 13, L. 1-6).

Q. What is the reason Jacobs provides for his recommendations?

A. Jacobs' reason for his recommendations is that PEF should "minimize all expenditures related to the CR3 EPU project." (Jacobs Test., P. 5, L. 10-11). Jacobs does not testify that the CR3 Uprate project should be cancelled or that EPU work should stop. Indeed, Jacobs agrees that engineering and licensing work, and LLE procurement, must move ahead to continue the EPU project. (Jacobs Test., P. 12, L. 5-6). He argues that "[o]nly absolutely necessary expenditures should be incurred" prior to the decision to repair or retire CR3. (Jacobs Test., P. 11, L. 17-20). Jacobs allows, then, for the recovery by PEF of necessary expenditures in 2012 and 2013 for the EPU work on the CR3 Uprate project.

Q. Do you agree with Jacobs' recommendations?

A. No. First, Jacobs is simply incorrect that the Company will spend $186 million on the CR3 Uprate project at this time and that this entire projected amount represents avoidable or deferrable construction work. Second, Jacobs' recommendations are not based on any evidence that PEF's actual/estimated 2012 or projected 2013 costs are unreasonable because they are unnecessary for the EPU work or inaccurate or incorrect in amount because of something PEF did or did not do that it should have done. Finally, Jacobs' recommendations, if accepted by the Commission, will actually increase, not minimize, the cost of the EPU work to PEF's customers and may further delay implementation of the EPU phase of the CR3 Uprate project, thereby delaying receipt of fuel savings benefits to PEF's customers.

Q. Will PEF spend $186 million on the EPU work in 2012 and 2013?

A. No. PEF is not requesting $186 million for the CR3 Uprate project in this docket. Jacobs obtains the $186 million number from Schedule TOR-6 of Exhibit No. __ (TGF-6) to Mr. Thomas G. Foster's testimony in this docket. (Jacobs Test., P. 8, L. 1-4, n. 1). This $186 million represents the projected future spend on the EPU phase of the CR3 Uprate project in 2013, 2014, and 2015. PEF is not seeking recovery of carrying costs and other, recoverable costs under the nuclear cost recovery statute and rule for the projected 2014 and 2015 EPU costs in this docket. These 2014 and 2015 projected EPU costs will be the subject of requests for cost recovery in subsequent dockets, and subject to subsequent Commission reviews to determine if these costs are first reasonable, and then prudent, for the CR3 Uprate project. Accordingly, there is no reason for the Commission to review the projected CR3 Uprate 2014 and 2015 costs (an estimated $75.8 million) at this time because PEF is not requesting recovery for these costs in this docket. Only $110 million of the $186 million is at issue in this docket because this is the projected 2013 costs for the EPU work on the CR3 Uprate project.

Q. Are the projected $110 million costs for the CR3 Uprate project in 2013 reasonable?

A. Yes. As I explained, in my direct testimony filed in this docket on April 30, 2012, these costs are necessary for the EPU scope of work required to implement the power uprate. This work includes continued engineering and licensing support for the EPU LAR that was submitted to the NRC in June 2011 and accepted for review by the NRC in November 2011. I explain the general scope of this licensing work in my April 30, 2012 direct testimony. This work will continue through 2013 when NRC approval of the EPU LAR is expected. Further EPU work in 2013 includes design engineering finalization of the engineering change ("EC") packages for the EPU, continued payments and vendor oversight for LLE for the EPU, and the commencement of construction activities including starting mobilization of construction resources, the performance of constructability reviews, the receipt, storage, and organization of equipment and materials, the commencement of pre-fabrication activities, and continued vendor oversight. This work is also explained in my April 30, 2012 testimony. This EPU work is necessary in 2013 to perform the EPU construction work from June 2013 to June 2014 to install, test, and implement the power uprate when CR3 is currently expected to return to service.

The projected 2013 EPU costs include (1) an estimated $2.4 million in license application costs to obtain NRC approval of the EPU LAR in 2013; (2) $14.2 million for LLE procurement and contractual progress payments in 2013, and related vendor quality assessment, contract management, oversight, and LLE handling and storage; and (3) $7.8 million for design engineering work and related project management in 2013. See Exhibit No. ___ (JF-6) to my rebuttal testimony. Jacobs agrees that all of these projected 2013 EPU costs must be incurred to continue the CR3 Uprate project. (Jacobs Test., P. 12, L. 5-6). In addition to these 2013 EPU costs, related project management costs in the amount of $5.7 million are projected in 2013. These costs represent $30.1 million of the projected $110 million 2013 EPU costs.

Of the remaining $79 million in projected 2013 EPU costs, Jacobs does not identify any specific CR3 Uprate project cost that he claims PEF can avoid in 2013 or defer beyond 2013 and still implement the power uprate during the current CR3 outage. Jacobs nowhere testifies that any of the work that is encompassed by the remaining $79 million in projected 2013 costs is unnecessary in 2013. Jacobs simply assumes that these remaining 2013 EPU costs represent "construction costs" that can be avoided or deferred in 2013. In other words, Jacobs assumes that, because EPU installation work could be performed in an "outage lasting a few months," PEF should defer EPU construction activities and costs to "late" in the containment building repair process. (Jacobs Test., P. 12, L. 9-13). Jacobs fails to address in his testimony the impact his recommended "schedule" would have on the CR3 Uprate project in terms of the effect on the total project cost and the Company's ability to complete the power uprate during the current outage.

Q. Has PEF taken steps to minimize the CR3 Uprate project costs?

A. Yes, PEF has done exactly what Jacobs says PEF should do and minimized the CR3 Uprate costs to ensure that only those costs necessary for the EPU work on the CR3 Uprate project have been and will be incurred until a final decision to repair CR3 is made. In 2011, prior to the March 14, 2011 delamination, PEF was proceeding with a project plan and CR3 Uprate project schedule to complete the EPU work in a then-planned 2013 CR3 re-fueling outage. PEF obviously, then, had incurred and committed to incur EPU costs in the first quarter of 2011, prior to and immediately after the mid-March 2011 delamination, that were not amenable to revision as a result of this event. Subsequent to this delamination event, however, PEF evaluated the EPU phase work and determined that the reasonable course of action was to take steps to preserve the option of completing the CR3 Uprate work in the current CR3 outage without unnecessarily incurring costs for the CR3 Uprate project. This decision is confirmed by the Company's current evaluation of the feasibility of the CR3 Uprate project described at pages 29-36 of my April 30, 2012 direct testimony. Jacobs apparently agrees with PEF that this was a reasonable approach because he does not dispute the Company's determination that the CR3 Uprate project is feasible and he also proposes continuation of the CR3 Uprate project to complete the EPU phase work during the current CR3 outage, albeit on a more compressed time frame than the Company's current CR3 Uprate project schedule.

To develop the current CR3 Uprate project schedule, PEF evaluated the EPU phase work to identify what work was critical to proceed with to maintain a schedule to complete the EPU during the current CR3 outage and what work was not on this critical path. Based on this evaluation, PEF slowed down and postponed work on the EPU phase in 2011 and 2012 to minimize the CR3 Uprate project costs while preserving the Company's ability to complete the EPU work during the current CR3 outage and implement the power uprate when CR3 returns to service.

For example, no EPU phase work has been or is being accelerated, all overtime work has been postponed, and only regular work hours are permitted on EPU work that PEF has determined needs to be done to maintain the current CR3 Uprate project schedule. PEF also delayed the selection of a construction contractor for the EPU phase. PEF individually evaluated each contract and change order for the EPU phase work before execution. For contracts or change orders below $100,000, the EPU phase project manager performed this evaluation; for contracts or change orders at or above $100,000, the project manager conducted this evaluation and made recommendations with respect to execution of the contract or change order that were reviewed by the manager of nuclear projects and senior management. No contract or change order at or above $100,000 for the EPU phase work was executed without senior management approval. That approval was not granted unless there was a demonstration that the work under the contract or change order was reasonable and necessary to preserve the Company's ability to complete the EPU work on the current CR3 Uprate project schedule. This type of evaluation was conducted for each item of work for the EPU phase of the CR3 Uprate project.

Q. Have the Company's efforts to minimize the CR3 uprate costs in 2011 and 2012 actually resulted in the avoidance or deferral of costs to a later time period?

A. Yes. As I explain in my March 1, 2012 direct testimony, PEF was able to reallocate project management resources and reduce project management expenditures for the CR3 Uprate project by $4.7 million in 2011. PEF's 2011 Power Bock Engineering, Procurement, and related construction costs were reduced by $34.2 million. (See Direct Test. of Jon Franke, dated March 1, 2012, pp. 12-13). Likewise, PEF's efforts to minimize CR3 Uprate project costs in 2012 resulted in reductions of $4.4 million in project management costs, and $14.8 million in Power Block Engineering, Procurement, and related construction costs, compared to the estimate for these 2012 costs in 2011. (See Exhibit No. ___ (TGF-4), p. 16 of 50, to the April 30, 2012 Direct Testimony of Thomas G. Foster). PEF has reasonably minimized CR3 Uprate project costs in 2011 and 2012 while preserving its ability to complete the EPU phase of the CR3 Uprate project during the current outage.

Q. Can PEF minimize CR3 Uprate project costs further by adopting Jacobs' recommendation to defer all EPU construction work to the end of the current CR3 outage?

A. No. In fact, Jacob's recommendation that PEF defer all construction work until the end of the current CR3 outage would increase, not minimize, the cost to perform the EPU work. PEF currently plans to complete the EPU phase work during the current CR3 outage between June 2013 and June 2014. Jacobs recommends performing all of this work in an unspecified "few months" late in the CR3 containment building repair process. (Jacobs Test., P. 12, L. 10-13). Deferring EPU construction work until the end of the current CR3 outage and anticipated CR3 repair work requires PEF to completely re-order the current EPU phase work schedule. All efficiencies that PEF gained by carefully planning to perform this work over the one-year construction period in the current EPU work schedule will be lost. Additional contractor labor will be needed, additional on-site facilities will be required to house these additional contractors, extended shifts and overtime will be necessary for current employees and contractor employees, and additional project management and quality assessment will be needed to manage the additional contractors and shifts working around-the-clock to perform the work in a "few months" rather than a year. Coordination efforts will increase and added internal and contractor project management will be required. All of these factors, among others that necessarily flow from taking work planned for one year and performing it in a compressed time period, will increase the cost of the EPU work and, thus, increase the total CR3 Uprate project cost.

In addition, PEF has a detailed work schedule in place to perform this work under the current plan. I have attached as Exhibit No. ___ (JF-7) to my testimony a copy of the current EPU Level II schedule. This schedule includes the careful order of the installation of the EC work necessary for the EPU from the current date through June 2014 to implement the power uprate by the anticipated return of CR3 to service from the current outage. Behind each milestone entry for each EC that makes up the EPU work is a detailed work scope and time frame for that work scope ensuring the timely completion of the milestone under this current EPU work schedule. This detailed work scope and time frame for ECs involving contractor resources and material is premised on established contractual obligations and timelines. To move away from this detailed work schedule and implement another one in a much shorter time frame, as Jacobs suggests, will require PEF to invest substantial manpower and time to re-baseline the EC work and re-build the EPU construction and implementation schedule in a compressed time frame. This work alone will increase the costs of the project.

To re-baseline the EC work and re-build the EPU work schedule PEF also will have to re-negotiate existing contracts for this work at an additional cost to PEF. The cost of the work will escalate upon deferral and compression of the time frame to perform the work and PEF will likely incur cancellation costs and other damages under the existing contracts. Additionally, it may not be possible for PEF to re-negotiate some contracts to implement the EPU work schedule Jacobs recommends. For example, the current contracts with Siemens for installation of the low and high pressure turbines are based on the limited availability of Siemens resources for this work. Siemens resources may not be available for the installation of the low and high pressure turbines in the time frame Jacobs recommends for completion of the EPU work. PEF will also place itself in a position of weakness in negotiations with potential construction contractors because these contractors will know that the EPU phase work must be performed in a limited time-frame in order to implement the power uprate upon the anticipated return of CR3 to service. For all of these reasons, Jacobs' recommendation will increase, not decrease, the total cost of the project for PEF's customers.

Q. Are there other drawbacks to Jacobs' recommendation to defer the EPU construction work to a "few months" at the end of the anticipated repair schedule for CR3?

A. Yes. Deferral of all EPU construction work until the end of the current CR3 outage and anticipated CR3 repair work further places the EPU work on the critical path to return CR3 to service and impairs the Company's ability to timely complete the EPU work in order to implement the power uprate when CR3 does return to service. This increases the risk that unexpected delays in the EPU work or increases in the time necessary to perform the work will extend the current outage and delay the return of CR3 to commercial service. For example, risks inherent in compressing a construction schedule include industrial safety, quality control, and the time available to appropriately address unknown changes that are part of any construction project. The current implementation schedule also provides PEF additional time to perform post-modification testing prior to start-up testing for the power uprate. This schedule enables PEF to identify any equipment or performance issues in time to correct them before the anticipated return of CR3 to commercial service. That time would not be available to PEF under the EPU construction schedule that Jacobs recommends. As a result, implementation of the EPU phase work in a "few months" at the end of the anticipated CR3 repair schedule increases the risks that the EPU implementation may delay the return of CR3 to commercial service and, therefore, delay the fuel savings benefits from the return of CR3 to commercial service, and at the power uprate, to PEF and its customers.

Implementation during the extended CR3 16R outage provides PEF the opportunity to gain schedule and costs efficiencies and reduce risk because the EPU phase work no longer has to be completed during the limited timeframe of a typical re-fueling outage, but instead can be implemented over the course of the year. The current EPU phase work schedule and costs reflect these efficiencies. If Jacobs' recommendation to defer construction activities and costs was implemented, PEF and its customers would lose the time and cost efficiencies gained under the current implementation schedule, the total project cost would increase, and there would be an increased risk that the return of CR3 to commercial service and the receipt of the resulting fuel-savings benefits would be delayed to the added detriment to PEF and its customers.

V. JACOBS' OTHER "CONCERNS" REGARDING THE EPU ARE UNSUPPORTED BY ANY EVIDENCE AND IRRELEVANT TO THE ISSUES BEFORE THE COMMISSION.

Q. Jacobs states his "concern" that the CR3 Uprate total project costs have increased since the original estimate, and that they may continue to increase, do you agree that this is an appropriate "concern" for the project?

A. No. First, the reasons for these total project cost increases were explained in my testimony in prior dockets and in my current April 30, 2012 direct testimony in this docket. As I explain, these cost increases are the result of additional engineering changes, additional project scope, and licensing expenses necessary to implement the full power uprate. Jacobs nowhere disputes these reasons for the increases in the CR3 Uprate total project costs. Additionally, the mere fact that the total project cost has changed, with both increases and decreases in project scope, was addressed by the Commission in the 2010 nuclear cost recovery clause docket. The Commission concluded that the mere fact that the total project cost increased (and may continue to increase) is relevant to the utility's detailed feasibility analysis for the project, stating that "we believe that concerns regarding changes in estimated total project costs are best addressed in the project feasibility analysis issue where changes can be reviewed on an annual basis." See Order PSC-11-0095-FOF-EI, Docket No. 10000-09, p. 14. Jacobs does not challenge the long-term feasibility of the CR3 Uprate project. Accordingly, while Jacobs may be concerned simply because the total project cost has increased, regardless of the reasons for the increase or the continuing feasibility of the project, there is no reason based on the uncontradicted evidence explaining the cost increases and the continuing feasibility of the CR3 Uprate project for the Commission to be concerned about the mere increase in total project cost.

Q. Jacobs is also concerned that there will be "difficulty" in achieving regulatory approval by the NRC of the EPU LAR. Do you agree with this concern?

A. No. Jacobs' concern is unsupported by any evidence that it will in fact be "difficult" for PEF to obtain NRC approval of the EPU LAR. Jacobs refers only to the statement in the NRC acceptance letter, Exhibit No. __(JF-1) to my April 30, 2012 direct testimony, indicating that NRC review of the EPU LAR may take longer than one year and "possibly" up to two years to support his concern that it will be "difficult" to obtain NRC approval of the EPU LAR. The NRC does not say in this letter that it will be "difficult" for PEF to obtain EPU LAR approval, that it will in fact take two years to complete the NRC review, or that the reason it may take up to two years to complete the EPU LAR review is because of any difficulty with the EPU LAR. The NRC letter, therefore, does not mean that there is or will be difficulty in obtaining EPU LAR approval. In fact, feedback from the NRC reviewers during the Request for Additional Information ("RAI") process to date has been positive and the review has continued without delay. While this is a first-of-its kind EPU LAR application, PEF continues to work closely with the NRC on the EPU LAR, and the NRC has not identified any difficulty in review and approval of PEF's EPU LAR. PEF fully expects to obtain EPU LAR approval. There is no evidence to date that the NRC will not approve the EPU LAR.

VI. CONCLUSION.

Q. Can you summarize your response to the intervenor testimony with respect to the issues before the Commission in this docket regarding the CR3 Uprate project?

A. Yes. PEF has demonstrated that its 2011 CR3 Uprate project costs were prudently incurred and that PEF is entitled to recover them from customers. Jacobs does not dispute this evidence. PEF has demonstrated that its 2012 CR3 Uprate project actual/estimated costs are reasonable. Jacobs does not dispute this evidence. PEF has further demonstrated that the CR3 Uprate project is feasible. Jacobs does not address feasibility and, therefore, does not dispute this evidence. In fact, he must believe the CR3 Uprate project remains feasible because he does not opine that PEF should cancel the project and he in fact testifies PEF should continue with the project, albeit on a different schedule than the Company's current schedule. PEF has also demonstrated that its 2013 projected costs are reasonable. Jacobs nowhere testifies that any specific cost that PEF expects to incur in 2013 on the CR3 Uprate project is unreasonable. He recommends only that the Commission defer an unspecified amount of EPU construction-related costs to some period near the end of the CR3 containment building repair. He presents no evidence to dispute PEF's testimony that it has prudently managed the CR3 Uprate project and has minimized all costs it found reasonable to do so while still preserving the benefits of the project for PEF and its customers on an efficient implementation schedule. Indeed, Jacobs' recommendations to defer and then accelerate EPU construction would increase the costs of the project and result in increased risk for the Uprate project. There is, therefore, no basis for the Commission to accept Jacobs' recommendations and the Commission should approve PEF's 2013 projected costs as reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BY MR. WALLS:

Q And Mr. Franke, do you have a summary of all of your testimony for the Commission?

A I do.

Q Will you provide that at this time?

A Certainly. My March 1st, 2012 direct testimony supports the prudence of the company's 2011 actual costs incurred for the Crystal River Unit 3 uprate project. These costs were prudently incurred and the company is therefore entitled to recover them. My testimony also supports the reasonableness and prudence of the company's project management, contracting and cost oversight controls.

My April 30th, 2012 direct testimony and exhibits support the reasonableness of the company's 2012 actual and estimated and 2013 projected costs for the CR3 Uprate project and presents the company's long-term feasibility analysis for the CR3 Uprate project.

Based on the Commission's granting Progress Energy Florida's motion for deferral of a determination on the reasonableness of 2012 and 2013 CR3 Uprate costs and feasibility, my understanding is that these issues are deferred until the 2013 NCRC proceedings.

I am available to answer any questions you may have regarding the company's actual 2011 costs and the company's management of the uprate project in 2011. Thank you.

MR. WALLS: We tender Mr. Franke for cross examination.

CHAIRMAN BRISE: All right. Mr. Moyle?

MR. MOYLE: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. MOYLE:

Q Just so we're clear and we don't talk past each other, it's my understanding that the monies that you all are seeking, asking this Commission to award to you, relate only to 2011 costs; s that your understanding?

A Yes, today we're seeking prudency and recovery of 2011 cost. The 2013 and 2012 proceeding have been deferred.

Q Okay, so I'm not going to ask questions about those, and if I happen to stray into those, please tell me so, okay?

A Yes, sir.

Q Okay. And the amount of money you're asking this Commission to find is prudent is how much?

A Let me refer. I believe the total figure is right around $49 million for 2011 costs.

Q And I guess maybe you can help me understand. You do say 49, I think, on page five, line four. But then in your position statement in the order you say -- this is again on issue --

A I'm assuming you're referring to my March testimony?

Q Yes, sir, March 1, 2012, on line four, page five, you say you're asking for 49 million, right?

A Yes, under paragraph four, that's correct.

Q But in the position statement, issue 15, you asked for 49 million for capital costs, approximately half a million for O&M costs, and then carrying costs of north of 16 million, is that right?

A Yes, sir, and the number on line four of page five of my testimony is in reference to capital costs, only. You are correct, the other O&M and carrying costs associated with 2011 would be at issue today, as well.

Q Okay. So you would agree that's north of 66 million, give or take, that you're asking?

A Short of doing the math, yes, sir.

Q Okay. And I'm going to ask you some questions about the uprate project and also the CR3 status. And you had a second delamination event that occurred in 2011, the year for which you're seeking cost recovery, correct?

A That is correct.

Q And when did that occur?

A I'm not certain which delamination event you're referring to, but I believe you're referring to March 14th of 2011 during the retensioning of the containment building

following our initial repair.
Q Okay. And there was a previous delamination event, as well, correct?
A I'm not certain which one you're speaking to, but we repaired a delamination that occurred in 2009 and were repairing -- recovering the unit in March of 2011 when a second delamination occurred.
Q Okay. Has there been a third?
A Yes, sir, there was one in July 26th of 2011, as well.
Q All right, and as we sit here today there has not been a decision as to whether to repair Crystal River 3, correct?
A I don't agree with the way you've worded that. Our current position is we will be repairing Crystal River 3. We are proceeding with --
Q Let me just rephrase it. Did you review the testimony or did you follow the testimony when the CEO of Duke Energy appeared in front of this Commission a few weeks ago?
A No, sir, I have not reviewed his testimony.
Q Okay. So if I represented to you that he said they were considering whether to repair or retire the Crystal River 3 and that that was an issue that the Board would ultimately have to consider, would you disagree with that

representation?

A Your question was had we decided to repair the unit yet or not. I would say that the decision right now is to repair the unit. Now, as with all projects of this complexity and cost, we have an ongoing process by which we're going to review that decision going forward.

Certainly over the last year we have developed extensive engineering knowledge of what that repair will technically look like, the cost and schedule of that repair. And subject to review of that information, it's my understanding the Board of Directors will make a final determination to proceed with the current path, which is to repair the unit, or to retire it at a future date.

Q Maybe we're talking past each other. You know, I don't want to play words games. But isn't it correct that the ultimate decision whether to repair or retire this unit rests with the Board of Directors?

A Yes, sir.

Q And isn't it also true that the Board of Directors has not yet considered whether to repair or retire the Crystal River plant?

A I would say that they will be gathering the additional information. We are working on today to make a decision whether to repair or retire the plant in the future. As of right now, our path is to retire.

Q Mr. Chairman, if I can get a yes or a no -- your answer was we're gathering information, we're going to be presenting it to them. It's assumed that since you're gathering information that -- my question was, isn't it true that the Board has not yet acted to decide whether to repair or retire the Crystal River 3 unit?

A I'm not trying to -- I apologize if it appears I'm trying to dance around your question. I'm sincerely not. As part of Progress Energy, last year the Board of Directors was appraised of our decision to repair the unit in June of 2011. That decision has not changed.

Now, we know that since June of 2011 we have learned a lot more about what that repair will require, both technically, and the risks associated with that work, as well as other quantifiable and non-quantifiable issues surrounding this repair. And I am also aware that this issue will go up to the new Duke Board of Directors in the future for a continuation on that decision to repair or retire the unit.

So I guess what I'm trying to say is I'm trying to fully answer your question, but I believe that's the best way to answer it.

Q Okay. Well, you've injected a lot more into the response that we, I guess, need to explore. The Board of Directors that you're referring to was the Board of Directors of Progress Energy Florida, correct?

A Yes, sir.

Q Okay. The Board of Directors of Progress Energy Florida no longer exists, correct?

A That's correct, sir.

Q And as you sit here today, the Board that has operational control, responsibility, oversight of Progress Energy Florida is a newly constituted Board that I think is known essentially as Duke's Board, correct?

A Yes, sir, it has members from the former Progress Energy Board, as well, but it is the new Duke Energy Board of Directors.

Q Okay, and to call it, just for shorthand, the new Duke Energy Board of Directors --

A Yes, sir.

Q -- as we sit here today, the new Duke Energy Board of Directors has not made a decision to repair the Crystal River 3 plant, correct?

A I would say the most accurate way to describe that is they have not made a decision to change the current path with Crystal River 3. They will make a final decision on repair or retirement in the future.

Q So is it your testimony that the current assumption is that the Crystal River 3 unit is going to be repaired and that people should basically take the position of the company as we're going to repair the Crystal River 3 plant --

A Right now --

Q -- absent a change?

A Right now our decision is to repair the unit and that that decision will be reviewed in the future with the Board of Directors.

Q Do you know if you've made a filing with the SEC to indicate that the decision has been made to repair the Crystal River 3 unit?

A I believe our filings with the SEC have indicated we would be repairing the unit and that that decision would be reviewed with the Board of Directors in the future.

Q Do you know the purpose of the review with the Duke Board of the decision?

A Certainly. There are several purposes. First, the Duke Board of Directors were not as familiar with the issues, both technically and otherwise, revolving around a potential Crystal River 3 repair. So the first purpose was to inform them of the facts surrounding the questions.

Second, we have to remember that today we know much more about the repair than we did when the initial determination was made by the previous Board of Directors. So it's also -- the purpose is also to review with the current Board of Directors the additional facts that we are aware of.

Q Have you been asked for your recommendation as to whether to repair or retire the plant?

A No, sir, not directly.

Q You would agree there's a distinct possibility that the Duke Board, when being fully advised as to the Crystal River 3 situation, that they could decide to retire the plant, correct?

A Yes, sir, that is one option.

Q And you've been here throughout the proceeding this morning, correct?

A Yes, sir.

Q And you've heard the discussion about qualitative risk and quantitative risk?

A Yes, sir.

Q Okay. And just briefly, what -- explain your understanding of the distinction between a qualitative risk and a quantitative risk.

A Well, I mean, it's fairly obvious. A qualitative risk is one that a number can be placed against, and it may represent a financial risk associated with a decision. A qualitative risk is one that may not have a number applied to it, but may have just as much significance.

An example might be net present value to the customer would be qualifiable risk and a quantifiable risk are things like fuel diversity, impact on our community, other items like that that would be qualifiable.

Q So with respect to the availability of NEIL insurance proceeds, as we sit here today, do you know whether the NEIL insurance proceeds will be available to assist with the repair of the Crystal River 3 unit?

MR. WALLS: I'd like to object to this line of questioning. This is way afield of his testimony. We've given Mr. Moyle some latitude, given the delaminations happened in 2011, to address questions, but this is way beyond the project management and decisions made in '11 with respect to the uprate project.

CHAIRMAN BRISE: Mr. Moyle?

MR. MOYLE: Well, I think in terms of what I had mentioned in my opening statement, that the qualitative risk vis-a-vis this and Levy are worth exploring, that, you know, it's worth exploring NEIL to the extent they have the burden of showing that the project is feasible and moving forward and there are a lot of uncertainties out there, such as insurance. I think that's something that can be explored or should be explored.

MR. WALLS: We're here on the uprate project. There is a completely separate docket for the delamination phase two and phase three to come down the path later on, when the time is right, to address those decisions, and that is the place to address those questions.

MR. MOYLE: But I think we've already had testimony that the uprate doesn't work unless you get the Crystal River 3 unit repaired. I mean, it's wholly dependent on the repair of the Crystal River 3 unit, so I don't think you can divorce them as cleanly as counsel for Progress would suggest.

CHAIRMAN BRISE: Okay. Mary Anne, any thoughts?

MS. HELTON: Maybe if Mr. Moyle could help us point to what issue is being addressed here. As I understand the whole process, the delamination issues are being addressed in the other docket.

BY MR. MOYLE:

Q Let me come at it another way. So it is true that you're seeking money today associated with the uprate project, correct?

A Yes, sir.

Q Okay. But the uprate project is not effective -- won't do anything to the extent that the Crystal River 3 unit is not repaired, correct?

A Without repair of the unit and return to service, the uprate project would not be placed in service.

Q So if there is a decision that is made to retire the unit, wouldn't it follow that all of the money spent on the uprate will not produce measurable benefits for the ratepayers?

A Yes, sir.

Q And I think we've talked about whether a decision has been made, you know, on the repair-retire decision. I guess what I was trying to do is to have a quick conversation about NEIL proceeds and ascertain whether there's any certainty, you know, on those as a relevant point of inquiry, as well.

CHAIRMAN BRISE: No, you'll move on beyond that.

BY MR. MOYLE:

Q Do you have an understanding as to who has the burden of proof to prove that this is a viable feasible uprate project?

A I believe that's a question for my lawyers. As I understand the statute we are -- we submit information associated with feasibility every year and that specific point has been deferred in these proceedings.

Q Okay. I'm just asking you in your layman's understanding with respect to the project being feasible. Do you have an understanding whether it's your burden or whether the consumers have to show that the project is not feasible?

MR. WALLS: Asked and answered.

MR. MOYLE: If he doesn't know, he doesn't know.

CHAIRMAN BRISE: Yeah, restate your question.

BY MR. MOYLE:

Q Do you have an understanding -- you've testified in a number of PSC proceedings.

A Yes, sir.

Q Do you have an understanding as to who has the burden of proof to show that the uprate project is feasible?

A I believe my answer remains the same. The statute requires that the company submit feasibility annually and that the feasibility of this project has been deferred in the current hearings.

Q So you can't answer that yes or no?

A I'm not a lawyer. I'm not sure what the phrase burden of proof means.

Q Okay. Let me refer you to page 18 of your testimony.

A Yes, sir.

Q On page 18, line 21, you say that the contract requisition then goes through the bidding or finalization process. And am I -- am I correct that with respect to contracts that you either have sole source contracts or competitively bid them for work related to the uprate?

A Yes, sir.

Q Okay. And out of the capital dollars that are being requested, the 50 million, approximately, do you know how much of that was secured or procured through a sole source?

A That information is available. I don't have it ready at my fingers right now, but each of the contracts in my -- that are presented -- significant contracts in my testimony indicate rather a sole source or a bid process was used so the math could be done to come up with those numbers.

Q Okay. And with respect to the March 14th delam event.

A Yes, sir.

Q After that took place, did you all huddle and say, my goodness, this is the second delam that we've had, does it make sense to continue charging ahead with our uprate project that is dependent on the Crystal River 3 being repaired? You know, I'm saying that in a colloquial fashion, but I assume you all got together and had a meeting or two meetings to discuss that, is that correct?

A Yes.

Q And out of the 50 million in capital costs, do you know how much of that 50 million was incurred following the March 14th delam event?

A I don't have it down to the day, but I know that approximately 31 million was incurred between April and December.

Q So a majority was incurred after the delam event?

A Yes, but it represented a significant slowing of expenditures as expected and planned for 2011.

Q But you still -- you didn't put things on hold and say, you know, stop, we've had another delam, let's not spend any further money after that March event, correct?

A A more accurate description is provided in my testimony. We did put a significant slowdown in expenditures and controls in place to control spending going forward due to the uncertainty as well as due to the longer timeline now allowed by a longer extended outage in order to accomplish the extended power uprate work.

So, for example, I believe last year, prior to the delamination, our estimated expenditures in 2011 was just over -- well, I think the right comparison is about 94 million in 2011, and we ended up spending only 49, and the reason was because of that conscious effort to slow down certain pieces of the project and move forward on others.

Q Okay. And I'm not faulting you for the decision to slow down. I guess where I'm inquiring is, you know, did you put on the brakes fast enough and hard enough, really. And I wanted to spend a couple of minutes asking you about certain components of that.

A Certainly.

Q And it is true that after the March delam event you continued to spend money on license application activities, correct?

A That's exactly correct.

Q Okay. And you also continued to spend money on project management expenses?

A On some project management expenses. Others were deferred or slowed down.

Q Okay. And again, I'm just wanting to know that it was not a complete shut down. The permitting -- you continued to spend money on permitting, correct?

A That's correct.

Q You continued to spend money on on-site construction activities, correct?

A A small amount, yes, sir.

Q And you continued to spend money on non-power block engineering, correct?

A Yes.

Q And you continued to spend money on non-power block procurement?

A Yes.

Q And you continued to spend money on related construction to the non-power block engineering and procurement, correct?

A There was very little construction cost expended following the delamination, but I believe there may be some. If you look in the details there would be some there.

Q And to the extent that an ultimate decision is made not to move forward with this repair, all of those monies will have been, in effect, classified as -- you know, the common term is throwing good money after bad; you would agree with that, correct?

A No, no.

MR. MOYLE: Okay. I don't -- you may view the world differently than I. That's okay. Thank you, that's all I have.

CHAIRMAN BRISE: At this time we'll go ahead and take our afternoon break, and give our court reporter some rest there. So we will reconvene at 3:20.

(Brief recess)

CHAIRMAN BRISE: We're going to get ready to reconvene. We were getting ready for cross by OPC. Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. Chairman. And before I begin my cross examination, several preliminary items. First of all, I have discussed with counsel for Progress and to some degree talked to them about the scope of my questions. I am going to be asking questions of the witness in all three sets of testimony.

The scope of my inquiry is about the actual cost for final prudence determination and cost recovery from customers in 2013 under the NCRC. The issues related to the April 30th and the July testimonies relate to the process that the 2011 costs were evaluated against, and I just wanted to state that as a preliminary matter.

I have also passed out a confidential exhibit that relates to contracts sponsored by Mr. Franke and relates to that decision making. I have not provided copies to the two parties that are not signatories to the nondisclosure agreement with the company. And I have discussed with the company that the witness should avoid verbalizing certain information in of the agreements. I think he's well schooled in these contracts, but nevertheless, I am going to proceed cautiously in this area.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q So with no further ado, good afternoon, Mr. Franke.

CHAIRMAN BRISE: Before you move forward, that is the understanding?

MR. WALLS: Yes, Commissioner.

CHAIRMAN BRISE: Okay.

BY MR. REHWINKEL:

Q I would like to turn you first to your March 1st testimony, if I could.

A Yes, sir.

Q And on page three, lines 18 and 19, you discuss Schedule T-7 for contracts in excess of a million dollars for 2011, do you see that?
A Yes, sir.
Q Okay. And we'll come back to that -- to that later. As I understand -- if I could get you to turn to page -- well, first of all, Mr. Moyle asked you a question that I just thought I should ask a clarifying question about. He took you through some numbers and got you to agree, subject to check, that they equated to about $66 million, do you recall that?
A I believe 66 sounds like the amount reduced in 2011 from the original budget. Is that the figure you're asking about?
Q Well, I was talking about the 49 million --
A Oh, okay. Yes, sir.
Q -- plus some carrying costs. Do you recall that?
A Yes, sir. Yes, sir. Now I understand.
Q Just to be clear for the record, the company is asking for $40 million in revenue requirements to recover in 2013; is that your understanding?
A That -- subject to check, that sounds correct.
Q Okay. And the $49.6 million is the capital additions that you reference, correct?
A That is correct.

Q And those dollars, that $49 million, if the Commission agrees with the company, those dollars will be given a final prudence approval, correct?

A That is correct.

Q And those dollars then will be recovered from customers when they are added to the plant-in-service accounts in the rate base and recovered as a part of the base rates, is that your understanding?

A That's my understanding.

Q Okay. So there's not a $49.6 million capital addition recovery other than the carrying costs associated with those?

A That's correct. I was answering the questions relative to his question about capital expenses, is how I read his question, sir.

Q Okay. I just didn't want there to be a headline that there was a $66 million request from customers.

A I was asking in terms of the expenses, not the revenue requirements.

Q Perfect. I understand. Thank you. So isn't it true that the -- if I take you to page 12 of your March 1 testimony and direct you generally to lines six through 12, that the $49 million number that Mr. Moyle asked you about earlier is the resulting balance after reducing your capital expenditures by $45.2 million from the prior estimate?

A Yes, sir, that's correct.
Q Okay. Now, Mr. Moyle asked you about your license application costs, do you recall that? And I want to ask you some follow-up questions along that line. I believe that your testimony shows that you had $2.8 million of LAR or license application renewal -- is it license application --
A Request.
Q -- request, or LAR dollars in 2011, is that right?
A That is correct, 2.8 million were applied in 2011.
Q Okay. And just so I understand what your testimony states here on page 12, you describe a variance of $1.2 million and you say that it is because the AREVA engineering support costs were budgeted to engineering but invoiced to licensing. Do you see that?
A That's correct.
Q Is that saying that it was actually -- should have been always licensing and it just happened to be budgeted the wrong way? Is that right?
A I think that's correct. Remember that some of these engineering costs, specifically the AREVA costs, it's almost -- it's challenging to know which bucket to put it in because they both support engineering and the license application. But in this case this was a reflection of some that had been budgeted to engineering but got applied to the licensing portion in this budget year.

Q Okay. What I'm asking about this is would you accept, subject to check, that for 2012 the amount was 2.8 million for LAR costs?
A I would agree, subject to check.
Q And for 2013 it was 2.4 million?
A I would agree, subject to check.
Q I say was. It was projected to be that amount.
A Yes, sir.
Q So is there something about the LAR process that it's in that 2.4 to 2.8 million dollar region regardless, or does it just happen to work out that way? Can you tell me why they're kind a of steady state number?
A These were based on our best projections at the time that the filings were made. Obviously the licensing work is one difficult to know exactly what the costs are because essentially it's the amount of money required to initially do the analysis, but then once we get into the review process with the NRC, it's how much costs are required to respond to questions we haven't -- we haven't received yet.
So it's -- of course it's difficult to know how much it will cost to answer a question you don't know what the question is yet. So these numbers tend to be a little uncertain because we're not certain how much detail the NRC may ask for, although we do our best to prescribe how much it

should cost, and these are our best estimates.

Q Okay. Just so I understand -- and I'm not trying to replow old ground, but for 2011, were the license application costs, regardless of how they were budgeted or invoiced, were they a million six, or were they 2.8 million?

A They were 2.8 million.

Q Okay. Now, is there anything to your knowledge about the LAR costs that would allow them to be avoidable or deferrable in any way?

A Once the work is done then it needs to be paid for, be it either by the NRC or by our vendors for doing the engineering work in support of that licensing work.

Q When you say by the NRC, you're talking about payments to them for the work?

A Yes, sir, we pay them for their review of this license application.

Q Okay. Okay. Can you tell me, on page 13, if you can turn there, about what you mean on lines 15 and 16 when you talk about 25 percent of the variance -- and here you're talking about the Power Block Engineering, procurement and related construction costs. Twenty-five percent of that variance to budget is attributed to deferring 2011 contingency funds. Can you tell me what that means?

A Well, I think what it means is, we tried to detail why the money was spent -- was below our projection and obviously there are contingency funds assigned to specific activities like, for example, construction. You have a budget for the construction phase of a particular engineering product and there's an amount of contingency that is applied to that portion.

In this case, for example -- and obviously, you know, there's a lot of different places where this would apply. But a typical example for this would be a construction activity that we had earlier in the year envisioned occurring in 2012 not occurring. The contingency funds associated with that construction activity would move with the construction activity as we delayed that work.

Q Okay. So my question is along these lines. I'm looking on line eight. There's a variance of $34.2 million. Do you see that?

A Yes, sir.

Q So roughly eight million or so would be 25 percent of that 34, right?

A That's correct.

Q So customers would probably want to know, given the state of the containment building and the repair, why there would be any contingency they would be asking to pay for. So is contingency part of what is being asked for recovery, or are you saying because you spent 46.8 million, there was no contingency, it's just what you spent?

A The 49 is what we spent. It does not include contingency money. But as we project future costs, we include contingencies so that the actual values notified ahead of time better match what the actual spend is after the work is completed. Does that make sense?

Q Okay. So if you proceed with the project -- and this is kind of more of a process issue as I'm trying to understand how you go through and whittle down costs to the absolute minimum and still keep your project on schedule and keep the repair viable.

What steps do you take to minimize contingency with respect to what customers are being asked to pay for, whether it's an actual estimate or even in the projected categories?

A Well, the way I understand the way the customers will be paying, they'll only pay what is actually spent. So for the purposes of future budgets we identify contingency funds to address unknown aspects of the project and be able to pay for those in future years.

In this case we're only asking for prudency on 2011 actual costs, and the only place where 2011 actual costs may have -- they may have represented a contingency fund before we got to that problem and that money would have actually been spent, I assume, in 2011.

Q Okay. Let's go to your April 30th testimony.

Just so I understand, on page ten, near the bottom of the page, lines 21 through 23 -- and when I ask you questions about 2012 and 2013, I'm trying to understand your process. I'm not going to ask you -- my question isn't intended to go to you explaining the prudence or the reasonableness of any costs for 2012 and 2013.

But would you be able to explicate here for the benefit of the Commission what you mean by the statement that starts with current project costs in 2012 are virtually identical? Do you see that?

A Yes.

Q And I'm asking you that in the context of what we heard earlier in the day where delay adds costs in the form of carrying costs.

A I do believe that delay can add cost, but I believe when we wrote this statement here we felt that there was enough contingency available in this project, as we described earlier, that it may not represent a significant increase in this specific project due to the nature of the work that remained in this project.

Q Okay. On page 12 of your testimony, carrying through to the top of page 14, you discuss the status of the LAR, the L-A-R. For purposes of your evaluation of the feasibility of this project on an ongoing basis, has the status of the LAR changed any since you filed your testimony?

A Only that the LAR has continued to move forward with the NRC. We've had both meetings with them to talk through technical issues associated with that licensed application, as well as received numerous sets of requests for information from the Staff, and answered those requests.

I believe, as each month goes by, we gain continued confidence in the ability to complete the licensed application with the NRC.

Q Okay. So on the top of page 14 you state that the company believes that NRC will approve the EPU LAR in 2013.

A Yes, sir.

Q Is that -- is there an early, middle, late of the year estimate that you have?

A The last information I received was that they -- we have heard and responded to 17 of the 18 technical branches' questions. We're anticipating the last branch to be submitting their questions very soon, and that the NRC should be writing up their response if they continue to find our application acceptable this fall, and that we may be in hearings in early next year.

Q Why are you expecting a hearing?

A It's part of the process. This is just an ACRS committee hearing. These aren't public hearings.

Q Okay. So you don't have any Atomic Safety and Licensing Board contentions?

A No contentions, no, but those boards will hear the application.

Q So if -- we talked earlier about $2.8 million of LAR costs -- I'm sorry, 2.4 million in 2013. Are you expecting that these costs -- you would incur somewhere in the same neighborhood in 2013, even though you expect to get your LAR in 2013?

A That's what we believe right now, but obviously, again, like I said, licensing costs are difficult to predict because they're based on, you know, uncertainty as to how many questions and what type of typical questions will be needed to be responded to.

Q Okay, and just one last LAR question. Is it the company's position that LAR-related costs really are not going to vary regardless of whether you slow down or curtail other type of work; it's pretty much a fixed cost with respect to pursuing the project?

A Yes, sir, we believe that the LAR costs will be the same whether we sped the project up or slowed it down. But once it is in the process it's important to continue the licensing application through its end, and that's what we're doing.

Q Okay. Now, with respect to your testimony starting on line 12 through 21, on page 14 of your April 30th testimony, this is where you talk about awarding the EPU phase construction contract in 2013 under your current schedule. Do you see that?

A Yes, sir, I do.

Q Okay. Is there any cost that the company incurs to have the ability to award that contract to a vendor or has this gone out to bid yet?

A No, it has not gone out to bid, although we have spoken with a number of firms about the scope of work to try to -- we've used those discussions to create the budgets that you've seen, to create the cost estimates that we've seen for the construction phases, so we haven't actually bid the project, but we have let vendors look at the scope of work so that we could best estimate our construction costs.

Q And is it 100 percent that you will bid this work out?

A No. Well, we will -- when we -- if and when the decision to continue with the EPU project is made, yes, we will bid it. If your question is will we bid the project, absolutely. But we will delay signing a construction contract until we have the best understanding of a repair schedule for the containment as well as that final decision on retirement or repair of the facility.

Q Okay. So to the extent -- let's say that for whatever reason in the future the company decides not to pursue the EPU, for whatever reason. Costs associated with the construction contract are entirely avoidable. You don't have any up-front costs or reservation or retainer costs or anything like that because you haven't bid it out, right?

A It's always difficult to state an absolute. Some construction costs would still occur, but I would say the vast majority of construction costs would be retrievable.

Q Okay. Retrievable in the sense that if they were projected it would never occur, then?

A They would never be spent. They would never be spent.

Q Okay. Let's look at the bottom of 14, continuing on to page 15. And this is something I want to spend a little bit of time with you on. On lines 22 and 23 you talk about necessary progress payments on the LLE. That's long lead equipment, right?

A Yes, sir.

Q For the uprate in 2012 and 2013. But you reference reviewing this process in 2011, right?

A That's correct.

Q Okay. So did you use the same kind of review process to evaluate or seek to curtail long lead equipment progress payments in 2011 or were any of those costs subject to this type of analysis?

A Oh, absolutely, they were. They were reviewed under a review process prior to completing to any additional long lead costs.

Q Okay. Were there long lead equipment costs that you were able to avoid or mitigate in the procurement process with respect to 2011, once the March delamination occurred?

A There were some that were delayed after the March, 2011. Most of our long lead contracts, based on the original schedule, had already -- had already been executed and the majority of the work on fabrication on most of those long lead items had occurred. But, for example, there was a request to purchase two new feed water heaters as a scope addition that was -- that came forward in the first quarter of 2012, or soon after the delamination in March of 2011.

The decision to commit to that purchase was delayed until the schedule indicated we needed to go ahead and let that contract in order to support our strategy of being capable of executing the extended power uprate during the current outage.

Q Okay. So in that example those costs would have been deferred from recovery in '11 but would be subject to recovery in a later period?

A Yes, that's correct. And we have executed those contracts now and that did push the money into years after 2011. So that's an example where we used that to process.

Q Okay. So that $45.2 million number that we talked about in your March testimony --

A Yes, sir.
Q -- on page 12, some of those dollars weren't necessarily avoided completely, they would be -- they would have been deferred and encumbered in the sense that you were legally obligated to pay for them, but at a later time?
A That is correct. There is a subset of that money that was delayed to future years but we are still encumbered on. Some of them are dollars that by choosing not to execute a contract in 2011, should the project ever be cancelled, would never be spent. So there are dollars in both those categories in that 45 million.
Q Do you have any idea, of that 45.2 million, what the breakdown would be?
A You know, it would be challenging to come up with an accurate figure, because every contract is written a little bit different.
Q Okay. Tell me again about -- let's go back to page 14 of your April 30th testimony and let's talk about these progress payments. Just talk about them for a second. What do they represent? Do they represent payments that you are obligated to make under the contract if you are going to take delivery of certain LLE items?
A Yes. Typically a manufacturing contract would require committing to pay funds based off of the work accomplished at the factory, for example. So if the LP

turbines were already manufactured, and the manufacturing was complete, that contract would require a certain amount of obligation by the company, based on that manufacturing point. But the total contract may not be paid until delivery, for example. So it all depends on the way the contract is written and the milestone payments and payment against work already achieved.

Q Okay. So if I go down and look on page 15, lines seven through nine, there's the sentence that says most of the LLE Progress payments for 2012 and 2013 reflect preexisting contractual commitments.

A That's correct.

Q And was that same statement true with respect to 2011?

A Yes, that is principally true, in general. And why I say -- remember our original plan was to execute the last phase in '11 and then as the project moved we did delay some of those into 2012. So by the nature of long lead equipment purchases, they have to be ordered and committed to prior to, obviously, the outage in which they're going to be installed. So in general that is accurate.

Q Okay. And I understand -- I'm asking you about what's on 15, really, with respect to what happened in '11. So when I look at lines nine through 12, there were payments, it says deferral of these payments -- and that refers to long lead equipment progress payments, correct?

A   Yes, sir.

Q   Deferral of these payments cannot be accomplished without cancellation or suspension of contracts, which would result in penalties and an uncertain future regarding LLE contract renewals to meet the current EPU work phase work schedule.

Is it your testimony that what you did in '11 was to analyze your progress payments that were coming due under your contracts and made a cost benefit analysis about whether to make the payments or to engage in whatever penalties or uncertainties would inure to not making the payments, i.e., having to review the contract?

A   I would agree with the way you've described it, but it wasn't simply a cost benefit analysis. And as explained in my testimony, we established a policy that we wanted to be able to execute the extended power uprate during this current outage as an option, so in some cases long lead item procurement needed to proceed in order to be able to maintain the option of execution during that outage. Does that make sense?

So in some cases it was purely a, listen, we've already paid for that component, all we're talking about left is the delivery cost associated with receiving it; it makes sense to go ahead and pay that delivery cost, from a cost benefit analysis.

In other cases, specific long lead items might be ordered or we'll continue a contract for a long lead item in order to support our stated decision, which was to maintain viability of execution of the project during this outage.

Q I think -- I think with respect to a question from Mr. Moyle and in relation to that $49.6 million that you actually spent in '11 --

A Yes, sir.

Q -- I think you said something -- maybe it was 31 million was spent after -- say from April to December, is that right?

A Yeah, I believe so. There's a schedule that shows our month-by-month payments, and I believe the total is around $31 million spent in April to December.

Q Is that schedule in the -- in your -- is it an exhibit to your testimony?

A It's an exhibit to, I believe, Mr. Garrett's testimony that I helped sponsor. And it's -- I'm probably going to get caught up in -- the figures can be found in the schedule, I believe. I'm looking at -- I'm looking at Schedule T-2.3, which is in Mr. Garrett's testimony, page 5 of 36.

And I know I'm going to get outside my expertise relative to what category of capital expense this is, but if you look at line one, this is a very close approximation. It's construction cost, plant additions to the period, and it shows month by month the expenditures. And I believe the figures could be calculated from there.

Q Okay. So you're talking about the amounts?

A Yes, sir. It gives a reflection of how much was spent month by month.

Q Okay.

A Now, we didn't cut it off on March 14th, but by the end of the month the figures are available.

Q Okay. So of that $31 million, do you have any familiarity with what percentage of that was based on long lead equipment obligations that you were legally required to make under preexisting contractual commitments?

A I'd have to go back and go through each contract to know a certain number, but I have been given a figure of approximately 16 million of the 31 million.

Q Okay. So would it be fair to say that for the balance of that, the other, say -- the other half, 15 million or so, would those have been engineering activities required to support the minimal construction path activities that you were -- that you had decided to undertake?

A That would be a good example. It would also include licensing activities associated with that same path. So as I detailed in my testimony, in general, after the March delamination, we continued with expenditures in the following areas. One was the long lead items we've now had a discussion concerning; engineering activities in order to finalize the engineering plan for execution of the remaining phase of the extended power uprate; the licensing activities associated with achieving the NRC approval for that work.

And then there's some other costs, like facility costs, that were necessitated, for example, for receipt of those long lead items, some, obviously, construction facilities to store those things, items, properly.

But in essence only those activities which were required to maintain the ability to execute during the current shut down were approved and moved forward, and we did continue moving forward with all the licensing and engineering work.

Q Okay. On pages 16 and 17 you talk about the POD tower, the point of discharge tower.

A Yes, sir.

Q Do you see that? Were any of these costs -- these meaning relating to the POD tower -- were any of those deferred out of 2011?

A I'd have to go back and look. I believe most of the 2011 POD costs had already been deferred for other reasons. Principally the only costs right now we have in this area have to do with storage and maintenance of the current components so that should that project be cancelled we have salvage value on that equipment.

Q Is it possible that you -- depending on what happens with the EPA rules and Crystal River 1 and 2, that you may not have to implement that aspect of the project at all?

A That is correct.

Q Finally, in your April 30th testimony, if I could get you to look on page 20, on lines 12 -- on line 12 there's the $617 million figure. Do you see that?

A Yes, sir.

Q And I think that was also the number last year.

A Yes, sir, it has not changed.

Q Okay. At the time you wrote the testimony it was 617. Is that subject to change as we are in this hearing today?

A No, that's still the figure that we currently have.

Q Okay. We heard some discussion, again, about delay can cause costs to go up. Will this number change if the project is delayed beyond the existing estimate of in service, I think, what, in early '14? No, I'm sorry, early '15, right?

A I think the best way to resolve this kind of goes as follows, Mr. Rehwinkel. When this 617 number was derived, there was a certain amount of contingency booked at that time based on the uncertainty in engineering and uncertainty in construction costs associated with these last phases of the project. And the project manager has continued to monitor that total project cost as the delays have occurred and as we've learned more about the project.

Now, remember that this is a -- there's a lot of, you know, moving balls in this juggling act. One, the number may have been based off of a short, compressed schedule during an R-17 outage where costs to install are much higher due to overtime costs and requirements for much more personnel to implement over a shorter time frame.

Okay, now we're envisioning construction over a longer period of time to reduce those costs, so that would cause the project costs to go down. Additionally, since that may be executed later in time, while we have less man hours to implement the project, less overtime hours to implement the project, there's going to be a cost increase due to it being done later in time.

So it's my understanding the project manager believes that this figure, with this contingency, still represents the best known cost for the total project.

Q Okay, I sort of lied. Now let's talk about JF-5. I meant to ask you one question about that.

A Yes, sir.

Q On page five of six of your JF-5 -- can I get you to turn to that?
A Yes, sir.
Q And we see that through the end of 2011 you show total project costs, it looks like, of 333.6 million. Do you see that?
A Yes, sir.
Q Okay. And then there's a number of 20 million, which is, I guess, if you cancelled sometime like today you'd have additional costs throughout '12 to give you a total of 353.3 million. You could get out of the project for this amount of money, is that right?
A Well, that was the estimate at the time of this presentation. Obviously this presentation was made over a year-and-a-half ago, I think, now. So these numbers, for example, have changed. For example, the 2012 estimate, this was canceling at --
Q February of '12?
A Right, before the delamination occurred, even, so --
Q I'm looking on page one. It says February of '12.
A I'm sorry, I got the wrong year. So it is February of '12.
Q All right.
A So there's a couple things that have changed.

First of all, I think the costs through 2011, actually, if it was not -- well, okay, so it is 333.6. I know there's another figure in Mr. Garrett's number which I think relates to what portion is under NCRC, and what may be under other cost recovery mechanisms. But I believe the number for our purposes is actually 318 million, as shown in Mr. Garrett's figures. And the 2012 estimate here would have been for canceling it in February. So obviously, as we spend money each month, that figure changes.

Q Okay. So it will be whatever the actuals are after February through today?

A It's -- not exactly. And the reason for it, obviously, to get out of some contracts there would be some continued payments associated with some contracts that have ongoing work, and it would depend on the terms and conditions of those individual contracts.

Q Okay. Let's go to your July 9th testimony. And I want to take you to pages 12 through 15.

A Yes, sir.

Q And this, on lines seven through nine, you talk about incurred and committed EPU costs in the first quarter of 2011, and those costs were not amenable to revision as a result of this event.

A That's correct.

Q Can you give me just a little more explication about what those are? Is that everything but the $31 million that you talked about?

A Well, some of them -- some of these monies are included in the 31 million. So I believe -- you're referring to lines five through seven, starting with in 2011, prior to the March 14th delaminations?

Q Well, actually, talking about the first quarter of 2011 costs in lines seven through nine.

A Yes, sir.

Q Okay.

A So some of that -- some of these costs -- this is discussing the fact that prior to the delamination the company had committed to expenditures that were -- we were not able to get out of, and as a result those costs would continue going forward.

Q Okay. On line 20, you state that to develop the current CR3 Uprate project schedule, PEF evaluated the EPU phase work to identify what work was critical to proceed with to maintain a schedule to complete the EPU, et cetera. Do you see that?

A Yes, sir.

Q Okay. When was this evaluation done that you describe here?

A It was done immediately after the delamination, later in the month of March. And then, again, we looked back and sat down and continued to discuss this concept of continuing moving forward with those critical tasks only that maintain the option and delaying and deferring all other costs. So it was done immediately after the delamination and then going forward it was applied to each decision as we moved forward.

Q Okay. And then so you describe on page 13, lines four through nine, and actually continuing on, but the bulk of what your analysis is, you say, no EPU phase work has been or is being accelerated, all overtime work has been postponed, only working regular hours on EPU. And, again, we talk about delaying the selection of the contractor. Do you see that?

A Yes, sir.

Q And individually evaluated each contract and change order.

A Yes, sir.

Q So this is -- this is a process that's ongoing, it doesn't just revolve around testimony deadlines or hearing schedules, you do this --

A Absolutely.

Q -- year round?

A Absolutely.

Q Okay. And is this protocol -- is this process still in place?

A Absolutely.

Q What do you mean by EPU phase work? Can you tell me what that means?

A I believe they're just referring to the third phase of EPU.

Q Okay. Okay. So it's the extended uprate phase, the third --

A Right.

MR. REHWINKEL: Okay. All right. Mr. Chairman, at this time I would like to take up the confidential exhibit.

CHAIRMAN BRISE: Sure.

MR. REHWINKEL: And let me -- this exhibit probably needs a number.

CHAIRMAN BRISE: Sure. We're at 127.

MR. REHWINKEL: And for a short title you can call it 2011 through 2013 T Schedules.

CHAIRMAN BRISE: Okay.

(Exhibit 127 marked for identification.)

MR. REHWINKEL: And this is a confidential document. Let me describe for the Commission what I have done. What Progress does each year for both aspects of the NCRC, whether it's Levy or CR3, is they're required to give you certain information about contracts over a certain threshold amount. They keep certain of the information confidential for business reasons.

I have taken selected contract items and I have put a hand-numbered, randomly assigned letter, and I would -- so my purpose is for this document to go into the record, it would be kind of a key, to get from the discussion to the confidential information without revealing the confidential information.

So it's important whether the witness is answering questions or others are answering questions about it that there be no reference to the information that's in here, especially associating information that is in the public record with the letter.

So I am going to be focusing mostly on the amounts in Column G, for example, that are expended in the current year.

BY Mr. REHWINKEL:

Q So with that explanation, Mr. Franke, are you familiar with this document?

A Yes, I am. I have had a chance to look it over.

Q Okay. And these schedules, whether they're for '11, '12 or '13, are ones that you are a sponsor of, correct?

A That's correct.

Q Okay. I just want to ask you a few questions about certain of these contracts, and I would ask you to err on the side of not disclosing information unless you're absolutely certain that it's -- the way you talk about it is not confidential if you verbalize it.

A I understand.

Q But if you see Item E -- and I'm not going to refer to where on the page it is, it's just an item that's on this page.

A Which page are you referring to?

Q Let's go to the first one. This would be the estimated, the AE schedule. These are amounts that you would have estimated in 2011.

A So this is Schedule AE-7?

Q Yes, for 2011.

A Yes, sir.

Q If I look in column G, I see a certain amount, and if I turn over three pages to T-7 for 2011, I see an amount that's different and materially lower for the same Item E. Do you see that, in column G? Am I doing this right?

Q Yes, I am -- your E was a little difficult to find on T-7, but --

A Okay. You see a group of E, I and B?

A I found the same one, yes, sir.

Q Okay. Yeah, I didn't write a very good E there.

A So as I -- you're referring to two number. On the AE-7 filed in 2011, there was an amount in column G that was the amount projected to be expended in 2011, the year -- during the hearings or during the filings in support of 2011 hearings.

Q Correct.

A Okay. And then on the T-7 schedule, they're referring to column G, this is the amount actually expended in 2011, filed the next year.

Q Right. For that contract, right?

A Yes, sir.

Q This is one of the -- well, can you tell me the difference in the amount, roughly?

A It looks like it's just less than $4 million.

Q Okay. And is that difference -- is that part of the slowdown and expenditures as a result of the delamination?

A Yes, this specifically was some engineering work that did not need to proceed at the same pace and so that work was slowed down and not as much work was applied in this case.

Q Okay. And if I look at item I -- do you see item I, back on the AE schedule?

A Yes, I do.

Q Okay. Now, as I look in column G and then do the same comparison to I -- and I, in this case, on the T Schedule for 2011, is right next to E, is it not?

A That is correct. That is correct.

Q And it looks to me that there is more expended in 2011, actually, than was estimated.

A Yeah, it looks like if I do the math, in round numbers, approximately 800,000 more expended for that line item for item I than had originally been estimated in 2011.

Q Now, why would that happen in the context of what was going on, if you can tell without revealing confidential information?

A I don't think it -- yeah, I think this specifically was there were scope -- early in 2011 there were scope additions identified that required additional work in this particular area in order to meet that need that we described earlier, which was maintain the ability to execute during the current outage.

So there was scope additions which required engineering work that would be charged to this particular contract that were identified in 2011. Those scope additions met the requirement we discussed relative to being required to be completed to maintain the option of executing the extended power uprate.

Q Now, without reading out loud, even though it's not confidential, the work description over in the far column, does anything about that work description tell you whether this -- what phase of the project this related to?

A I know it's phase three.
Q Okay. And if I can get you to look at item H.
A Yes, sir.
Q And if I compared column G for item H to column G for item H in the actuals, again, it looks like there was -- it's not a significant amount, but there was an increase in what was spent versus projected, is that right?
A This is item H?
Q Yes.
A Yes, there's a small increase, on the order of about $350,000, it looks like --
Q Okay.
A -- between the two line items.
Q Do you have any information about why that would have been --
A I believe that was --
Q -- in the other direction?
A Yeah, I know that this particular line item was some late scope additions, so I suspect it was a refinement of the actual costs between 2011 and then earlier in the year than when they were actually procured at the end. I know there were some scope changes on this specific line item. And those scope changes are included in other -- in one of my attachments to my March testimony.
Q Okay. So -- but generally, if I compared these

items in this -- the contracts from AE of '11 to final '11 --
A Yes, sir.
Q -- they generally would be reduced compared to the estimate?
A Yeah, this is -- this is -- I would say it's best described as a subset of that reduction in expenditures that we discussed earlier between the approximately $94 million and the actual money expended in 2011.
These contracts and the changes between the estimated during 2011 and the actual by the end of the year is a subset of that reduction in expense in 2011.
Q Okay, thank you. Let me go -- let me take you now to the 2012 and 2013 contract amounts. And I just want to ask you, if we look again at item E --
A Yes, sir.
Q -- do you see that for -- actually, I think, what I have done, I have put these backwards. So the last page is '12, so if you could go to the last page, that's the 2012 one.
A I believe that you're talking about the P-7 schedule?
Q I may have -- mine may be out of order. I'm looking -- I'm trying to look at AE-7 for 2012 which in mine is the last page. Do you see that one? All these are on one page instead of two pages.

A Hold on.
Q You see the very last page? It's in smaller print.
A Yes, this is an AE-7 schedule docketed this year.
Q Okay, this is for 2012.
A Page 17 of 50?
Q Yes, sir.
A Okay. Yes, sir.
Q Okay. So if we look at item B, you see an amount in column G. Do you see that?
A Yes.
Q And if you go back to the page 15 of 47 for 2013, on the P-7 schedule -- this is all projected -- you see another amount next to the dollar sign. Do you see that?
A Are you talking about column F?
Q In column G.
A Column G.
Q That's a number.
A Yes.
Q Okay. If you compare those two numbers, does it tell you anything about what is going on? Is it because the work was being deferred or was there another reason why there was a difference in the number in '13 versus '12, if you can say?
A Let me make sure I understand. You're asking

about the difference between a projected expended in 2013 --
Q Right.
A -- on the P-7 schedule --
Q Correct.
A -- versus the amount projected expended in 2012?
Q Correct. I understand these are not -- this is not a true-up, these are just different amounts in different years, right?
A Yes. I guess -- I'm not trying to -- I'm not trying to be smart. I don't understand the relationship you're seeking between a 2012 estimate and a 2013 estimate.
Q I guess my question is, is there a reason why there's a difference directionally in 2013 that you would spend under this contract, which is the same contract, you know, for --
A I think it's more a reflection of that the majority of this work is expected to be completed in 2012.
Q Okay.
A So the number in 2013 is -- I guess it can't be proprietary, but the number is zero, on the P Schedule that we're anticipating in 2013. But that's because we believe that scope of work would be completed in 2012.
Q Okay, that's what I wanted to know, whether the work was being done or was there any --
A Well, to your point, there may be some money move

into 2013 as this work is slowed down.

Q Okay.

A So when we filed this testimony, it was envisioned that this work would be completed in 2012. There may be some of that scope of work and how it reflects specifically to costs, it would be difficult to project today, as I sit here, but there might be some of that work that was deferred that ends up going into 2013. So we may have some money expended in 2013 on this contract, but that would be due to the slowdown.

Q Okay. So if that happened, that deferral wouldn't represent a cost to the customers in the sense that you just wouldn't incur it in 2012, you would incur it in 2013 --

A That's correct.

Q -- there wouldn't be any carrying costs, because it would be trued up because you didn't expend it, et cetera?

A That's exactly correct. This particular contract is one that's principally time and material, so it's man hours expended. So as the man hours expend, we are required to pay them. The slowdown allows that expense to be delayed.

Q Okay. And now, item B, if I could get you to stay on 2012.

A Yes.

Q Okay. Item B, you see a certain amount --

A Yes.

Q -- in column G for item B, and then the corresponding item B for 2013, you see an amount that's materially different.

A Yes, there's a -- you're referring to 2012, item bravo, B.

Q Right.

A There is a number and the number is not necessarily proprietary. It's 3.9 million. And then in 2013 right now is a $10 million number.

Q Okay.

A Relative to this specific contract to, I believe, the questions you're asking, that 10 million principally is construction and installation costs, the vast majority of it is. So in this case the decision to implement that construction can be deferred until later. We do not have a current committed contract to do that construction activity and so if it's not actually performed then the work would not have to -- would not cause any expenses and therefore they would not go to the customers under the clause.

MR. MOYLE: Mr. Chairman, my -- I just need a little help. My impression was all the '12 and '13 costs were being deferred and being delayed, and, you know, I refrained from interposing this objection but all this seems to be '12 and '13, you know, information, and the document speaks for itself if the document is coming in. I'm not sure of the relevancy of the '11 cost.

CHAIRMAN BRISE: Mr. Rehwinkel?

MR. REHWINKEL: I don't think -- do I have a respond to an objection from Mr. Moyle?

MR. MOYLE: I'll object to relevancy grounds. It's not relevant based on the issues that are in play.

MR. REHWINKEL: I am probing the process that the company is going through. And part of my method is to understand if they are applying it consistently and if there is items that can be deferred or avoided. And this is more of an exercise in how the company makes its decision, rather than these specific costs. I have one more question on this particular item here.

CHAIRMAN BRISE: Go right ahead, Mr. Rehwinkel.

MR. WALLS: We have no objection to Mr. Rehwinkel's line of questions.

BY MR. REHWINKEL:

Q Mr. Franke, is it possible that these items in -- these dollars in item B can be avoided in entirety or --

A Yes, just --

Q I'm just saying, if you don't complete the project, could these be avoided entirely?

A Yes, sir. In fact, the specific line item you're on now, line bravo, there's approximately a $10 million expense associated with construction activities, that, for example, right now is shown in this particular schedule is in 2013.

We are in the process right now, under the policies we described, of evaluating would this be implemented in 2013. While that decision has not been made, it is likely this particular construction activity would be delayed so that money would not be expended in 2013 under the policies we've described. And should the project be cancelled, there would be no charge ever -- you know, no invoice ever received, no cost experienced, and this particular cost of 10 million would be vastly reduced.

There would be some very minor costs associated with some materials that may have already been manufactured for this activity, but it would be small in nature to the total price.

Q Okay, thank you. And let's -- I would like to ask you about one further contract, and this would be item D, as in David. And I ask you to go to the last page, the 2012 AE-7.

A Yes, sir.

Q You see an amount in column G, and then if you go back to the prior page for 2013, there's a column G amount. These are numbers that are materially different. I think I've deposed you ad nauseam about this particular item that's the subject of this contract here.

A Yes, sir, we spent a lot of time on this one last year.

Q Are these costs avoidable in entirety, or are you legally encumbered on these?

A These particular costs, the vast majority we're encumbered upon. This particular contract required manufacture of components that had to be tested in order to achieve our licensed application and those components are all but manufactured, going into testing now, so most of this money we are encumbered to expend.

Q Okay. So these are just -- the examples I've gone through are different types of analyses that you're going through. Some of them are time and materials, you can avoid them entirely. Some are maybe more hard assets that you may be able to defer or avoid entirely some of those costs. And then some of them, you've bought them?

A Yes, sir. And I would say, also, some of the ones we've bought, there may be some salvage value to receive the components and then dealing with them on the back end, should the project ever be cancelled.

Q Now, if you have a salvage value on an item, especially a hard asset, that would ultimately be trued up at some point down the road?

A That's my understanding, yes, sir.

Q Okay. The last line of inquiry, if I could, Mr. Chairman, is in your Exhibit JF-7. This is in your Level II Schedule. This document is all public record, correct?

A I'm trying to find my JF-7.

Q Oh, I'm sorry. It's part of your rebuttal testimony.

A There we go. Yes, sir.

Q Okay, this is all public, even though it's a nice color document, it's public, right?

A Yes, sir.

Q Okay. As I understand this, if I look in the far left-hand side of this document, if I see something that's in black and I look at the key, it's something that's in progress, is that right, at the time that this schedule was attached to your testimony?

A That would be correct.

Q Like if I go to the second page, you have an engineering project related to overall margin, and that's kind of a licensing basis sort of analysis you have to do, right?

A Yes. So if you have a color copy, the black -- the transition from black to blue on these lines represent the date the report was made. So to the left represents work accomplished on this project. To the right in the blue lines would represent the work on the schedule that has not been achieved on this particular line item.

Q Okay. So if we see stuff on the right that's in the light blue, what does hammock mean in the context of this document?

A Hammock is a scheduling term which means a group of work that has a common -- a common purpose. For example, in this case, the example you just gave, there's an engineering hammock, which means -- a scheduler calls it a hammock. It's a -- there's a lot of little bitty activities underneath that hammock, so they all are inside that same window of start and this hammock just represents the timeline to complete the engineering work.

Q Okay. So most of the things -- like if I look at this item on the second page of this exhibit, which is page 2 of 14, you've got that one, and if I turn to page 4 of 14, the hammock down there at the bottom for the low pressure injection cross tie --

A Yes, sir.

Q -- work order planning process, that's an engineering process that's been underway for a while.

A In this case, it's actually turning that engineering product into work constructions.

Q Okay. So you're basically taking engineering and putting it into your WBS or your work schedule so it can be done when the time comes for that?

A Yes, it's turning the engineering design into actual instructions on how to do the welding, what to bolt up where. It's the package that a craftsman would use to install the component, as opposed to the engineering work that supports that instruction.

Q Okay. And then if we go to page seven, you've got a black for item in progress related to the makeup tank bypass line?

A Yes, sir.

Q And then the next page, inadequate core cooling, this is one of the instrumentation items that was part of the scope change from the beginning of the project?

A That is correct.

Q Okay. And then the next page, your low pressure turbine monitoring system, this is -- again, are you putting the engineering into work order?

A Yes, this is work order planning for that particular engineering work.

Q Okay. And there's an item down here, fiber optics work order planning process.

A I see the pipe vibration monitoring.

Q Yes. Okay.

A Yes.

Q So am I correct, if I look at this Level II Schedule, a lot of the work, the engineering work, has been done, you're kind of waiting to actually install a lot of this equipment, the equipment has been ordered, a lot of the costs have already been incurred, and what will be remaining will be either some final equipment costs and some final engineering and then the construction contract costs. Is that essentially what's left to be done?

A Yes, sir, for most projects the engineering is well along, almost complete. In many of the projects we're turning that engineering work into work instructions. It's a necessary step in the process, not the major cost component of the process. But to your point, it's the construction activities where most of the remaining dollars would be expended and they have yet to be started.

MR. REHWINKEL: Okay, thank you, Mr. Franke.

Mr. Chairman, those are all the questions I have. Thank you.

CHAIRMAN BRISE: Thank you. Mr. Brew?

MR. BREW: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. BREW:

Q Good afternoon, Mr. Franke. Could I refer you to the Exhibit 127 that Mr. Rehwinkel just showed you, the last page, the AE-7.

A Yes, sir.

Q If you can actually read column G, you've got better eyes than mine.

A I'm using my cheating glasses.

Q I just wanted to spend a brief time going through my understanding of the 2011 events, if I may.

A Certainly.

Q Now, according to your testimony you've been in your current position since April of 2009?

A That is correct.

Q And you filed testimony last year relating to the Crystal River unit items, including the uprate?

A That's correct.

Q Okay. And you also have responsibility relating to the containment repair?

A I'm site vice-president for the plant. The repair project going forward is not being accomplished underneath me, but obviously I'm informed of those -- of that project.

Q Fine. So you're aware of what's going on with that and you have been all along?

A Yes, sir.

Q Okay. So in January of 2011 the company was attempting to complete the repair from the 2009 delamination?

A Correct.

Q And you were planning to do the phase three of the uprate and refueling 17?

A That's correct.

Q Okay. And then in March 14 we had the later delamination.

A That's correct.

Q And then you said shortly after that the company made a decision to go forward with the EPU sufficiently to preserve the option of doing it during the current extended outage?

A Yes. You may remember there was a time frame between March and June where we did our first review of should the company proceed with the intent to repair the building or not, or should we proceed with our retirement at that time.

We studied a number of options, both what retirement would look like as well as various ways to conduct a repair. And in June of 2011 we moved forward with the intent that remains today to repair Crystal River 3. And so our decision relative to EPU was informed of that intent to repair the unit.

Q That's actually the time frame I wanted to spend a little bit of time on. So we had the delamination in mid March?

A Yes, sir.

Q And sometime, I believe, the company gave the Commission a briefing in mid June to describe the status of the CR3 repair, something thereabouts. And during that time frame the company made a parallel decision to move forward with the EPU sufficient to preserve the option of going forward in this outage?

A Yes, sir. I would say that we looked at what we needed to do in the interim and we did not want to do anything that would challenge the ability to execute the extended power uprate, and then we validated that after the June decision as the right strategy going forward.

Q But in the meantime, in May, you filed testimony regarding the 2011 actual and estimateds and the feasibility of the EPU project, right?

A Yes, sir.

Q Okay. And claiming that moving forward with the EPU was still feasible and economic?

A That's correct.

Q And then in June the company -- during this time frame the company had brought in other vendors to examine potential repair options and possibilities, is that right? You assembled a variety of options for potential repair?

A That's right. We contracted with a specific engineering firm to help us with reviewing potential repair options for the building in late March and they worked with us until June.

Q Until June. So that work was underway in May when you filed your 2011 actual estimated and feasibility estimates?

A That's correct.

Q And then in mid June you moved forward and filed your LAR request with the NRC?

A That's correct.

Q Okay. And about that same time is when you revealed the repair options that you were considering for the containment structure?

A Yes, sir.

Q Okay. So at the time that you made those filings last year to go forward with EPU, was that with full knowledge that there may be a risk that the unit would not be repaired?

A Yes. I mean, that risk was known.

Q Okay. And the filing of the LAR request kicked off the NRC's process that you described earlier in terms of their questions and submittals regarding that application, is that right?

A Yes and no. Their process requires a review of the licensed application for acceptability, so they do a review of the application before they go into their formal review process just to say that the application is acceptable for review. And they actually spent several months doing that.

Q So -- but the June filing kicked that process off, which led to them making a determination in November to accept the filing?

A That's correct.

Q Okay. And then the process continued from there in terms of additional questions that you have pending today?

A Yes, sir.

Q Okay. Do you know, has Duke decided today, if you know, whether or not the containment repair is technically feasible?

A We are working through that decision now. We certainly know that it is possible to repair the building but we're looking at the repair options and other scopes relative to a repair to understand -- to answer your question, relative to its technical feasibility and the risks associated with a specific method of repairing the building.

Q Okay. So my question was, has Duke determined whether it is technically feasible to do the containment repair?

A The best answer to that is there's nothing that is impossible. The question is what's the right scope of work and what is the right option to use as the repair scenario to evaluate its technical feasibility and the risks associated with that work.

Q Okay. So is the answer to my question not yet, they have not made a final determination yet?

A I would say we're currently in the process of reviewing all technical aspects of a repair, including feasibility of the chosen repair method, the associated risks associated with various repair methods, in order to come to a best understanding of which repair would be used to compare against a retirement scenario for a decision to be made by the Board of Directors later.

Q And so the next step of my question would be in terms of economic feasibility, as part of that -- the Duke Board is still looking at whether it's economic to do the repair as part of that analysis of your chosen options and the risks associated with it?

A And that's why it's challenging to answer your question. You know, can it technically be repaired, yes, but part of that feasibility would be economic and other qualitative and quantitative factors that have to be weighed in. We're in the process of working through those full understandings now, and that information would be provided to our Board of Directors and they'll make a determination on the final decision to repair.

Q Okay. And that final decision has not been made as of today?

A That's correct.

Q Does the tentative repair plan still assume roughly 35 months to accomplish?

A I believe our latest published schedule is 30 months.

Q Okay, 30 months. So that hasn't changed?

A Not yet, sir, no.

Q If it does change, would that affect the timetable for doing the EPU?

A Yes, sir.

MR. BREW: It would? That's all I have. Thank you.

CHAIRMAN BRISE: Thank you. FEA?

LT. COL. FIKE: No questions, Mr. Chairman.

CHAIRMAN BRISE: All right. SACE?

MR. WHITLOCK: I just have one quick question, Mr. Chairman.

CHAIRMAN BRISE: Sure.

CROSS EXAMINATION

BY MR. WHITLOCK:

Q Good afternoon, Mr. Franke.

A Good afternoon.

Q Evening, I guess. Exhibit 127, these contracts, do you have any knowledge as to whether any of these contracts have force majeure provisions, acts of God provisions in them?

A You know, I don't know the details, but it would be standard to have some force majeure provisions in them, yes.

Q Okay. In all -- most, if not all of the contracts?

A Yes.

MR. WHITLOCK: Okay, thank you.

CHAIRMAN BRISE: Mr. Wright?

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

CHAIRMAN BRISE: Okay. Staff?

MR. LAWSON: No questions.

CHAIRMAN BRISE: Commissioners? Okay, redirect.

MR. WALLS: Yes, briefly.

REDIRECT EXAMINATION

BY MR. WALLS:

Q Mr. Franke, you may recall Mr. Moyle asked you several questions on whether the company has decided to repair CR3. Do you recall that?

A Yes, sir.

Q Does the company have the present intent to repair the unit and put the uprate into service?

A Yes, our present intent is to repair the unit and place the uprate in service.

Q Is it possible that despite this present intent the company may ultimately choose not to repair the plant?

A Yes, it is possible that we would come to a decision that we would not repair the plant.

Q And the company has not and still must make that final decision?

A That's correct.

MR. WALLS: No further questions.

CHAIRMAN BRISE: All right, let's deal with exhibits.

MR. WALLS: Yes, we would move into evidence witness Exhibits JF-1 through JF-5 for his direct testimony, which are Exhibits 17 through 21 of the comprehensive exhibit list.

CHAIRMAN BRISE: Okay, 17 through 21.

MR. WALLS: And then Exhibits JF-6 and 7, which are Exhibits 31 and 32 in the comprehensive Staff exhibit list.

CHAIRMAN BRISE: Okay. If there are no objections, we will move Exhibits 17 through 21 and Exhibits 31 and 32 into the record at this time.

(Exhibits 17 through 21 and 31 and 32 admitted in evidence.)

MR. REHWINKEL: Public Counsel moves Exhibit 127.

CHAIRMAN BRISE: Okay, we will move Exhibit 127 into the record at this time, seeing no objections.

(Exhibit 127 admitted in evidence.)

MR. WALLS: I believe that concludes our case.

CHAIRMAN BRISE: All right. So that concludes Progress's case. Mr. Franke, you are excused.

MR. REHWINKEL: Mr. Chairman, the exhibit that I passed out, the Commissioners' copies and the Staff copies need to be collected and returned. Thank you. The witness can keep his.

CHAIRMAN BRISE: All right, thank you, Progress. Now I think we move into OPC?

MR. REHWINKEL: Yes. Mr. Chairman, pursuant to agreement with the parties, Public Counsel would ask that the testimony of Dr. William Jacobs and the associated Exhibits 22 through 24 on the Staff's list be moved into the record.

CHAIRMAN BRISE: Okay, we will move the testimony of Dr. Jacobs into the record and the Exhibits 22 through 24, seeing no objections. Okay, seeing no objections, we will move those in the record.

(Exhibits 22, 23 and 24 admitted in evidence.)

(Whereupon, the direct testimony was inserted.)

DIRECT TESTIMONY

Of

WILLIAM R. JACOBS JR., Ph.D.

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 120009-EI

I. INTRODUCTION

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

A. My name is William R. Jacobs, Jr., Ph.D. I am an executive consultant with GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia, 30067.

Q. DR. JACOBS, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Mechanical Engineering in 1968, a Master of Science in Nuclear Engineering in 1969 and a Ph.D. in Nuclear Engineering in 1971, all from the Georgia Institute of Technology. I am a registered professional engineer and a member of the American Nuclear Society. I have more than thirty years of experience in the electric power industry including more than twelve years of power plant construction and start-up experience. I have participated in the construction and start-up of seven power plants in this country and overseas in management positions including start-up manager and site manager. As a loaned employee at the Institute of Nuclear Power Operations ("INPO"), I participated in the Construction Project

Evaluation Program, performed operating plant evaluations and assisted in the development of the Outage Management Evaluation Program. Since joining GDS Associates, Inc. in 1986, I have participated in rate case and litigation support activities related to power plant construction, operation and decommissioning. I have evaluated nuclear power plant outages at numerous nuclear plants throughout the United States. I was on the management committee of Plum Point Unit 1, a 650 MWe coal fired power plant in operation near Osceola, Arkansas. As a member of the management committee, I assisted in providing oversight of the Engineering, Procurement and Construction ("EPC") contractor for this project. I am currently the Georgia Public Service Commission's (GPSC) Independent Construction Monitor for Georgia Power Vogtle 3 and 4 nuclear project. As the Independent Construction Monitor, I assist the GPSC Commissioners and Staff in providing regulatory oversight of the project. My monitoring activities include regular meetings with project management personnel and regular visits to the Vogtle plant site to monitor construction activities and assess the project schedule and budget. My resume is included as Exhibit WRJ(PEF)-1.

Q. WERE YOU ASSISTED BY OTHER GDS PERSONNEL IN THIS EFFORT?

A. Yes I was. The GDS team involved in the review and evaluation of the requests for authorization to recover costs consisted of me and Mr. James P. McGaughy, Jr., a former nuclear utility executive with over 37 years of experience. The resume of Mr. McGaughy is attached to this testimony as Exhibit WRJ(PEF)-2. I have reviewed the work of Mr. McGaughy and am familiar with his input and have incorporated and adopted it as my own.

Q. WHAT IS THE NATURE OF YOUR BUSINESS?

A. GDS Associates, Inc. ("GDS") is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Corpus Christi, Texas; Manchester, New Hampshire; Madison, Wisconsin; and Auburn, Alabama. GDS provides a variety of services to the electric utility industry including power supply planning, generation support services, rates and regulatory consulting, financial analysis, load forecasting and statistical services. Generation support services provided by GDS include fossil and nuclear plant monitoring, plant ownership feasibility studies, plant management audits, production cost modeling and expert testimony on matters relating to plant management, construction, licensing and performance issues in technical litigation and regulatory proceedings.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am representing the Florida Office of Public Counsel ("OPC") who represents the ratepayers of Progress Energy Florida ("PEF" or "Company").

Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?

A. I was asked to assist the OPC to conduct a review and evaluation of requests by PEF for authority to collect historical and projected costs associated with the Extended Power Uprate ("EPU") project being pursued at Crystal River Unit 3 ("CR3") through the capacity cost recovery clause.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified on behalf of the OPC in the previous Nuclear Cost Recovery Clause ("NCRC") proceedings in Docket Nos. 080009-EI, 090009-EI, 100009-EI and 110009-EI.

Q. PLEASE SUMMARIZE PEF'S REQUEST FOR COST RECOVERY FOR THE CR3 EPU PROJECT IN THIS DOCKET UNDER THE NUCLEAR COST RECOVERY CLAUSE.

A. The total estimated revenue requirements for the CR3 EPU project are $17.8 million for 2012 with projected total revenue requirements of $37.3 million in 2013.

II. METHODOLOGY

Q. PLEASE DESCRIBE THE METHODOLOGY THAT YOU USED TO REVIEW AND EVALUATE THE REQUESTS FOR AUTHORIZATION TO COLLECT COSTS SUBMITTED BY PEF UNDER THE NUCLEAR COST RECOVERY CLAUSE.

A. I first reviewed the Company's filings in this docket and assisted in the issuance of interrogatories and requests for production of documents. To evaluate the issues related to project schedule and cost, I reviewed internal documents, status reports and correspondence with regulatory authorities. I reviewed responses to discovery requests and issued additional discovery requests as needed.

Q. WERE YOU ASKED BY THE OPC TO MAKE ANY ASSESMENT OF, OR PROVIDE ANY JUDGEMENT ABOUT, THE ADEQUACY OF PEF'S PROJECT MANAGEMENT AND COST CONTROLS?

A. No. Due to the circumstances of this docket this year, I was not asked to focus my efforts in that area. So I offer no opinions as to the adequacy of these efforts. However, the absence of any testimony on my part concerning the adequacy of PEF's project management and cost controls should not be construed as evidence supporting a finding that PEF's project management and cost controls were adequate.

III. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE CRYSTAL RIVER 3 EPU PROJECT?

A. The Commission should ensure that PEF minimize all expenditures related to the CR3 EPU project. I recommend that the avoidable or deferrable remaining EPU construction work not be contracted for or performed until late in the containment repair process when the success of the repair and NRC acceptance of that repair is assured. In addition, the Commission should require that PEF provides timely updates on the status of the containment repair decision and update its EPU project plan, even if it requires supplemental testimony.

IV. THE CRYSTAL RIVER 3 EPU PROJECT

Q. PLEASE PROVIDE A BRIEF UPDATE OF THE STATUS OF THE CR3 EPU PROJECT.

A. The scope of the CR3 EPU project remains as I have described in my prior testimony. However, the schedule has been severely impacted primarily by the damaged CR3 containment building. The EPU project that was planned for completion in 2011 will not likely be ready to provide energy to customers until 2015 at the earliest.

If the project is completed and the License Amendment Request ("LAR") is approved, it will increase the output of CR3 by 180 MWe by increasing reactor power and thereby increasing steam output. Additional output is provided by increasing the size and efficiency of the plants turbine-generator and by increasing the accuracy of plant instrumentation. The project was originally conceived to be carried out in three phases. Phase 1, completed in 2007, improved the accuracy of plant measurements of plant parameters and allowed output to be increased about 12 MWe. Phase 2 was scheduled to be completed in 2009 and Phase 3 in 2011. Phase 2 consisted of replacing the turbine-generator and other non-nuclear portions of the plant. As originally planned, this would have increased plant output by 28 MWe immediately, and allowed for the increased steam flow to be provided by Phase 3. Two highly significant events occurred in 2009 that prevented Phase 2 from being completed according to schedule.

1. The new turbines failed testing in Germany and had to be modified.
2. The reactor containment building suffered a delamination in October 2009 while PEF was cutting a hole in the building to facilitate removing and replacing steam generators. Since that time, PEF's primary efforts have been to repair the damaged containment building.

As a result of the delamination, there is continued uncertainty surrounding when Phases 2 and 3 of the EPU project will be completed. Progress Energy CEO William Johnson has stated that the Company has yet to make a final decision whether to attempt another repair of the building. The Company has publically stated that it will take approximately 30 months to effectuate a repair based on current information. Since commencement of containment building repairs will likely not begin any earlier than the latter part of this year, if at all, based on publically known information and my judgment, the remaining two phases of the EPU project will likely not be placed in service until 2015 at the earliest – if they can be and are implemented during the current extended outage.

When the project was initially proposed to the Commission in 2006, according to the testimony of PEF Witness Javier Portuondo in Docket Nos. 060642-EI and 070052-EI, the total cost of the EPU project at-the-plant-site was estimated to be less than $300 million, not including transmission. The Company at the time included $89 million in transmission costs in the original EPU project cost estimate. As shown in TOR-7, sponsored by PEF Witness Daniel Roderick in Docket No. 080009-EI, Progress performed a transmission study and determined that the transmission costs initially included were no longer necessary for the EPU project. Since 2006, Generation Plant costs increased from approximately $250 million to over $489 million, and the NCRC-recoverable Total Uprate Project Cost (without transmission) increased from $293 million to over $556 million. See Table 1 in Exhibit ____ (WRJ(PEF)-3) entitled CR3 EPU Cost Estimates 2006-2012. Table I was created from publically available documents in Docket Nos. 060642-EI, and 070052-EI, and the Company's TOR-7 (True-up to original, Schedule 7) filed in Docket Nos. 080009-EI, 090009-EI, 100009-EI, 110009-EI, and 120009-EI. As one can see in Table 1, most of the significant EPU project cost increases have taken place since 2010.

As shown in Exhibit TGF-6, Schedule TOR-6, from 2006 through 2011, Progress has actually spent over $318 million on the EPU project, and plans to spend $51.5 million in 2012 (Actual/Estimated) and another $110.2 million in 2013 (Projected). If Progress spends according to its currently filing, by the end of 2013, Progress will have spent nearly $480 million on the EPU project, none of which can be used and useful due to the extended outage. To complete the project, according to TOR-6, Progress must spend in 2013 to 2015 another $186 million.[1] Based on past experience, we can expect further and significant cost increases until the project is completed.

Q. MR. FRANKE STATES IN HIS TESTIMONY THAT THE INITIAL COST OF THE PROJECT WAS PROJECTED TO BE $439,300,000. IS THAT CORRECT?

A. First of all I do not concur that the "original" cost of the project presented to the Commission was $439.3 million. When the project was first proposed to the Commission for a need determination in 2006, the estimate was $382 million and not $439.3 million. Mr. Franke's characterization of the initial project estimate is misleading because it includes a 15% "indirect cost" adder which the Company included in the Total Project Cost in 2008 when it initially filed for recovery through the NCRC. According to the TOR-7, filed in Docket No. 080009-EI, the adder was first included in Total Project Cost to make "initial milestones" amount comparable to the "revised milestone" amounts. Therefore, a more accurate starting point for the original total project cost estimate would be $382 million. In my judgment, an even more accurate starting point for comparing original to current project cost estimate would be to deduct unnecessary transmission cost that the Company removed from the uprate project in early 2008.

By the time the Company filed its first request for recovery in the NCRC docket, transmission and its associated costs were no longer part of the overall uprate project according to TOR-7 filed in 2008, and not necessary for the inside-the-plant

[1] $110.2 million in 2013 + $64.5 million in 2014 + $11.3 million in 2015 = $186 million.

project. If the $102.4 million in transmission cost is deducted from Mr. Frank's $439.3 million "original" total project cost estimate included in the current filings, the comparable original total project estimate (without transmission) would be $337 million. If the adder is excluded from the 2006 and 2007 costs initially presented to the Commission, then on a truly comparable basis Mr. Franke's "original" total project estimate (less transmission costs) would be $293 million instead of $439.3 million.

For a comparison of estimated uprate costs from 2006 to 2012, please refer to Table 1 of Exhibit___(WRJ(PEF)-3). This table illustrates how various componants of the CR3 EPU Project have increased over time. It includes a category called "Total Uprate Project Cost (without Transmission)" that illustrates how the Total Project Cost has increased from $239 million in 2006 to over $556 million in 2012 and offers a clear view of the true nature of the project's cost escalation.

Q. WHAT ARE YOUR CONCERNS REGARDING THE CR3 EPU PROJECT?

A. My concerns focus upon the significant increases in cost over the original cost estimate experienced by the project to date and the difficulty in achieving regulatory approval by the NRC of the power uprate.

The cost increases I described above have largely been caused by increased scope and licensing issues as pointed out by PEF Witness Franke. Mr. Franke states in his April 30, 2012 testimony at line 17 of page 21 that the Company's current estimate "...is accurate between -15 and +20%..." However, the history of this project reveals that Mr. Franke's upper limit of +20% will be more likely. On page 23 of his testimony, Mr. Franke admits now that "... the full scope and assessment of the EPU phase work was not known and could not be known earlier..." until the design work was complete.

Mr. Franke admits that engineering design work is *now* only 70% complete, the NRC is only six months into what may be a 24-month review of the LAR, and the construction contracts have not been awarded at this time. This means there are still a lot of unknowns out there which can still drive the final cost upwards. It is important to point out that 70% of engineering design work complete does not mean that the project is 70% complete. It does mean that at least 30% of the anticipated scope of the design has not been done. Also to be done is new design, known as "emergent work" and work that will come out of new requirements that inevitably are the result of the NRC's review of the requested license amendment (or NRC permission to operate at increased power). Oftentimes, much of a project's new costs become evident while performing the last 30% of the engineering design work. For example, for FPL's EPU project, which is supposed to complete in less than a year from now, project cost estimates have gone up enormously in the past year alone as the project engineering approached substantial completion.

As examples of heretofore unknown EPU project cost drivers, Mr. Franke highlighted a number of expensive project revisions. Project scope and engineering changes that had not been originally contemplated and have now been determined to be necessary include new feedwater heaters, condensate system modifications, ICCMS (instrumentation) and new booster feed pumps. The original estimate obviously did not include enough contingency for Commission understanding and evaluation for reasonableness or prudency.

Regarding NRC licensing concerns, I pointed out in my 2010 testimony that the CR3 uprate (originally Phase 3) of 140 MWe for the nuclear reactor itself is by far the largest ever requested to be approved for a U.S. pressurized water reactor (PWR). To be able to operate at this increased reactor power level, an amendment to the operating license is required. PEF had originally planned to file the CR3 EPU LAR in 2009. PEF finally submitted the LAR in June 2011. The NRC, in their acceptance letter (Franke Exhibit JF-1) for the LAR, stated that, while a normal uprate review would take one year, this review will take up to two years. The NRC required an extended review because it is a "...first-of-a-kind application for a Babcock and Wilcox..." plant and because of some new, unreviewed safety systems that are made necessary by this design. The NRC also stated that they may delay their review depending on the schedule of when and if the containment will be repaired. This intense and delayed NRC review can only lead to increased project scope and cost.

Q. WHAT DO YOU RECOMMEND REGARDING FUTURE EXPENDITURES FOR THE CR3 EPU PROJECT?

A. I recommend that the avoidable or deferrable remaining EPU construction work not be contracted for or performed until late in the containment repair process when the success of the repair and NRC acceptance of that repair is assured. Only absolutely necessary expenditures should be incurred because any expenditures will be wasted if the decision is made to retire CR3 rather than repair the containment building and return the plant to service.

Q. HAVE YOU IDENTIFIED ANY PLANNED EXPENDITURES THAT SHOULD BE DEFERRED UNTIL THE CONTAINMENT REPAIR DECISION HAS BEEN MADE?

A. Yes. There are approximately $186,000,000 of planned expenditures remaining to complete the EPU project plus the possible additional +20% that Mr. Franke has estimated. These expenditures are for project management, onsite construction facilities, power block engineering and construction, and non–power block engineering and construction. If the EPU project is to continue at all, engineering and licensing work must continue and long-lead equipment items must be procured. The bulk of the remaining money will be spent on construction contracts for turbine-generator replacement, new nuclear safety systems, feedwater heaters, condensate pumps and other equipment. This work can be done during an outage lasting a few months. Since the containment repair will take several years, I recommend that the avoidable or deferrable remaining EPU construction work not be contracted for or performed until late in the containment repair process when the success of the repair and NRC acceptance of that repair is assured. If the Company places the avoidable or deferrable remaining EPU construction work on hold as per my recommendation and the unit is not successfully returned to service or a decision is made to retire the plant, a large portion of the approximately $186,000,000 of planned expenditures of the customers' money will not be spent. Based on the present uncertainty surrounding the return to service date for CR3 and until the decision to proceed in earnest with the repair is made, there is certainly no need to spend this large sum of money more than two years early.

Q. WHAT NOTICE SHOULD THE COMMISSION PROVIDE THE COMPANY REGARDING THESE DEFERRED EPU EXPENDITURES YOU ARE RECOMMENDING?

A. If the Company decides to incur avoidable or deferrable expenditures on the EPU in the face of the uncertainty surrounding the return of CR3 to service prior to 2015, the Commission should withhold any determination of reasonableness for expending this money in 2012 and 2013, and put the Company on notice that any EPU money spent in 2013 will be held subject to refund until PEF makes an official decision to repair the building and to begin that repair in earnest.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS REGARDING THE CR3 EPU PROJECT?

A. Yes, I recommend that the Company update the Commission regarding the status of the containment repair plan and schedule in a timely manner and not wait until the required NCRC filing dates. If a decision to repair or retire is made before the 2012 NCRC hearing, the Company should file supplemental testimony, notifying the Commission of this decision. If the decision is made after the NCRC hearing but before the Commission votes on the 2013 factor, the Company should make the appropriate filing in this docket to inform the Commission.

V. <u>THE LEVY NUCLEAR PROJECT</u>

Q. DO YOU HAVE ANY COMMENTS REGARDING THE LEVY NUCLEAR PROJECT?

A. No, I do not. Due to the settlement involving the Levy Nuclear Project, I have been asked to limit the scope of my review to the CR3 EPU project.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes it does.

MR. REHWINKEL: Thank you.

CHAIRMAN BRISE: Staff?

MR. LAWSON: We would ask at this time that the testimony of Jeffrey Small and the associated exhibits numbered for identification as 26 and 27 on the comprehensive exhibit list all be moved into the record at this time.

CHAIRMAN BRISE: Okay, the testimony of Jeffrey Small, and you said the Exhibits 26 -- would you repeat the exhibit numbers for me, please?

MR. LAWSON: 26 and 27, sir.

CHAIRMAN BRISE: 26 and 27. Okay, we will move the testimony of Mr. Jeffrey Small into the record, seeing no objections, as well as Exhibits 26 and 27.

(Exhibits 26 and 27 admitted in evidence.)

(Whereupon, the direct testimony was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF JEFFERY A. SMALL

DOCKET NO. 120009-EI

JUNE 19, 2012

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 Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission (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 EDP applications into these programs.

Q. Have you presented expert testimony before this Commission or any other

regulatory agency?

A. Yes. I have provided testimony in the Progress Energy Florida, Inc., (PEF) Nuclear Cost Recovery Clause filings, Docket Nos. 080009-EI, 090009-EI, 100009-EI and 110009-EI. I have also 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. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor two staff audit reports of PEF which address the Utility's application for nuclear cost recovery in 2011. The first audit report was issued May 9, 2012, and addressed the pre-construction and construction cost as of December 31, 2011, for Levy County Nuclear Units 1 & 2. This audit report is filed with my testimony and is identified as Exhibit JAS-1. The second audit report was issued May 9, 2012, and addressed the 2011 power uprate costs for the Crystal River Unit 3 nuclear power plant. This audit report is filed with my testimony and is identified as Exhibit JAS-2.

Q. Were these audits prepared by you or under your direction?

A. Yes, these audits were prepared by me or under my direction.

Q. Please describe the work you performed in these audits.

For the first audit report, to address the pre-construction and construction costs as of December 31, 2011, for Levy County Nuclear Units 1 & 2:

- We reconciled the Company's filing to its general ledger and verified that the costs incurred were posted to the proper accounts.
- We reconciled and recalculated a sample of the monthly revenue requirement accruals displayed on Schedule T-1 to the supporting schedules in the Company's 2011 NCRC filing.
- We reconciled the monthly preconstruction, and construction carrying cost balances

displayed on Schedules T-2.2, and T-2.3, respectively, to the supporting schedules in the Company's 2011 NCRC filing. We recalculated the schedules and reconciled the Allowance for Funds Used During Construction (AFUDC) rates applied by the Company to the rates approved in Order No. PSC-05-0945-S-EI, in Docket No. 050078-EI, issued September 28, 2005.

- We reconciled the monthly preconstruction deferred tax carrying cost accruals displayed on Schedule T-3A.2 to the supporting schedules in the Company's 2011 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-S-EI.
- We recalculated a sample of the monthly recoverable O&M expenditures displayed on Schedule T-4 of the Company's 2011 NCRC filing. We sampled and verified the O&M cost accruals and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated the respective overhead burdens the Company applied.
- We recalculated a sample of monthly jurisdictional nuclear construction accruals displayed on Schedules T-6.2, and T-6.3, respectively, of the Company's 2011 NCRC filing. We sampled and verified the generation cost accruals and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated a sample of the respective overhead burdens that the Company applied.

For the second audit report, to address the uprate cost as of December 31, 2011, for Crystal River Unit 3,

- We reconciled the Company's filing to its general ledger and verified that the costs incurred were posted to the proper accounts.
- We reconciled and recalculated a sample of the monthly revenue requirement accruals displayed on Schedule T-1 to the supporting schedules in the Company's 2011 NCRC

filing.

- We reconciled the monthly construction carrying cost balances displayed on Schedule T-2.3 to the supporting schedules in the Company's 2011 NCRC filing. We recalculated the schedule and reconciled the Allowance for Funds Used During Construction (AFUDC) rates applied by the Company to the rates approved in Order No. PSC-05-0945-S-EI.
- We reconciled the monthly construction deferred tax carrying cost accruals displayed on Schedule T-3A.3 to the supporting schedules in the Company's 2011 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-S-EI.
- We reconciled and recalculated a sample of the monthly CPI accruals displayed on Schedule T-3B.3 to the supporting schedules in the Company's 2011 NCRC filing. We recalculated the Company's CPI rate and reconciled the component balances to the Company's general ledger.
- We recalculated a sample of the monthly recoverable O&M expenditures displayed on Schedule T-4 of the Company's 2011 NCRC filing. We sampled and verified the O&M cost expenditures and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated the respective overhead burdens the Company applied.
- We recalculated a sample of monthly jurisdictional nuclear construction accruals displayed on Schedule T-6.3 of the Company's 2011 NCRC filing. We sampled and verified the capital cost expenditures and traced the invoiced amounts to supporting documentation. We verified a sample of salary expense accruals and recalculated the respective overhead burdens that the Company applied.

Q. Were there any audit findings in the audit report, JAS-1, which addresses the 2011 pre-construction and construction cost for Levy County Nuclear Units 1 & 2.

A. No

Q. Were there any audit findings in the audit report, JAS-2, which addresses the 2011 power uprate costs for the Crystal River Unit 3 (CR3) nuclear power plant.

A. Yes, Audit Finding No. 1 provides information on legal costs included as recoverable O&M expenditures on Schedule T-4 of the filing that the Company states will be removed by posting a journal adjustment in April 2012 that will reduce next years Schedule T-4 filing by $12,683 ($11,716 jurisdictional).

Q. Does this conclude your testimony?

A. Yes, it does.

MR. WALLS: And I believe that's all we have for witnesses for Progress today.

CHAIRMAN BRISE: All right. Well, I think we have come to the conclusion of Progress, issues associated with Progress. Are there any other issues that we need to deal with with respect to Progress?

MR. WALLS: Mr. Chair, may we be excused from the FPL portion of the proceeding?

MR. REHWINKEL: FPL had to sit through theirs.

MR. BREW: PCS supports Progress's request.

CHAIRMAN BRISE: Yes, Progress, you may be excused. Let me go through some dates for you. Hearing transcripts will be available September 21st, 2012. Briefs, October 1, 2012. Staff recommendation is expected on November 7, 2012, and we will have a special agenda on November 20, 2012.

All right, with that, I guess, Progress, you are free to go.

It is 4:45. I suppose we'll probably get through the preliminary matters for FPL this evening, and then begin taking witnesses tomorrow morning.

All right, we'll take, I guess, five minutes or so to give people an opportunity to switch out and move their belongings and so forth so that we can move right along. Okay, so we will reconvene at 4:50.

(Brief recess)

CHAIRMAN BRISE: Okay, all right, so this evening what we're going to do, we're going to deal strictly with preliminary matters. We will move into opening statements tomorrow morning, and so forth. So I know that there are some preliminary matters that we have to deal with, so we want to go ahead and deal with those in the next ten minutes or so.

MS. BENNETT: If I might, Mr. Chairman and Commissioners, the first item, at the break we handed out an exhibit that I would like to have marked for identification as a partial stipulation for Issue 29.

CHAIRMAN BRISE: Sure. That will be 128.

(Exhibit 128 marked for identification.)

MS. BENNETT: 128, and we'd like to go ahead and move that into the record and then we'd ask for a vote on that partial stipulation.

CHAIRMAN BRISE: All right, we will move 128 into the record, seeing no objections. And Commissioners, Commissioner Edgar?

(Exhibit 128 admitted in evidence.)

COMMISSIONER EDGAR: Mr. Chairman, I move that we approve the proposed stipulation for Issue 29 as reflected in Exhibit 128.

CHAIRMAN BRISE: All right, it's been moved. Is there a second?

COMMISSIONER BALBIS: I'll second for purposes of discussion. I just have a question or two on it.

CHAIRMAN BRISE: Okay, it's been moved and seconded. Discussion? Commissioner Balbis?

COMMISSIONER BALBIS: Thank you, Mr. Chairman. I have a question for Staff on this. I believe witness Reed that we did hear from last week dealt with a lot of the issues associated with the stater (phonetic) core work, and I just wanted to make sure that this stipulation -- because the amount that's listed in here, it's listed as confidential --

MS. BENNETT: Correct.

COMMISSIONER BALBIS: -- so I want to make sure that the negotiation covers the additional cost associated with the outage that audit staff stated in their audit report.

MS. BENNETT: The confidential amount is -- technical staff did a review of the dollar amounts associated with that, and keep in mind that it goes through the nuclear cost recovery clause instead of the fuel clause. And so because of the dollar amount that -- the confidential dollar amount and the fact that it bears AFUDC and actually lowers customer bills, we believed that it was actually a better benefit for the customers with this renegotiated contract amount.

COMMISSIONER BALBIS: Okay, thank you. That's all I have.

CHAIRMAN BRISE: All right, thank you. It's been moved and properly seconded. We've had good discussion. Seeing no further discussion, all in favor say aye. (Vote taken)

CHAIRMAN BRISE: All right, it's moved, so we have approved this stipulation. Are there other issues that we need to address?

MS. BENNETT: Yes, Mr. Chairman. I believe that Winnie Powers was previously excused, but based on the partial stipulation, it is my understanding that now, if there are no other questions from Commissioners, that Staff witnesses Fisher and Rich could also be excused.

CHAIRMAN BRISE: Okay, Commissioners, do we have any further questions for witnesses Rich and Fisher? Okay. Okay, no? Okay, seeing that there's no further questions for them, then they can be excused.

MS. BENNETT: Thank you. For housekeeping purposes, there are two rebuttal witnesses, Ferrer and Diaz, and their testimony will not be admitted into the record because of this partial stipulation.

CHAIRMAN BRISE: Okay, so then I guess we can excuse Ferrer and Diaz from rebuttal testimony.

MS. BENNETT: And then one last preliminary matter on Staff's behalf, and that is, we have some interrogatories and production of documents that we would like to be moved into the record. I understand that parties do not have an objection, so we would like Staff Exhibits 104, 105 and 106 moved into the record at this time.

CHAIRMAN BRISE: 104, 105, and 106. Okay, we'll move those into the record. Are there any objections? All right, seeing no objections, we will move 104, 105 and 106 into the record.

(Exhibits 104, 105 and 106 admitted in evidence.)

MS. BENNETT: Thank you. And I believe that's all the preliminary matters there are, unless the parties had something.

CHAIRMAN BRISE: All right. Mr. Wright?

MR. WRIGHT: Thank you, Mr. Chairman, just a question for clarity. Do I understand correctly that the rebuttal testimonies of Mr. Ferrer and Mr. Diaz are being withdrawn? Is that what it means when they're not coming into the record?

MS. BENNETT: That's my understanding is that Ferrer and Diaz's rebuttal testimony is going to be withdrawn.

MR. ANDERSON: Or put another way, they will not be submitted into the record as though read, so they'll not be part of the record in this proceeding, that's correct.

MR. WRIGHT: Thank you.

CHAIRMAN BRISE: In essence, they'll be withdrawn. Okay. All right, so with that I think we're done with our preliminary matters for this evening.

We expect to begin tomorrow morning at 9:30. Be prepared to go to about 6:00 tomorrow evening. We will take a break for lunch tomorrow at about noon, and you all know about the two hour breaks in between there for our court reporters. With that, we look forward to seeing you tomorrow at 9:30. We stand at recess until tomorrow.

(Whereupon, the hearing was recessed at 4:50 p.m. and the transcript continues in sequence in Volume 5.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, LAURA MOUNTAIN, Court Reporter, do hereby certify that I was authorized to and did Stenographically report the foregoing proceedings; and that the transcript is a true record of the aforesaid proceedings.

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

Dated this 18th day of September, 2012.

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