BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 150009-EI

NUCLEAR COST RECOVERY CLAUSE.
_________________________________/

VOLUME 1

(Pages 1 through 157)

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER JULIE I. BROWN
COMMISSIONER JIMMY PATRONIS

DATE: Tuesday, August 18, 2015

TIME: Commenced at 1:32p.m.
Concluded at 2:30 p.m.

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

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

APPEARANCES:

JESSICA CANO and KEVIN I.C. DONALDSON, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

MATTHEW BERNIER, DIANNE M. TRIPLETT, and JOHN BURNETT, ESQUIRES, 299 First Avenue North, St. Petersburg, Florida 33701; and JAMES MICHAEL WALLS and BLAISE N. GAMBA, ESQUIRES, Carlton Fields Law Firm, P.O. Box 3239, Tampa, Florida 33607-5780, appearing on behalf of Duke Energy Florida, Inc.

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

JOHN T. LAVIA, III, and ROBERT SCHEFFEL WRIGHT, ESQUIRES, Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of the Florida Retail Federation.

VICTORIA MÉNDEZ and MATTHEW HABER, ESQUIRES, 444 SW 2nd Avenue, Suite 945, Miami, Florida 33130-1910, appearing on behalf of the City of Miami.

APPEARANCES (Continued):

GEORGE CAVROS, ESQUIRE, 120 East Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida 33334, appearing on behalf of the Southern Alliance for Clean Energy.

J. R. KELLY, PUBLIC COUNSEL, and CHARLES REHWINKEL, PATRICIA A. CHRISTENSEN and ERIK SAYLER, ESQUIRES, Office of Public Counsel, c/o the Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

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

CHARLES BECK, GENERAL COUNSEL, and MARY ANNE HELTON, ESQUIRE, Florida Public Service commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing as Advisors to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	15	15
2 - 71	(as identified on Comprehensive Exhibit List)	15	
28 - 43			128
47 - 65			23
66 - 68			128
70 - 71			128

P R O C E E D I N G S

CHAIRMAN GRAHAM: Good afternoon, everyone. It's interesting, I'm not used to people getting quiet before I open my Diet Coke, but I guess in the afternoon things are different.

Welcome all. Before we get started and we start the hearing, we one have of our legislators that are here, and I always encourage legislators that want to come down and address us to come. And Representative Rodriguez from the South Miami area is here, and we agreed to let him come down and talk to us.

Representative, welcome.

REPRESENTATIVE RODRIGUEZ: Good morning, Chair, members. It's good to see you. I really appreciate your, I guess, latitude in giving me a chance to address you, and also to the members of the public and everybody who's here.

So my name is José Javier Rodriguez. I'm a state representative down in Miami, as you said, Mr. Chair. And the reason why I did want to say a few words is to address one of the matters that's -- that's before you today and kind of share my perspectives as a state representative for my constituents, and that is specific to the cost recovery, to the feasibility that you're going to be looking at today with Florida Power & Light and Turkey Point 6 and 7.

My vantage point -- all of my constituents are the ratepayer -- are among the ratepayers who are and will be on the hook for advanced nuclear cost recovery. And, of course, the FP&L rate-paying region is a large part of the state, but if you zero down, those of us in Miami-Dade -- of course, my constituents are not only ratepayers, they live -- you know, Turkey Point is where they live. Turkey Point is in our backyard. So that's an added level of -- of viewpoint that I bring representing the area.

And what I did want to say is that, you know, obviously I personally, as a state representative I'm not a party to the proceedings, but to the extent that the parties that are here do represent, I think, the interests of my constituents, which is to -- to reject the feasibility study that's before you today and to go further and re-examine the determination of need from '09. The reason being -- and I'll speak to two issues specifically that are receiving a lot of attention in my neck of the woods.

Number one is the fact that there is an economic cost to adjusting for sea level rise. And when we're talking about plans that could -- that have to account for a span of 70 years from now, it is completely unrealistic to rely on one foot of sea level rise as the cost of sea level rise adjustment that we'll need to make at Turkey Point.

And I think the second vantage point also is that when we are -- with the existing units at Turkey Point, we are already having to deal with effects on our potable water supply. Those also have economic impacts that are not accounted for in what's before you. And I understand that, you know, the determination of need is not before you right now, you're looking at a feasibility, but I would encourage you to look with a high degree of scrutiny specifically on those two issues which are not accounted for in the economic costs that -- that we as ratepayers will be expected to bear.

And I think some of the -- the parties have mentioned the concept of sunk costs. And right now for our rate -- for ratepayers in the region, we're $250 million. And so the decision, I think, to put the brakes on this should be made now and not when that 250 million becomes 2 billion. And so that's what I would -- that is the position that I would take as someone representing my constituents.

But separate and apart from my position on this particular issue, I really appreciate the conversations that -- that some of us have had about a request to see if it's possible to have one of your upcoming meetings in Miami. I know that, along with some of the local mayors in South Florida, we'd requested that a meeting be held in South Florida. And I appreciate your openness, Mr. Chair, to some alternatives, you know, if we're not able to prevail on you on, that there are alternatives available in terms of allowing constituents who are hundreds of miles away, you know, in Miami, 500 miles away, but, of course, you know, the rate-paying region is very large, to at least allow us, even if it's not an opportunity for public testimony, allow us to get a better understanding for the decisions that are being made for the next decades, especially if, even, you know, under what you have before you, it is not necessarily even my constituents but my constituents' children who are going to see a return on investment. And so to the extent that these decisions affect us particularly in South Florida, to find ways to make these proceedings and these decision-making more accessible. I appreciate your openness to considering alternatives.

So I thank you very much for allowing me, like I said, the latitude to address you this morning. Thank you.

CHAIRMAN GRAHAM: Thank you, Representative. Hold on. Let's see if there's any questions.

I -- I guess I have one. This is my little misunderstanding. You're talking about sea level rise. What specifically are you talking about? More about climate change?

REPRESENTATIVE RODRIGUEZ: Thank you, Mr. Chair.

What I'm -- what I'm talking about is there are a number of environmental changes, climate change at sea level rise. You can either look at it as part of climate change, which I think almost everyone would, or you can simply look at the fact that there are requirements either from NOAA or other agencies to really -- to look at projected levels of sea level rise; right? And so a lot of that also has to do with storm surge. And Turkey Point sits on a low peninsula out into a shallow bay. And so just for example, with very minimal level of sea level rise, the storm surge that we would have to account for could be very, very large.

And so if we're projecting out 70 years from now -- and I'm saying 70 because obviously if we're looking at a 60-year life span, at some point, you know, in the future, perhaps maybe ten years from now is when the plant would be built and then would have a lifespan. So if we're looking at 70 years out, no projection from any agency or expert says that one foot of sea level rise is reasonable to plan for.

And so when I'm talking about sea level rise, I'm talking about the economic impact being that we are going to have to adapt to sea level rise in one way or the other. And specifically for Turkey Point at the location that it's at, I don't think anybody would say it's reasonable to account for one foot of sea level rise in the next 70 years. And to the extent that our community has costs and to the extent that FP&L will see future costs with sea level rise, with storm surge that high, I think that from everything that I've heard that it's unreasonable what's before you today.

CHAIRMAN GRAHAM: I'm sorry. That's what I misunderstood, because I thought you were saying that this was going to generate carbon, which is going to cause climate change, and that's not what you're saying. You're saying that sea level rise is coming anyway, and you're more worried about the location.

REPRESENTATIVE RODRIGUEZ: Yes, Mr. Chair.

CHAIRMAN GRAHAM: Okay.

REPRESENTATIVE RODRIGUEZ: I'm specifically talking about sea level rise, adaptation to sea level rise as an additional cost to take into account.

CHAIRMAN GRAHAM: Okay. That's my misunderstanding.

REPRESENTATIVE RODRIGUEZ: Thank you, Mr. Chair.

CHAIRMAN GRAHAM: Commissioners, any other questions? Okay. Well, Representative, thank you very much for coming for -- I know that you guys are in session today. I take it you guys didn't go too long.

REPRESENTATIVE RODRIGUEZ: Yeah. We didn't go too long, but we're still -- we're going to be here a while. And I know you have your 5-hour Energies up there because we may go late today, so we'll pass the baton to you on long hearings. Thank you.

CHAIRMAN GRAHAM: Well, thank you very much. Thanks for coming down.

REPRESENTATIVE RODRIGUEZ: Thank you, Mr. Chair.

CHAIRMAN GRAHAM: Okay. Well, as the Representative said, and just fair warning for you guys, I plan on going late today, so I hope you guys are all ready.

Let the record show this is the Nuclear Cost Recovery Clause, the date is August the 18th, and we will convene this hearing. It is Docket No. 150009-EI. And, staff, if I can get you to read the notice, please.

MS. BARRERA: Yes. By notice issued June 24th, 2015, this time and place was set for this hearing in Docket No. 150009-EI, the Nuclear Cost Recovery Clause. The purpose of this hearing is set forth in the notice.

CHAIRMAN GRAHAM: Okay. Let's take appearances.

MS. CANO: Good afternoon. Jessica Cano and Kevin Donaldson on behalf of Florida Power & Light Company.

MR. BERNIER: Good afternoon. Matt Bernier on behalf of Duke Energy Florida. I'd also like to enter an appearance for John Burnett and Dianne Triplett, as well as for Mike Walls and Blaise Gamba of Carlton, Fields, Jorden, Burt. Thank you.

MR. HABER: Victoria Méndez and Matthew Haber for the City of Miami.

MR. CAVROS: Good afternoon. George Cavros on behalf of the Southern Alliance for Clean Energy.

MR. MOYLE: Jon Moyle with the Moyle Law Firm appearing on behalf of the Florida Industrial Power Users Group, FIPUG.

MR. LAVIA: Good afternoon, Mr. Chairman. J. LaVia on behalf of the Florida Retail Federation with the Gardner Law Firm. I'd also like to enter an appearance for Robert Scheffel Wright. Thank you.

MS. CHRISTENSEN: Patty Christensen with Erik Sayler on behalf of the Office of Public Counsel for the FPL portion of this case.

MR. REHWINKEL: Charles Rehwinkel for the Duke portion. And I'd also -- like to also enter an appearance for J. R. Kelly for both.

MS. BARRERA: Martha Barrera and Kyesha Mapp for staff.

MS. HELTON: Mary Anne Helton, advisor to you today.

MR. BECK: Charlie Beck, General Counsel to the Commission.

CHAIRMAN GRAHAM: Okay. Once again, welcome everybody. Let's go on to preliminary matters. Staff, are there any preliminary matters?

MS. BARRERA: Yes. Staff notes PCS Phosphate has been excused from the hearing.

Staff has prepared a Comprehensive Exhibit List. The list itself is marked as Exhibit No. 1. There are no objections to the Comprehensive Exhibit List. At this time, staff requests that Exhibit No. 1 be entered into the record.

CHAIRMAN GRAHAM: If there's no concerns about the staff Comprehensive Exhibit List, we will enter that into the record.

(Exhibits 1 through 71 marked for identification.)

(Exhibit 1 admitted into the record.)

MS. BARRERA: Thank you, Chairman.

The parties have stipulated to certain of staff's exhibits. They are numbered 28 to 43, 66, 67, 68, 70, and 71. Exhibit 38A has not been stipulated and will be proffered at the appropriate time. Staff requests that the stipulated exhibits be entered into the record.

CHAIRMAN GRAHAM: Are there any objections to the stipulated exhibits?

MR. MOYLE: Could she just read them back for us?

MS. BARRERA: Pardon?

MR. MOYLE: Would you read them back, please?

MS. BARRERA: Yes. As I stated in the emails, they are numbers 28 to 43, 66, 67, 68, 70, and 71. And Exhibit 38A has not been stipulated to.

CHAIRMAN GRAHAM: Are there any objections? Okay. Staff.

MS. BARRERA: Duke Energy Florida has filed a motion for approval of the stipulation. The Prehearing Order provides that FP&L's petition be addressed first, then DEF's. However, in light of DEF's motion for approval of stipulation, staff recommends that the Commission take up DEF's case first.

CHAIRMAN GRAHAM: Is that something that we have to rule on, or I can just make that determination?

MS. BARRERA: No. You just have to make a determination.

CHAIRMAN GRAHAM: Okay. I don't see any problem with taking Duke's portion of the hearing up first. So let's -- Duke, if you would present your motion.

MR. BERNIER: Thank you, Mr. Chairman. Good afternoon again, Commissioners.

Before you today is a stipulation that, if approved, would settle all of DEF's issues in this year's NCRC docket. The stipulation entered by the signatories to the Commission-approved Revised and Restated Stipulation and Settlement Agreement has two general components.

First, it stipulates to the total jurisdictional amount to be included in establishing DEF's 2016 capacity cost recovery factors, which amounts relate only to the Crystal River uprate project.

Second, regarding the Levy Nuclear Project, it recognizes that there are some project costs and credits that remain to be addressed to determine the ultimate recovery under the NCRC, and recognizes that there are some project-related costs that could possibly be incurred in future periods, but it defers consideration of all issues related to the remaining known project costs or credits until the 2017 NCRC cycle. It also recognizes that parties to the stipulation retain and do not waive any arguments, positions, or rights as to the recoverability of any alleged, known, or future project costs. With that, we urge the Commission to approve the stipulation, and can answer any questions.

CHAIRMAN GRAHAM: Okay. We'll start with the Intervenors.

George, do you have any concerns or questions on the stipulation?

MR. CAVROS: I do not. We took no position on it.

CHAIRMAN GRAHAM: Okay. Mr. Moyle?

MR. MOYLE: No. We, we agreed to the stipulation and are fine, fine with it being accepted by the Commission.

CHAIRMAN GRAHAM: John?

MR. LAVIA: Same for Florida Retail Federation.

CHAIRMAN GRAHAM: OPC?

MR. REHWINKEL: Public Counsel supports it.

CHAIRMAN GRAHAM: Okay. Commissioners?

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Commissioner Brown.

COMMISSIONER BROWN: Thank you, Mr. Chairman. And I just want to ask a question of Office of Public Counsel, Mr. Rehwinkel. Consistent with the stipulation, it appears that it does further the previous settlement agreement approved by the Commission and is in the public interest, and if you could just elaborate for the reasons why.

MR. REHWINKEL: Yes, Commissioner. The Public Counsel supports it as being in the public interest because the -- for the -- with respect to the Levy portion. This stipulation means that there will be no costs imposed on customers in the 2016 or 2017 billing cycles. It preserves all arguments that Public Counsel and other Intervenors and the company could make today to be made in the 2017 hearing cycle because there are significant unknowns out there at this time that will hopefully be more known in two years. So all things considered, it is in the best interest of the customers and in the public interest to defer the decision for two years.

COMMISSIONER BROWN: Thank you, Mr. Chairman. If any of the other Intervenors want to chime in, please feel free to. Otherwise, Mr. Chairman, if the Commissioners don't have any questions, I'm prepared to make a motion.

CHAIRMAN GRAHAM: Sure.

COMMISSIONER BROWN: I move to approve the motion for approving the stipulation, all matters here.

COMMISSIONER BRISÉ: Second.

CHAIRMAN GRAHAM: It's been moved and seconded. Any other further discussion?

I'd like to thank all parties involved for all the hard work you guys did going into this. I do agree -- I remember the conversation came up during the prehearing, and I guess for, as Mr. Rehwinkel said earlier, a lot of things will come to better vision, better focus in a year or two. So I think you're right, and I think this is a good stipulation and settlement.

So if there's nothing else, all in favor, say aye.

(Vote taken.)

Any opposed? By your action, you've approved -- we'll call it the Brown motion.

Okay. Staff.

MS. BARRERA: Commissioners, the -- there is also a set of stipulations that are Type B stipulations that are reflected in the Prehearing Order, and at this time it would be prudent to have a vote on them.

CHAIRMAN GRAHAM: And tell me again, where is that?

MS. BARRERA: I believe they're on the Prehearing Order.

CHAIRMAN GRAHAM: Okay. Where in the Prehearing Order?

MS. BARRERA: This would be issues dealing with DEF -- let's see -- beginning with -- okay. I am so sorry. Those issues were covered by the motion. Just ignore me.

CHAIRMAN GRAHAM: So you're trying to confuse me?

MS. BARRERA: No. I live in a state of perpetual confusion, so just blame me.

CHAIRMAN GRAHAM: You threw me off there a little bit.

Okay. So as far as -- what else do we

need to do to conclude Duke?

MS. BARRERA: At this time, the parties to the DEF portion of the hearing have waived opening argument, and the following DEF and staff witnesses have been excused from the DEF portion of the hearing. They're Thomas Foster, Mark Teague, Christopher Fallon, Ronald Mavrides, William Coston. And we're asking that DEF -- to move exhibits and testimony into the record, and staff will also move for the entry into the record the testimony of Ronald Mavrides and William Coston as though read.

CHAIRMAN GRAHAM: Okay. So, Duke, are you going to enter -- move your exhibits and testimony into the record?

MR. BERNIER: Yes, sir, Mr. Chairman.

At this time we'd like to move the March 2nd and May 1st prefiled testimonies of Mr. Thomas Foster, Mr. Christopher Fallon, and Mr. Mark Teague into the record as though read. And I think from staff's Comprehensive Exhibit List those are Exhibits 47 through 65.

CHAIRMAN GRAHAM: Is there any objection to moving Exhibits 47 through 65 into the record? Okay. Let the record show there are no objections, so we will move those exhibits into the record.

(Exhibit 47 through 65 admitted into the record.)

MS. BARRERA: At this time staff moves to enter into the record the testimony of Mavrides and Coston as though read, and staff witness exhibits have already been entered.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 150009-EI

DIRECT TESTIMONY OF THOMAS G. FOSTER

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Duke Energy Business Services, LLC, as Director, Rates and Regulatory Planning.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida, Inc. ("DEF"). These responsibilities include regulatory financial reports and analysis of state, federal, and local regulations and their impact on DEF. In this capacity, I am also responsible for the Levy Nuclear Project ("LNP") and the Crystal River Unit 3 ("CR3") Extended Power Uprate ("EPU") Project ("CR3 Uprate") Cost Recovery filings, made as part of this docket, in accordance with Rule 25-6.0423, Florida Administrative Code ("F.A.C.").

Q. Please describe your educational background and professional experience.

A. I joined Duke Energy on October 31, 2005 as a Senior Financial Analyst in the Regulatory group. In that capacity I supported the preparation of testimony and exhibits associated with various Dockets. In late 2008, I was promoted to Supervisor Regulatory Planning. In 2012, following the merger with Duke Energy Corporation ("Duke Energy"), I was promoted to my current position. Prior to working at Duke Energy I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was responsible for ensuring proper accounting for all fixed assets as well as various other accounting responsibilities. I have 6 years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a Nuclear Operator. I received a Bachelors of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance from the University of South Florida and I am a Certified Public Accountant in the State of Florida.

II. PURPOSE OF TESTIMONY.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Florida Public Service Commission ("FPSC" or the "Commission") review and approval, the actual costs associated with DEF's LNP and CR3 Uprate project activities for the period January 2014 through December 2014. Pursuant to Rule 25-6.0423, F.A.C., DEF is presenting testimony and exhibits for the Commission's determination of prudence for actual expenditures and associated carrying costs. Additionally, I will also present the LNP and CR3

Uprate project 2014 accounting and cost oversight policies and procedures pursuant to the nuclear cost recovery statute and rule.

Q. Are you sponsoring any exhibits in support of your testimony on 2014 LNP and CR3 Uprate project costs?

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

<u>2014 Costs:</u>

- Exhibit No. __ (TGF-1), reflects the actual costs associated with the LNP and consists of: 2014 True-Up Summary, 2014 Detail Schedule and Appendices A through E, which reflect DEF's retail revenue requirements for the LNP from January 2014 through December 2014; however, I will only be sponsoring the 2014 True-Up Summary, portions of the 2014 Detail Schedule, and Appendices A, B and C. Christopher Fallon will be co-sponsoring portions of the 2014 Detail Schedule and sponsoring Appendices D and E.
- Exhibit No. ___ (TGF-2), reflects the actual costs associated with the CR3 Uprate project and consists of: 2014 True-Up Summary, 2014 Detail Schedule and Appendices A through E, which reflect DEF's retail revenue requirements for the CR3 Uprate project from January 2014 through December 2014; however, I will only be sponsoring the 2014 True-Up Summary, portions of the 2014 Detail Schedule, and Appendices A, B, and C. Mark Teague will be co-sponsoring the 2014 Detail Schedule and sponsoring Appendices D and E. The 2014 Detail Schedules for the LNP and the CR3 Uprate project contain the same

calculations provided in the Nuclear Filing Requirement ("NFR") Schedules prior to project cancellation in a more concise manner.

These exhibits are true and accurate.

Q. What are the 2014 Detail Schedules and the Appendices?

A.
- Schedule 2014 Summary reflects the actual 2014 year-end revenue requirements by Cost Category for the period, and final true-up amount for the period.
- Schedule 2014 Detail reflects the actual calculations for the true-up of total retail revenue requirements for the period.
- Appendix A (CR3 Uprate) reflects beginning balance explanations and various Uprate in-service project revenue requirements.
- Appendix A (Levy) reflects beginning balance and period amortization of the Regulatory Assets.
- Appendix B reflects Other Exit/Wind Down expenditure variance explanations for the period.
- Appendix C provides support for the appropriate rate of return consistent with the provisions of Rule 25-6.0423, F.A.C.
- Appendix D describes Major Task Categories for expenditures and variance explanations for the period.
- Appendix E reflects contracts executed in excess of $1.0 million (if any).

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

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

Q. What is the final true-up amount for the LNP for which DEF is requesting recovery for the period January 2014 through December 2014?

A. DEF is requesting approval of a total over-recovery amount of ($6,833,655) for the calendar period ending December 2014. This amount can be seen on Line 3 of the 2014 Summary Schedule of Exhibit No. ___ (TGF-1). Line 1 of the 2014 Summary represents current period exit and wind down costs, carrying costs on the unrecovered investment balance (including prior period (over)/under balances), and was calculated in accordance with Rule 25-6.0423, F.A.C.

Q. What is the final true-up amount for the CR3 Uprate project for which DEF is requesting recovery for the period January 2014 through December 2014?

A. DEF is requesting approval of a total over-recovery amount of ($1,070,629) for the calendar period of January 2014 through December 2014. This amount can be seen on Line 3 of the 2014 Summary of Exhibit No. ___ (TGF-2). Line 1 of the 2014 Summary represents the current period exit and wind down costs, carrying costs on the unrecovered balance including prior period (over/under) balances, as well as the revenue requirements associated with the various in-service projects, and was calculated in accordance with Rule 25-6.0423, F.A.C..

Q. What is the carrying cost rate used in the 2014 Detail Schedule?

A. Beginning in 2013 for both the CR3 Uprate and the LNP, DEF started using the rate specified in Rule 25-6.0423(7)(b), F.A.C. The carrying cost rate used for this time period in the 2014 Detail Schedule was 7.23 percent. On a pre-tax basis, the rate is 10.29 percent. This annual rate was also adjusted to a monthly rate consistent with the Allowance For Funds Used During Construction ("AFUDC") rule, Rule 25-6.0141, Item (3), F.A.C. Support for the components of this rate is shown in Appendix C of Exhibit Nos.___(TGF-1) and (TGF-2).

III. COSTS INCURRED IN 2014 FOR THE LEVY NUCLEAR PROJECT.

Q. What are the total retail costs DEF incurred for the LNP during the period January 2014 through December 2014?

A. The total retail costs for the LNP are $23.5 million for the calendar year ended December 2014, as reflected on 2014 Detail Schedule Line 22 in Exhibit No__(TGF-1). This amount includes $10.2 million in exit/wind-down and disposition costs as can be seen on Lines 5a and 19d, and $13.3 million for the carrying costs on the unrecovered investment balance shown on Line 8d. These amounts were calculated in accordance with the provisions of Rule 25-6.0423, F.A.C.

Q. How did actual Generation expenditures for January 2014 through December 2014 compare with DEF's actual/estimated costs for 2014?

A. Appendix D (Page 2 of 2), Line 4 shows that total Generation project costs were [redacted], or [redacted] lower than estimated. By cost category, major cost variances between DEF's projected and actual 2014 LNP Generation project costs are as follows:

Wind-Down Costs: Expenditures for Wind-Down activities were [redacted] or [redacted] lower than estimated, as explained in the testimony of Christopher Fallon.

Disposition: Expenditures for Disposition activities were [redacted] or [redacted] lower than estimated, as explained in the testimony of Christopher Fallon.

Q. Did the Company incur Transmission expenditures for January 2014 through December 2014?

A. No.

Q. Were there any true-up adjustments that needed to be made that did not affect the total estimated revenue requirements for the Levy project?

A. Yes, there were two adjustments made in April 2014. The adjustment in the Generation section of approximately [redacted] that represents costs that were previously accrued for in prior periods, but actual payments were either not made or the actual amount paid was lower than the accrual. The adjustment in the Transmission section of [redacted] that represents costs that were previously incurred and cash paid in a prior period, without an offsetting accrual.

The amounts and offsets are shown on Line 1a & Line 2a and Line 3a & Line 4a, respectively, in the 2014 Detail Schedule in Exhibit No. __ (TGF-1).

These adjustments will not affect the revenue requirements, as it affects only the presentation of the figures in the Detail schedules.

Q. What was the source of the separation factors used in the 2014 Detail Schedule?

A. The jurisdictional separation factors are consistent with Exhibit 1 of the Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement") approved by the Commission in Order No. PSC-13-0598-FOF-EI in Docket No 130208-EI.

IV. OTHER EXIT/WIND-DOWN COSTS INCURRED IN 2014 FOR THE LEVY NUCLEAR PROJECT.

Q. How did actual Other Exit/Wind-Down expenditures for January 2014 through December 2014 compare with DEF's actual/estimated costs for 2014?

A. Appendix B, Line 5 shows that total Other Exit/Wind-down costs were $0.4 million or $7,073 lower than estimated. There were no major variances with respect to these costs.

V. COSTS INCURRED IN 2014 FOR THE CR3 UPRATE PROJECT.

Q. What are the total retail costs DEF incurred for the CR3 Uprate during the period January 2014 through December 2014?

A. The total retail costs for the CR3 Uprate are $23.5 million for the calendar year ended December 2014, as reflected on 2014 Detail Schedule Line 22 in Exhibit No.__(TGF-2). This amount includes ($0.3) million in exit/wind-down, sales & salvage of assets credits, disposition costs and other adjustments as can be seen on

Lines 2e, 16d and 19; and $23.8 million for the carrying costs on the unrecovered investment balance shown on Line 5d. These amounts were calculated in accordance with the provisions of Rule 25-6.0423, F.A.C.

Q. How did actual expenditures for January 2014 through December 2014 compare to DEF's actual/estimated costs for 2014?

A. Appendix D (Page 2 of 2), Line 4 shows that total project costs were ($0.4) million or $0.9 million lower than estimated. By cost category, major cost variances between DEF's actual/estimated and actual 2014 Generation Wind-Down and Disposition costs are as follows:

EPU Wind-Down: Expenditures for Wind-Down activities were $41,938 or $0.4 million lower than estimated, as explained in the testimony of Mark Teague.

Sales or Salvage of Assets: DEF did not project any sales, transfer or salvage proceeds in the Estimated / Actual filing in May 2014. Proceeds for sale, transfer and salvage of assets were $0.5 million as explained in the testimony of Mark Teague.

Q. Were there any true-up adjustments that needed to be made that did not affect the total estimated revenue requirements for the CR3 Uprate project?

A. Yes, there were two adjustments. There was an accounting entry made in April 2014 of approximately $2.6 million that represents costs that were previously incurred and cash paid in a prior period, without an offsetting accrual adjustment.

The other entry was made in November 2014 for approximately $0.3 million that represents costs that were previously accrued for in prior periods, but actual payments were not made or the actual amount paid was lower than the accrual.

The amounts and offsets are shown on Line 1a and Line 2a, respectively, in the 2014 Detail Schedule in Exhibit No. __ (TGF-2). These adjustments will not affect the revenue requirements, as it affects only the presentation of the figures in the Detail schedules.

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

A. Yes. Investment activity shown on the 2014 Detail Schedule, Line 1d is gross of Joint Owner Billings, but expenditures and revenues (from sale, transfer and salvage activity) have been adjusted as reflected on the 2014 Detail Schedule, Line 2b to reflect billings to Joint Owners related to the CR3 Uprate project. Due to this, no carrying cost associated with the Joint Owner portion of the CR3 Uprate project are included in the 2014 Detail Schedule. Total Joint Owner billings were $0.2 million for 2014, as seen on Line 2b.

Q. What was the source of the separation factors used in the 2014 Detail Schedule?

A. The jurisdictional separation factors are consistent with Exhibit 1 of the 2013 Settlement Agreement approved by the Commission in Order No. PSC-13-0598-FOF-EI in Docket No. 130208-EI.

VI. OTHER EXIT/WIND-DOWN COSTS INCURRED IN 2014 FOR THE CR3 UPRATE PROJECT.

Q. How did actual Other Exit/Wind-Down expenditures for January 2014 through December 2014 compare with DEF's actual/estimated costs for 2014?

A. Appendix B, Line 4 shows that total Other Exit/Wind-down costs were $229,449 or $21,558 lower than estimated. There were no major variances with respect to these costs.

VII. 2014 PROJECT ACCOUNTING AND COST CONTROL OVERSIGHT.

Q. Have the project accounting and cost oversight controls DEF used for the LNP and CR3 Uprate project in 2014 substantially changed from the controls used prior to 2014?

A. No, they have not. The project accounting and cost oversight controls that DEF utilized to ensure the proper accounting treatment for the LNP and CR3 Uprate project in 2014 have not substantively changed since 2009. In addition, these controls have been reviewed in annual financial audits by Commission Staff and were found to be reasonable and prudent by the Commission in Docket Nos. 090009-EI, 100009-EI, 110009-EI, 120009-EI, and 140009-EI.

Q. Can you please describe the project accounting and cost oversight controls process DEF has utilized for the LNP and CR3 Uprate project?

A. Yes. Starting at the initial approval stage, DEF continues to determine whether projects are capital based on the Company's Capitalization Policy and then projects are documented in PowerPlant.

The justifications and other supporting documentation are reviewed and approved by the Financial Services Manager, or delegate, based on input received from the Financial Services or Project Management Analyst to ensure that the project is properly classified as capital, eligibility for AFUDC is correct, and that disposals/retirements are identified. Supporting documentation is maintained within Financial Services or with the Project Management Analyst. Financial Services personnel, and selected other personnel (including project management analysts), access this documentation to set-up new projects in PowerPlant or make changes to existing project estimates in PowerPlant. The PowerPlant system administrators review the transfer and termination information provided by Human Resources each pay period and take appropriate action regarding access to the systems.

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

Finally, to ensure that all new projects have been reviewed each month, Financial Services Management reviews a report of all projects set up during the month prior to month-end close.

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

The Company uses cost reports produced from accounting systems to complete these monthly reviews. Financial Services may produce various levels of reports driven by various levels of management, but all Nuclear project reporting is tied back to the total cost reporting for the Nuclear fleet, which is tied back to Legal Entity Financial Statements.

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

A. Yes, the Company also has Disbursement Services Controls and Regulated Accounting Controls.

Q. Can you please describe the Company's Disbursement Services Controls?

A. Yes. 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 in the various Business Units, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition.

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

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

Q. Can you please describe the Company's Regulated Accounting Controls?

A. Yes. The journal entries for deferral calculations, along with the summary sheets and the related support, are reviewed in detail and approved by the Lead Accounting Analyst and/or Director of Florida Accounting, pursuant to the Duke Energy Journal Entry policy. The detail review and approval ensures that recoverable expenses are identified, accurate, processed, and accounted for in the appropriate accounting period.

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

For balance sheet accounts established with Regulated Utilities, Florida Accounting is the responsible party and a Florida Accounting member will reconcile the account on a monthly or quarterly basis, as required by Duke Energy policy. This reconciliation will be reviewed by the Lead Accounting Analyst or Director of Florida Accounting to ensure that the balance in the account is properly stated and supported and that the reconciliations are performed regularly and exceptions are resolved on a timely basis.

The review and approval will ensure that regulatory assets or liabilities are recorded in the financial statements at the appropriate amounts and in the appropriate accounting period.

Q. How does the Company verify that the accounting and costs oversight controls you identified are effective?

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

With respect to management's testing of internal controls over financial reporting, the Internal Controls Group within the Controller's Department facilitates the review of controls documentation and management testing. Based on this testing, management determines whether the controls are operating effectively. If any control is identified with a design deficiency or is determined to be operating ineffectively, such issues are logged and monitored for remediation by the Internal Controls Group.

With respect to external audits, Deloitte and Touche, DEF's external auditors, determined that the Company maintained effective internal control over financial reporting during 2014.

Q. Did the cancellation of the LNP and CR3 Uprate project change the Company's accounting and cost oversight control processes?

A. No. DEF continued to follow the same policies and processes as I described above to ensure prudent accounting and cost oversight for the projects as they are being closed out.

Q. Are the Company's project accounting and cost oversight controls reasonable and prudent?

A. Yes, they are. DEF's project accounting and cost oversight controls are consistent with best practices for project cost oversight and accounting controls in the industry and have been and continue to be vetted by internal and external auditors. We believe, therefore, that the accounting and cost oversight controls continue to be reasonable and prudent.

Q. What process have you implemented to ensure that 2014 costs related to the LNP Combined Operating License ("COL") are not included in the NCRC?

A. As discussed by Mr. Fallon, on a project team level DEF has always segregated project costs incurred by specific project code and this process did not change for 2014. The project team continues to charge COL-related labor, Nuclear Regulatory Commission ("NRC") fees, vendor invoices and all other COL-related cost items to the applicable COL project codes. The Florida Regulated Accounting and Rates and Regulatory Strategy groups have ensured that the COL-related project codes and associated costs incurred in 2014 and beyond were not included in the Company's NCRC Schedules, and thus not presented for nuclear cost recovery. We continue to track the COL-related costs for accounting purposes consistent with the 2013 Settlement Agreement.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 150009-EI

DIRECT TESTIMONY OF THOMAS G. FOSTER IN SUPPORT OF LEVY AND CR3 UPRATE ESTIMATED/ACTUAL AND PROJECTION COSTS

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Duke Energy Business Services, LLC as Director, Rates and Regulatory Planning.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida, Inc. ("DEF" or the "Company"). These responsibilities include: preparing regulatory financial reports and analysis of state, federal, and local regulations and their impact on DEF. In this capacity, I am also responsible for the Levy Nuclear Project ("LNP") and the Crystal River Unit 3 ("CR3") Extended Power Uprate ("EPU") Project ("CR3 Uprate") Cost Recovery filings, made as part of this Nuclear Cost

Recovery Clause ("NCRC") docket, in accordance with Rule 25-6.0423, Florida Administrative Code ("F.A.C.").

Q. Please describe your educational background and professional experience.

A. I joined the Company on October 31, 2005 as a Senior Financial Analyst in the Regulatory group. In that capacity I supported the preparation of testimony and exhibits associated with various Dockets. In late 2008, I was promoted to Supervisor Regulatory Planning. In 2012, following the merger with Duke Energy Corporation, I was promoted to my current position. Prior to working at Duke Energy I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was responsible for ensuring proper accounting for all fixed assets as well as various other accounting responsibilities. I have 6 years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a nuclear operator. I received a Bachelor's of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance from the University of South Florida and I am a Certified Public Accountant in the State of Florida.

II. PURPOSE OF TESTIMONY.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Florida Public Service Commission ("FPSC" or the "Commission") review, DEF's expected 2015 and 2016 costs associated with the Levy and CR3 Uprate projects consistent with Rule 25-6.0423(7), F.A.C., in support of setting 2016 rates in the Capacity Cost Recovery Clause ("CCRC"). As discussed further in the testimony of Witnesses Christopher Fallon and Mark Teague, at this time there are certain Levy and EPU costs or credits that are not known or knowable and DEF has not included these in our estimates.

Q. Are you sponsoring any exhibits in support of your testimony?

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

- Exhibit No. _ (TGF-3), reflects the actual and estimated costs associated with the LNP and consists of: 2016 Revenue Requirement Summary, 2015 Revenue Requirement Detail Schedule, 2016 Revenue Requirement Detail Schedule, 2015 Long Lead Equipment ("LLE") Deferred Balance Detail Schedule, 2016 LLE Deferred Balance Detail Schedule, 2016 Estimated Rate Impact Schedule, and Appendices A through E, which reflect DEF's retail revenue requirements for the LNP from January 2015 through December 2016. Witness Fallon will be co-sponsoring portions of the 2015 Actual/Estimated Revenue Requirement Detail Schedule Lines 1 (a – e) and Lines 3 (a – e), 2016 Projection Revenue Requirement Detail Schedule Lines 1 (a – e) and Lines 3 (a – e), and sponsoring Appendices D and E.

- Exhibit No. _ (TGF-4), reflects the actual and estimated costs associated with the CR3 Uprate project and consists of: 2016 Revenue Requirement Summary, 2015 Revenue Requirement Detail Schedule, 2016 Revenue Requirement Detail Schedule, 2016 Estimated Rate Impact Schedule, and Appendices A through F, which reflect DEF's retail revenue requirements for the project from January 2015 through December 2016. Mark Teague will be co-sponsoring portions of 2015 Actual/Estimated Revenue Requirement Detail Schedule Lines 1 (a – d) and 2016 Projected Revenue Requirement Detail Schedule Lines 1 (a - d) and sponsoring Appendices D and E.

The 2015 and 2016 Revenue Requirement Detail Schedules for the LNP and the CR3 Uprate project contain the same calculations provided in the Nuclear Filing Requirement ("NFR") Schedules prior to project cancellation in a more concise manner.

These exhibits are true and accurate.

Q. What are the 2015-2016 Detail Revenue Requirements Schedules and the Appendices?

A. • The 2015 Revenue Requirement Detail Schedule reflects the actual/estimated calculations for the true-up of total retail revenue requirements for the period.

- The 2016 Revenue Requirement Detail Schedule reflects the projection calculations for the true-up of total retail revenue requirements for the period.
- The 2015 LLE Deferred Balance Detail Schedule (Levy only) reflects the revenue requirement calculations for the LLE deferred balance for the period.
- The 2016 LLE Deferred Balance Detail Schedule (Levy only) reflects the revenue requirement calculations for the LLE deferred balance for the period.
- The 2016 Estimated Rate Impact Schedule reflects the estimated Capacity Cost Recovery Factors for 2016.
- Appendix A (CR3 Uprate) reflects beginning balance explanations and support for the 2015 and 2016 Regulatory Asset Amortization Amount.
- Appendix A (Levy) reflects beginning balance explanations and support for the 2015 and 2016 Regulatory Asset Amortization Amount.
- Appendix B reflects Other Wind Down/Exit Cost variance explanations for the period.
- Appendix C provides support for the appropriate rate of return consistent with the provisions of Rule 25-6.0423(7), F.A.C.
- Appendix D describes Major Task Categories for expenditures and variance explanations for the period.
- Appendix E reflects contracts executed in excess of $1.0 million.
- Appendix F (CR3 Uprate) reflects a summary of the 2013-2019 Uprate Amortization Schedule for the Uncollected Investment Balance.

III. CARRYING COST RATES AND SEPARATION FACTORS FOR BOTH THE CR3 UPRATE PROJECT AND THE LEVY NUCLEAR PROJECT.

Q. What is the carrying cost rate used in the 2015 and 2016 Revenue Requirement Detail Schedules?

A. DEF is using the rate specified in Rule 25-6.0423(7)(b), F.A.C. as follows: "The amount recovered under this subsection will be the remaining unrecovered Construction Work in Progress balance at the time of abandonment and future payment of all outstanding costs and any other prudent and reasonable exit costs. The unrecovered balance during the recovery period will accrue interest at the utility's overall pretax weighted average midpoint cost of capital on a Commission adjusted basis as reported by the utility in its Earnings Surveillance Report filed in December of the prior year, utilizing the midpoint of return on equity (ROE) range or ROE approved for other regulatory purposes, as applicable."

This annual rate was also adjusted to a monthly rate consistent with the Allowance for Funds Used During Construction ("AFUDC") rule, Rule 25-6.0141, Item (3), F.A.C. Support for the components of this rate is shown in Appendix C of Exhibit Nos.___(TGF-3) for the LNP and (TGF-4) for the CR3 Uprate project.

Q. Has DEF changed how it is applying the carrying cost rate under Rule 25-6.0423(7)(b) since 2014?

A. Yes, initially DEF read the following language in the Rule --- "the unrecovered balance during the recovery period will accrue interest at the utility's overall pretax weighted average midpoint cost of capital on a Commission adjusted basis as reported by the utility in its Earnings Surveillance Report filed in December of the prior year, utilizing the midpoint of return on equity (ROE) range or ROE approved for other regulatory purposes, as applicable" --- to mean the rate would be frozen at the level from the year prior to cancellation. After receiving questions from Staff financial auditors and further consideration, DEF believes it is reasonable to interpret this language in the Rule to mean DEF should update the rate annually based on the prior year December surveillance report. Consequently, DEF has applied this methodology and included an adjustment that can be seen on Levy 2015 Revenue Requirement Detail Schedule line 5e and on CR3 Uprate 2015 Revenue Requirement Detail Schedule line 2j to recognize the impact of this change on reported 2014 carrying costs. The impact of this change reduces 2014 carrying costs by $242,632 ($87,249 for Levy, and $155,383 for EPU). Included in the amount shown for EPU on line 2j is an adjustment to the Joint Owner credit discussed later in my testimony. This change also reduces the carrying costs in 2015 and 2016.

Q. What was the source of the separation factors used in the 2015 and 2016 Revenue Requirement Detail Schedules?

A. The jurisdictional separation factors are consistent with Exhibit 1 of the Revised and Restated Stipulation and Settlement Agreement ("2013

Settlement Agreement") approved by the Commission in Order No. PSC-13-0598-FOF-EI in Docket No 130208-EI.

IV. COST RECOVERY FOR THE LEVY COUNTY NUCLEAR PROJECT.

A. ACTUAL/ESTIMATED LNP COSTS.

Q. Have you provided schedules that reflect the Commission's decision on DEF's Petition to End the Fixed Levy Nuclear Project Rate Component of the Nuclear Cost Recovery Clause Charges consistent with the 2013 Settlement Agreement and the nuclear cost recovery statute and rule?

A. Yes. These revenue requirements can be seen in the 2015 Revenue Requirement Detail Schedule and on the 2015 Detail –LLE Deferred Balance Schedule. They have been shown in two schedules for ease of tracking. The schedules reflect collection of the revenue requirements approved for collection through April 2015. Per the Commission's vote on April 16th on DEF's Petition, as of May 2015 DEF has set the Levy billing factors to zero and, therefore, DEF is not collecting any revenues for the Levy project during the remainder of 2015.

DEF will collect 2015 period costs, as well as any true-ups, while deferring $54 million (System) which corresponds to the amount in dispute under DEF's claims in the WEC litigation, in accordance with the NCRC statute and rule. At such time as the WEC litigation concludes, and there is a final determination with respect to the DEF and WEC claims in that litigation, DEF will submit any resulting costs or refunds to the Commission for review and approval.

Q. Has DEF calculated the 2015 and 2016 revenue requirements in its LNP actual/estimated and projected cost schedules consistent with the Commission's April 16th vote on DEF's Petition and the Nuclear Cost Recovery Statute and Commission Rule?

A. Yes. DEF's actual/estimated and projected LNP costs, including carrying charges on the deferral of $54 million equivalent to the LLE amount in dispute in DEF's claims against WEC in the WEC litigation, reflect prudent LNP costs that DEF is entitled to recover from customers pursuant to the Commission's vote, prior NCRC Orders, the 2013 Settlement Agreement, and Section 366.93, Florida Statutes, and Rule 25-6.0423, F.A.C.

The Commission granted DEF's Petition to end the fixed Levy component of the NCRC charge, but it did not decide DEF's request in that Petition that the Commission provide DEF direction with respect to the available approaches to recover carrying charges on the $54 million adjustment to DEF's projected LNP costs pursuant to the Commission's 2014 NCRC Order. The Commission accepted Staff's recommendation that the Commission did not need to approve the approach to recover these carrying charges because the regulatory treatment for such prudently incurred charges is provided in Section 366.93, Florida Statutes, and Rule 25-6.0423, F.A.C. DEF, accordingly, is including carrying charges on the $54 million in its 2015 actual/estimated and 2016 projected LNP costs in its

Schedules consistent with Section 366.93, Florida Statutes, and Rule 25-6.0423, F.A.C.

The Commission decision to order a $54 million downward adjustment to DEF's projected expenses and subsequent approval to end the fixed Levy charge results in a reduction in the amount of the prudent but uncollected capital investment to be collected in the LNP project in 2015. As a result, there will be an "unrecovered balance" of $54 million until the resolution of the $54 million LLE claims in the WEC litigation. DEF, accordingly, is including carrying charges on the $54 million in its 2015 actual/estimated and 2016 projected LNP costs in its Schedules consistent with Section 366.93, Florida Statutes, and Rule 25-6.0423, F.A.C.

Q. Is this treatment of the carrying costs on the $54 million also consistent with the 2013 Settlement Agreement?

A. Yes. The 2013 Settlement Agreement did not alter the provisions for submittal, evaluation, and approval for recovery of the LNP costs under Section 366.93, Florida Statutes, and Rule 25-6.0423, F.A.C.

The 2013 Settlement Agreement also expressly recognizes that DEF is entitled to recover all prudently incurred costs, which includes carrying costs on prudently incurred costs, for the LNP consistent with Section 366.93 and Rule 25-6.0423. Specifically, paragraphs 10 and 12c of the 2013 Settlement Agreement provides that DEF "shall" be permitted to recover "all" costs "associated with the termination of the LNP, including but not limited to the LNP EPC Agreement, through the NCRC" consistent with Section 366.93 and Rule 25-6.0423.

Q. What are the total estimated period revenue requirements for the LNP for the calendar year ended December 2015?

A. The total projected period revenue requirements for the LNP are $6.1 million for the calendar year ended December 2015 as reflected on the two 2015 Revenue Requirement Detail Schedules. The $2.9 million on the 2015 Revenue Requirement Detail Schedule Line 22 in Exhibit No._(TGF-3) includes $0.2 million in exit/wind-down and disposition costs as can be seen on Lines 5a and 19d, a credit to the 2015 revenue requirement of $0.1 million due to DEF's decision to update the weighted average cost of capital ("WACC") used to calculate carrying cost in 2014 shown on Line 5e, and $2.8 million for the carrying costs on the unrecovered investment balance shown on Line 8d. The $3.2 million is reflected in 2015 Detail Schedule-LLE Deferred Balance on Line 4 in Exhibit No._(TGF-3). These amounts were calculated in accordance with the provisions of Rule 25-6.0423, F.A.C. and are exclusive of the amortization of prior period balances.

B. EXIT & WIND-DOWN COSTS INCURRED IN 2015 FOR THE LEVY NUCLEAR PROJECT.

Q. What are the exit and wind-down costs incurred for the Levy Nuclear Project for the period January 2015 through December 2015?

A. The 2015 Detail Revenue Requirement Schedule Exhibit No.__(TGF-3) Lines 1e, Line 3e, and Line 12e show that total exit and wind-down expenditures excluding carrying costs were approximately [redacted].

Q. What do these costs include?

A. The expenses included on Line 1e and 3e represent [redacted] related to project management wind-down costs and anticipated sales proceeds of [redacted] from the sale of some LLE as described in the testimony of Mr. Fallon. There are no expenses anticipated at this time for Transmission related wind-down costs. The expenses on line 12e, of approximately $0.3 million, represent other exit and wind-down costs including regulatory and legal on-going wind-down support costs that the Company expects to incur in 2015 related to the LNP that DEF is seeking recovery of through the NCRC.

Q. How did these expenditures for January 2015 through December 2015 compare with DEF's projected costs for 2015?

A. Appendix B, Line 4 shows that total Other Exit & Wind-Down Costs were approximately $0.3 million or $0.1 million lower than estimated. As shown in Appendix D, wind down and sale or salvage costs are approximately [redacted] lower than originally anticipated as DEF did not budget for project management costs due to uncertainties around the Levy project. DEF also did not project any sales or credits related to LLE equipment that occurred in 2015. The sales proceeds of [redacted] was the driver for the net credit in 2015 shown in the 2015 Revenue Requirement Detail Schedule Exhibit No.__(TGF-3) Line 5a. There are no expenses anticipated at this time for Transmission related wind-down costs.

Q. Did you reflect any credits for the sale or other disposition efforts for the Levy project assets for the calendar year 2015 or 2016, for which a sale was made, but for which you have not yet received proceeds?

A. Yes. Approximately [redacted] was recovered for the sale of Levy LLE shown on line 1c in the 2015 Revenue Requirement Detail Schedule. This recovery for Levy LLE disposition is further discussed by Mr. Fallon.

Q. Did you project any other credits for the sale or other disposition efforts that could result in credits for the Levy project assets?

A. No. Value received from any future disposition of an LNP asset will be credited against the uncollected investment at the time of disposition.

Q. Have you continued to ensure that future costs related to the Levy site COL are not included in the NCRC as of January 1, 2014?

A. Yes, on a project team level DEF has always segregated project costs incurred by specific project code and this process will not change for 2015 and 2016. The project team continues to charge Combined Operating License ("COL")-related labor, Nuclear Regulatory Commission ("NRC") fees, vendor invoices and all other COL-related cost items to the applicable COL project codes. The Regulatory Accounting and Regulatory Strategy groups, ensure that the COL-related project codes and associated costs incurred in 2014 and beyond are not included in the Company's NCRC Schedules, and thus not presented for nuclear cost recovery. We will however continue to track the COL-related costs for accounting purposes consistent with the 2013 Settlement Agreement.

Q. What is the estimated true-up for 2015 expected to be?

A. The 2015 true-up is expected to be an over-recovery of $4.1 million as reflected in Line 5 on the 2016 Summary Detail in Exhibit No._ (TGF-3).

C. LNP COST PROJECTIONS FOR 2016.

Q. What is included in the Total Revenue Requirements for the Period 2016?

A. The total current-period revenue requirements of $5.5 million in 2016 includes: period wind-down costs of $0.2 million, $0.2 million carrying costs on the net $5 million of the remaining LNP unrecovered investment balance (exclusive of the $54 million deferral), and $5.1 million of current-period carrying cost on the $54 million LLE Deferred Balance.

Q. What is included in the Total Return for the Period on the 2016 Revenue Requirement Detail Schedule, Line 8d and 2016 Detail Deferred Balance Schedule, Line 3d?

A. The Revenue Requirements of $0.2 and $5.1 million depicted on these Schedules on Line 8d and 3d respectively represent carrying costs on the average uncollected investment balance. The Schedules start with the 2016 beginning balance, add the monthly capital expenditures, remove the previous month's capital expenditures, remove the monthly amortization of the uncollected investment balance and compute the carrying charge on the average monthly balance. The equity component of the return is grossed up for taxes to cover the income taxes that will be paid upon recovery in rates.

Q. What are the exit and wind-down costs incurred for the Levy Nuclear Project for the period January 2016 through December 2016?

A. The 2016 Revenue Requirement Detail Schedule Exhibit No.__ (TGF-3) Lines 1e, 3e and Line 10e show that total exit and wind-down expenditures excluding carrying costs are estimated at [redacted].

Q. What is the total jurisdictional projected exit and wind-down costs that will be incurred for the period January 2016 through December 2016?

A. As shown on Line 5c and Line 17d of the 2016 Revenue Requirement Detail Schedule in Exhibit No._(TGF-3), total projected jurisdictional costs for 2016 are $0.2 million. The costs have been adjusted to a cash basis for purposes of calculating the carrying charge and the appropriate jurisdictional separation factor has been applied.

Q. What are the total estimated revenue requirements, exclusive of the revenue tax multiplier, for the LNP for the calendar year ended December 2016?

A. As can be seen in Exhibit No. _ (TGF-3), 2016 Summary Schedule Line 6, the total estimated revenue requirements are $13.5 million. This consists of $12.1 million associated with amortizing the remaining unrecovered investment balance, exclusive of the $54 million adjustment, $5.5 million in period carrying costs and recovery of current period exit and wind-down activities, and $4.1 million of prior period net over-recoveries.

Q. Has DEF included all of its 2015 and 2016 LNP costs or credits in this filing?

A. No it has not. There are potential costs or credits that DEF has not included in its actual/estimated 2015 and projected 2016 LNP costs because DEF is unable to accurately estimate them, as explained in more detail by Mr. Fallon.

V. COST RECOVERY FOR THE CRYSTAL RIVER 3 UPRATE PROJECT.

Q. What are you requesting with respect to the CR3 Uprate project?

A. DEF requests that the Commission approve recovery of the remaining unrecovered investment in the CR3 Uprate project and the future payment of all outstanding costs and any other reasonable and prudent exit costs consistent with Section 366.93(6), Florida Statues, and Rule 25-6.0423(7), F.A.C. In support of this request, DEF has prepared Exhibit No. _ (TGF-4), which shows the unrecovered investment and expected future payments and exit costs through the end of 2016 for purposes of setting 2016 rates. DEF requests that the Commission approve the revenue requirements for 2016 to be placed into the CCRC of $56.5 million as shown on 2016 Revenue Requirement Summary Line 6 of Exhibit No._(TGF-4).

Q. What is the total unrecovered investment in the CR3 Uprate project as of year-end 2014?

A. The total year-end 2014 unrecovered investment to be amortized is approximately $217.9 million as shown on lines 3a – 3b beginning balance amount in the 2015 Revenue Requirement Detail Schedule of Exhibit No._(TGF-4). This net amount represents the construction costs incurred that have not been placed in service. This amount does not include prior period over/under recoveries, prior period amortization, or period costs like wind-down/exit costs.

Q. How is DEF recovering this investment?

A. DEF is continuing to recover this balance over the remaining five (5) year period from 2015-2019 as approved by the Commission in the 2013 Settlement in Order PSC-13-0598-FOF-EI, Docket No. 130208-EI, which allowed DEF to recover the estimated year-end 2013 balance over the 2013-2019 period.

Q. Will DEF account for salvage or CR3 Uprate asset sales?

A. Yes. To the extent DEF receives any salvage or re-sale value for the CR3 Uprate assets currently recovered through the NCRC, DEF will apply that value to reduce the unrecovered balance.

Q. How is DEF calculating the carrying cost collected over this amortization period?

A. DEF is using the rate specified in Rule 25-6.0423(7)(b), F.A.C. The carrying cost rate used for this time period is 6.95 percent. On a pre-tax basis, the rate is 10.08 percent. This rate is based on DEF's December 2014 Earnings Surveillance Report. This annual rate was also adjusted to a monthly rate consistent with the AFUDC rule, Rule 25-6.0141, Item (3), F.A.C. Support for the components of this rate is shown in Appendix C of Exhibit No._(TGF-4).

Q. What are the total estimated period revenue requirements for the CR3 Uprate project for the calendar year ended December 2015?

A. The total estimated period revenue requirements for the CR3 Uprate project are $19 million for the calendar year ended December 2015, as reflected on page 4 line 22 of Exhibit No._(TGF-4). This amount includes $19 million for the carrying costs on the unrecovered investment balance shown on Line 5d, $0.3 million current period wind-down costs shown on Lines 2e and 16d, and net revenue requirement adjustments of $0.2 million shown on

Line 2j. These amounts were calculated in accordance with the provisions of Rule 25-6.0423, F.A.C.

Q. What is the total estimated over or under recovery for the CR3 Uprate project for the calendar year ended December 2015?

A. The total estimated over-recovery is $0.9 million as shown in Exhibit No._(TGF-4), the 2015 Revenue Requirement Detail Schedule Line 24.

Q. Did you reflect any credits for the sale or other disposition efforts for the CR3 Uprate project assets that occurred in the calendar year 2014, but for which receipt of payment did not occur in 2014?

A. Yes. Settlement of the auction proceeds from the sale of EPU assets are reflected in January 2015. Additionally, DEF has reflected receipt of the final payment for the POD Cooling Tower equipment that was sold on April 30, 2014, as described in Mark Teague's March 2, 2015 testimony.

Q. Did you project any other credits for the sale or other disposition efforts for the CR3 Uprate project assets?

A. No. DEF has not estimated the salvage or re-sale value for the remaining CR3 Uprate assets at this time because that value is presently unknown and uncertain. Value received from any future disposition of an EPU asset will be credited against the uncollected investment at the time of disposition.

Q. Were there any true-up adjustments that needed to be made to calculate the total estimated revenue requirements for the CR3 Uprate project for the calendar year ended December 2015?

A. Yes. As can be seen in Exhibit No. _(TGF-4), 2015 Revenue Requirement Detail Schedule Line 2j there is a credit of $229,139. In 2015, DEF recognized that an incorrect calculation was made regarding the joint owner credit related to the previous year's sale of the POD asset. The current year's revenue requirements were reduced to reflect the 2014 impact of this adjustment of $64,650 plus 2015 carrying costs (January through May 2015). As discussed previously in my testimony, we have also reflected a reduction to the carrying costs in 2014. The current year's revenue requirements reflect the 2014 impact of this adjustment of $155,383 plus 2015 carrying costs (January through May 2015). Details of these calculations can be seen in Exhibit No. ___ (TGF-4), Appendix A.

Q. What are the total estimated revenue requirements, exclusive of the revenue tax multiplier, for the CR3 Uprate project for the calendar year ended December 2016?

A. As can be seen in Exhibit No. _ (TGF-4), the 2016 Summary Schedule Line 6, the total estimated revenue requirements are $56.5 million. This consists primarily of $43.7 million associated with amortizing the unrecovered construction cost spend, $14.9 million in period carrying costs and recovery of current period exit and wind-down activities, and $2.1 million of prior period over-recoveries. These amounts are shown on lines 1, 2-4 and 5 of the above-mentioned Schedule respectively.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 150009-EI

DIRECT TESTIMONY OF CHRISTOPHER M. FALLON

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Christopher M. Fallon. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Corporation ("Duke Energy") as Vice President of Nuclear Development. Duke Energy Florida, Inc. ("DEF" or the "Company") is a fully owned subsidiary of Duke Energy.

Q. Please summarize your educational background and work experience.

A. I received Bachelor of Science and Master of Science degrees in electrical engineering from Clemson University in 1989 and 1990, respectively. I am also a registered professional engineer in North Carolina. I began my career with Duke Energy's predecessor company Duke Power in 1992 as a power quality engineer. After a series of promotions, I was named manager of transmission planning and engineering studies in 1999, general manager of asset strategy and planning in 2006, and the managing director of strategy and business planning for Duke Energy starting in 2007. In this role, I had responsibility for developing the strategy for the company's operating utilities; commercial support for operating utility activities such as acquisition of generation assets and overseeing Requests for Proposals for renewable generation resources; and major project/initiative business case analysis. In 2009, I was named Vice President, Office of Nuclear Development for Duke Energy. In that role, I was responsible for furthering the development of new nuclear generation in the Carolinas and Midwest. This included identifying and developing nuclear partnership opportunities, as well as integrating and advancing Duke Energy's plans for the proposed Lee Nuclear Station in Cherokee County, South Carolina. I was promoted to my current position on July 1, 2012. As Vice President of Nuclear Development, I am responsible for the Levy nuclear power plant project ("LNP").

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports DEF's request for cost recovery for the LNP actual costs in 2014. These costs were incurred for the LNP wind-down following DEF's decision not to proceed with construction of the LNP in summer 2013 and DEF's termination of the Engineering, Procurement, and Construction ("EPC") Agreement with Westinghouse Electric Company LLC ("WEC") and Stone & Webster, Inc. ("S&W") (together the "Consortium") in January 2014. DEF is seeking a prudence determination for (1) the Company's LNP wind-down costs incurred from January 2014 through December 2014, and (2) DEF's 2014 LNP project management, contracting, and cost controls, pursuant to Rule 25-6.0423(7), F.A.C. and Florida Public Service Commission ("PSC" or the

"Commission") Order No. PSC-13-0598-FOF-EI approving the Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement").

Q. Do you have any exhibits to your testimony?

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

- Exhibit No. ____ (CMF-1), DEF's confidential January 2014 letter to the Consortium terminating the EPC Agreement;
- Exhibit No. ____ (CMF-2), the confidential LNP Long-Lead Equipment ("LLE") Disposition Plan;
- Exhibit No. ____ (CMF-3), the confidential final resolution with S&W for costs under the EPC Agreement;
- Exhibit No. ____ (CMF-4), the confidential Tioga LNP LLE final disposition settlement memorandum;
- Exhibit No. ____ (CMF-5), the confidential DEF letter to the Consortium accepting the Tioga LNP LLE final disposition settlement offer; and
- Exhibit No. ____ (CMF-6), the confidential January 12, 2015 Status Update for Levy Nuclear Plant Long-lead Equipment Disposition Memorandum.

I will also be co-sponsoring the cost portions of the 2014 Detail Schedule, and sponsor Appendices D and E, which are included as part of Exhibit No. ___ (TGF-1) to Mr. Thomas G. Foster's direct testimony in this proceeding. Appendix D is a description of the major tasks and reflects expenditure variance explanations. Appendix E is a list of the contracts executed in excess of $1.0 million and provides details for those contracts.

All of these exhibits, schedules, and appendices are true and accurate.

Q. What is the current status of the LNP?

A. The Company elected not to complete construction of the LNP pursuant to the nuclear cost recovery statute and rule, Section 366.93(6), Florida Statutes, and Rule 25-6.0423(7), Florida Administrative Code ("F.A.C."), as amended, with its execution of the 2013 Settlement Agreement. Subsequently, DEF commenced development of the process to start winding down the LNP in an orderly fashion, which was fully put in place after the Commission voted to approve the 2013 Settlement Agreement. In January 2014, because DEF was unable to obtain the LNP Combined Operating License ("COL") from the Nuclear Regulatory Commission ("NRC") by January 1, 2014, DEF terminated the EPC Agreement with the Consortium. The termination letter is attached as Exhibit No. ___ (CMF-1) to my direct testimony.

The LNP wind down process involves the disposition of the LNP LLE and the resolution of remaining costs under the EPC Agreement with the Consortium. As explained in more detail below, DEF developed and implemented a LLE Disposition Plan and, pursuant to that Plan, DEF has been able to disposition or will soon disposition the LNP LLE. A copy of the LNP Disposition Plan is included as Exhibit No. ___ (CMF-2).

DEF paid S&W its remaining costs after DEF terminated the EPC Agreement in January 2014 and resolved all costs with S&W under the EPC Agreement. A copy of that final resolution with S&W is included as Exhibit No. ___ (CMF-3). DEF attempted to resolve, but was unable to resolve any remaining costs with WEC under the EPC Agreement. WEC demanded substantial additional costs from DEF for terminating the EPC Agreement. These claims, and DEF's claims against WEC under the EPC Agreement, will be resolved in the lawsuit DEF filed against WEC in March 2014 in the United States District Court for the Western District of North Carolina.

The only remaining LNP work is for the LNP Combined Operating License ("COL") from the NRC. DEF agreed to exercise reasonable and prudent efforts to obtain the LNP COL by March 31, 2015 in the 2013 Settlement Agreement. Throughout 2014 DEF continued with the work necessary to obtain the LNP COL including environmental permitting work necessary to obtain the Section 404 permit from the United States Army Corps of Engineers ("USACE"). DEF, however, is not seeking cost recovery in this proceeding for costs incurred in 2014 to obtain the LNP COL. DEF agreed to account for the 2014 COL-related costs as construction work in progress and agreed to remove them from recovery in the Nuclear Cost Recovery Clause ("NCRC") proceeding in the 2013 Settlement Agreement. DEF has segregated its 2014 COL-related costs from the 2014 LNP wind-down costs. The 2014 COL-related costs are not presented by DEF for cost recovery in the 2015 NCRC proceeding.

Q. Please summarize your testimony.

A. DEF prudently incurred necessary wind-down costs for the LNP in 2014. DEF appropriately minimized these costs pursuant to the 2013 Settlement Agreement. DEF terminated the EPC Agreement in January 2014 when DEF was unable to obtain the Levy COL from the NRC by January 1, 2014. Unnecessary project activities were eliminated and a LLE Disposition Plan was developed and implemented. DEF incurred only those contractually committed or necessary costs for the LNP wind-down activities in 2014. DEF has prudently managed the LNP in 2014, consistent with merged policies and procedures that implement Duke Energy best practices, that in substance are similar to the project management, contracting and cost control policies and procedures previously audited by the Commission Staff and reviewed and approved by the Commission.

III. 2014 LNP WIND-DOWN COSTS.

Q. What were the total LNP actual 2014 costs?

A. As can be seen in Appendix D of Exhibit No.___(TGF-1), total actual LNP costs for 2014, excluding the carrying costs on the unrecovered investment balance, were approximately [redacted]. This is about [redacted] less than DEF's actual/estimated costs for 2014. The reasons for this variance are described below.

Q. Please describe the Levy wind-down activities and costs.

A. DEF's LNP wind-down activities involved the LLE disposition and EPC Agreement. Costs for these wind-down activities were incurred for (1) final EPC Agreement contract payments to S&W to close out S&W's module program development work for the LNP; (2) storage, insurance, and quality assurance of the completed and partially completed LNP LLE until final disposition; (3) internal Duke Energy labor to assist with the LLE disposition; (4) WEC support to gather information from its LLE suppliers and assist with LLE disposition; and (5) regulatory and administrative LNP wind-down support.

Q. What were the costs to terminate the EPC Agreement with S&W?

A. DEF incurred approximately [redacted] to close out the S&W costs for S&W's module program development work for the LNP pursuant to the EPC Agreement. A copy of the agreement to close out this work under the EPC Agreement with S&W is attached as Exhibit No. ___ (CMF-3) to my direct testimony.

Q. Is S&W a party to the lawsuit with WEC in North Carolina?

A. No. S&W only sought to recover the costs for the work actually necessary to close out the LNP module development work under the EPC Agreement. S&W did not claim that DEF owed S&W a termination fee under the EPC Agreement and S&W did not claim that DEF owed S&W termination costs for additional work on the LNP that was never billed to or included in a change order request to DEF. As a result, DEF was able to resolve all costs for the LNP with S&W under the EPC Agreement, but DEF was not able to resolve all costs for the LNP with WEC under the EPC Agreement.

Q. What were the wind-down costs for the LNP LLE disposition in 2014?

A. The principle LNP LLE disposition cost in 2014 was the negotiated settlement payment to terminate the LLE purchase order with WEC and the sub-contractor Tioga for the reactor coolant-loop ("RCL") piping components for the LNP. These costs included a [redacted] payment and the reversal of an accrual for an RCL milestone payment of approximately [redacted] that was not made because of the cancellation of the purchase order for this equipment for a net cost impact of [redacted]. The decision to make this settlement payment to disposition the

RCL LLE components was made pursuant to DEF's LLE Disposition Plan guidelines.

DEF's LLE disposition objectives in its Disposition Plan are consistent with the 2013 Settlement Agreement. DEF's objectives are to disposition the LNP LLE in a manner that (i) minimizes the financial costs and risks of the LLE disposition to DEF's customers; (ii) minimizes other costs to DEF and its customers; and (iii) evaluates the potential future use of the LNP LLE for other AP1000 power plant projects. This includes minimizing LLE evaluation costs and purchase order or contract termination costs, minimizing the risks of financial loss associated with the LNP LLE, and maximizing the LNP LLE disposition cash value. A copy of the LLE Disposition Plan in included as Exhibit No. ___ (CMF-2).

Q. Can you explain how DEF and WEC and Tioga arrived at the settlement payment for the RCL piping?

A. The manufacturing process for the RCL LLE component started in 2013. As a result, this LLE component was being manufactured when DEF elected not to complete construction of the LNP in the 2013 Settlement Agreement. Because manufacturing costs were being incurred at that point DEF contacted WEC to authorize WEC to contact Tioga about Tioga's willingness to place a manufacturing hold on the RCL piping to allow DEF additional time to analyze the disposition of this LLE. Tioga responded that there was a cost associated with a manufacturing hold and required a change order for the payment of that cost to place a hold on the RCL piping manufacture. At this point, DEF authorized WEC to contact Tioga about the cost to cancel the RCL piping purchase order and manufacture of the RCL piping. Tioga provided WEC with an all-inclusive cancellation cost of [redacted]. This settlement offer to cancel the RCL piping purchase order and resolve all WEC and Tioga claims with respect to this LNP LLE component was evaluated by DEF under the DEF's LLE Disposition Plan objectives and determined to be the most cost-effective option for DEF and its customers.

Q. How was the RCL LLE component settlement consistent with the objectives in DEF's LLE Disposition Plan and cost effective for customers?

A. DEF evaluated the quantitative and qualitative factors in the LLE Disposition Plan guidelines to determine that the settlement was the most cost-effective option for DEF and its customers. This evaluation is explained in the confidential evaluation memo included as Exhibit No. ___ (CMF-4). The settlement with WEC and Tioga for the RCL LLE piping resulted in a minimum net savings of [redacted] to DEF's customers, compared to all other reasonably available options, accordingly, DEF accepted the offer. DEF's letter to WEC confirming that DEF accepted the Tioga LLE disposition settlement offer is included as Exhibit No. ___ (CMF-5).

Q. What is the disposition status of the remaining LNP LLE?

A. There were thirteen LNP LLE components in addition to the RCL piping component for the LNP. Four of these LLE components were with Mangiarotti and were also in manufacture in 2013. DEF terminated the purchase orders for the Mangiarotti LNP LLE, and settled with WEC and Mangiarotti in 2013, when DEF determined the settlement was cost effective for DEF and its customers pursuant to DEF's LLE Disposition Plan. This settlement payment was explained, and the settlement costs were determined to be prudent, in the 2014 NCRC proceeding.

Fabrication was complete for only two of the remaining nine LNP LLE. These are the Steam Generator Tubing and the Variable Frequency Drives ("VFDs"). The other LNP LLE items were suspended in 2010 as part of the April 2009 notice of partial suspension of the EPC Agreement, which was reflected in Amendment Three to the EPC Agreement. For these LLE items fabrication had not started or, if it had started, the manufacturing was suspended and these LLE items remain only partially complete. DEF evaluated the disposition of these remaining nine LNP LLE items pursuant to DEF's LLE Disposition Plan in 2014. This evaluation process and the results of that process are described in detail in the confidential January 2015 Status Update for Levy Nuclear Plant Long-Lead Equipment Disposition Memorandum included as Exhibit No. ___ (CMF-6).

As explained in more detail in confidential Exhibit No. ___ (CMF-6), DEF obtained in the litigation with WEC copies of the LNP LLE purchase orders, reviewed them, and exercised its right under the EPC Agreement to assume the purchase order for the completed VFDs. For the reasons provided in confidential Exhibit No. ___ (CMF-6) DEF did not exercise its right to assume the purchase orders for the remaining eight LLE items. DEF, however, was able to reach an agreement with WEC for the sale of certain, small items of the incomplete Squib valve LLE components and with the vendor, SPX, for the disposition of the remaining Squib valve LLE material. Because DEF did not assume the purchase orders for the remaining seven LLE items, WEC must protect and preserve the LLE items and use commercially reasonable efforts to dispose of the remaining LLE under the EPC Agreement. DEF's remedy is to enforce these contractual obligations in the litigation with WEC.

Q. If DEF has sold parts of the LLE components why is there no salvage value indicated in the Company's 2014 Detail Revenue Requirement Calculations schedule attached to Mr. Foster's direct testimony?

A. DEF did reach an agreement with WEC for WEC's purchase of part of the Squib valve LLE components and the agreed upon price for the parts of that incomplete LLE component are included in confidential Exhibit No. ___ (CMF-6). WEC, however, has taken the position that these agreed-upon payments should be offset against WEC's claims for alleged additional costs under the EPC Agreement. DEF disputes WEC's claims for alleged additional costs, and will defend these claims in the litigation. Until that litigation is resolved DEF does not expect WEC to pay the agreed upon prices for these small parts of the Squib Valves.

DEF negotiated directly with the Squib Valves vendor, SPX, for the purchase and salvage of the remaining Squib Valve material components. The vendor agreed in December 2014 to pay DEF the amount indicated in confidential Exhibit No. ___ (CMF-6) for the remaining Squib Valve material components on the terms indicated in that Exhibit. Because the vendor only agreed to this resolution in December 2014, the payment was not recorded in 2014. This payment will be reflected as salvage value in 2015.

Q. What does DEF plan to do with the VFDs?

A. At this time, DEF is evaluating various disposition options consistent with DEF's LLE Disposition Plan. DEF previously canvassed Duke Energy affiliates and contacted external utilities through WEC and on its own for any interest in acquiring the completed VFDs. These contacts included utilities with existing or potential AP1000 nuclear power plant projects. None of these entities expressed an interest in acquiring the VFDs. The most likely potential buyer, then, is the original equipment manufacturer. DEF is pursuing a potential sale of the VFDs to the original equipment manufacturer. DEF has also offered the VFDs for sale on RAPID, a utility industry parts sales website, and recently initiated a bid event on Feb. 15, 2015 for the VFDs utilizing Power Advocate bidding/sourcing software to further canvas the market. DEF will continue to evaluate the potential disposition of the VFDs in a reasonable and prudent manner consistent with the objectives in DEF's LLE Disposition Plan.

Q. How did DEF's actual LNP wind-down expenditures for 2014 compare to DEF's estimated/actual wind-down costs for 2014?

A. As I explained above, LNP wind-down costs were approximately [redacted], or [redacted] less than DEF's actual/estimated wind-down costs for 2014. One reason for this variance is that approximately [redacted] in projected LLE storage costs were not incurred in 2014 because DEF was able to disposition the majority of the LNP LLE items sooner than projected. The status of the majority of the LNP LLE items is described above and in confidential Exhibit No. ___ (CMF-6).

Another reason for this variance is that DEF did not make an approximately [redacted] LLE disposition payment that it expected to make in 2014. As DEF has explained previously, DEF anticipated a [redacted]. As I explained above and as explained in confidential Exhibit No. ___ (CMF-6), DEF did not assume the purchase order for this LLE component and, therefore, WEC is obligated under the EPC Agreement to preserve and protect this LLE material and to take commercially reasonable steps to disposition this incomplete LLE component material. DEF is not aware of any actions WEC may or may not have taken to cancel the purchase order or disposition the Steam Generator Balance at this time.

Q. To summarize, were all of the wind-down costs that the Company incurred in 2014 for the LNP reasonable and prudent?

A. Yes, the specific costs for the LNP contained in the 2014 Detail schedules, which are attached as exhibits to Mr. Foster's testimony, reflect the reasonable and prudent wind-down costs DEF incurred for LNP work in 2014. DEF took reasonable steps in 2014 to minimize the LNP work and wind-down costs. These steps are explained in my testimony above and in detail in DEF's LLE Disposition Plan included as Exhibit No. ____ (CMF-2) and in DEF's confidential Status Update for Levy Nuclear Plant Long-lead Equipment Disposition Memorandum included as Exhibit No. ___ (CMF-6). All of these wind-down activities and their associated costs were necessary, reasonable and prudent for the LNP.

In addition, DEF terminated the EPC Agreement in late January 2014, after disposition of the Tioga LLE --- the final LLE component being manufactured --- under a provision that allowed DEF to terminate the EPC Agreement without paying WEC a termination fee. Under this provision, DEF does not have to pay WEC the termination fee if either party terminated the EPC Agreement because DEF was unable to obtain the COL from the NRC by January 1, 2014. When DEF was unable to obtain the LNP COL from the NRC by January 1, 2014, DEF reasonably and prudently exercised its contractual right to terminate the EPC Agreement without paying WEC the termination fee.

Q. What is the status of DEF's lawsuit with WEC?

A. As I explained above, DEF filed a lawsuit against WEC in the United States District Court for the Western District of North Carolina in March 2014. WEC soon after filed its own lawsuit against DEF for breach of the EPC Agreement in federal district court in Pennsylvania. The lawsuit in Pennsylvania has now been dismissed, and the claims under the EPC Agreement are proceeding before the North Carolina District Court in the lawsuit filed by DEF. WEC has filed a counterclaim against DEF in the lawsuit pending in the federal district court in North Carolina. On August 19, 2014, the federal district court issued a Pretrial Order and Case Management Plan that currently schedules a trial date to resolve the claims between DEF and WEC under the EPC Agreement in February 2016.

Q. What does DEF plan to do with its pending lawsuit with WEC in the federal district court in North Carolina?

A. DEF is vigorously pursuing its claims and defending against the claims that WEC has brought in that lawsuit. The ultimate resolution of these claims, however, will be by a court and DEF cannot predict the outcome of this litigation at this time.

IV. LNP COMBINED OPERATING LICENSE APPLICATION UPDATE.

Q. Can you summarize the Combined Operating License Application process?

A. Yes. There are three parts to the NRC Combined Operating License Application ("COLA") review process. All three parts must be complete before the NRC will issue a COL. The three parts of the NRC COLA review process are: (1) the environmental review process; (2) the safety review process; and (3) the formal hearing process. DEF also must obtain environmental permits for the LNP COL.

Q. What is the status of the LNP NRC COLA review process?

A. The environmental review for the LNP COLA was complete when DEF received the LNP final environmental impact statement ("FEIS") on April 27, 2012. The remaining two parts of the NRC COLA review process for the LNP are incomplete.

The Final Safety Evaluation Report ("FSER") for the LNP COL has not been issued. The Advanced Safety Evaluation Report ("ASER") for the LNP COLA was initially completed with no open items, however, subsequent, significant design changes due to WEC design errors were identified by WEC that now require revisions to the ASER to incorporate these design changes before NRC review can be finalized. This work must be completed before NRC review and issuance of the FSER for the LNP COL. These design changes are now the critical path items to completion of the NRC review and issuance of the LNP COL.

WEC has significantly delayed the NRC LNP COLA review because WEC has failed to provide information in a timely manner to the NRC regarding these design changes. In fact, due to WEC's repeated failure to provide required information regarding WEC's design changes to correct WEC design errors in a timely manner, the NRC has notified DEF that it cannot provide DEF with a new schedule until a firm schedule for resolving technical issues that have been identified with the AP1000 certified design is provided. Until a firm schedule is received from WEC, DEF cannot identify an expected receipt date for the LNP FSER and, accordingly, the LNP COL from the NRC.

Q. What is the status of the formal hearing process for the LNP COLA?

A. One part of the two-part formal hearing process for the LNP COLA was completed in March 2013 when the NRC Atomic Safety Licensing Board ("ASLB") issued its ruling on the remaining contested contention to the LNP COLA regarding the environmental impacts of dewatering and salt drift as a result of the LNP. Following an evidentiary hearing in October and November 2012, and the submission of Findings of Fact and Conclusions of Law in December 2012, the NRC ASLB unanimously resolved all issues in DEF's favor in March 2013. The ASLB concluded that the LNP FEIS complied with all legal and regulatory requirements.

The second part of the two-part formal hearing process is the LNP COLA mandatory hearing before the NRC Commissioners. The LNP COLA mandatory hearing process cannot commence until the LNP FSER is issued. For the reasons provided above, the NRC does not presently have a schedule for issuance of the LNP FSER. As a result, the mandatory hearing for the LNP COLA has not been scheduled by the NRC.

Q. What is the status of the environmental permits for the LNP COL?

A. DEF continued its work with the USACE for the Section 404 permit for the Levy site in 2014. The USACE Section 404 permit allows for and regulates the construction of structures in wetlands and regulated waterways. This work included discussions and the development of information for USACE regarding mitigation on government lands, the assessment of secondary wetlands impacts, and revisions to the Environmental Monitoring Plan ("EMP"). Further engineering and permitting work was performed to revise Section 404 permit drawings for the USACE and to address issues regarding the EMP, specifically with respect to the timing of potential alternative water supply from desalination, to determine the use of ground water for the LNP. Other than USACE review and finalization of the proposed Wetland Mitigation Plan ("WMP"), which is needed for the Section 404 Permit, all of these issues were resolved in 2014. The USACE is still reviewing the proposed WMP. DEF expects to resolve the WMP and any new Section 404 permit issues the USACE may raise as they finalize their review this year to allow for USACE issuance of the Section 404 permit for the LNP. Likewise, while this work continued in 2014, the 2014 costs associated with this work are not included in the NCRC.

V. PROJECT MANAGEMENT, CONTRACTING, AND COST OVERSIGHT.

Q. Can you explain the Company's 2014 LNP project management, contracting, and cost control oversight policies and procedures?

A. Yes. Nuclear Development ("ND") is responsible for the LNP management. As a result, ND is responsible for the process of implementing best practices and lessons learned for the LNP and other nuclear development projects. ND has implemented or adopted policies and procedures for the management of the LNP that reflect the collective experience, knowledge, and best practices of Duke Energy and the nuclear utility industry.

Q. Are the Company's 2014 LNP project management, contracting, and cost control oversight policies and procedures substantially the same as the Company's prior project management, contracting, and cost control oversight policies and procedures?

A. Yes. Changes in the 2014 LNP project management, contracting, and cost oversight control policies and procedures for the LNP are changes more in structure than substance. The Company's 2014 LNP project management, contracting, and cost control oversight policies and procedures reflect best practices, lessons learned, and efficient and effective LNP management and oversight of the LNP costs.

Q. Are the Company's 2014 LNP project management, contracting, and cost control oversight policies and procedures reasonable and prudent?

A. Yes, they are. The LNP 2014 project management, contracting, and cost control policies and procedures are substantially the same as the collective policies and procedures that have been vetted in the annual project management audit in this docket and previously approved as prudent by the Commission. *See* Order No. PSC-09-0783-FOF-EI, issued Nov. 19, 2009; Order No. PSC-11-0095-FOF-EI, issued Feb. 2, 2011; Order No. PSC-11-0547-FOF-EI, issued Nov. 23, 2011; Order No. PSC-12-0650-FOF-EI, issued Dec. 11, 2012; and Order No. PSC-14-0617-FOF-EI, Issued Oct. 27, 2014. We believe, therefore, that the LNP project management policies and procedures are consistent with best practices for capital project management in the industry and continue to be reasonable and prudent.

Q. Have the Company's project management, contracting, and cost control oversight policies and procedures changed as a result of the Company's decision not to complete construction of the LNP and to terminate the EPC Agreement?

A. No, the Company's ND project management, contracting, and cost control oversight policies and procedures have not changed. These are Duke Energy-wide policies and procedures, applicable to all nuclear generation development, and in some cases such as the fleet-wide policies and procedures, existing operating nuclear power plants. Duke Energy did not change its ND project management, contracting and cost control oversight policies and procedures because of the Company's decisions not to complete construction of the LNP and to terminate the EPC Agreement. Some of these policies and procedures are no longer applicable to the LNP going forward as a result of these decisions. Some new processes, like the LLE Disposition Plan included as Exhibit No. ____ (CMF-2) to my direct testimony, were developed and implemented as a result of these decisions. But the Company is still managing the LNP in the LNP wind-down process, and as a result, the Company is still following all applicable project management, contracting, and cost control oversight policies and procedures for the LNP.

Q. Has DEF implemented a process to ensure that costs related to the LNP COL are not included in the NCRC as of January 1, 2014?

A. Yes, from a project team perspective, DEF has always segregated project costs incurred by specific project code. This did not change for 2014 and the project team continued and will continue to charge COL-related labor, NRC fees, vendor invoices and all other COL-related cost items to the applicable COL project codes. The Regulatory Accounting and Regulatory Strategy groups ensure that the COL-related project codes and associated costs incurred in 2014 and beyond are not included in the Company's NCRC Schedules, and thus not presented for nuclear cost recovery. These COL-related costs will, however, continue to be tracked for accounting purposes consistent with the 2013 Settlement Agreement.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE
BY DUKE ENERGY FLORIDA, INC.
FPSC DOCKET NO. 150009-EI
DIRECT TESTIMONY OF CHRISTOPHER M. FALLON

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Christopher M. Fallon. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. Who do you work for and what is your position with that company?

A. I am employed by Duke Energy Corporation ("Duke Energy") as Vice President of Nuclear Development. Duke Energy Florida, Inc. ("DEF" or the "Company") is a fully owned subsidiary of Duke Energy.

Q. Have you previously provided testimony in Docket No. 150009-EI?

A. Yes. I submitted direct testimony in this docket on March 2, 2015.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your May 1, 2015 direct testimony?

A. One purpose of my testimony is to describe DEF's wind-down activities for the Levy Nuclear Project ("LNP" or "Levy"). These activities relate to the disposition of long lead time equipment ("LLE") with Westinghouse Electric Company LLC ("WEC") and its suppliers subsequent to the termination of the Engineering, Procurement, and Construction ("EPC") Agreement with WEC and Stone & Webster, Inc. ("S&W") (together, the "Consortium"). I present and support DEF's 2015 actual/estimated and 2016 projected LNP wind-down costs related to these wind down activities.

Another purpose of my testimony is to provide the Florida Public Service Commission (the "Commission") an update on the Company's Combined Operating License Application ("COLA") with the Nuclear Regulatory Commission ("NRC") for the Combined Operating License ("COL") for the Levy site. The Company, however, is not seeking any costs related to the Company's pursuit of the COL, environmental permitting, wetlands mitigation, conditions of certification, and other costs related to the COL for the Levy site in this Nuclear Cost Recovery Clause ("NCRC") docket. DEF agreed that it would not seek to recover these costs from customers through the NCRC pursuant to the 2013 Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement") approved by the Commission in Order No. PSC-13-0598-FOF-EI.

Q. Do you have any exhibits to your testimony?

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

- Exhibit No. ____ (CMF-7), a confidential chart of the Company's LNP LLE disposition actions and status; and
- Exhibit No. ____ (CMF-8), a chart of the expected LNP COLA schedule.

I am also sponsoring or co-sponsoring portions of the Schedules attached to Thomas G. Foster's testimony as Exhibit No. ___ (TGF-3). Specifically, I am co-sponsoring portions of the 2015 and 2016 Detail Schedules and sponsoring Appendices D and E. These Schedules reflect the 2015 and 2016 actual/estimated revenue requirement calculations, the major task categories and expense variances, and a summary of contracts and details over $1 million.

All of these exhibits and schedules are true and accurate to the best of my knowledge and information.

Q. Please summarize your testimony.

A. DEF is nearly complete with its wind-down plan for the LNP. Final disposition decisions have been made for all but one of the Levy LLE. DEF anticipates making the final disposition decision for this remaining Levy LLE component this year.

DEF and WEC initiated litigation against each other for claims under the EPC Agreement. DEF will continue to advance its claims against WEC and defend the claims WEC has asserted against DEF in the North Carolina federal court litigation.

DEF currently plans to continue its COLA work to obtain the COL for the Levy site from the NRC. DEF currently anticipates COL receipt in May of 2016.

III. LNP WIND-DOWN ACTIVITIES.

Q. Does DEF have actual/estimated costs in 2015 as a result of Levy wind-down activities?

A. Yes. DEF's actual/estimated 2015 wind-down costs are [redacted]. *See* 2015 Detail LNP Schedule of Exhibit No. ___ (TGF-3) to Mr. Foster's testimony. Mr. Foster also describes other wind-down costs projected for 2015 and 2016. These total costs are offset by the approximately [redacted] projected to be received for the sale or salvage of Levy LLE shown on line 1c in the 2015 Detail Schedule.

Q. Please describe the Levy wind-down activities and costs.

A. Wind-down cost were incurred and will be incurred in 2015 for (1) storage, insurance, and quality assurance for the remaining Levy LLE component, the Variable Frequency Drives ("VFDs"), until final disposition; (2) internal Duke Energy labor to assist with disposition of the LLE; and (3) regulatory and wind-down support. DEF does not include in this filing potential, future wind-down or LLE disposition costs or credits that DEF cannot reasonably quantify at this time.

Q. Can you explain the current status of the Levy VFDs?

A. Yes. As I explained in my March testimony in this Docket, the VFDs are the sole remaining Levy LLE component that DEF must disposition. Disposition decisions for the other Levy LLE components have been made. *See* Exhibit No. ___ (CMF-7). Because fabrication for the VFDs was completed, and DEF assumed the Purchase Order ("PO") for the VFDs, DEF has offered the VFDs for sale or salvage consistent with its LLE Disposition Plan. DEF has marketed and offered the VFDs for sale to Duke Energy affiliates and to external utilities, including utilities with existing or potential AP1000 nuclear power projects in the United States and in China. DEF also offered the VFDs for sale on the external utility parts market through RAPID, a utility industry parts website, and DEF further offered the VFDs to scrap buyers. DEF then re-offered the VFDs for sale in a bid event utilizing the Power Advocate bidding/sourcing software to further canvas the potential market for the VFDs.

None of these efforts yielded an offer for the VFDs for any value beyond scrap value. Siemens, the VFDs manufacturer, [redacted]

Unrelated to DEF's attempts to sell or salvage the Levy AP1000 VFDs, [redacted]

[redacted] X [redacted] Following its evaluation, DEF will choose the option [redacted] that provides the greatest value to DEF's customer.

Q. When does DEF expect to make a final decision with respect to the VFDs?

A. DEF expects to make a final decision with respect to the VFDs by the late summer.

Q. Does DEF project that it will incur Levy wind-down costs in 2016?

A. DEF expects minimal wind-down costs of [redacted] for project management and regulatory support in 2016 as shown on line 1e of the 2016 Detail LNP Schedule attached as Exhibit No. ___(TGF-3) to Mr. Foster's testimony. As I mentioned above, this projection does not take into account any costs that DEF simply is not able to reasonably quantify at this time.

Q. What is the status of DEF's litigation with WEC?

A. DEF's lawsuit with WEC is currently pending before the United States District Court for the Western District of North Carolina. DEF continues to vigorously pursue its claims and to vigorously defend against the claims WEC has brought in that lawsuit. The current case management schedule in this lawsuit includes a trial date for February 2016. DEF cannot reasonably predict the outcome of this litigation at this time. DEF cannot project the costs or refunds resulting from the resolution of the claims in this litigation.

IV. LEVY COMBINED OPERATING LICENSE APPLICATION UPDATE.

Q. What is the status of the Levy COLA for the COL for the Levy site?

A. There are three parts to the NRC COLA review process and all three parts must be complete before the NRC will issue a COL. Those three parts of the NRC COLA review process are: (i) the environmental review process; (ii) the safety review process; and (iii) the formal hearing process.

The environmental review process for the Levy COLA was complete when DEF received the Levy final environmental impact statement ("FEIS") on April 27, 2012. The remaining two parts of the NRC COLA review process for the Levy COLA are incomplete although steps in these review processes have been completed.

Q. What is the status of the NRC safety review for the Levy site COL?

A. The Final Safety Evaluation Report ("FSER") for the Levy COL has not been issued. The Advanced Safety Evaluation Report ("ASER"), was initially completed with no open items on September 15, 2011, however, as I also explained in my March testimony, subsequent, significant WEC design errors identified by WEC now require revisions to the ASER to incorporate changes to correct these design errors before NRC review can be finalized. Resolution of these changes is now the critical path item to complete NRC review and issue the COL for the Levy site.

As I also explained in my March testimony, WEC significantly delayed this NRC review of the design changes by failing to timely provide information regarding these design changes to the NRC. Due to WEC's repeated failure to provide the required information when promised by WEC, the NRC notified DEF that it could not provide DEF with a new COLA review schedule until a firm schedule for resolving the issues identified as a result of the WEC design errors has been established. DEF continues to work with WEC to obtain the required information from WEC for the NRC and to re-establish a schedule for the issuance of the COL for the Levy site. At this time, however, DEF still does not have a formal NRC COLA review schedule from the NRC.

Q. Does DEF expect these design changes to be resolved and reviewed by the NRC?

A. Yes. DEF continues to work with WEC to resolve the WEC design errors and to obtain NRC review and approval of the design changes to address the WEC design errors in the ASER. At this time, DEF believes it is reasonable for the Company to continue its work to obtain the COL and DEF is working with WEC and the NRC to obtain the FSER to reach that goal. The ACRS has also requested review of one of the WEC design changes after completion of NRC review and issuance of the revised ASER. At this time, DEF expects NRC review and issuance of the revised ASER in time for the ACRS subcommittee review in September 2015 and ACRS full committee review in October 2015.

Q. What is the status of the formal hearing process for the Levy site COL?

A. There are two parts to the NRC formal hearing process: (1) a contested hearing before the NRC Atomic Safety and Licensing Board ("ASLB"), and (2) a mandatory hearing before the NRC. The contested hearing was conducted in the fall of 2012 and on March 26, 2013, the NRC ASLB issued its ruling in DEF's favor on all issues.

The mandatory hearing for the COL is conducted by the NRC Commissioners. The COL mandatory hearing, however, cannot commence until the FSER for the Levy site is issued. As I explained above, DEF does not have a formal NRC schedule for the COLA for the Levy site, but based on DEF's current information in working with the

NRC to resolve all issues related to the Levy site FSER described generally above, the Company currently expects the NRC to complete the mandatory hearing by second quarter 2016. Exhibit No. ___ (CMF-8) to my direct testimony contains DEF's estimate for the Levy COLA schedule.

Q. What is the status of the environmental permits for the Levy COL?

A. DEF expects the U.S. Army Corps of Engineers ("ACOE") to issue the Section 404 Permit for the Levy site some time in 2015. DEF is working with the ACOE and waiting on ACOE review and finalization of the Wetland Mitigation Plan ("WMP") for the Levy site. All other issues have been resolved. As a result, DEF expects to receive the Section 404 permit for the Levy site from the ACOE this year.

Q. When does DEF expect to receive the COL for Levy?

A. The Company's current internal estimate is that the NRC will issue the Levy COL in May 2016.

Q. What are DEF's current plans for the Levy site if DEF receives the COL?

A. DEF does not have a contract to build the Levy nuclear power plants and DEF has no definite plan to construct them at this time. DEF currently plans to obtain the COL to preserve the option of building new nuclear at the Levy site based on, among other factors, energy needs, project costs, carbon regulation, natural gas prices, existing or future legislative provisions for cost recovery, and the requirements of the COL. DEF will reassess plans for the construction of nuclear power plants at the Levy site after receipt of the COL.

V. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the LNP since your testimony was filed in March 2015?

A. No. The Company continues to utilize the Company policies and procedures that I described in my March testimony to ensure that wind-down costs for the LNP are reasonably and prudently incurred. The Company will continue to review policies, procedures, and controls on an ongoing basis, and make revisions and enhancements based on changing business conditions, organizational changes, and lessons learned, as necessary. This process of continuous review of our policies, procedures, and controls is a best practice in our industry and is part of our existing Levy project management and cost control oversight. Additionally, the Senior Management Committee ("SMC") review occurs at least quarterly and more often when needed. Significant financial decisions are also taken to the Transaction and Risk Committee ("TRC") and the Board of Directors, as necessary, pursuant to the Approval of Business Transactions ("ABT") policy. Finally, the Company continues to ensure that all COLA-related costs are segregated out and not included in the NCRC.

VI. CONCLUSION.

Q. Has DEF acted in a reasonable and prudent manner to wind-down the Levy project and disposition the Levy LLE?

A. Yes. DEF reasonably dispositioned all Levy LLE in 2014 with the exception of the VFDs. DEF will continue to review reasonable options for the sale or salvage of the VFDs and will make the prudent disposition decision for the benefit of DEF's customers. DEF intends to vigorously pursue and defend its rights under the EPC Agreement in the current litigation with WEC. DEF's actions have been and will continue to be reasonable and prudent for DEF and its customers.

Q. Does this conclude your direct testimony?

A. Yes it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 150009-EI

DIRECT TESTIMONY OF MARK R. TEAGUE

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Marcus ("Mark") R. Teague. My current business address is 400 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services, LLC as Managing Director of Major Projects Sourcing ("MPS") in the Supply Chain department.

Q. What are your responsibilities as the Managing Director of MPS?

A. My role includes providing management oversight in the disposition of the Crystal River Unit 3 ("CR3") Extended Power Uprate ("EPU") assets by ensuring that Supply Chain employees at CR3 follow Duke Energy Florida Inc.'s ("DEF" or the "Company") processes and procedures. I also have responsibility for the Supply Chain functions for Duke Energy International and with most Duke Energy Corporation ("Duke Energy") Major Projects, both regulated and non-regulated.

Q. Please summarize your educational background and professional experience.

A. I have a Bachelors of Engineering Technology degree in Civil Engineering from the

University of North Carolina at Charlotte and a Masters of Business Administration from Wake Forest University. I have 32 years of experience with Duke Energy and I am a licensed Professional Engineer in the state of North Carolina. My prior roles at Duke Energy include design engineering professional, project controls professional, and project management professional in both Nuclear Generation and Fossil/Hydro Generation and I have also managed each of those functional roles in the past. For the last four years, I have served as Managing Director in the Supply Chain organization – two years leading the Fossil/Hydro Supply Chain organization and two years leading the Major Projects Sourcing Supply Chain organization.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. In accordance with the cancellation of the CR3 EPU project, resulting from the decision to retire and decommission the CR3 nuclear power plant, my direct testimony supports the Company's request for cost recovery pursuant to Section 366.93(6), Fla. Stat. and Rule 25-6.0423(7), Florida Administrative Code ("F.A.C.") for the prudent exit costs incurred in 2014 to demobilize and close-out the EPU project. I will explain the status of the investment recovery project efforts to disposition EPU-related assets and materials and the related proceeds from those efforts. My testimony also supports the prudence of DEF's 2014 project management, contracting, and cost oversight policies and procedures for the EPU project wind-down and investment recovery efforts.

Q. Do you have any exhibits to your testimony?

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

- Exhibit No.___(MT-1), the CR3 Administrative Procedure, AI-9010, Conduct of CR3 Investment Recovery, Revision 1;
- Exhibit No. ____ (MT-2), the CR3 Investment Recovery Project, Project Execution Plan, Revision 0;
- Exhibit No. ___(MT-3), the Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development;
- Exhibit No. ___(MT-4), a confidential chart of EPU-related assets disposed of through sales to third parties or affiliate transfers in 2014; and
- Exhibit No. ____(MT-5), the confidential Integrated Change Form for the retention of an auction company used to sell CR3 plant assets, including EPU-related assets.

I am also co-sponsoring the 2014 Detail Schedule, and sponsoring Appendices D and E, which are included as part of Exhibit No. ___ (TGF-2) to Mr. Thomas G. Foster's direct testimony in this proceeding.

These exhibits were prepared by the Company, and they are generally and regularly used by the Company in the normal course of its business, and they are true and correct.

Q. Please summarize your testimony.

A. My direct testimony supports DEF's request for a prudence determination for the actual costs it incurred in 2014 for the EPU project close-out, offset by the proceeds received from the sale or salvage of EPU-related assets. I also provide an update on the EPU project close-out and asset disposition investment recovery project progress. In 2014, DEF continued to disposition EPU-related assets using a step-wise approach under its investment recovery policies and procedures to obtain the most prudent value for the EPU-related assets for DEF's customers. DEF sold or transferred several EPU-related assets, including the Point of Discharge ("POD") Cooling Tower components, at fair market value for the EPU-related assets. In mid-2014, after conducting extensive internal and external solicitation efforts pursuant to DEF's policies and exhausting direct sale or transfer opportunities, DEF made the decision to hire an auction company to conduct a global auction for the remaining CR3 assets, including EPU-related assets. The auction was conducted in September 2014 and DEF successfully sold various EPU-related assets at the auction. Auction proceeds were accounted for in January 2015 and will be presented in my May 2015 testimony in this docket.

DEF's 2014 EPU close-out costs were lower than anticipated because DEF overestimated the time necessary to perform the required preventative maintenance on the remaining equipment. Contributing factors included the sale of some of the major EPU-related assets in the middle of the year. DEF's 2014 EPU close-out costs are also lower than estimated because DEF used the proceeds from the sale or salvage of EPU-related equipment prior to the auction to offset the estimated costs. DEF did not estimate sale or salvage proceeds because DEF could not reasonably estimate those proceeds.

DEF prudently followed its policies and procedures to close-out the EPU project, while managing its costs, and DEF has successfully sold or transferred several EPU-related assets in 2014. Proceeds from the sales or transfers of EPU-related assets are returned to customers.

III. ACTUAL COSTS INCURRED IN 2014 FOR THE EPU PROJECT.

A. Status of the EPU Project Close-Out.

Q. Will you please describe the status of the EPU project close-out and the investment recovery efforts for EPU-related assets in 2014?

A. Yes. The last remaining stage for the EPU project close-out is the final disposition of EPU-related assets and materials. During 2014, the DEF investment recovery team worked diligently to market and transfer or sell EPU-related assets in accordance with the CR3 Administrative Procedure AI-9010, Conduct of CR3 Investment Recovery, Revision 1 ("AI-9010"), attached hereto as Exhibit No. ___(MT-1); the CR3 Investment Recovery Project, Project Execution Plan, Revision 0 ("Project Plan"), attached hereto as Exhibit No. __(MT-2); and the Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development ("IRGD-001"), attached hereto as Exhibit No. ___(MT-3). These policies and procedures provide the overall governance for the project and outline the asset pricing requirements and minimum reviews, approvals and records required for the execution of transactions for the disposal of assets from CR3, including EPU-related assets.

Q. What disposition strategy did DEF use for the sale of EPU-related assets in 2014?

A. Under the investment recovery procedure, assets were first offered for internal transfer to Duke Energy affiliates in accordance with the Affiliate Asset Transfer

Transactions policy. If DEF was unable to locate an appropriate internal transfer opportunity, DEF then solicited external interest from distributors, original equipment manufacturers ("OEM"), and re-sellers and, if there was sufficient interest, DEF conducted a bid event using Power Advocate (an electronic bidding tool). DEF also marketed some EPU components on RAPID, a utility parts website, and worked with Pooled Inventory Management ("PIM"), a program run by the Southern Company to market major components for joint purchase by multiple utilities for components to keep as "spares" in the event of a future need.

Several small EPU-components were transferred internally in 2014 and some components were sold at bid events as shown on the 2014 EPU Asset Sales/Transfers List, attached hereto as Exhibit No. ___(MT-4).

For the remaining equipment, as I describe in more detail below, the investment recovery team decided to utilize the assistance of an auction company to enable DEF to reach the widest audience possible for its CR3 and EPU-related assets. For assets that were not sold at the auction, DEF has continued to pursue sale options with OEMs and DEF is pursuing additional independent bid event as appropriate. Remaining installed EPU-related equipment is being evaluated in 2015 for the most cost-effective disposition option.

Q. What EPU-related assets were disposed of through transfer or sale in 2014?

A. My Exhibit No. ___(MT-4) is a list of the EPU-related assets that were transferred or sold in 2014 along with the price, transaction type, and date of sale or transfer.

Q. The POD Cooling Tower assets are listed as being sold at a bid event, can you please describe the sale of the POD Cooling Tower assets?

A. Yes. A bid event for the sale of the POD Cooling Tower components was released in December 2013. The bid list was developed by contacting more than 50 cooling tower contacts, including utilities, as well as contacting targeted interested bidders using Supply Chain information. The Cooling Tower bid event was finalized, bids received and evaluated, and negotiations were conducted with the high bidder. These sale negotiations were completed on April 30, 2014 and the sale was finalized. The sales price is listed on my Exhibit No. ___(MT-4). The buyer absorbed the cost to remove the Cooling Tower components [redacted] The Nuclear Cost Recovery Clause ("NCRC") portion of the sales proceeds is shown on Exhibit No. __(MT-4) and it is also included in Line 1.b., Column May 2014, of Schedule Detail 2014 included in Mr. Foster's testimony as Exhibit No. __(TGF-2).

Q. Why did DEF decide to use an auction company to sell the CR3 equipment, including the remaining EPU-related equipment?

A. In accordance with its policies and procedures, DEF had exhausted efforts to disposition CR3 and EPU-related assets at fair market value through competitive bidding processes for direct sales to third parties or transfers to Duke Energy affiliates. DEF had already followed its process under these policies and procedures and offered CR3 and EPU-related assets for sale or transfer internally, solicited the market and offered assets for direct sale externally to third parties, including soliciting buy-back from equipment OEMs. After those steps, in mid-2014, DEF decided to evaluate using an outside auction company to sell the remaining CR3 plant assets, including EPU-related assets. DEF determined in this evaluation that if DEF used an auction company to sell assets, compared to singular bid events for the assets, DEF would be able to access the aggressive marketing of the auction company and reach a broader, indeed, world-wide market. This evaluation is reflected in DEF's Integrated Change Form ("ICF") included as Exhibit No. ___ (MT-5).

Q. Can you please describe who DEF retained to conduct the auction and when it was conducted?

A. Yes. DEF retained Heritage Global Partners Asset Advisory & Auction Services to conduct the auction. This auction was advertised world-wide to over 100,000 potential buyers through various mediums including print and electronic advertising and direct e-mail solicitation, in addition to personal contact with power plants world-wide. The auction was conducted over three days on September 24-26, 2014 in Crystal River, Florida. The EPU-related assets that were sold through the auction along with the sales prices are listed on my Exhibit No. ___(MT-4).

Q. What EPU-related assets remain to be sold or salvaged in 2015?

A. The following EPU related assets were unable to be sold either prior to or at the auction and are still in DEF's possession:

- Siemens High Pressure Turbine and equipment,
- Siemens Turbine Lubricating Oil Cooler Bundles,

- Siemens New Stator Core and Rewound Generator Rotor,
- Siemens Exciter,
- Siemens Hydrogen Coolers,
- Two General Electric Induction Motors,
- Siemens Low Pressure Turbine rotors, blades, cylinders, and parts,
- Installed Feedwater Heat Exchanger CDHE-3A/3B,
- Installed Belly Drain Heat Exchanger CDHE-7A/7B, and
- Installed Moisture Separator Reheaters.

DEF followed its disposition strategy, described above, for each of the remaining assets and was unable to transfer the assets internally or sell the assets to third parties. DEF has reevaluated its disposition options for each piece of equipment and is actively attempting to disposition this equipment through sale to the equipment OEM, salvage as necessary if a sale to the OEM is not possible, or abandonment of the installed equipment if that is the most cost effective option. DEF anticipates making final decisions on this remaining equipment in the first quarter of 2015.

B. <u>EPU Project Close-Out 2014 Actual Costs.</u>

Q. What costs did DEF incur related to the EPU project close-out in 2014?

A. As can be seen in Appendix D of Exhibit No. ___(TGF-2), costs for 2014, gross of joint owner billing, exclusive of carrying costs, and net of sale, transfer, or salvage proceeds, and exclusive of accounting adjustments, were ($0.4 million). This is almost $0.9 million less than DEF estimated for 2014. Costs to close-out the project were incurred in the category of EPU Wind-Down and sale, transfer or salvage proceeds were applied in the category of Sale or Salvage of Assets. Schedule 2014 Detail in Exhibit No.___(TGF-2) to Mr. Foster's testimony provides further details on these costs.

Q. Please describe the total EPU Wind-Down Costs incurred and explain why the Company incurred them.

A. DEF incurred approximately $42,000 in EPU Wind Down Costs in 2014. These costs were incurred to conduct preventative maintenance for EPU-related assets to preserve their marketability for sale.

Q. Please describe what sale, transfer, or salvage proceeds were received in 2014 and explain how DEF accounted for these proceeds.

A. DEF received approximately $450,000 in proceeds from the sale, transfer, or salvage of EPU-related assets during 2014. These transactions and the proceeds from these transactions are listed on Exhibit No. ___ (MT-4). Proceeds from the September 2014 auction are not included in the $450,000 total even though they are listed on Exhibit No. ____ (MT-4) because those auction proceeds have not yet been credited to the EPU account. The proceeds from the auction of the EPU-related assets will be included in my May 1, 2015 testimony and the Company's schedules at that time.

Q. How did actual expenditures for 2014 compare to DEF's actual/estimated costs for the EPU project?

A. DEF's actual expenditures as can be seen in Appendix D of Exhibit No. __(TGF-2) for the EPU project in 2014 were lower than DEF's actual/estimated costs for 2014 by almost $0.9 million. This variance is based on DEF's actual expenditures for 2014 compared to the 2014 Estimated/Actual Detail Schedule attached to Mr. Foster's prior May 1, 2014 testimony as Exhibit No. ___(TGF-5) in Docket No. 140009-EI.

Q. What accounts for this variance between the actual/estimated costs and actual 2014 EPU costs?

A. This variance is principally due to the fact that the actual/estimated costs did not include estimated sale, salvage, or transfer proceeds for EPU-related assets, which offset the actual 2014 EPU costs. DEF could not reasonably estimate the potential proceeds from sale, transfer, or salvage of assets because credits for these proceeds were unknown. DEF obtained approximately $450,000 in proceeds from the sale, transfer, or salvage of EPU-related assets in 2014 and these proceeds offset the actual 2014 EPU costs resulting in the variance between the actual/estimated costs and the actual costs for 2014. In addition, DEF incurred less preventative maintenance costs than originally estimated because DEF overestimated the amount of time necessary to conduct the required preventative maintenance and there was less equipment to be maintained because some of the EPU equipment was sold in the middle of the year. See Appendix D to Exhibit No. __(TGF-2) to Mr. Foster's testimony.

Q. Were DEF's 2014 EPU project costs prudently incurred?

A. Yes, they were. DEF only incurred costs necessary to maintain EPU-related equipment as marketable for potential resale. DEF conducted numerous single bid events, and conducted an auction with international reach in order to attempt to maximize sales proceeds for DEF's customers. DEF was able to prudently disposition several items of EPU-related equipment. DEF is re-evaluating the disposition options for the remaining EPU-related equipment and DEF will provide an update on the disposition decisions for the remaining EPU equipment in my May 1, 2015 testimony.

Proceeds from the sale of EPU equipment in 2014 were offset against the EPU wind-down costs incurred in 2014 and will be returned to customers. Additional EPU-related proceeds from the auction or other EPU-related equipment sale or salvage will also be returned to customers through the NCRC and will be reflected in my May 1, 2015 testimony in this docket.

Q. Are the 2014 EPU project wind-down costs included in this NCRC docket for recovery separate and apart from those that the Company incurred in 2014 to decommission CR3?

A. Yes, DEF has only included for recovery in this proceeding those costs that were incurred solely for the EPU project close-out. Conversely, all proceeds from the sale, transfer, or salvage of EPU-related equipment are being tracked and used to reduce the EPU unrecovered investment.

IV. 2014 PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Did the Company utilize prudent project management and cost oversight controls for the close-out of the EPU project?

A. Yes it did. The Company developed its close-out and investment recovery plans and procedures utilizing the project management policies and procedures that have been reviewed and approved as prudent by this Commission in prior year's dockets.

Q. Please explain the project management and cost control oversight processes used for the EPU wind-down in 2014.

A. The investment recovery project, including EPU close-out, is governed by procedure number AI-9010 as discussed above and attached hereto as Exhibit No. ___(MT-1). AI-9010 was developed specifically for CR3 asset disposition and outlines the pricing requirements, minimum reviews, and approvals required for the execution of transactions and the record keeping requirements necessary for the disposition of assets from CR3. AI-9010 provides specific instructions on expectations, assets pricing, disposition transaction review and approvals, project assurance and removal of installed assets and provides approved forms to document asset disposition.

The investment recovery Project Plan continues to be used and supplies the overall governance for the investment recovery project and defines the organization, work processes, and systems necessary for the successful disposition of all CR3 assets. See Project Plan attached hereto as Exhibit No. __ (MT-2). In 2014, DEF also issued the Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development. See Exhibit No. ___(MT-3) to my testimony. This document provides additional instruction to conduct sales and develop complete documentation packages for the investment recovery project

In 2014, DEF conducted the close-out of the EPU project in accordance with these policies and procedures.

Q. What other oversight mechanisms did DEF use to oversee the IR process?

A. The Company utilized Key Performance Indicators ("KPIs") to monitor the status of the investment recovery project. These KPIs were reviewed by the investment recovery team on a regular basis. Additionally, weekly progress/status meetings were held to review open issues in the project including action items, trends, key schedule milestones and other issues. Monthly progress reports were issued reporting financial results for the overall project, for the prior month. Additionally, risk review meetings were held on a regular basis in accordance with PJM-0013-ENTSTD, Project Risk Management, and a formal risk register was maintained for the investment recovery project and updated as necessary.

Q. Are DEF's project management, contracting, and cost oversight controls reasonable and prudent?

A. Yes, they are. These project management policies and procedures reflect the collective experience and knowledge of the combined Company and industry best practice based on benchmarking for project management. These policies and procedures were reviewed in an annual Commission project management audit in the 2014 NCRC docket and the Commission determined that these policies and procedures were prudent in the 2014 NCRC docket. See Order No. PSC-14-0617-FOF-EI (issued October 27, 2014) The EPU project management, contracting and cost oversight controls for the close-out and investment recovery efforts are reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. 150009-EI

DIRECT TESTIMONY OF MARK R. TEAGUE

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Marcus ("Mark") R. Teague. My current business address is 400 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services, LLC as Managing Director of Major Projects Sourcing ("MPS") in the Supply Chain department.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony in support of DEF's 2014 actual costs incurred for the Crystal River Unit 3 ("CR3") Extended Power Uprate ("EPU") project on March 2, 2015.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My testimony describes the status of the CR3 EPU project wind-down and investment recovery efforts in 2015 to date and expected final closeout activities for 2015. My testimony also supports the reasonableness and prudence of DEF's 2015 actual/estimated costs associated with the cancellation and closeout of the EPU project, pursuant to Section 366.93(6), Florida Statutes, and Rule 25-6.0423(7), Florida Administrative Code ("F.A.C."). As of the date of my testimony DEF does not anticipate incurring any 2016 EPU project related costs other than minimal other wind-down/exit costs as described in the testimony and exhibits of Mr. Thomas G. Foster filed contemporaneously with my testimony in this docket.

Q. Do you have any exhibits to your testimony?

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

- Exhibit No. ___ (MT-6), DEF Abandon In-place Justifications for (1) New Stator Core and Rewound Generator Rotor; (2) Feedwater Heat Exchangers CDHE-3A/3B; (3) Belly Drain Heat Exchangers CDHE-7A/7B; (4) Isolated Phase Bus Duct Coolers; and (5) Moisture Separator Reheaters.
- Exhibit No. ___(MT-7), CR3 Investment Recovery Project (IRP) Closeout and Long-Term SAFSTOR Asset Recovery Plan, Rev. 0, effective March 1, 2015.

I am also co-sponsoring portions of the Schedules 2015 and 2016 Detail, and sponsoring Appendices D and E, which are included as part of Exhibit No. ___ (TGF-4), to Mr. Foster's May 1, 2015 testimony. These Schedules reflect the revenue requirement calculations, the major task categories and expense variances, and a summary of contracts and details over $1 million.

All of these exhibits are true and correct.

Q. Please summarize your testimony.

A. In 2015, DEF continued work in accordance with the CR3 investment recovery policies and procedures to disposition the remaining EPU assets and materials that it was not able to disposition in 2014. As discussed in my March 2, 2015 testimony, in 2014 the Investment Recovery Project ("IRP") team was able to disposition many of the EPU assets, through internal transfers, bid events and a world-wide auction. In 2015, the IRP continued its disposition efforts for the remaining items of EPU equipment and made or is in the process of making final disposition decisions on the remaining pieces of EPU equipment in accordance with the CR3 investment recovery policies and procedures.

In addition, the team also closed out the CR3 IRP on April 30, 2015. DEF anticipates closing out the EPU portion of the IRP in the summer of 2015 once all EPU related assets are finally disposed of and removed from the plant or abandoned in-place. Value received from sale or salvage of EPU-related assets has been and will be credited back to DEF's customers through the Nuclear Cost Recovery Clause ("NCRC") to reduce the remaining unrecovered investment. For these reasons, DEF requests that the Commission determine that its 2015 actual/estimated costs are reasonable and that DEF is entitled to recover its EPU project wind-down and exit costs pursuant to the NCRC statute and rule.

III. FINAL EPU PROJECT CLOSEOUT ACTIVITIES.

A. Status of the EPU Project Closeout.

Q. Will you please describe the status of the EPU project closeout and the investment recovery efforts for EPU assets in 2015?

A. Yes. As I discussed in my March 2, 2015 testimony, the last remaining stage in the EPU project closeout is the final disposition of remaining EPU assets and materials. In 2015, the IRP team worked to disposition the remaining EPU assets in accordance with CR3 Administrative Procedure AI-9010, Conduct of CR3 Investment Recovery, Revision 1 ("AI-9010"), the CR3 Investment Recovery Project, Project Execution Plan, Revision 0 ("Project Plan"), and the Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development ("IRGD-001"). These policies and procedures provide the overall governance for the project and outline the asset pricing requirements and minimum reviews, approvals and records required for the execution of transactions for the disposal of assets from CR3, including EPU-related assets.

Q. What assets remained for disposition in 2015?

A. As I described in my March 2, 2015 testimony, the following EPU assets were unable to be cost-effectively sold or salvaged either prior to or at the auction conducted in September of 2014:

- Siemens High Pressure Turbine ("HPT') and equipment,
- Siemens Turbine Lubricating Oil Cooler Bundles,
- Siemens Exciter,
- Siemens Hydrogen Coolers,

- Siemens Low Pressure Turbine ("LPT") rotors, blades, cylinders, and parts,
- Installed Siemens New Stator Core and Rewound Generator Rotor,
- Installed Isolated Phase Bus Duct Cooler,
- Installed Feedwater Heat Exchanger ("FWHE") CDHE-3A/3B,
- Installed Belly Drain Heat Exchanger CDHE-7A/7B, and
- Installed Moisture Separator Reheaters ("MSRs").

Q. What did DEF decide to do with these remaining EPU assets?

A. With regard to the equipment that was installed at CR3 – the FWHE CDHE-3A/3B, Belly Drain CDHE-7A-7B, Isolated Phase Bus Duct Coolers, New Stator Core and Rewound Generator Rotor, and MSRs – following an analysis of the cost of removal net of salvage proceeds versus abandonment, DEF determined that the most cost-effective option was to abandon the equipment in-place in the plant. DEF did not receive any cost-effective bids (i.e., offers that were more than the cost of removal) on this equipment at the auction, nor had DEF been able to disposition this equipment prior to the auction via internal or external solicitation of affiliates and the market. Scrap dealers also bid at the auction and no bid for the above installed equipment was determined to be cost effective versus abandoning the equipment in place and salvaging the equipment through the decommissioning process of the CR3 unit during the SAFSTOR period. The decision to salvage or abandon these materials was made taking into account the cost of removal and transport of the components and any fees of the scrap dealer versus the potential salvage value of the materials compared against the cost, if any, to abandon in-place. Attached as Exhibit No. ___(MT-6) are DEF's Justifications to Abandon In-place the FWHE 3A/3B, Belly Drain CDHE

7A/7B, MSRs, Isolated Phase Bus Duct Cooling, and New Stator Core and Rewound Generator Rotor.

Q. What is the disposition status of the remaining EPU Siemens components?

A. With regard to the remaining Siemens components – HPTs and associated equipment, Turbine Lubricating Oil Cooler Bundles, Exciter, Hydrogen Coolers, and LPT rotors, blades, cylinders, and parts – [redacted] DEF had previously exhausted all efforts to sell this equipment to internal affiliates and repeatedly tested the market through a competitive bidding process and through conducting the world-wide auction in 2014 discussed in my March testimony. [redacted]

DEF anticipates that final decisions will be made in the next month or two and then it will take through the summer of 2015 to finalize disposition and removal or abandonment of all remaining EPU components.

Q. Has DEF included costs or credits in its projections related to the potential sale and the salvage/abandon decision for these remaining Siemens components?

A. No we have not. [redacted] DEF does not believe that it is reasonable to include those possible credits in its May 1, 2015 filing. As it has done in the past, DEF has only included in this filing costs or credits it reasonably knows and can project at this time. As such, DEF has not included any potential costs or credits associated with the potential sale and salvage of the remaining Siemens components.

Q. You mentioned in your March 2015 testimony that DEF had not yet received final payment for the POD Cooling Tower; as of the date of this May testimony has DEF received the final payment for the POD Cooling Tower?

A. Yes. Final payment was received from the purchaser in March 2015 and all cooling tower equipment has been removed from the CR3 site. The NCRC credit for this final payment amount can be seen on the 2015 Detail Schedule line 1b Exhibit No. __(TGF-4) attached to Mr. Foster's testimony.

Q. When will the EPU portion of the IRP be concluded?

A. DEF reasonably estimates that it will take until July of 2015 to complete the disposition of all components at the plant whether through removal and sale/salvage or abandon in place. Accordingly, the EPU portion of the IRP will not conclude until all asset dispositions are finalized, projected for July of 2015.

Q. What is the total amount of sale or salvage value DEF has received from sale of EPU Assets since the CR3 plant was retired in 2013?

A. The chart below shows the total amount of actual proceeds received by year to date and notes that there will be additional 2015 proceeds if Siemens component sale and salvage proceeds are received as discussed above.

YEAR	EPU ASSETS SALE/SALVAGE PROCEEDS
2013	$46,000
2014	$454,000
2015 (year to date actuals)	$126,000
2015 Total	$ TBD

Q. Has DEF ensured that credits related to sale and salvage of EPU assets are credited back to customers?

A. Yes. Where appropriate, EPU components have been physically segregated from other CR3 components for disposition to ensure they are tracked and accounted for correctly. In addition, all EPU asset disposition credits are directed to a unique project number created for EPU component dispositions, with the exception of the POD items, which are credited back directly to the POD project numbers. Credits allocated to the EPU are then to be applied through the NCRC to reduce the remaining unrecovered investment. As seen on the 2015 Detail Schedule attached to Mr. Foster's testimony as Exhibit No. ___(TGF-4), proceeds are credited in the month they are received.

IV. EPU ACTUAL/ESTIMATED 2015 AND PROJECTED 2016 COSTS.

Q. What are the actual/estimated costs for the EPU project closeout in 2015?

A. The total actual /estimated net costs for the EPU project wind-down in 2015 are $126,292. This consists of $252,811 in EPU Wind-Down Costs offset by proceeds of $126,000 from Sale or Salvage of EPU Assets in 2015. DEF only included in this filing costs or credits it reasonably knows and can project at this time. DEF did not include any potential costs or credits associated with the potential sale and salvage of the remaining Siemens components.

Q. What activities are associated with these 2015 actual/estimated EPU closeout costs?

A. EPU project wind-down costs were incurred in the beginning of 2015 for periodic maintenance and preservation of uninstalled EPU assets. Additionally, as of May, 2015, when the IRP project was closed, project personnel necessary to disposition the remaining EPU components began billing their time related to EPU asset disposition directly to EPU. DEF also self-identified an allocation error that resulted in EPU related contract charges being charged to the IRP in 2014. DEF made an accounting adjustment in April 2015 for that amount and it is reflected on line 1a of Schedule 2015 Detail attached to Mr. Foster's testimony as Exhibit No. __(TGF-4).

Q. What accounts for the variance in the total actual/estimated costs for the EPU closeout in 2015 versus what was projected in May 2014?

A. In the May 1, 2014 filing in Docket No 140009-EI, the system projection for 2015 EPU Wind-Down costs was estimated at $130,000, while the 2015 system actual estimated costs in this testimony is estimated at $252,811 resulting in a variance of approximately $123,000. This variance is primarily related to the EPU IRP project management costs being incurred in May through August specifically for EPU equipment disposition and the accounting adjustment to properly account for EPU contract charges.

In addition, there were no Sale or Salvage of Assets proceeds estimated in the May 1, 2014 filing projection and in this filing there is an actual amount of $126,000 in proceeds in the actual/estimated 2015 Detail Schedules this year. This variance is attributed to receipt of proceeds from the auction held in 2014 and final payment from the sale of the POD Cooling Tower (NCRC portion).

Thus, there is a total net under variance of approximately $4,000 when salvage value is considered.

Q. What costs are projected to be incurred for EPU project Wind-Down activities in 2016?

A. As shown on lines 1a -- c of Schedule 2016 Detail of Mr. Foster's Exhibit No. __ (TGF-4), there are no 2016 EPU closeout costs projected for 2016. There are minimal other wind-down/exit costs projected for 2016 as discussed in the testimony of Mr. Foster.

Q. Are the actual/estimated 2015 costs for the EPU project separate and apart from costs that DEF is incurring to decommission the plant?

A. Yes, they are. DEF included for recovery in this proceeding only those costs that were incurred or that will be incurred solely for EPU wind-down and asset maintenance activities. No costs are included in this request for decommissioning the plant.

V. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the EPU since your testimony was filed on March 2, 2015?

A. No, the Company continues to utilize Company policies and procedures and specific IRP processes and procedures that I described in my March 2, 2015 testimony to ensure that wind-down and exit costs for the EPU are reasonably and prudently incurred.

Q. Are there other IRP guidance documents that have been created for the closeout of the IRP that encompasses the EPU assets?

A. Yes. In March of 2015 the CR3 Decommissioning Transition Organization, of which the IRP is a part, created and approved the CR3 Investment Recovery Project Closeout and Long-Term SAFSTOR Asset Recovery Plan, Rev. 0, attached as Exhibit No. __(MT-7) ("IRP Closeout Plan"). The IRP Closeout Plan presents the closeout and turnover plan for the CR3 IRP and discusses the cessation of proactive IRP activities and future responsibilities for asset dispositions, if any. It is intended to be a "living" document and will likely be revised and updated as activities evolve.

The EPU asset disposition accounting structure will remain in place during the SAFSTOR period. See Exhibit No. ___(MT-7), p. 5. As such, DEF has created and is implementing a reasonable and prudent method to finally closeout the IRP while recognizing there may be continuing EPU accounting obligations.

VI. CONCLUSION.

Q. Are DEF's EPU project closeout costs in 2015 reasonable?

A. Yes they are. DEF has worked and continues work in 2015 to disposition all remaining EPU assets working through its Supply Chain and Investment Recovery organizations to ensure that closeout of the EPU project and disposition of assets is in accordance with DEF's policies and procedures. Moreover, any proceeds from the sale or salvage of EPU assets have been and will be credited through the NCRC to reduce the remaining unrecovered investment. Only those costs that are reasonable and prudent project exit or wind-down costs were or will be incurred in 2015. For these reasons, as more fully explained above, these costs are reasonable to facilitate the prudent closeout of the EPU project and should be approved for recovery.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF RONALD A. MAVRIDES

DOCKET NO. 150009-EI

June 22, 2015

Q. Please state your name and business address.

A. My name is Ronald A. Mavrides. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

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

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

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Science Degree in accounting from the University of Central Florida in 1990. I am also a Certified Internal Auditor, Certified Government Auditing Professional and a Certified Management Accountant licensed in the State of Florida. I have been employed by the FPSC since October 2007.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause Docket Nos. 090001-EI and 110001-EI and I filed testimony in the Nuclear Cost Recovery Clause Docket No. 140009-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor two staff audit reports of Duke Energy

Florida, Inc. (DEF or Utility) which address the Utility's filings in Docket 150009-EI, Nuclear Cost Recovery Clause (NCRC) for costs associated with its Nuclear units. The first audit report was issued June 8, 2015, and addressed the costs for Crystal River Unit 3 (CR3) as of December 31, 2014. The audit report is filed with my testimony and is identified as Exhibit RAM-1. The second audit report was also issued on June 8, 2015, and addressed the costs as of December 31, 2014, for Levy Nuclear Units 1 & 2 (Levy 1 & 2). This audit report is filed with my testimony and is identified as Exhibit RAM-2.

Q. Were these audits prepared by you or under your direction?

A. Yes, both audits were prepared by me or under my direction.

Q. Please describe the work in the first audit addressing the costs for Crystal River Unit 3.

A. Our overall objective was to verify that the Utility's 2014 NCRC filings for Crystal River Unit 3 in Docket No. 150009-EI are consistent with and in compliance with Section 366.93, Florida Statutes, and Rule 25-6.0423, Florida Administrative Code. We performed the following procedures to satisfy the overall objective.

<u>Construction Work in Progress (CWIP)</u>

We reconciled the company's transaction details to the general ledger and filing. We judgmentally selected transactions from the transaction details and tested them for: 1) Compliance with contracts, 2) Correct paid amounts, and 3) Correct recording periods.

<u>Recovery</u>

We traced the amount collected on Exhibit TGF-2 to the 2014 NCRC jurisdictional amount approved in Order No. PSC-14-0701-FOF-EI and to the Capacity Cost Recovery Clause in Docket No.150001-EI.

<u>Expense</u>

We judgmentally selected costs from the transaction details and reviewed them for the proper period, amounts, and that they are allowable NCRC costs. For costs that are for a service or product that is under contract, we: 1) traced the invoiced cost to the construction contract of other type of original source document, 2) reconciled the invoice to the contract terms and pricing, 3) ensured that the amounts billed are for actual services or materials received, and 4) investigated all prior billing adjustments and job order changes to the contract(s). We sorted the transaction detail listings by O&M expense category and reconciled them to the filing. We judgmentally selected one employee each from the months of November and December 2014 from the transaction details for sampling. We used employee time sheets to verify that labor hours charged to employee labor expense are correct. We recalculated employee incentive pay for October 2014.

True-up

We traced the December 31, 2013 True-Up Provision to the Commission Order No. PSC-13-0493-FOF-EI. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the approved AFUDC rate, and the 2014 costs.

Q. Please describe the work in the second audit addressing the costs for Levy Nuclear Units 1 & 2.

A. Our overall objective was to verify that the Utility's 2014 NCRC filings for Levy Nuclear Units 1 & 2 in Docket No. 150009-EI are consistent with and in compliance with Section 366.93, Florida Statutes, and Rule 25-6.0423, Florida Administrative Code. We performed the following procedures to satisfy the overall objective.

Construction Work in Progress (CWIP)

We took the beginning balances of the costs and reconciled them to the ending balances for the prior year's filing. We judgmentally selected transactions from the provided transaction details and tested them for: 1) Compliance with contracts, 2) Correct paid amounts, and 3) Correct recording periods. We reconciled the filing to the general ledger.

Recovery

We traced the beginning balances of the 2014 Detail Calculation of the Revenue Requirements to the ending 2013 Detail Calculation of the Revenue Requirements. We reconciled the amount collected on the 2014 Detail Calculation of the Revenue Requirements to the 2014 NCRC jurisdictional factors approved in Order No. PSC-14-0701-FOF-EI and to the Capacity Cost Recovery Clause in Docket No. 150001-EI.

Expense

We reconciled the trial balance accounts to the filing. We judgmentally selected costs from the transaction details and reviewed them for the proper period and amounts, and that they are allowable NCRC costs. For costs that are for a service or product that is under contract we: 1) Traced the invoiced cost to the construction contract or other type of original source document, 2) Reconciled the invoice to the contract terms and pricing, 3) Ensured that the amounts billed are for actual services or materials received, and 4) Investigated all prior billing adjustments and job order changes to the contracts. We sampled costs charged in 2014, including labor, and obtained the supporting backup. We recalculated labor costs using employee time sheets and labor rates for employees who provided labor charged to the NCRC during the sample months. We verified the hours worked and recalculated the labor charges recorded by the Utility charged to the NCRC. We verified the costs for proper account, period, and amount.

True-up

We traced the December 31, 2013 True-Up Provision to the Commission Order No. PSC-13-0493-FOF-EI. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the approved AFUDC rate, and the 2014 costs.

Q. Please review the audit findings in the audit report, Exhibit RAM-1.

A. For 2014, the Utility applied the rate reported in its Earnings Surveillance Report filed for December 2012, which was 7.23%, to the remaining unrecovered Construction Work in Progress balance. Audit staff believes that Rule 25-6.0423(7)(b) - Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery, Florida Administrative Code, requires that the Utility should have applied the rate reported in its Earnings Surveillance Report filed for December 2013, which was 7.10%. We requested the Utility to calculate the Total Period Revenue Requirement for 2014 using the rate of 7.10%. This calculation reduces the Total Period Revenue Requirement of $23,501,504 as filed to $23,346,121. DEF has adjusted its May 1, 2015 filing.

Q. Please review the audit findings in the audit report, Exhibit RAM-2.

A. For 2014, the Utility applied the rate reported in its Earnings Surveillance Report filed for December 2012, which was 7.23%, to the remaining unrecovered Construction Work in Progress balance. Audit staff believes that Rule 25-6.0423(7)(b) - Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery, Florida Administrative Code, requires that the Utility should have applied the rate reported in its Earnings Surveillance Report filed for December 2013, which was 7.10%. We requested the Utility to calculate the Total Period Revenue Requirement for 2014 using the rate of 7.10%. This calculation reduces the Total Period Revenue Requirement of $23,508,493 as filed to $23,421,244. DEF has adjusted its May 1, 2015 filing.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT JOINT TESTIMONY OF

WILLIAM COSTON

DOCKET NO. 150009-EI

JUNE 22, 2015

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 (Commission) as a Public Utilities Analyst IV, 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. Fisher and I jointly conducted the 2014 audit of Duke Energy Florida, Inc.'s (DEF) project management internal controls for the close-out of the Extended Power Uprate project at Crystal River Unit 3 and for the 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 eleven 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 Nos. 090009-EI, 100009-EI, 110009-EI, 120009-EI, 130009-EI and 140009-EI. This prior testimony addressed the audits of DEF'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 2014. Additionally, in 2005 I filed testimony in Docket No. 050078-EI, which addressed Progress Energy Florida Inc's vegetation management, lightning protection, and pole inspection processes.

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

A. My testimony presents the attached confidential audit report entitled *Review of Duke Energy Florida, Inc.'s Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects* (Exhibit WC-1). This audit was completed to assist with the evaluations of nuclear cost recovery filings. The report describes key project events and contract activities completed during 2014 through April 2015 for the Crystal River 3 EPU project and the Levy Nuclear Project. The report also describes and assesses project management internal controls employed by DEF to close out the Extended Power Uprate (EPU) project.

Q. Please summarize the areas examined by your review of controls.

A. The Office of Auditing and Performance Analysis conducted an audit of the internal controls and management oversight for close-out of the CR3 EPU project, and activities around the Levy Nuclear Project.

The audit focuses on the organization, processes, and controls used by the company to execute the EPU project close-out at CR3, and the actions, activities, support processes, and key activities around the Levy Nuclear Project.

The primary objective of this audit was to assess and evaluate key project developments, along with the organization, management, internal controls, and oversight that

DEF used 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 WC-1. The audit report's observations are summarized in the Executive Summary chapter for both the EPU project and the Levy Nuclear Project.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN GRAHAM: Any objections to staff moving Exhibits 66, 67, and 68 into the record as though read? There's no objection, so we'll move those into the record as though read. And you said 69 through 71 have already been moved into the record; correct?

MS. BARRERA: Yes, sir.

CHAIRMAN GRAHAM: Okay.

MS. BARRERA: Not Exhibit 69.

CHAIRMAN GRAHAM: One more time.

MS. BARRERA: It would be 28 through 43, 66, 67, 68, 70, and 71.

CHAIRMAN GRAHAM: Okay.

MS. BARRERA: 69 is not being proffered.

CHAIRMAN GRAHAM: 69 has not been moved into the record.

MS. BARRERA: Right.

(Exhibits 28 through 43, 66 through 68, 70, and 71 admitted into the record.)

CHAIRMAN GRAHAM: Okay. Okay. There's no objections, so what other matters need to be addressed to conclude Duke's portion?

MS. BARRERA: Staff is not aware of any other matters.

CHAIRMAN GRAHAM: Parties, are there any other matters that need to come before us?

Okay. Well, then we will adjourn the Duke portion of this. Sorry it took so long to get to this point.

MR. BERNIER: I appreciate it very much. With that, can I -- can I be excused?

CHAIRMAN GRAHAM: You can be excused.

MR. BERNIER: Thank you very much.

CHAIRMAN GRAHAM: Thank you very much.

Okay. I guess now we will convene the Florida Power & Light portion of this hearing. Staff, are there any preliminary matters?

MS. BARRERA: Yes, Chairman.

First, staff witness Iliana Piedra and David Rich have been excused, and staff will move their testimony into the record at the appropriate time.

FPL's witness Nils Diaz has been excused.

There is a reminder that OPC Witness Jacobs cannot make it tomorrow, and there's been a request that there be a -- that he be heard today out of turn. If he -- if he has not testified by 7:00 p.m., he should be the next witness.

FPL has a clarification they would like to enter into the record. OPC has requested to extend the time for filing briefs from September 1st to September 4th. None of the parties object to this request. And we're not aware of any other preliminary matters.

CHAIRMAN GRAHAM: Okay. So for Witness Jacobs, we're probably going to go until about -- well, I guess, depending on where we're going, I'll start looking at it about between 6:00 and 6:30. If it looks like we may be done by 8:00, then we'll probably just go straight through to 8:00. If it looks like it's going to go past that, we'll probably take a dinner break around -- sometime around that time. And so when we come back from dinner, we'll definitely take up Jacobs then. And we'll go -- we'll play it by ear to see how late we're going to go today. I would anticipate being here at least until 10:00, and then we'll start tomorrow again -- I believe it's at 9:30, staff?

MS. BARRERA: Yes, sir.

CHAIRMAN GRAHAM: Okay. So we'll start again tomorrow at 9:30.

The Florida Power & Light clarification, what is that?

MS. CANO: Yes. Good afternoon. Just a point of clarification on the Prehearing Order. If you'll turn to page 5 where the issues are listed for each witness, for the issues provided there for Steven Scroggs, there's a comma between Issues 1 and 2, and that should be a dash because he addresses Issues 1, 1A, 1B, 2, et cetera. And I think that's something that the parties and everyone are already aware of, but I just wanted to make that clear.

CHAIRMAN GRAHAM: Okay.

MS. CANO: That's all. Thank you.

CHAIRMAN GRAHAM: All right. That seems simple enough.

OPC's extended time, you wanted to file for briefs rather than September 1st?

MS. CHRISTENSEN: I wanted to make sure that we were able to address that matter.

CHAIRMAN GRAHAM: Now is a good time.

MS. CHRISTENSEN: Yes. Yes. I would like to ask that the Commission move the brief filing dates currently scheduled for September 1st and change that to September 4th. Given the heavily contested nature of the issues in this year's FPL portion of the docket, that would give us two full weeks with the transcript. And I contacted all the parties. To my knowledge, all the other parties were supportive and did not object to it. And I don't know that staff had a position on that, but it's our contention that that would not put staff at any grave disadvantage. We're talking a three-day addition of time.

MS. BARRERA: Staff does not disagree.

CHAIRMAN GRAHAM: Are there any objections from any of the parties? Let the record show everybody is shaking their head no.

Commissioner Brisé.

COMMISSIONER BRISÉ: Ms. Christensen, for your Witness Jacobs, is it Issues 1 through 2 or is it Issues 1 and then 2?

MS. CHRISTENSEN: I believe -- he's discussing the feasibility analysis. To the extent that there are subissues A, 1A, and 2, it probably should be a dash as well.

COMMISSIONER BRISÉ: Okay.

MS. CHRISTENSEN: It touches on that.

COMMISSIONER BRISÉ: Sure.

MS. CHRISTENSEN: So just to be on the cautious side, I would say add a dash.

COMMISSIONER BRISÉ: Okay. Thank you.

CHAIRMAN GRAHAM: Okay. So we will

extend that to September 4th. Are there any other preliminary matters from parties? From staff?

MS. BARRERA: No, sir.

CHAIRMAN GRAHAM: Okay. Then I guess we're -- opening statements. It looks like we are giving Florida Power & Light ten minutes for opening statements, and all Intervenors are given five. Thank you.

Florida Power & Light.

MS. CANO: Thank you. Good afternoon again, Chairman Graham and Commissioners.

FPL asks that the Commission approve its request to recover approximately $34 million in 2016 to continue progress on the Turkey Point 6 and 7 project. Let me review briefly what this project is and where we are in its development.

Turkey Point 6 and 7 is a project to build two new nuclear generating units at an existing FPL power plant site. It will generate 2,200 megawatts of emission-free baseload power, providing much desired fuel diversity to FPL's system and providing an important hedge against unknown future fossil fuel prices and emission compliance costs.

Based on the current NRC licensing schedule and the current nuclear cost recovery statute, the earliest practicable in-service dates for these new units is 2027 and 2028 respectively. At this time and continuing into 2016, FPL is focusing on obtaining the combined license from the NRC and related permits and approvals necessary for the project. FPL is also asking to recover only the costs associated with these licensing-related activities.

As demonstrated in FPL's testimony, its 2014 costs were prudently incurred, and its 2015 and 2016 costs are reasonable. No party has presented testimony disputing any particular cost that FPL seeks to recover in 2016.

FPL also is seeking approval of its 2015 feasibility analysis, which fully supports continuing another year of licensing activities. FPL's analysis indicates that completion of the project is projected to be economical for FPL's customers in a majority of future fuel and environmental compliance cost scenarios analyzed.

Intervenors take issue with certain inputs to FPL's feasibility analysis, including its nonbinding project cost estimate range, CO2 compliance cost forecasts, and, to a lesser extent, certain transmission planning assumptions.

FPL's nonbinding cost estimate range is reasonable for the reasons that you'll hear from Mr. Scroggs. And this is also supported by Mr. Reed.

OPC Witness Jacobs' suggestion that FPL obtain binding EPC contractor bids now to revise the project cost estimate is not commercially reasonable, and it's questionable whether it's even permissible under the current nuclear cost recovery statute. FPL's CO2 compliance cost forecast and its transmission planning assumptions are similarly reasonable, as discussed by Dr. Sim.

With respect to the CO2 cost forecast, FPL relied upon an independent, reputable firm, the same firm used in the need determination for the development of that forecast, and there is simply no basis for the arbitrary hypothetical adjustments to FPL's inputs that is suggested by the City of Miami's witness, Mr. Meehan.

FPL's feasibility analysis is analytically sound, relies on reasonable inputs, is consistent with analyses provided in previous nuclear cost recovery dockets, and should be approved.

There is also a dispute this year about costs that FPL is not even seeking to recover at this time. These costs are for studies that FPL is performing to refine project schedule and cost information for next year's feasibility analysis, and these are referred to as initial assessments. The dispute is both a legal one and a factual one, so little legal context is appropriate.

Since 2006, the nuclear cost recovery statute and rule have identified three categories of cost for recovery: site selection, preconstruction, and construction.

Preconstruction costs by definition are all costs incurred during the time between site selection and construction. Accordingly, all of FPL's Turkey Point 6 and 7 costs since 2007 have been preconstruction costs, and there doesn't seem to be any disagreement on that.

Now when the Legislature amended the statute in 2013, it identified two particular types of activities within this broader preconstruction category. The first type is activities related to obtaining a combined license from the NRC. The second type is preconstruction work beyond the activities necessary to obtain or maintain the license.

Now let me pause here and be clear. FPL

has not begun preconstruction work. It intends to seek approval from this Commission in 2016 to begin preconstruction work in 2017 upon receipt of its combined license. What FPL has begun is the work to support that 2016 request that's coming to this Commission. These initial assessments are being performed to provide the company, the Commission, and Intervenors with the best information it can in the 2016 feasibility analysis.

While one would expect Intervenors to support that effort, which is consistent with some of the calls for additional project certainty made by their witnesses, it nonetheless has become a major point of contention in this docket.

OPC and other Intervenors have taken the position that FPL cannot incur these costs at this time, essentially that FPL can't perform these studies. Now it just seems illogical that FPL should be discouraged from providing the best information it can to this Commission in the feasibility analysis intended to support moving forward to preconstruction work. But, moreover, as I will very briefly discuss, there is nothing in the nuclear cost recovery statute that precludes FPL from incurring these costs now.

Staff has already distributed for me a copy of Section 366.93, ***Florida Statutes***, and I just want to briefly draw your attention to two subsections on point.

CHAIRMAN GRAHAM: You're at the 5-minute mark.

MS. CANO: Thank you. And they're highlighted on your copies. Subsection (3)(b), which is at the top of the second page, states, "During the time that a utility seeks to obtain a combined license from the Nuclear Regulatory Commission for a nuclear power plant or a certification for an integrated gasification combined cycle power plant, the utility may recover only costs related to, or necessary for, obtaining such licensing or certification."

Now FPL's position is that the initial assessments are related to obtaining the license. But even if one disputed that relationship, the plain language of this statute only addresses the recovery of costs, not in currents. As I stated previously, FPL is not seeking recovery of these costs at this time.

Next, subsection (3)(c) requires the utility to petition for approval before proceeding with preconstruction work beyond the activities necessary to obtain or maintain the license. Subsection (3)(c)(1) makes it clear that the only costs the utility can recover prior to obtaining that Commission approval are costs previously approved or necessary to maintain the license.

Again, the plain language of the statute speaks only to recovery, and FPL is not seeking to recover the initial assessment costs at this time.

In conclusion, I'd like to review why we are here and what we are seeking in this docket. FPL is seeking approval and recovery of its 2014 true-up, 2015 true-up, and 2016 projection of costs associated with continuing licensing of the project.

FPL also is seeking approval of its 2015 feasibility analysis, which is based on reasonable current inputs and which demonstrates that the project remains economic for customers.

With respect to initial assessments, FPL is seeking a determination that it's reasonable for FPL to perform these studies to present the best information it can in next year's feasibility analysis. That is the extent of FPL's request. It is consistent with the deliberate, step-wise approach that FPL has taken on this project since its inception, it is imminently reasonable, and it should be approved. Thank you.

CHAIRMAN GRAHAM: Thank you.

Okay. Ms. Christensen, I apologize for not asking this question earlier. Would you like to go first or last?

MS. CHRISTENSEN: First is fine.

CHAIRMAN GRAHAM: Okay.

MS. CHRISTENSEN: Good afternoon, Commissioners. Patty Christensen on behalf of the citizens of Florida and FPL customers. I have a brief opening.

As you know, the Legislature changed the nuclear cost recovery statute in 2013, which created phases for the nuclear cost recovery process. The first phase is to obtain and maintain a combined operating license, or COL.

The second phase is the preconstruction work phase. The amendments to the statute require that the company -- require the company to request approval from the Commission to begin preconstruction work before initiating any preconstruction activity, and then to seek recovery through the Nuclear Cost Recovery Clause. In order for the company to get this approval, Section

366.93(3) states it must show that the project remains feasible and the project costs are reasonable.

The third phase is construction, which has a similar pre-approval requirement as the second preconstruction phase before the company can initiate or begin to initiate construction activity for recovery through the Nuclear Cost Recovery Clause.

Clearly, today we are at the stage where FPL is still seeking to obtain its COL. However, FPL also wants to start incurring and deferring for later recovery through the NCRC some initial assessment study costs which OPC does not believe are related to obtaining or maintaining the COL.

Now OPC has several concerns with FPL's request for these costs. First, the feasibility study that FPL has submitted for 2015 we believe is flawed. The costs for its feasibility study are understated because the sources of these costs are old, dated, and understated. FPL used a ten-year-old study of the TVA Bellefonte site as a basis for its nonbinding cost estimates. The TVA Bellefonte site was originally a different reactor design and only later changed to an AP1000 reactor design, yet it must be noted that this site was never built. Thus, the Summer and Vogtle projects are the first of its kind AP1000 designed nuclear plants actually being built and constructed today.

For the NCRC, FPL did a price check on their nonbinding cost estimates in 2010 to construct Turkey Point Units 6 and 7. For this price check, FPL used 2009 Westinghouse pricing data. However, this data is now over six years old. FPL also used the Summer and Vogtle projects as a price check for their nonbinding estimates and to support the reasonableness of their proposed estimates, yet the publicly reported numbers utilized by FPL are seriously understated.

Our witness, Dr. Jacobs, is the site monitor for the Vogtle project for the Georgia Public Service Commission. He details in his testimony that the Vogtle contractors are incurring costs that are not being publicly reported. As a result, OPC believes that the cost inputs being utilized by FPL need to be updated to use the best current information available for the feasibility analysis, especially before seeking Commission approval to begin the preconstruction phase.

We think the binding bids are best;

however, short of that, the higher cost of the Summer and Vogtle projects should be reflected in FPL's analysis along with a reasonable contingency. Furthermore, we are concerned that FPL has asked in this docket to incur and then later defer for recovery the cost of the initial assessment studies before the COL has been obtained.

As I stated earlier, the Legislature has amended the statute to create phases for the NRC. The statute now limits NRC recovery to only those costs that are necessary to obtain or maintain the COL or were previously approved by the Commission. Only after obtaining the COL may the utility seek approval to initiate preconstruction activity for recovery under the NRC.

With this request, FPL, we believe, is putting the cart before the horse. Since the initial assessment studies are not related to obtaining or maintaining the COL and these studies were not previously approved by this Commission, under the new statutory scheme for the NRC, these studies must wait until second phase approval.

So in conclusion, OPC submits that before the Turkey Point Units 6 and 7 project move forward from the COL phase into preconstruction phase, the feasibility analysis must be updated using realistic, current cost information. In addition, FPL's request for approval to incur these costs of the initial assessment study should be denied at this time. Thank you.

CHAIRMAN GRAHAM: Well, that wasn't your first time. That was exactly five minutes.

Retail Federation.

MR. LAVIA: Thank you, Mr. Chairman. I'll be very brief. The Retail -- Florida Retail Federation supports OPC's position, and with that we waive the rest of our time. Thank you.

CHAIRMAN GRAHAM: Thank you, sir.

FIPUG.

MR. MOYLE: Thank you, Mr. Chairman. FIPUG has a brief opening statement we would -- we would like to make. And let me -- let me start by saying that as a general proposition, that FIPUG supports reasonably priced nuclear energy, with the key again being reasonably priced.

And this case and the cases over the years brings to mind a -- a story, it's actually a metaphor, but I think it's appropriate for -- for our discussion here in the next couple of days. And it's a story about -- about a frog and how you go about cooking a frog. And if you get the pot and you boil the water and it's really hot and you drop that frog in it, that frog will jump right out. But if you put the frog in a pot of water and the water is tepid, the frog is okay. And then you slowly start turning that heat up on the frog, and all of the sudden the frog is like this is okay, it's okay. And slowly, slowly, slowly, incrementally, a little bit here, a little bit there, a little bit there, you turn the heat up on the frog, and the frog doesn't realize it but it's being cooked. And what I believe we're seeing here with this nuclear cost recovery docket reminds me of the heat on the frog.

And Mr. Steven Scroggs will be a witness. He was a witness in the first case when y'all had a need determination. And I'm going to ask him how much the Turkey Point 6 and 7 was projected to cost then and what's it projected to cost now. The answer will be it was a lot less then than it is now.

And to the point about the heat incrementally being turned up, you don't have to look a lot further than the difference between last year what they said it was going to cost and this year what they said it was going to cost. So

Mr. Scroggs will get this question, but I'll preview it and tell you that last year the cost was estimated to be between 12.6 billion on the low end and 18.4 billion on the high end. This year the number is 13.7 billion on the low end and 20 billion on the high end. So simple math for me shows an increase of between 1.1 billion to 1.6 billion. And, again, you can characterize that, the slow heat, going, well, you know what, at the top end this is going to be a 20 billion -- a $20 billion project, so, you know, 1.6 billion, that's less than 10 percent. I mean, that's not a huge amount when you look at it from a percentage standpoint, but 1.6 billion to the ratepayers of Florida is a significant amount.

And you'll hear a witness that will say, well, we're looking for 34 million or 32 million from you all. Now that equates to about one penny for the average residential ratepayer. Well, if you take that math and apply it to 1.6 -- 1.6 billion, that's $16 per month, and $16 per month times 12 is $192 per year, and that, according to my math, is what's represented by only the 1.6 slow heat, incremental increase. This project is now on the top end projected to be $20 billion.

I'm going to ask Mr. Scroggs and say, okay, you're the guy, you're the expert. Any chance of this cost going down as time goes on? I think he's going to say no. And why? Because, well, there's carrying costs associated with this. Things increase over time.

So if you look at the track record of the nuclear project from the beginning until now, the metaphor of the frog fits very appropriately. Started out it was tepid, it's getting turned up and getting turned up, it's starting to get warm, it's starting to get warm.

And for FIPUG, with respect to the reasonableness, we're hoping, hoping that the Commission will exercise its duties and responsibilities as this conversation continues, as this heat continues, and make sure that the ratepayers of Florida don't get cooked. Thank you.

CHAIRMAN GRAHAM: Thank you, Mr. Moyle.

SACE.

MR. CAVROS: Good afternoon, Commissioners. George Cavros on behalf of Southern Alliance for Clean Energy. Southern Alliance for Clean Energy is a non-profit, non-partisan organization that advocates for the use of low-risk and low-cost resources in meeting electricity demand for the benefit of customers.

The proposed Turkey Point 6 and 7 nuclear reactors are neither low cost nor low risk. The reactors have escalated in cost again this year. They are almost a decade delayed, most recently being delayed a third time. The company will not commit to building the reactors, and all the financial risk falls on the shoulders of ratepayers.

So, Commissioners, you know, just to be honest here, these reactors would never be built in a competitive market. We don't have a competitive market here in Florida. That's why customers need to subsidize the construction of these plants. And you, Commissioners, are the firewall that protects customer interest in this regard.

Now the evidence will show that the levelized cost of this plant is over 16 cents a kilowatt-hour. It will raise rates, it is raising rates, and that especially hits low income and fixed income customers the hardest.

Now the company will argue don't look at the rates, don't look at the cost, look at the fuel savings we're going to provide, but the fact of the matter is realistically customers won't realize a fuel savings benefit until 60 years from today. To put that in perspective, if you're an FPL customer and you're 45 years old today, you won't break even on this proposition until you're 105 years old. Okay. And let me put that into further perspective. There are counties that Florida Power & Light serves within its service territory where almost half the population is 45 years or older. So -- so we can do better, Commissioners.

The irony here, of course, is that the company has come before this Commission before and argued about rate impacts as it relates to energy efficiency, arguing that it will make rates go up even though it reduces energy use and helps customers save money on their bills. That's especially important for low income folks. You've heard similar arguments from the company regarding rooftop solar.

What these resources are bad for is shareholder value. They don't maximize shareholder value. The company makes money by constructing power plants. Now they come to you with a $20 billion addition to their base rate. They will earn a 10.5 percent return on that, and they will move mountains to get you to approve that, and they will force-feed rate increases to their customers courtesy of the early cost recovery rule.

Nevertheless, the company has to come before you and provide a reasonable and realistic feasibility analysis, and they have failed to do so. The analysis fails to take into consideration the realities that are now taking place at the Vogtle plant in Georgia. That experience has not been incorporated into their feasibility analysis.

Their CO2 projections are not well supported, and, quite frankly, very unrealistic CO2 projections beyond 2035, and they use these high and somewhat unrealistically supported projections to support and bolster their support for a nuclear project which is quickly losing its economic benefit to customers. Again, they use now a 60-year useful life. If the project does not -- doesn't show an economic benefit over 40, go ahead and extend the life to 60, stretch it out, even though there are no reactors in the United States that have ever had -- or operated for 60 years.

Lastly, the -- the Ten-Year Site Plan, which is the foundation for the feasibility analysis, never places energy efficiency and the nuclear project on a level playing field. In fact, it was never compared to energy efficiency and they never had a chance to go head to head.

So, Commissioners, right now there's been about $250 million spent on this project. Customers will never see that money back, and -- but that, you know, could just be a fraction of what they could be in store for if we continue down this road.

The sunk costs are still fairly low, they're manageable, the resource addition is well off into the future, and now is the time to terminate the project. You have the statutory authority to do it. We ask you to find that costs going forward are no longer reasonable. Thank you.

CHAIRMAN GRAHAM: Thank you, sir.

City of Miami.

MR. HABER: Good afternoon, Mr. Chairman, Commissioners. The City of Miami is thankful to be here and for the opportunity to voice our concerns.

Our goal in this proceeding is to gain an accurate picture of the value of the Turkey Point 6 and 7 project to ratepayers. FPL has not accurately shown that value because its long-term feasibility analysis relies on a critically flawed portrayal of the cost savings that the project is expected to provide when compared to the likely alternative.

FPL's faulty analysis burdens its project alternative with arbitrary and unjustified costs. For example, the assumption that the only -- that only the proposed project and not its alternative can be constructed in Miami-Dade County allows almost an additional $2 billion in transmission costs to be added to the price of the likely alternative.

FPL's faulty analysis also includes outdated forecasts for the cost of the power plant's carbon emissions. And by that, I mean the alternative power plant. The same analysis assumes a tax on carbon that is well over twice the projected price of natural gas fuel.

Any scenario that includes a tax that is over twice the fuel price is beyond unlikely. It is unrealistic. However, this assumption is important to FPL's argument because it enables the project to appear competitive with likely alternatives.

FPL's witnesses have, in testimony, agreed that avoiding these transmission and these carbon costs are significant drivers of their project's long-term feasibility. Again, the assumptions behind these drivers are not justified. FPL has not met its burden to produce a reasonable long-term feasibility analysis. Without reliable information, the Commission cannot make an informed decision about the project moving forward or provide ongoing oversight. Informed oversight is critical because many ratepayers will wait over 50 years to break even on FPL's project, and many ratepayers will never be paid back. Therefore, FPL's flawed analysis should be rejected. Only with an accurate analysis of the plant's value can the Commission make an informed decision whether or not to move forward with future recovery. Thank you.

CHAIRMAN GRAHAM: Thank you.

Okay. We'll move on to witnesses. A couple of things before we get to that. Most of you have been before me. The City of Miami has not, so I'll go through some of my usuals.

There is no friendly cross, number one. Number two, when you're cross-examining, you pretty much control the flow of what's going on with the witness. When you ask the witness a question, the witness should -- the witness should do their best to answer the question yes or no, and then they can go on briefly and explain that answer yes or no. I'll let the witnesses editorialize as long as they want. You can decide when that's enough as you're asking those questions. So that's upon you. But you do need to give them a brief period of time to explain the answer yes or no. The witness is allowed to restate the question if he doesn't understand the question or if he can't answer it yes or no. Some of this stuff we'll -- we'll feel through it as we go through it. And I think that's about it.

If I can get the witnesses that are here in the audience to stand so I can swear you in.

If I can get you to raise your right -- your right hand. Do you hereby swear or affirm that the testimony you give here before this hearing is true, yes or no?

(Chorus of affirmative responses.)

Thank you.

(Witnesses collectively sworn.)

Okay. Each witness will be allowed five minutes to summarize their testimony, and then we will -- you would ask me to have their prefiled direct testimony entered into the record or the rebuttal testimony entered into the record. And after the witness is done, we'll enter the exhibits, and I'll allow that witness to be excused.

All right. So before we call the first witness, let's take a quick five-minute break so people can kind of get reorganized. The first witness looks like it's going to be Mr. Scroggs.

MR. MOYLE: Can I just ask one point of clarification real quick?

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: Are we doing direct and rebuttal separately or together?

CHAIRMAN GRAHAM: Staff, separately?

MS. BARRERA: Yes. The order of witnesses are as listed in the Prehearing Order, and those are separately.

CHAIRMAN GRAHAM: Separately.

MR. MOYLE: Okay. Last -- last week we had a hearing and it got combined kind of at the last minute.

CHAIRMAN GRAHAM: Well, that was -- that was discussed in prehearing.

MR. MOYLE: Yeah. I just wanted to know. Thanks. So they're separate.

CHAIRMAN GRAHAM: Okay. Five minutes by that clock back there, which is 2:35.

(Recess taken.)

(Transcript continues in sequence with

Volume 2.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 25th day of August, 2015.

Linda Boles
____

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