BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20220001-EI

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
_________________________________/

VOLUME 1
PAGES 1 - 228

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ANDREW GILES FAY
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Thursday, November 17, 2022

TIME: Commenced: 9:30 a.m.
Concluded: 4:40 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
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APPEARANCES:

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MARIA JOSE MONCADA and DAVID LEE, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420; appearing on behalf of Florida Power & Light Company (FPL).

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

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RICHARD GENTRY, PUBLIC COUNSEL; CHARLES J. REHWINKEL, DEPUTY PUBLIC COUNSEL; PATRICIA A. CHRISTENSEN and MARY A. WESSLING, ESQUIRES, OFFICE OF PUBLIC COUNSEL, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400; appearing on behalf of the Citizens of the State of Florida (OPC).

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JON C. MOYLE, JR. and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, 118 North Gadsden Street, Tallahassee, FL 32301; appearing on behalf of Florida Industrial Users Group (FIPUG).

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JAMES W. BREW and LAURA W. BAKER, Stone Law Firm, 1025 Thomas Jefferson Street NW, Suite 800 West Washington, DC 20007; appearing on behalf of Florida White Springs Agricultural Chemicals, Inc., d/b/a PCS Phosphate - White Springs (PCS).

PETER J. MATTHEIS, MICHAEL K. LAVANGA and JOSEPH R. BRISCAR, ESQUIRES, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, D.C. 20007; appearing on behalf of Nucor Steel Florida, Inc., (NUCOR).

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

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I N D E X

P R O C E E D I N G S

CHAIRMAN FAY: All right. I think everybody is setted in here for the 01 docket.

Commissioners, we will take up some of these issues, like I mentioned this afternoon, and just kind of where we land as to where we will work through tomorrow. I plan on working to, you know, normal business hour today to see what we can get through, and then we will -- we will set out the agenda for tomorrow.

So with that, Ms. Brownless, will you start us off with any preliminary matters that we may have?

MS. BROWNLESS: Yes, sir.

There are proposed Type 2 stipulations for all issues except Issues 3A, 8 through 10, 16, 18 and 20. FPUC has all of its issues stipulated to with the exception of Issue 3A, which deals with its treatment of its 2022 fuel under-recovery $15,143,447.

The issues for which there are proposed Type 2 stipulations can be voted on today.

It is my understanding that OPC wishes to make an oral request for reconsideration of the Prehearing Officer's decision not to include its proposed Issues A and B. This decision is found on page 60 of the prehearing order.

CHAIRMAN FAY: Okay. Why don't we go ahead and take that motion up now, then before we get into any of the testimony -- and, Ms. Brownless, it's OPC contested Issues A and B, is that correct?

MS. BROWNLESS: Yes, sir.

CHAIRMAN FAY: Okay. With that, then, Mr. Rehwinkel, we will give you some time to address the Commission. I know there probably will be parties that maybe will also want to address. Would five minutes be sufficient for you to present?

MR. REHWINKEL: Well, Mr. Chairman, I have two aspects of this. One is I need to state an objection. I made an objection at the prehearing, and I want to reiterate it. I want to move for reconsideration, but I will waive my opening if I can make my remarks here. I think it will still save time.

CHAIRMAN FAY: Okay. Just for clarity, your remarks will still deal with your objection to the exclusion of the two issues?

MR. REHWINKEL: It will -- that, and an objection to the hearing process itself. I need to state an objection for the record.

CHAIRMAN FAY: Okay.

MR. REHWINKEL: But I will do both of these in lieu of making any opening statement when it comes time for that.

CHAIRMAN FAY: Okay. Well, just for clarity, so essentially speaking to the A and B exclusion, I just view this as an opening statement. You will be speaking to it in your comments here.

MR. REHWINKEL: Yes.

CHAIRMAN FAY: And there is a second objection that you want to raise. If you could make sure there is clarity as to the two separate objections that you are bringing forward here. Because the A and B we have the information in front of us, but it sounds like, if you are raising a second one that hasn't been raised before, that we don't want to include that in your reconsideration vote here. It sounds like that would be essentially out of procedure, and I just want to make sure we don't exclude that objection.

MR. REHWINKEL: Okay. I think they are fairly well separated in my remarks.

CHAIRMAN FAY: Okay.

MR. REHWINKEL: But to understand, is it your decision that I can make both of those here, or you

just want to make sure that there is a --
     CHAIRMAN FAY: There is clarity. Yeah. I mean, I would prefer if we went ahead and addressed the Issues A and B, and then went on from there and you can state your objection just as a preliminary matters just into the record for your procedure objection.
     MR. REHWINKEL: Okay. I hadn't contemplated separating them, but let me -- let me make sure I start -- I handled the second one first.
     CHAIRMAN FAY: And, Mr. Rehwinkel, I can give you a few minutes, but we can't -- we can't blur those two. I mean, a motion for reconsideration, you know, speaks strictly to that objection that the Commission excluded something and, therefore, unless you feel that they are just completely intertwined, I am going to need to you separate those.
     MR. REHWINKEL: Well, there is interconnection to them, but I will -- I will make my motion for reconsideration, and then I would still require to be able to state an objection for the record.
     CHAIRMAN FAY: Okay. That works. And do you need a few minutes or are you good to go?
     MR. REHWINKEL: I'm ready to go.

CHAIRMAN FAY: Okay. Go ahead. You are recognized.

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

And we are asking the Commission to reconsider the ruling that's contained on page 60 of Order No. 2022-3 -- 0390. Simply because the utilities have chosen to disregard -- well, let me start off by saying, the ruling struck the two issues that we asked the Commission to consider given the state of this record, and one was: What is the appropriate carrying cost, if any, for the 2022 under-recovery amount voluntarily deferred for recovery for the duration of the voluntary deferral period? And Issue B is: Over what period should 2022 under-recoveries be collected, and at what carrying cost?

Simply because the companies have choose -- chosen to disregard the intent and spirit of the midcourse correction rule and the Order Establishing Procedure in this docket that embodies the Commission policy and practice on how fuel costs are litigated and collected, we are being told now, because they made those choices, that we cannot have the Commission decide what the appropriate period for recovery of a staggering amount of money should be, or what should be the carrying costs associated with it.

Meanwhile, in this same docket, as you just heard, the smallest utility in the state has at least included an amount of 2022 under-recoveries in its proposed factor, and they are attempting to assign both a recovery period and a carrying cost to the deferred portion of the balance.

In our view, there is a legal problem with the denial of our issues, and that is it is a violation of Sections 20.569(1) and 125.7(11)(b) Florida Statutes which afford the customer parties the opportunity to raise and contest all disputed issues of material fact.

The factors that affect what customers will pay are at issue in this docket, and they are directly influenced by the recovery period and the carrying costs associated with that balance.

We submit to you, Commissioners, that is error to let the utilities decide what you get to consider. It is arbitrary to take evidence on one company on these two elements while you are refusing to decide the issue for the others.

The fact that inconsistent results can occur because of this duality is further reason why you should allow this issue and reconsider and reverse the decision on this point. So we ask that you decide to allow and consider and determine Issues A and B in this proceeding today.

So, Commissioners, that concludes my argument on reconsideration of those issues, and at the appropriate time, I can make my standing objection as well.

CHAIRMAN FAY: Okay. Why don't we -- you can go ahead and do that now, and then we will have Ms. Brownless get us in the right posture for the motion for reconsideration.

MS. HELTON: Mr. Chairman.

CHAIRMAN FAY: Yep.

MS. HELTON: You might want to go ahead and hear from the utilities now with respect to whether they have any response to Mr. Rehwinkel's motion --

CHAIRMAN FAY: Okay.

MS. HELTON: -- ore tenus motion.

CHAIRMAN FAY: Why don't we --

MS. HELTON: It looks like Mr. Brew has, yes, and the parties.

CHAIRMAN FAY: Yeah. No. So why don't we go ahead and have the parties provide their comments on this motion, and I can start from the left and move right, and whoever wants to be included in that can, and then we will come back to you, Mr. Rehwinkel, to address that second objection.

Okay. So with that, Ms. Moncada, I would start with you.

MS. HELTON: Mr. Chairman, I think Mr. Brew might be aligned with Mr. Rehwinkel, so I think you would hear from him first and then hear from the utilities.

CHAIRMAN FAY: Okay.

MR. BREW: And where do you get that?

MS. HELTON: Oh, okay. Well --

CHAIRMAN FAY: Very judgmental of you, Mary Anne.

So we will start on the right here then and work our way, assuming that these -- the parties over here may align with that, and then we will have the utilities respond.

So go ahead, Mr. Brew.

MR. BREW: Thank you. Good afternoon, Commissioners.

I have one additional preliminary matter. On Issues 10 and 16 of the Prehearing Order, it was listed that PCS having no position, or no position

at this time. We actually corrected that he
prehearing.

CHAIRMAN FAY: Okay. One second, Mr. Brew. So this is -- this is what I was trying to --

MS. HELTON: I'm sorry. I thought were you wanting to --

MR. BREW: No. No --

MS. HELTON: Oh --

MR. BREW: -- because I was going to talk about those issues, I wanted to make sure it was noted that our position was agreeing with OPC.

CHAIRMAN FAY: Okay. So we will go ahead and do that. But then as another preliminary matter, we will address this other issue that you are bringing up.

MR. BREW: Okay.

CHAIRMAN FAY: I'm in the sure what clarity needs to be done, but it sounds like it's a separate --

MR. BREW: It's just a minor administrative thing.

CHAIRMAN FAY: Okay. So -- yeah, go ahead, Ms. Brownless.

MS. BROWNLESS: Excuse me.

I think it would be clearer for the record, now that we have Mr. Rehwinkel's statement with regard to his reconsideration of the ruling on Issues A and B, that we let all parties who wish to comment on that comment on that, and then we have a ruling -- then you can ask Mary Anne and I for our recommendation, if you wish, and then vote on that so we get that squared up, and then we will go forward with the preliminary matters that Mr. Brew has or --

CHAIRMAN FAY: Or any other party at that time. Yeah, and that's what I was trying to do, but, Mary Anne, is there a reason you wanted to start over here first?

MS. HELTON: I think that if any of the intervenors have a comment on Mr. Rehwinkel's motion for reconsideration, that they should go before the utilities so the utilities can respond in kind to all of the intervenors.

CHAIRMAN FAY: Okay. I don't have an issue with that.

Do you -- presuming that the intervenors on this side do have anything to weigh in on Mr. Rehwinkel's motion for reconsideration. You obviously don't have to.

So we will start with Mr. Brew, you do have --

MR. BREW: Yes.

CHAIRMAN FAY: -- a comment on this. Okay. Go ahead. You are recognized, and then I will work my way left.

MR. BREW: Thank you.

PCS strongly supports OPC's request to include Issues A and B. Very quickly, how the Commission chooses to recover the under-recoveries for 2022 is a core issue in this docket. There is no getting around it. It is directly stated in Issue 8: What is the appropriate amount of under-recovery for 2022?

So to the extent that the answer is anything other than exactly what is shown on the utilities' exhibits, that issue is in play, as well as the appropriate carrying costs on any amounts that are not recovered now but would be recovered later.

So from our perspective, the issues that OPC raised are necessarily in play in order to decide what is amounts to a multi-billion dollar issue for the fuel docket.

Thank you.

CHAIRMAN FAY: Okay. Thank you.

Nucor.

MR. BRISCAR: Nucor just simply reiterates

OPC's position. We support their motion for reconsideration and inclusion of Issues A and B for consideration.

Thank you.

CHAIRMAN FAY: Okay. Thank you.

Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman. Thank you again for indulging me to start at the beginning of this hearing.

Retail Federation supports OPC's motion for reconsideration. Very specifically, I agree with what Mr. Brew said. These are these issues because Issues 8, 9 and 10 remain live issues in this case. What's the amount of the 2022 under-recovery? What amount should be recovered? And what's the total amount of the dollars, the total dollars, that's Issue 10, that are to be recovered through the utilities' fuel charges in 2023? Those issues contemplate, and the FRF has taken clearly stated positions in our prehearing statement and as set forth in the Prehearing Order, that part of those costs should be recovered beginning in January of 2023, which I will develop on cross-examination.

But these are live issues, and it's completely appropriate to address carrying costs, if any amount of those are going to be. You know, you, the Commission, can ultimately say, no, we are not going to allow any of that, or we are not going to approve any recovery. But regardless, the issue of a carrying cost on anything that's going to be recovered, which is a live issue in his docket, should be addressed, and so since those three issues, 8, 9 and 10, are all live issues in the case, I really think that OPC's motion for reconsideration is well placed.

Thank you.

CHAIRMAN FAY: Great. Thank you, Mr. Wright.

Mr. Moyle.

MR. MOYLE: Thank you. And a slightly different vantage point and perspective on this.

One of the things that FIPUG is keenly interested in obtaining in this fuel docket is information about what cost FIPUG members and other customers of the utilities are going to be confronting next calendar year. And, you know, that's important to businesses so that they can plan and know what their variable cost, a significant variable cost, the cost of energy is going to be; and I would respectfully say it's important for families to know that as well. And I think that the two issues that OPC is seeking to put forward are relevant to that information. What are -- what are the carrying costs going to be, if any?

That's something that this -- this commission should consider. And then what period of time will they be asked to pay for this? I mean, it's a big difference, and I know there has been conversations amongst the Commission about what's the -- what's the right time period? Is it a year? Is it 18 months? Is it two years?

And everyone is here. We got all the parties here. We are in November, you know, fast approaching Thanksgiving, and people need to have this information to be able to plan for what 2023 looks like.

So that's, I think, not necessarily a legal argument, but a practical argument as to why we believe these issues should be allowed in, and questions asked along those lines for the purposes of getting good, valuable information that will be important, again, to my client and to other customers of the utilities.

Thank you.

CHAIRMAN FAY: Thank you, Mr. Moyle.

All right. Next we will go to the utilities. Ms. Moncada.

MS. MONCADA: Thank you. Good afternoon.

FPL agrees with Commissioner La Rosa's decision that was made and memorialized in the prehearing order, which is that OPC's Issues A and B are premature.

As to the legal argument that under 125.69 and 125.7, OPC and the other intervenors have been deprived of the opportunity to explore these issues, I would say they haven't been denied of that opportunity because we haven't presented the issues yet.

We spent some time this morning in Docket 07 hearing from OPC and from FIPUG that it's inappropriate to rule on cost recovery before costs are actually presented to the Commission, but now it seems that's exactly what they want here in the fuel docket.

We have the not -- FPL has not yet requested recovery of the 2022 under-recovery amount. We plan to make that filing in January. And at that time, we will present a plan that addresses the full amount. It will address the costs associated with it, and it will a plan for the time period over which those costs will be recovered.

I also want to address really quickly a statement that was made that what we, FPL, have done in this docket is in violation of the Order Establishing Procedure. It is not.

The Order Establishing Procedure asked us to file our 2022 actual estimated true-up on July 27th, and we did that. We filed a calculation at that time. We support Commissioner La Rosa's order memorialized in the Prehearing Order that said Issues 3A and 3B are premature, and we think that that order should stand.

CHAIRMAN FAY: Okay. Thank you.

Mr. Bernier, you are recognized.

MR. BERNIER: Thank you, Mr. Chairman.

I don't want to, you know, reiterate every point Ms. Moncada made. I very much agree with it. I would also like to point out that I disagree that we violated either the spirited or the intent of the midcourse correction rule as we made a notification letter pursuant to 25-6.04242, and we explained why we didn't think a midcourse correction was practical at that time. That's explicitly what the rule allows us to do. And prior to today, really, nobody took any issue with that. But other than that, I would just agree with Ms. Moncada's points.

Thank you.

CHAIRMAN FAY: Okay. Mr. Means, you are recognized for TECO.

MR. MEANS: I agree with the comments made by my colleagues for Florida Power & Light and Duke Energy Florida, and Tampa Electric supports Commissioner La Rosa's decision on this issue.

Thank you.

CHAIRMAN FAY: Okay. Thank you.

Ms. Keating.

MS. KEATING: No position.

CHAIRMAN FAY: Okay. All right. With that, Commissioners, I would like, Ms. Brownless, if you could weigh in kind of on the posture in that where we are at. I know there is a different legal standard for the motion for reconsideration than there is just taking up the issue originally. I guess, can you just, for the Commission, lay that out, and then if we have any questions specifically to that, you could answer those at that time?

MS. BROWNLESS: Yes, sir.

CHAIRMAN FAY: Okay.

MS. BROWNLESS: The standard for

reconsideration is whether there has been a mistake of fact or law, or whether the Prehearing Officer overlooked or failed to consider any argument presented.

Reading the language of the order on page 60, it's clear that the Prehearing Officer both understood and weighed all of the arguments presented by the Office of Public Counsel and the other intervenors, and found that it -- although these issues are relevant, when one is taking up the 2022 under-recovery and how these costs will be recovered from customers since FPL, Duke and TECO have not asked to recover those funds at this time, you are not denying OPC an opportunity to discuss that. You are simply deferring that until those matters are squarely put before the Commission in a petition for midcourse correction.

So we don't think the standard for reconsideration has been met and, therefore, we would recommend that the order issued by Commissioner La Rosa be approved?

CHAIRMAN FAY: Okay. And, Mary Anne, did you have anything you wanted to add?

MS. HELTON: No, sir?

CHAIRMAN FAY: Okay. Commissioners, with

that, we will take any questions or discussions on the item.

Commissioner Clark, you are recognized.

COMMISSIONER CLARK: I would just like to ask staff to clarify for me if this -- if denying the reconsideration would preclude any of the parties from crossing or arguing any points of the issues that are relevant to other issues that are -- that are still in play?

MS. BROWNLESS: No, sir. They can --

COMMISSIONER CLARK: So they -- you can --

MS. BROWNLESS: -- make all the arguments they wish to make on the issues that are there. In other words, on the issues that have been identified, 6, 9 --

COMMISSIONER CLARK: Okay.

MS. BROWNLESS: -- 8, 10.

COMMISSIONER CLARK: So the points can still be made? There is -- there will be no preclusion from making --

MS. BROWNLESS: They won't be precluded from making any argument about the issues that are still outstanding. And let me kind of explain what I am trying to get across here.

The companies that have not requested recovery of 2022 under-recovery costs, fuel costs, that is a position, and that is a response to the appropriate issues, 8, 9, 10, the, what I would call, fallout issues, okay. So they can still make their arguments about that. They clearly believe those requests should have been made now, rather than, you know, delayed to some point in the future, and they can still say that. So they are not precluded from making any argument they would otherwise be able to make.

COMMISSIONER CLARK: Thank you.

CHAIRMAN FAY: Ms. Brownless, I will go to my colleagues if they have anything.

I understand the legal standard that we take the reconsideration motion up on, but just for clarity, if -- if within that decision, I am trying to have a better understanding if it is actually deferred. I mean, I see what you are saying, but if there is no filing by the utilities, do we know when it would come in? I mean, do we know when 2022 it would come? I know FPL has stated that they will come in in January, but I didn't hear the other utilities' statement.

MS. BROWNLESS: One of the things that we will be doing today on cross-examination is developing that information.

CHAIRMAN FAY: Okay. All right. And, Commissioner Passidomo, I just want to make sure we did not exclude you if you had any questions for our staff, or any comments on this issue.

MS. PASSIDOMO: I have no questions, Mr. Chairman.

CHAIRMAN FAY: Okay. With that, Commissioners, if there are any other questions, or comments, or discussion, I will take up a motion on this motion for reconsideration.

COMMISSIONER CLARK: Move the motion for reconsideration be denied, Mr. Chairman.

CHAIRMAN FAY: Okay. We have a motion denial on the motion for reconsideration. Do we have a second?

COMMISSIONER GRAHAM: Second.

CHAIRMAN FAY: Okay. We have a motion and a second.

All those Commissioner that support that motion say aye.

(Chorus of ayes.)

CHAIRMAN FAY: Those opposed? I will be opposing this.

Commissioner Passidomo?

MS. PASSIDOMO: I support the motion.
CHAIRMAN FAY: Okay. I show that motion denied.
Ms. Brownless, do we have other preliminary matters that we need to address?
MS. BROWNLESS: I believe that --
CHAIRMAN FAY: Mr. Brew.
MS. BROWNLESS: -- Mr. Jay Brew would like to have a preliminary matters.
MR. BREW: Yes, there is a clerical error in the Prehearing Order. PCS had corrected its positions on Issues 8 and 16 to agree with OPC, and it wasn't reflected in the final prehearing order.
CHAIRMAN FAY: It is reflected in the prehearing order?
MR. BREW: It is not.
CHAIRMAN FAY: It is not.
MS. BROWNLESS: No.
MR. BREW: It was discussed at the prehearing conference, and staff followed up the next -- or PCS followed up the next day. It just didn't make it into the final.
CHAIRMAN FAY: Okay. And repeat those for me, Mr. Brew.
MR. BREW: 10 and 16 --

CHAIRMAN FAY: Okay.

MR. BREW: -- should be agree with OPC instead of what is stated.

CHAIRMAN FAY: Okay. Great. Thank you.

MR. BREW: That's it. Thank you.

CHAIRMAN FAY: Okay.

MS. BROWNLESS: And, Mr. Brew, I apologize for that oversight.

CHAIRMAN FAY: All right. With that, parties do we have any other preliminary matters?

Ms. Brownless, you didn't have any others?

MR. REHWINKEL: Public Counsel has an objection to make for the record at whatever point in time its appropriate.

CHAIRMAN FAY: Okay. Let's go ahead and take that up now, Mr. Rehwinkel. This is the other objection you wanted to put on the record?

MR. REHWINKEL: It would be our standing objection to the hearing.

CHAIRMAN FAY: Okay. Go ahead. You are recognized.

MR. REHWINKEL: Thank you, Mr. Chairman.

The Public Counsel takes this opportunity to follow through on and continue with an objection to the process that is taking place in this docket this year. The Public Counsel lodged its objection initially at the prehearing.

Commissioners, there is no rule that governs the fuel adjustment clause process that is by statute. There is, however, an OEP, order 020052 or, Order Establishing Procedure, that requires on page 11 that the actual estimated true-up testimony be filed on July 27th.

That standard in that order does not mean that you just put some numbers in paper -- on paper and send it to Mr. Teitzman at the Clerk's Office. It is intended to put the dollars on the table so that they can be considered as part of the three-part process that has been the policy and practice of this commission from time in memorial, which I actually go back to the beginning of, at least for the annual fuel process.

The fact that there is not a rule does not mean that there are no standards, practices or policies that govern the fuel clause. The OEP embodies and manifests the practice and policy of this commission.

Florida Statute Section 120.68(7)(e)3 mandates that it is reversible error for the Commission to fail to adhere to your officially stated agency policy or a prior agency practice. Order -- the OEP order embodies both your official agency policy, and it continues a prior agency practice.

Yes, that statute says that you must explain a deviation from these practices and policies, but that does not mean, and the Supreme Court has said, that just any old explanation will do being. The explanation must be rational.

There is no rational basis for the companies letting $3.4 billion in fuel costs to stack up and imperil the well-being of customers, both personal and economic. Until this year, the annual fuel cost recovery process has been composed of a systematic ongoing final true-up, estimation true-up and projection process that is designed -- designed to be implemented by policy and practice as objective, transparent and predictable.

The process that has occurred in 2022 in this case is akin to something out of the wild west, with little or no rules except for seemingly what is good for the companies but not necessarily for the customers.

The customers -- the companies have failed to follow the midcourse correction rule in the OEP issued in this docket. They have not, with respect to the rule, demonstrated, which is what the rule requires. It doesn't say explain. It says, demonstrate that the midcourse corrections were not practical.

$3.4 billion of piling up midcourse correction costs is significant, and it should require an enormous burden to overcome that it is not practical to put those costs where they belong, which is beginning to recover them.

The letters that you -- that you will see in this docket merely indicated on the face that volatility exists and the companies would monitor the market. This is not an adequate demonstration, and it falls short of a demonstration that does not comply with the rule's plain meaning and intent of the rule.

No rule waiver was sought in this case. No reconsideration of the OEP order was taken, and it became final before the first midcourse correction letter was filed on March 29.

The Public Counsel objects to the state of this docket and the failure of the companies to follow the OEP Commission policy and Commission practice. We ask --

So there is an enormous gap in the record in this case, the missing 2022 under-recovery element called for in the OEP, Commission practice and commission policy. And that gap is the $3.4 billion that will presumably land on customers' bills, and land with a vengeance.

It is unfair to customers to put them in the untenable position of having to guess at their fuel factor that will have an enormous impact on the bill, and then for us to have to come to the Commission and ask that those costs be put on the customer's bill. It's just simply wrong.

This case here is largely about what customers' bills will be in January through December. Every dollar that has been deferred since what reasonably would have been the first opportunity to begin recovering them back in July, accrues a compounding carrying costs and piles up for increasing customer bills, especially if those will be recovered in a defined and confined period.

The numbers that are unspoken in this docket are enormous and unprecedented. Commission policy and practice require that they should have been parts of the overall determination of the factor for the entire year of 2023 in this docket. Hearing new information sometime during this day or tomorrow does not cure the problem. So our objection to this process has been stated.

Thank you. Thank you for the opportunity.

CHAIRMAN FAY: Yep. Thank you, Mr. Rehwinkel.

With that, Commissioners, we will move next to prefiled testimony for the excused witnesses.

Ms. Brownless, can we take care of them first, and then we will go on to exhibits and the opening statements, and then witness prefiled testimony?

MS. BROWNLESS: Yes, sir.

CHAIRMAN FAY: Okay.

MS. BROWNLESS: It's our understanding that the following witnesses have been excused and the prefiled testimony of Lewter-Jenkins, Salvarezza, McClay, Rote, Curtland, Deaton, Young, Napier, Cutshaw, Sizemore, Bokor, Smith and Heisey have been stipulated to by the parties. We would ask that the prefiled testimony of these witnesses, with the exception of Dean Curtland, be moved into the record at this time.

With regard to it with regard to Dean Curtland's prefiled testimony, his September 2nd, 2022, testimony from page one, line one, to page three, line 16, should be placed into the record. Witness Curtland's April 1st, 2022, July 27th, 2022, September 2nd, 2022, testimony from line -- from page three, line 16, to the end of the document, and September 27th, 2022, testimony, shall not be included per agreement of the parties as approved by Prehearing Order PSC-2022-3906-PHO-EI, issued November 14th, 2022.

CHAIRMAN FAY: Okay. Ms. Brownless, let me just make sure I at least have the excused witnesses here with the exceptions that you provided on the back end.

So we have Lewter-Jenkins, Salvarezza, McClay, Rote, Curtland, Deaton, Young, Napier, Cutshaw, Sizemore, Bokor, Smith, and Heisey; is that correct?

MS. BROWNLESS: Yes, sir. They have been stipulated to. My understanding they have been stipulated by the parties and excused.

CHAIRMAN FAY: Okay. If that's correct with the parties. Okay.

All right. With that, Ms. Brownless, we will -- without any objection to that, we will show that testimony entered into the record.

(Whereupon, prefiled direct testimony of Mary Ingle Lewter was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20220001-EI

GPIF Schedules for
January through December 2021

DIRECT TESTIMONY OF
MARY INGLE LEWTER

March 16, 2022

Q. Please state your name and business address.

A. My name is M. Ingle Lewter. 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 Indiana, LLC ("DEI") as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization. DEI and Duke Energy Florida, LLC ("DEF" or "Company") are both wholly-owned subsidiaries of Duke Energy Corporation ("Duke Energy").

Q. Describe your responsibilities as Manager of Fuels and Fleet Analytics.

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation's regulated utility subsidiaries, including DEF, as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of DEF's Generating Performance Incentive Factor ("GPIF") reward/(penalty) amount for the period of January through December 2021. This calculation was based on a comparison of the actual performance of DEF's Seven (7) GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. _______ (MIL-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 24-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount has been calculated for this period?

A. DEF's calculated GPIF incentive amount is a penalty of $206,463. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward/(penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 15 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability primarily concern the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

In addition, the Bartow CC unit had data excluded during the period in which its steam turbine was in a planned outage. The Bartow CC unit has the capability to be operated in simple cycle mode while the steam turbine is in an outage. When operating in simple cycle mode, the unit's heat rate will deviate significantly from its normal range. DEF's heat rate target setting process for the Bartow CC unit excludes historical data from periods when the unit operated in simple cycle mode. From mid-October until mid-November 2021 the steam turbine was in a planned outage; during this period the Bartow CC unit was operated in simple cycle. To be consistent with the target setting process, simple cycle mode heat rate data was excluded from actuals for the purposes of calculating the heat rate for the Bartow CC in year 2021 during those times when the unit was being operated in simple cycle mode as the result of a planned outage.

Q. Have you provided the as-worked planned outage schedules for DEF's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 23 of my exhibit summarizes the planned outages experienced by DEF's GPIF units during the period. Page 24 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Mary Ingle Jenkins was inserted.)

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA
FOR
FUEL AND CAPACITY COST RECOVERY
FINAL TRUE-UP FOR THE PERIOD
JANUARY THROUGH DECEMBER 2021

FPSC DOCKET NO. 20220001-EI

GPIF TARGETS AND RANGES FOR
JANUARY THROUGH DECEMBER 2023

DIRECT TESTIMONY OF
MARY INGLE JENKINS

September 2, 2022

Q. Please state your name and business address.

A. My name is M. Ingle Jenkins. 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 Indiana, LLC (“DEI”) as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization. DEI and Duke Energy Florida, LLC (“DEF” or “Company”) are both wholly owned subsidiaries of Duke Energy Corporation (“Duke Energy”).

Q. What are your responsibilities in that position?

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation’s regulated utility subsidiaries, including DEF, as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming, and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period of January through December 2021 and outline the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2023. These GPIF targets and ranges have been developed from individual unit equivalent availability, average net operating heat rate targets, and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. What GPIF incentive amount was calculated and reported in your March 16, 2022 testimony for the period January through December 2021?

A. DEF's calculated GPIF incentive amount for this period was a penalty of $206,463. Please refer to my testimony filed March 16, 2022 for the details of how this incentive amount was calculated.

Q. Have there been any adjustments to the incentive amount filed in March?

A. No.

Q. Do you have an exhibit to your testimony?

A. Yes. I am sponsoring Exhibit No. _____ (MIJ-1P), which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2023 projection period, the GPIF program includes the following units: Bartow Unit 4, Citrus CC Unit 1, Citrus CC Unit 2, Crystal River Unit 4, and Hines Units 1 through 4. Combined, these units account for 82% of the estimated total system net generation for the period. Citrus CC Units 1 and 2 have been included for the projection period since they now have sufficient performance history to use in setting targets and ranges for these units.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my Exhibit No. ___ (MIJ-1P).

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance, and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate ("EUOR"). From operational data and these graphs, the individual target rates are determined through a review of three years of monthly data points. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage rates can then be converted into an overall equivalent unplanned outage factor ("EUOF"). Because factors are additive (unlike rates), the EUOF and planned outage factor ("POF") when added to the equivalent availability factor ("EAF") will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%. The supporting tables and graphs for the target and range rates are contained in pages 45-85 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Were adjustments made to historical unit availability to account for significant anomalies in historical performance?

A. No.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my Exhibit No. ___ (MIJ-1P).

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data to a linear relationship with Net Operating Factor (NOF), and ranges at a 90% confidence level were also established assuming a normal distribution. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 28-44 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in the case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of simulations was made using a production costing model in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2023?

A. The estimated maximum incentive for the Company is $25,485,802. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MIJ-1P).

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Anthony Salvarezza was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20220001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2021 - December 2021

REDACTED
DIRECT TESTIMONY OF
Anthony Salvarezza

April 1, 2022

Q. Please state your name and business address.

A. My name is Anthony Salvarezza. My business address is 299 First Ave North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as General Manager Regional Services. DEF is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy").

Q. Describe your responsibilities as General Manager of Regional Services.

A. As General Manager of Regional Services, I am responsible for leading and directing project engineering, project management, outage management, business planning and specialized maintenance in Regulated and Renewable Energy ("RRE"). I am responsible for safe, reliable, efficient, economic, environmental, and regulatory compliant maintenance activities through the development and implementation of processes and programs. Within this scope, I ensure longer term activities such as outage management, project scoping, planning, scheduling, execution, and turnover are managed consistently in accordance with the established Project Management Center of Excellence ("PMCoE") guidelines and a standardized set of methodologies and procedures. During non-outage periods, I am responsible for development and implementation of capital and O&M projects across DEF. My position is responsible for direct oversight and direction for 6 - 8 direct reports and a regional organization of approximately 80 employees.

As Regional Services GM, I am also responsible for managing internal and external resources used in the project engineering, project management, outage management, and maintenance services provided to the DEF RRE group. Ultimately, I am responsible for securing, planning and execution of outages, projects, and plant maintenance on approximately 11,000 MWs of generation residing in the state of Florida.

Q. Please describe your educational background and professional experience.

A. I have an Associate in Science electronics engineering, certification in distributed control system engineering, and a bachelor's degree in business. In addition, I have 44 years of related electric industry experience including numerous positions of increasing responsibility over my 44 years of employment with Duke Energy and its predecessors.

Introduction

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the cause of the combustion turbine outages at the Bartow combined cycle plant, explain the Company's response to the

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outages and steps to mitigate the risk of further outages, and ultimately to explain how the Company has at all times acted reasonably and prudently.

Q. Please provide a summary of your testimony.

A. My testimony explains the reasonableness and prudence of DEF's decisions and actions in relation to discovery of latent damage to the Bartow Combined Cycle ("Bartow CC") Combustion Turbine Generators ("CTGs") and the resulting outages, given the information known or reasonably knowable by DEF at the time those decisions were made and those actions were taken. Moreover, I explain how DEF prudently operated the CTGs at all times, including during the period when DEF now believes the damage to the units was initiated, and therefore that DEF's operation of the units did not initiate the damage to the units – a conclusion fully supported by the Original Equipment Manufacturer's ("OEM") root cause analysis. Finally, I explain that the CTG damage and outages currently at issue are completely unrelated to the Commission's previous determination of imprudence related to the operation of the Bartow Steam Turbine.

As I explain in detail below, as a result of standard maintenance testing, DEF first learned in March 2020 that one of the Bartow CTGs (Unit 4B) was damaged by [redacted] years earlier. Because the temperature alarms were never triggered, DEF could not have known of the issue during this period of operation, which ended after the OEM replaced a degraded component within the CTGs. During this period, DEF followed the OEM-provided operation parameters and completed all OEM-recommended inspections and maintenance, and therefore did not cause the damage.

I also explain why DEF's decisions and actions with regard to addressing the likelihood, though not certainty, that similar damage had been initiated on the remaining units were both reasonable and prudent given the information available to DEF. Given the type and location of the damage, there was no non-destructive testing available that could have been performed to definitively confirm the existence of the suspected damage or when such damage, if present, would reasonably be expected to propagate to the point of failure. Given the limited information available to DEF and the limited options available, I explain that the Company's plan to mitigate against future damage, which was adjusted over time as more information came available, was reasonable and prudent.

Finally, I explain that there is no correlation from an engineering or operational standpoint between the outages at issue and the Commission's previous finding of imprudence related to a separate component of the Bartow plant.

In sum, under the well-known standard of what a reasonable utility manager would do given the facts and circumstances known or reasonably knowable at the time, my testimony demonstrates that DEF's decisions and actions have at all times been prudent and DEF should be permitted to recover the replacement power costs incurred.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

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- Exhibit No.__ (AS-1), Root Cause Analysis (Confidential);
- Exhibit No. __ (AS-2), Siemens Product Bulletin PB-08-5038-GN-EN-01 [redacted] (Confidential); and
- Exhibit No. __ (AS-3), Siemens Product Bulletin PB3-13-0008-GN-EN-01 [redacted] (Confidential).

These exhibits are the property of Siemens Energy, Inc., and are designated as proprietary and confidential by Siemens. Therefore, DEF is seeking confidentiality to protect the third-party's interest in these materials.

Background

Q. Can you please provide a summary and timeline of events relating to the Bartow CTG outages?

A. Yes. The Bartow CC came online in summer 2009. There are four (4) Combustion Turbines ("CT") attached to Siemens model SGen6-1000A Combustion Turbine Generators ("CTG"). During planned outages in fall 2012 and spring 2013, DEF performed an inspection of the [redacted] consistent with guidance provided by Siemens Product Bulletin PB-08-5038-GN-EN-01 (Exhibit No. __ (AS-2)) and later updated by PB3-13-0008-GN-EN-01 (Exhibit No. __ (AS-3)). DEF discovered the [redacted] were degraded and, consistent with the OEM's guidance, contracted with Siemens to install upgrades.

As I explain below, unbeknownst to DEF, operation of the CTGs with the degraded [redacted] ultimately led to a series of outages impacting each of the CTGs: Unit 4B in 2019 (extension of a planned outage), Unit 4A in 2021 (forced outage), Unit 4C in 2021 (forced outage), and Unit 4D in 2021 (planned outage).

Q. Can you please provide more detail regarding these outages?

A. In late 2019, during a planned maintenance outage on Unit 4B CTG, the unit faulted during high potential ("hipot") maintenance testing. The hipot test, which was conducted in accordance with Institute of Electrical and Electronics Engineers ("IEEE") Standard 95 guidance with a target test voltage of 33 kV, revealed flaws in the insulation on stator bars T47 and T12. As a result of the root cause analysis ("RCA") finalized in March 2020, DEF determined similar damage could eventually manifest itself at the remaining CTGs at an indeterminate point in the future. The RCA is discussed in detail below and attached as Exhibit No. __ (AS-1).

In January 2021, the Unit 4A CTG experienced an in-service failure that DEF believed to be of the same cause. Later, in May 2021, the Unit 4C CTG likewise experienced a similar in-service failure. As a result, DEF accelerated the Unit 4D planned stator core rewind from 2022 to June 2021, eliminating the risk of an in-service failure on that unit.

<u>Root Cause Analysis</u>

Q. Did DEF perform Root Cause Analyses to determine the cause of these failures?

A. No. DEF contracted with Siemens to prepare the RCA after the Unit 4B CTG failed the maintenance hipot testing mentioned above. Because DEF determined the RCA's main contributor likely also applied to the other units, DEF determined a

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separate RCA was unnecessary when similar damage led to forced outages of Units 4A and 4C. That is, the same equipment and operating conditions were present in all four CTGs for the same duration, and therefore the resulting damage discovered on Unit 4B was considered likely to develop on the other units at some unknown point in the future. However, it was also clear that the damage DEF suspected had been initiated, if it existed at all, had not propagated to the same degree on Units 4A, 4C, and 4D at that time.[1]

Q. Please provide an overview of the Root Cause Analysis for the outages.

A. The outages were caused by stator bar failures. Despite the fact the temperatures of the stator core windings never triggered the OEM established RTD alarm, the stator bar failures were most likely initiated by [redacted]. The RCA determined the "main contributor" to the [redacted] was [redacted] which led to a period of operation at higher temperature levels than the [redacted]. The units' normal load cycling [redacted]

[1] The other units had each recently underwent the same maintenance hipot test at the same voltage levels and passed without any findings or engineering concerns (Unit 4A, 2019; Unit 4C, 2018; and Unit 4D, 2019).

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[redacted].

Q. Can you please elaborate on the RCA findings?

A. Yes. As mentioned above, in the fall 2019, in advance of return to service from a planned outage, maintenance high potential (hi-pot) testing on Unit 4B indicated stator winding faults on the CTG. Further investigation revealed two stator winding bars of two different phases had faulted to ground [redacted]

Forensic analysis determined the [redacted] Finally, the OEM established the "main contributor" to the [redacted] as [redacted] Exhibit No. __ (AS-1), p. 1.

What all this means is that the faulted stator bars resulted from [redacted]. This failure mode naturally led to the question of what led to the relatively [redacted].

The OEM analyzed the operational life of the unit to confirm or refute as many as eleven (11) secondary level elements. Its review of data noted that the stator slot

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temperatures dropped in early 2013, while the generator output (MW and MVAR) remained stable. It further found:

> [redacted].

Id. at p. 20.

Thus, the OEM recognized that the [redacted] were a symptom of the degraded [redacted]. When the [redacted] were replaced with an upgrade, the operating temperature was reduced to the lower operating range while generator output remained consistent (i.e., the [redacted] were not a symptom of the units being run outside of the OEM's established operating parameters). However, unbeknownst to DEF at the time, the [redacted]. *See id.* at p. 24.

Q. Why did the Company conclude that similar damage was likely to have occurred at the other Bartow CTGs?

A. The Company reasoned that, because the other three (3) CTGs operated at similar temperatures for a similar period of time (prior to receiving the same upgrades), it

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was likely that they had also suffered damage to the stator bars that would eventually require remediation – though it was unknown when that time would be.

Q. Did the stator winding temperatures observed during the 2009-2013 timeframe provide any basis for concern?

A. No. The stator winding temperature is monitored by an RTD alarm that alerts the Company if the stator winding temperature exceeds the OEM recommended threshold. The OEM alarm is based on [redacted], giving an alarm around [redacted] and unload at approximately [redacted], depending on specific ambient conditions on a particular day. It is important to note the alarm set-points allow for engineered operating margins built into generator design; for example, the alarm set-point of [redacted] is more than [redacted] below the IEEE-established failure point for Class F Insulation (the type of insulation at issue) of 311°F (155°C). The point being, given the information reasonably available to DEF during the 2009-2013 timeframe, according to the indicated stator RTD temperatures the insulation remained well below its temperature rating at all times. In fact, in 2013 when Siemens performed the [redacted] replacement discussed above, it inspected the end windings and main leads and found no signs of over-heating.

Q. Has DEF's and the OEM's understanding of the actual operating temperatures experienced during the 2009-2013 timeframe changed?

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A. Yes, based on the findings of the RCA, the OEM and DEF now believe that the [redacted]. *See id.* at pp. 19-21, 23. However, as discussed above, because the Bartow CTGs never triggered the RTD alarms, and because those alarms were set at a point that provided approximately [redacted] of margin before reaching the insulation's IEEE-established temperature rating, DEF had no way of knowing the temperature likely exceeded the rating limit and no reason for concern or to seek comparison with the remainder of Siemens' fleet.

Q. Did DEF operate the Bartow CTGs within the operating parameters established by the OEM?

A. Yes, at all times DEF operated the units consistent with the OEM's instructions as provided in the operating manual. DEF reviewed the units' operating history in Pi data from 2010 to the 2012/2013 outages when the [redacted] upgrade was performed. The data, which was sampled on an hourly basis, showed zero instances of operating the generators outside the OEM ratings as defined on the generator capability curve provided in that manual.

Specifically, the generators have a maximum capability of [redacted] MW and the operating history shows the maximum output of any of the four (4) generators was 213 MW. At this output of 213 MW, the allowable reactive power (MVAR) rating

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is [redacted] MVAR - the maximum MVAR output actually generated across this time period was 83 MVAR (as MW load decreases, the MVAR allowable increases). The table below provides the maximum MW and both maximum and minimum MVAR output of the four (4) CTGs over the period in question.

Unit	***Max MW***	***Max MVAR***	***Min MVAR***
4A	*211*	*80*	*-77*
4B	*209*	*71*	*-71*
4C	*210*	*77*	*-73*
4D	*213*	*83*	*-75*

Furthermore, the RCA shows that the OEM did not identify operation of the CTGs outside of their preapproved operating parameters as the cause of the damage to Unit 4B. The RCA determined that the main contributing cause of the stator bar damage was [redacted] which led to increased [redacted], but again, the OEM-established RTD temperature alarm was never triggered. The RCA also shows that after the degraded [redacted] were replaced in 2012 and 2013, the [redacted] while the generator output (MW and MVAR) remained stable. *See id.* at p. 20 & Fig. 16.

In short, DEF operated the CTGs within the OEM's defined operating parameters; hence, DEF's operation was not the cause of [redacted] and

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therefore not the cause of the damage to the units. Instead, the degraded [redacted], which DEF replaced in accordance with OEM recommendations once it discovered the issue, [redacted] and caused the [redacted].

DEF's Actions to Prudently Mitigate the Risk of Failure

Q. What steps did DEF take to prudently manage the likelihood of damage at the remaining units?

A. Once DEF learned the cause of Unit 4B's damage and the likelihood that the remaining units may have experienced similar damage, the Company took several proactive steps to evaluate the remaining units, monitor unit operations to detect damage propagation (to the extent possible), and ultimately remediate the likelihood of damage to the remaining units. First, DEF reconfigured the Electromagnetic Signature Analysis ("EMSA") collars on Units 4A and 4C[2] to potentially identify insulation degradation during continued operation.[3] Second, DEF scheduled borescope inspections on Units 4A and 4C to look for any visual indications of buckled insulation.[4] Third, DEF issued procurement specifications in anticipation of a bid event for a spare set of stator bars to have on hand in case of an in-service failure or failed indicative testing of one of the remaining CTGs. Finally, DEF scheduled generator rewinds for the remaining units, notwithstanding that a rewind would not typically be required for thousands of equivalent operating hours.

[2] As noted above, Units 4A and 4D underwent hipot testing in spring and fall 2019, respectively, resulting in no negative findings or engineering concerns.
[3] DEF previously relocated the EMSA collars on Units 4B and 4D in fall 2019.
[4] Unit 4D was thoroughly inspected in fall 2019 (when the Unit 4B damage was discovered), so a borescope inspection was unnecessary.

Q. Why did DEF take these specific actions?

A. As described above, each action DEF took was intended to reduce the risk exposure on the generators while continuing to provide a safe, reliable, and cost-effective power supply to DEF's customers. The EMSA collar relocation enhanced monitoring of the generator internals for signs of electrical abnormalities to provide a better understanding of internal generator health. The borescope inspections that were scheduled for spring 2021 planned outages were intended to specifically look for buckled insulation to assess risk on these units (although the ability to detect the buckling of insulation with a small borescope camera was not a proven method). The planned stator rewinds to replace the stator bars were significantly shortened (by over 10 years) since the RCA conclusions indicated the potential for a shortened life interval for the stator bar components within the generator.

Q. Please explain the reconfigured EMSA collars on Units 4A and 4C.

A. EMSA monitors electromagnetic interference that is emitted from a generator due to abnormalities. These abnormalities include, but are not limited to, partial discharge, corona, arcing, or gap discharges. While EMSA has been used for decades as a temporary measurement tool for motors, transformers, and generators, only more recently has the technology been applied in a permanent installation for continuous monitoring. When DEF first installed the radio frequency collars used to collect the electromagnetic signature for the Bartow generators, the collars were installed on the RTD wires consistent with industry practice at the time. More recent industry research concluded that EMSA signals are much higher fidelity when the collars are installed on the Neutral Ground Cable, since this is a more direct measurement of electromagnetic signatures within the generator and does not rely as much on the radiated signal, which can be heavily affected by ambient readings. Due to these findings, DEF implemented a plan to relocate the EMSA collars from the RTD wires to the Neutral Ground Cable to improve the EMSA signals and monitor for arcing within the generator. The EMSA collars were relocated on Units 4B and 4D in fall 2019 and on Units 4A and 4C in fall 2020.

EMSA is a dynamic and long-term trending tool for measuring slow degradation due to the long scan time and manual analysis methods used. The relocation of the collars was intended to ensure the inside of the generator was monitored as closely as possible to retain as much margin as possible given the risks identified. However, DEF recognized that EMSA would not typically detect cracks in insulation on a high voltage stator bar, as when insulation is breached the failure happens in milliseconds and not slowly over time. EMSA was a tool to enhance knowledge of generator internals, and not directly tied to detection and prevention of a stator bar failure that by its nature would be a rapidly progressing event.

Q. Please explain the Company's plan to rewind the remaining generators.

A. As discussed above, after learning of the main contributing cause of failure as determined by the OEM's RCA, DEF scheduled each of the three remaining CTGs for a stator rewind during upcoming planned major outage windows. The stator rewind for Unit 4D was scheduled for the spring 2022 planned major outage, the

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stator rewind for Unit 4A was scheduled for the fall 2023 planned major outage, and the stator rewind for Unit 4C was scheduled for the fall 2024 planned major outage. This schedule was intended to allow DEF to take advantage of previously scheduled outages in a measured cadence to avoid concurrent CTG outages (maximizing output from the remainder of the plant by allowing for operation in 3 on 1 configuration), to minimize the number of planned outages by performing multiple maintenance tasks during the same outages, and to provide time for the OEM to manufacture the stator bars and support the outages.

In an effort to prudently address and mitigate the risks to the other units suggested by the Unit 4B RCA, while also attempting to retain the benefits of Bartow's low-cost generation for customers by spacing the scheduling of planned major outages, DEF scheduled these stator rewinds to occur much earlier in the units' operating life than the Duke Energy fleet standard recommendation of [redacted] equivalent hours for this type of air-cooled unit. Specifically, Unit 4D was planned for a rewind at ~103,000 equivalent hours, Unit 4A at ~109,000 equivalent hours, and Unit 4C at ~116,000 equivalent hours.

Q. Was DEF able to maintain the schedule of proactive outages discussed above?

A. No, Unit 4A experienced an unexpected in-service failure in January 2021 that required a forced outage lasting into April 2021; as discussed above, due to the nature of the suspected damage and the limitations on available testing, DEF could not have anticipated when such a failure may occur (if at all). As a result of this outage, DEF accelerated the scheduled Unit 4C planned outage up to fall 2023.

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However, shortly after Unit 4A's return to service, Unit 4C also experienced an in-service failure in May 2021.

Q. Did these unexpected occurrences further alter DEF's plan?

A. Yes. Given the two in-service failures in a short period of time, DEF determined that this new information required a strategy shift. Therefore, the Company accelerated the planned outage of Unit 4D from spring 2022 to June 2021. DEF completed the stator rewinds and returned Units 4C and 4D to service in November and October 2021, respectively.

Q. You indicated that the two forced outages in a short period of time was "new information" that led to DEF's strategy change. Given that DEF determined in March 2020 that there was a likelihood of latent damage to the remaining units, how did the in-service failures constitute "new information"?

A. The new information I was referring to is the speed at which the [redacted], which was thought but not definitively known to exist, was propagating on the remaining units notwithstanding operation within the OEM-provided parameters and the normal fleet operating temperatures. Recall that DEF became aware of the main contributing cause of the damage to Unit 4B in March 2020. At that time, the units had been operating for approximately seven (7) years after the [redacted] is believed to have occurred without an in-service failure known to have resulted from the damage identified in the RCA; that is, DEF had only its experience and did not have any means to formulate a trend or projection for when subsequent failures may occur. At the time of the RCA conclusion in March 2020, DEF discussed the likelihood of failure with the OEM to gain a wider fleet perspective from the OEM fleet of similar generators, and the OEM did not have any specific fleet data or recommendation on likelihood or urgency of failure.

However, the in-service failure of Unit 4A followed shortly thereafter by Unit 4C provided new data points for the Company's risk analysis, which therefore led to the prudent decision to further accelerate the Unit 4D planned outage to June 2021, ~97,802 equivalent hours into its operational life.

Q. Given that Unit 4A failed in January 2021, would it have been possible for DEF to accelerate the planned outages at the remaining two units to avoid in-service failures?

A. The only guaranteed way to avoid an in-service failure at the two remaining units would have been immediately removing them from service. To immediately remove the units from service would have meant the Bartow plant would have been operating in in 1 on 1 configuration until Unit 4A returned to service in April 2021, bringing the plant back to 2 on 1 configuration until Units 4C and 4D could be rewound. Of course, the timing of the return to service for these units would have been very uncertain, as the outage duration would have been dependent on the ability of the OEM to fabricate the new stator windings and provide the workforce to perform the actual rewind.

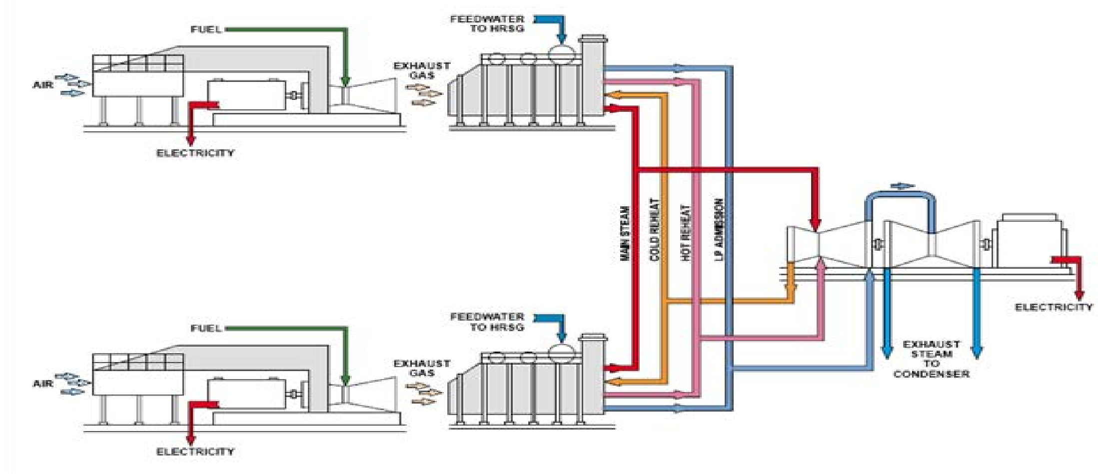
Another possibility would have been to remove one of the remaining CTGs from service when Unit 4A returned to service in April 2021. However, that may or may not have avoided a future in-service failure – for example, DEF may have opted to take Unit 4D out of service in April (as it was the next planned outage), but we now know that Unit 4C failed in May so a forced outage on that unit would not have been avoided. Alternatively, DEF may have opted to take Unit 4C out of service reasoning that Unit 4D had a planned outage scheduled for Spring 2022 and thus less risk of an in-service failure; what we do not and cannot know is when (or if) Unit 4D would have failed before the outage at Unit 4C could have been completed.

The point here is not to identify which of the alternative hypothetical scenarios may have been preferable, it is to underscore that any of the alternatives ultimately not selected carried its own set of risks and unknowns. For anybody to claim "what would have occurred had DEF chosen a different path" would be an exercise in conjecture or post hoc rationalization utilizing the benefit of hindsight, a luxury not available to utility managers at the time decisions must be made.

<u>The Set-up of the Bartow Combined Cycle and Relationship between the CTGs and Steam Turbine</u>

Q. Can you please explain how the Bartow Combined Cycle Plant is configured?

A. Yes. At the Bartow Combined Cycle Plant, natural gas powers the four combustion turbines to turn four separate combustion turbine generators; this process creates excess steam which is then reheated and used to turn the steam turbine ("ST"), which then powers a steam turbine generator. Below is a diagram of a typical 2 on 1 combined cycle. Though Bartow is a 4 on 1 combined cycle, the operational concept is the same with four (4) combustion turbines feeding one steam turbine.



Q. Are you familiar with the Commission's finding that DEF imprudently operated the Bartow Steam Turbine from 2009 to 2012?

A. Yes, I am aware of the Commission's determination, though I would also note that the Company does not agree with that finding and it is currently under appeal at the Florida Supreme Court.

Q. Is the damage to Bartow's Combustion Turbine Generators related to the Commission's previous determination regarding the Steam Turbine?

A. No, the two are unrelated. The Commission's previous finding was premised on the use of the ST in a 4 on 1 configuration (it was originally designed for 3 on 1 operation) resulting in the ST producing MWs in excess of its nameplate capacity without the OEM's explicit approval of operation at that level. The previous case had nothing at all to do with the CTGs and in fact the order does not even mention the CTGs (other than in the context of Bartow being operated as a combined cycle

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plant). Said differently, the prior order concerned operation of the Bartow Steam Turbine and contained no discussion regarding the operation of the CTGs. In fact, the Commission specifically noted "that this case is highly fact specific and for that reason will have limited precedential value."[5]

Conclusion

Q. In your opinion, has DEF acted prudently?

A. Yes. First, as I have explained above, the Company's operation of the units did not initiate the damage to the units, rather it was a function of [redacted] that the Company simply could not have contemporaneously known about. When DEF later determined the damage was likely present on the other units, it was confronted with a lack of information about: a) whether the other units (or some subset of those units) were actually damaged, and if so to what degree; and b) if the units were damaged, at what point the damage would be identifiable via available testing or when the units may experience a failure. Given this dearth of information, DEF made the reasonable decision to continue operating the units (benefitting customers by the continued generation of low-cost energy) and prudently took steps intended to mitigate the risk of future in-service failure. What we now know, but could not have known at the time, was the relatively short period in which the hypothesized damage would manifest. As I have explained above, as the Company learned additional facts, it prudently incorporated the new information into its analysis and made reasonable adjustments where possible. When making operations decisions in

[5] Order No. PSC-2020-0368A-FOF-EI, at p. 22.

real-time, the Company does not have the benefit of hindsight and cannot make decisions based on unknown or unknowable information. When the Company's actions are evaluated based on the standard of what a reasonable utility manager would do given the facts as they were known or reasonably knowable, DEF acted prudently.

Q. Does that conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of James McClay was inserted.)

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA, LLC. FOR

FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH JULY 2022

FPSC DOCKET NO. 20220001-EI

DIRECT TESTIMONY OF James McClay

July 27, 2022

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is James McClay. 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 Carolinas ("DEC"), an affiliate company of Duke Energy Florida, LLC ("DEF", "Petitioner" or "Company") as the Managing Director Natural Gas Trading. I manage the Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities in the Trading and Dispatch Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the financial hedging activities, oil procurement and natural gas procurement and scheduling needed to support the gas generation needs for Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida.

Q. Please describe your education background and professional experience.

A. I received a Bachelor Degree in Business Administration majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003 and then became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through present I've been employed in various managerial roles at Progress Energy and Duke Energy overseeing Natural Gas and Oil trading, hedging procurement. Prior to my tenure with Duke Energy, I was employed for approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and broker/dealers.

Q. What is the purpose of your testimony?

A. While DEF does not currently propose to hedge, given feedback from customer interveners, the purpose of this testimony is to outline DEF's hedging objectives and activities for 2023 if it were ordered to begin hedging.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibit:

- Exhibit No.___ (JM-1P) – 2023 Risk Management Plan (*filed July 27, 2022*).

Q. What are the objectives of DEF's hedging activities?

A. The objectives of DEF's hedging program are to reduce fuel price volatility risk and provide greater cost certainty for DEF's customers.

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Q. Describe the hedging activities that the Company will execute for 2023.

A. DEF is not proposing to implement hedging and outlined hedging activities. While DEF believes that hedging is a reasonable and prudent approach to mitigate price volatility, it understands that key consumer groups oppose hedging. Given this feedback from DEF's customers, DEF is proposing to continue the hedging moratorium through 2023. However, if the Commission decides that DEF should hedge, DEF is providing its 2023 Risk Management Plan to demonstrate how it would hedge if so ordered. If the 2023 Risk Management Plan is implemented, DEF would hedge a percentage of its projected natural gas burns utilizing approved financial agreements. With respect to hedging activity, natural gas represents the largest component of DEF's overall hedging activity given it is the largest fuel cost component. DEF's target hedging percentage ranges would be between [redacted] to [redacted] percent of its forecasted calendar annual burns. Hedging in the ranges provided would allow DEF to monitor actual fuel burns, updated fuel forecasts, and make any adjustments as needed throughout the year. If hedging were to start in 2023 the Risk Management Plan outlines the activities DEF would implement to start its hedging program in 2023 without existing hedges in place and as the hedging program begins to mature it would take DEF all of 2023, 2024 and into the first half of 2025 to execute the layered hedging strategy and reach the minimum levels outlined in the Risk Management Plan.

Q. What were the results of DEF's hedging activities for January through July 2022?

A. As approved by the Commission, DEF is currently under a moratorium on hedging and has not executed any financial hedges for any periods since October 21, 2016, and therefore does not have any hedges in place for 2022.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA, LLC. FOR

FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH JULY 2022

FPSC DOCKET NO. 20220001-EI

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Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Charles R. Rote was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20220001-EI

MARCH 16, 2022

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company, as Business Services Director in the Power Generation Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from DePauw University with a Bachelor's degree in Industrial Psychology in 1991. I subsequently earned a Master of Business Administration from Pace University in New York in 1994. I am a Certified Public Accountant in the state of New York. Prior to 1999, I held various auditing positions at Price Waterhouse LLP and Pfizer Inc. From 1999 to 2009, I worked for Rinker Materials (acquired by Cemex in 2008) in various audit, accounting and development capacities. I have been in my current role at FPL since 2009 where I have responsibility for all budgeting, forecasting, regulatory and internal controls activities for FPL's fossil and solar generating assets. Since 2013, I have also overseen the preparation of the Generating Performance Incentive Factor ("GPIF") filings including testimony, exhibits, audits and discovery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report the pre-consolidated Florida Power & Light Company's ("FPL") and pre-consolidated Gulf Power Company's ("Gulf") actual 2021 performance for Equivalent Availability Factors ("EAF") and Average Net Operating Heat Rates ("ANOHR") for the GPIF generating units and to calculate the resulting GPIF reward/penalties. I compared the performance of each unit to the targets approved in the final Commission Order No. PSC-2020-0439-FOF-EI issued November 16, 2020 for the period January through December 2021 and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the results of these calculations: $16,307,675 of fuel savings to FPL's customers and $2,341,814 of fuel losses for Gulf's customers, which result in a GPIF reward of $8,151,853 for FPL and a GPIF penalty of $1,157,234 for Gulf. When combined, this represents a net of $13,965,861 of fuel savings and a net reward of $6,994,619. I have presented FPL units separately from Gulf units to align with pre-consolidation targets.

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

A. Yes. Exhibits CRR-1 and CRR-2 show the reward/penalty calculations for FPL and Gulf.

Q. Please explain in general terms how the total FPL GPIF reward amount was calculated.

A. The steps involved in making these calculations are provided in Exhibit CRR-1. Page 2 provides the overall GPIF performance of +3.9738 points or $16,307,675 in fuel savings which represents a reward of $8,151,853. Page 3 provides the calculation of the maximum allowed incentive dollars as approved by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's weighting factors, and the associated GPIF unit points.

Page 5 shows the actual EAF and adjustments summary. This page lists each of the GPIF units, the targets, the adjusted actual EAF and the Generating Performance Incentive Points for each unit for availability as determined by interpolating from the tables shown on pages 8 through 20. These tables are based on the targets and target ranges previously approved by the Commission.

Continuing with Exhibit CRR-1, page 7 shows the adjustments to ANOHR. Columns 2 through 4 show the target heat rate formula, the actual net output factor ("NOF") and ANOHR for each GPIF unit. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column

9 contains the Generating Performance Incentive Points as determined by interpolating from the tables shown on pages 8 through 20. These tables are based on the targets and target ranges previously approved by the Commission.

Q. Please explain the primary reason FPL will receive a reward under the GPIF for the January through December 2021 period.

A. The primary reason that FPL will receive a reward for the period is that adjusted actual EAF for eight out of the thirteen FPL GPIF units were better than their targets. In addition, five out of the thirteen FPL GPIF units operated with an adjusted actual ANOHR that was below the ±75 Btu/kWh dead band.

Q. Please summarize each nuclear unit's performance as it relates to the EAF.

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 88.9%, compared to its target of 80.6%. This results in +10.0 points, which corresponds to a GPIF reward of $1,903,699.

St. Lucie Unit 2 operated at an adjusted actual EAF of 89.3%, compared to its target of 84.0%. This results in +10.0 points, which corresponds to a GPIF reward of $1,407,260.

Turkey Point Unit 3 operated at an adjusted actual EAF of 84.5% compared to its target of 85.7%. This results in -4.00 points, which corresponds to a GPIF penalty of $553,878.

Turkey Point Unit 4 operated at an adjusted actual EAF of 99.5% compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $1,407,260.

In total, the nuclear units' EAF performance results in a net GPIF reward of $4,164,341.

Q. Please summarize each nuclear unit's performance as it relates to ANOHR.

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,413 Btu/kWh compared to its target of 10,422 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The St. Lucie Unit 2 adjusted actual ANOHR is 10,307 Btu/kWh compared to its target of 10,297 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The Turkey Point Unit 3 adjusted actual ANOHR is 10,660 Btu/kWh compared to its target of 11,234 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +10.0 points, which corresponds to a GPIF reward of $414,383.

Turkey Point Unit 4 adjusted actual ANOHR is 10,476 Btu/kWh compared to its target of 10,888 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +10.0 points, which corresponds to a GPIF reward of $322,070.

In total, the nuclear units' heat rate performance results in a net GPIF reward of $736,453.

Q. What is the total GPIF reward for FPL's nuclear units?

A. $4,900,794.

Q. Please summarize the performance of FPL's fossil units.

A. Regarding EAF performance, five of the nine fossil generating units performed better than their availability targets as shown on Exhibit CRR-1, page 5, resulting in a combined reward of $1,239,866. The other four performed worse than their availability target as shown on Exhibit CRR-1, page 5, resulting in a penalty of $515,722. Thus, the total FPL fossil units' EAF performance results in a net GPIF reward of $724,144.

Regarding ANOHR, three of the nine FPL fossil units operated below the ±75 Btu/kWh dead band so they received a combined reward of $2,526,915. The other six operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties. Thus, the total fossil unit heat rate performance results in a net GPIF reward of $2,526,915.

Q. What is the total GPIF reward/penalty for FPL's fossil units?

A. The net GPIF fossil availability performance reward of $724,144 plus the net GPIF heat rate fossil performance reward of $2,526,915 results in a total GPIF reward for FPL's fossil units of $3,251,059.

Q. Please explain in general terms how the total Gulf GPIF penalty amount was calculated.

A. The steps involved in making these calculations are provided in Exhibit CRR-2. Page 11 shows the EAF summary. This page lists each of the GPIF units, the targets, the adjusted actual EAF and the Generating Performance Incentive Points for each unit for availability as determined by interpolating from the tables shown on pages 34 through 38. These tables are based on the targets and target ranges previously approved by the Commission.

Pages 19 through 23 show the adjustments to ANOHR. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit.

Page 26 shows the heat rate summary. This page lists each of the GPIF units, the targets, the adjusted actual ANOHR and the Generating Performance Incentive Points for each unit for heat rate as determined by interpolating from the tables shown on pages 34 through 38. These tables are based on the targets and target ranges previously approved by the Commission.

Page 28 shows the calculation of Gulf's penalty of $1,157,234. Page 32 provides the calculation of the maximum allowed incentive reward and penalty as approved by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. Page 33 shows the calculation of the system actual -5.42 generation performance incentive points, and page 39 shows the calculation of $2,341,814 in fuel losses.

Q. **To recap, what is FPL and Gulf's combined total GPIF result for the period January through December 2021?**

A. The combined total GPIF result for the period January through December 2021 is $13,965,861 of fuel savings and a GPIF reward of $6,994,619 as a result of the availability and efficiency of the combined GPIF generating units.

Q. **Does this conclude your testimony?**

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20220001-EI

SEPTEMBER 2, 2022

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL") as the Business Services Director in the Power Generation Division of FPL, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil and solar generating assets.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor ("EAF") targets and average net operating heat rate ("ANOHR") targets used in determining the Generating Performance Incentive Factor ("GPIF") for the period January through December 2023.

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

A. Yes, I am sponsoring Exhibit CRR-3. This exhibit supports the development of the 2023 GPIF EAF and ANOHR targets. The first page of this exhibit is an index to its contents. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Are you including the pre-consolidated Gulf Power Company ("Gulf") generating units in your GPIF preparation?

A. Yes, I am.

Q. Do any generating units from Gulf qualify for GPIF when combined with the FPL units?

A. No, they do not. According to the GPIF manual, in order to determine the units to be considered in the GPIF calculation, each generating unit is ranked from highest to lowest according to their estimated net generation for the projected period. When the estimated generation from the Gulf generating units is combined with FPL's, they are fall outside the top 80% ranking of FPL's and Gulf's combined total forecasted system net generation as calculated pursuant to the GPIF manual.

Q. Please summarize the 2023 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December 2023, FPL projects a weighted system equivalent planned outage factor ("EPOF") of 7.0% and a weighted system equivalent unplanned outage factor ("EUOF") of 6.8% which yield a weighted system EAF target of 86.2%. The targets for this period reflect planned refuelings for St. Lucie Unit 2, Turkey Point Unit 3 and Turkey Point Unit 4. FPL also projects a weighted system ANOHR target of 7,044 Btu/kWh for the period January through December 2023. These targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

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

A. Yes, I have. Exhibit CRR-3, pages 6 and 7, contains the information summarizing the individual targets and ranges for EAF and ANOHR for each of the 15 generating units that FPL proposes to be considered as GPIF units for the period January through December 2023. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

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

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

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

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

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

A. As mentioned before, in accordance with the GPIF Manual, the GPIF units selected are responsible for no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the GenTrader model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the 15 units which FPL proposes to use for the period January through December 2023 represent the top 80.2% of the total forecasted system net generation for this period including the Gulf generating units but excluding the Dania Beach Energy Center ("DBEC"). DBEC was declared to be in commercial operation status on May 31, 2022. Consequently, it was excluded from the GPIF calculation because there is insufficient historical data to include it. Consistent with the GPIF Manual, this unit will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2023 EAF and ANOHR performance targets as shown on Exhibit CRR-3 represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Dean Curtland was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DEAN CURTLAND

DOCKET NO. 20220001-EI

SEPTEMBER 2, 2022

Q. Please state your name and address.

A. My name is Dean Curtland. My business address is 15430 Endeavor Drive, Jupiter, FL 33478.

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

A. I am employed by Florida Power & Light Company ("FPL") as Vice President of Nuclear.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy to be produced by our nuclear units measured in Million British Thermal Units or ("MMBtu"). Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs included in the proposed fuel cost recovery factors for the period January 2023 through December 2023. I am also supporting FPL's projected 2023 incremental plant security and Fukushima-related costs. Finally, I address the 2022 outage event which occurred at the St. Lucie Plant.

Nuclear Fuel Costs

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

A. FPL's nuclear fuel cost projections are developed using projected energy production at its nuclear units and current operating schedules for the period January 2023 through December 2023.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2023 through December 2023.

A. FPL projects the nuclear units will burn 296,609,866 MMBtu of energy at a cost of $0.4777 per MMBtu for the period January 2023 through December 2023. Projections by nuclear unit and by month are listed in Schedule E-4 of Exhibit RBD-7, which is attached to FPL witness Deaton's testimony.

Nuclear Plant Incremental Security Costs

Q. What is FPL's projection of incremental security costs at its nuclear power plants for the period January 2023 through December 2023?

A. FPL projects that it will incur $34.1 million in incremental nuclear power plant security costs in 2023. The costs consist of $6.0 million of capital expenditures and $28.1 million of O&M expenses.

Q. Please provide a brief description of the items included in incremental nuclear power plant security costs.

A. The projection includes the additional costs incurred in maintaining a security force as a result of implementing the NRC's fitness-for-duty rule under 10 CFR Part 26, which strictly limits the number of hours that nuclear security personnel may work; additional personnel training; maintenance of the physical upgrades resulting from implementing the NRC's physical security rule under 10 CFR Part 73; and impacts of implementing the NRC's cyber security rule under 10 CFR Part 73. It also includes force-on-force modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force, as required by NRC inspection procedures.

<u>Fukushima-Related Costs</u>

Q. What is FPL's projection of Fukushima-related costs at its nuclear power plants for the period January 2023 through December 2023?

A. FPL's current projection of Fukushima-related costs for 2023 is approximately $0.6 million in O&M expenses.

Q. Please provide a brief description of the items included in this projection of Fukushima-related costs.

A. The projection includes FPL's share of costs incurred for equipment, storage, and transportation, to support the shared Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).

[redacted]

[redacted]

(Whereupon, prefiled direct testimony of Renae B. Deaton was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20220001-EI

APRIL 1, 2022

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Senior Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Please state your education and business experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. I have over 30 years' experience in retail and wholesale regulatory affairs, rate design and cost of service. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. In 2016, I assumed my current position, where my duties include providing direction as to the appropriateness of inclusion of costs through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery. Prior to joining FPL, I was employed at the South Carolina Public Service Authority (d/b/a Santee Cooper) for fourteen years, where I held a variety of positions in the Corporate Forecasting, Rates, and Marketing Department and in generation plant operations. As part of the various roles I have held with FPL, I have testified before this Commission on rate design and cost of service in base rate and clause recovery dockets. I have also testified before the Federal Energy Regulatory Commission supporting rates for wholesale power sales agreements and Open Access Transmission Tariffs.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause net true-up amounts for the period January 2021 through December 2021 for pre-consolidated FPL and pre-consolidated Gulf Power Company ("Gulf"). If approved by the Commission at the 2022 hearing in this docket, these 2021 net true-up amounts will be included in the calculation of FPL's 2023 FCR and CCR Factors.

FPL's 2021 FCR final net true-up is an under-recovery, including interest, of $11,681,957 (Exhibit RBD-1, page 1) and Gulf's 2021 FCR final net true-up is an over-recovery, including interest, of $21,938,913 (RBD-3, page 1). FPL is requesting Commission approval to include the combined over-recovery amount of $10,256,956 in the calculation of its 2023 FCR Factors.

FPL's 2021 CCR final net true-up is an over-recovery, including interest, of $3,634,686 (Exhibit RBD-2, page 1) and Gulf's 2021 CCR final net true-up is an under-recovery, including interest, of $3,937,996 (Exhibit RBD-4, page 1). FPL is requesting Commission approval to include the combined under-recovery of $303,310 in the calculation of its 2023 CCR Factors.

Finally, FPL is requesting Commission approval to include $13,855,504 in the calculation of the FCR factors for the period January 2023 through December 2023, which represents FPL's share of the 2021 Asset Optimization Program gains described in the testimony of FPL witness Yupp and presented on page 1 of Exhibit GJY-1.

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

A. Yes, I have. Exhibits RBD-1 and RBD-2 contain the schedules supporting the calculation of the 2021 final net FCR and CCR true-up amounts for FPL and Exhibits RBD-3 and RBD-4 contain the schedules supporting the calculation of the 2021 final net FCR and CCR true-up amounts for Gulf. In addition, FCR Schedules A1 through A12 for the January 2021 through December 2021 period for FPL and Gulf have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

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

2021 FCR FINAL TRUE-UP CALCULATION– FPL

Q. Please explain the calculation of FPL's 2021 FCR net true-up amount.

A. Exhibit RBD-1, pages 1 through 3 provide the calculation of the FCR net true-up for the period January 2021 through December 2021 for FPL, which is an under-recovery of $11,681,957.

Page 1 shows the actual end-of-period true-up under-recovery for the period January 2021 through December 2021 of $597,548,321 on line 1. By Order No. PSC-2021-0460-PCO-EI, issued on December 15, 2021 in Docket No. 20210001-EI, the Commission approved FPL's 2022 mid-course correction petition, which included a revised 2021 actual/estimated true-up under-recovery amount of $585,866,364, which is shown on line 3. Line 1 less line 3 results in the final net true-up under-recovery for the period January 2021 through December 2021 of $11,681,957 shown on line 5.

The calculation of the FCR true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Page 2 shows the calculation of the FCR actual true-up by month for January 2021 through December 2021.

Q. Have you provided a schedule showing the variances between actual and revised actual/estimated FCR costs and applicable revenues for 2021?

A. Yes. Exhibit RBD-1, page 4, (sum of lines 42 and 43) compares the actual end-of-period true-up under-recovery of $597,548,321 (column 3) to the revised actual/estimated end-of-period true-up under-recovery of $585,866,364 (column 4) resulting in a net under-recovery of $11,681,957 (column 5). Exhibit RBD-1, page 4 shows that the variance consists of a decrease in jurisdictional fuel costs of $2.0 million (line 41) combined with a decrease in revenues of $13.7 million (line 36).

Q. Please summarize the variance schedule on page 3 of Exhibit RBD-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $3.448 billion for 2021 (Exhibit RBD-1, page 4, line 41, column 4). The actual jurisdictional total fuel costs and net power transactions for the 2021 period are $3.446 billion (Exhibit RBD-1, page 4, line 41, column 3). The resulting jurisdictional total fuel costs and net power transactions are $2.0 million, or 0.1 % lower than previously projected (Exhibit RBD-1, page 4, line 41, column 5). Jurisdictional fuel revenues net of revenue taxes for 2021 are $13.7 million, or 0.5% lower than previously projected (Exhibit RBD-1, page 4, line 36, column 5).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $2.0 million variance.

Fuel Cost of System Net Generation: $23.9 million increase (Exhibit RBD-1, page 3, line 2, column 5)

The table below provides the detail of this variance.

Fuel Variance	Final True-up	Actual/Estimated True-up	Difference
Heavy Oil			
Total Dollar	$10,240,212	$10,239,974	$237
Units (MMBtu)	876,873	876,873	0
$ per Unit	11.6781	11.6778	0.0003
Variance Due to Consumption			0
Variance Due to Cost			$237
Total Variance			$237
Light Oil			
Total Dollar	$11,339,553	$9,854,761	$1,484,792
Units (MMBtu)	707,034	616,750	90,285
$ per Unit	16.0382	15.9785	0.0597
Variance Due to Consumption			$1,442,616
Variance Due to Cost			$42,176
Total Variance			$1,484,792
Coal			
Total Dollar	$68,616,835	$79,678,954	($11,062,119)
Units (MMBtu)	24,035,453	28,758,268	(4,722,815)
$ per Unit	2.8548	2.7706	0.0842
Variance Due to Consumption			($13,085,244)
Variance Due to Cost			$2,023,125
Total Variance			($11,062,119)
Gas			
Total Dollar	$3,469,361,592	$3,435,307,893	$34,053,699
Units (MMBtu)	643,087,086	631,210,778	11,876,308
$ per Unit	5.3949	5.4424	(0.0476)
Variance Due to Consumption			$64,635,738
Variance Due to Cost			($30,582,039)
Total Variance			$34,053,699
Nuclear			
Total Dollar	$150,856,989	$151,453,962	($596,973)
Units (MMBtu)	305,493,510	306,002,191	(508,681)
$ per Unit	0.4938	0.4949	(0.0011)

Fuel Variance	Final True-up	Actual/Estimated True-up	Difference
Variance Due to Consumption			($251,769)
Variance Due to Cost			($345,204)
Total Variance			($596,973)
Total			
Total Dollar	$3,710,415,180	$3,686,535,544	$23,879,636
Units (MMBtu)	974,199,956	967,464,859	6,735,097
Variance Due to Consumption			$52,741,341
Variance Due to Cost			($28,861,705)
Total Variance			$23,879,636

Note: The total fuel cost of system net generation, in the table above, for the 2021 final true-up does not tie to the amount provided on the 2021 final true-up E1b Schedule by $250.00 due to minor adjustments that impacted A1/A2 and A3/A4 schedules that were previously filed for 2021. These adjustments were included on the impacted A-Schedules in the months in which they occurred.

Fuel Cost of Power Sold: $17.0 million increase (Exhibit RBD-1, page 4, line 5, column 5)

The variance of $16,950,643 for the Fuel Cost of Power Sold was primarily attributable to higher than projected economy power sales and higher than projected fuel costs for economy power sales. FPL sold 439,089 MWh more of economy power, resulting in a volume variance of $10,467,567. In addition, the average unit fuel cost on economy power sales was $2.00/MWh higher than projected, resulting in a cost variance of $6,484,867. The combination of higher than projected economy power sales and higher than projected fuel costs on economy power sales resulted in a net variance for economy power sales of $16,952,434. The remaining variance of $1,791 was attributable to lower than projected St. Lucie Plant Reliability Exchange sales that were partially offset by higher than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

Gains from Off-System Sales: $9.0 million increase (Exhibit RBD-1, page 4, line 6, column 5)

The variance for Gains from Off-System Sales was attributable to higher than projected economy power sales and higher than projected margins on economy power sales. FPL sold 439,089 MWh more of economy power, resulting in a volume variance of $4,728,409. Margins on economy power sales averaged $1.31/MWh higher than projected, resulting in a cost variance of $4,244,570. The combination of higher economy power sales and higher margins on economy power sales resulted in a total variance for Gains from Off-System Sales of $8,972,979.

Variable Power Plant O&M Attributable to Off-System Sales: $0.285 million increase (Exhibit RBD-1, page 4, line 13, column 5)

The variance of $285,408 was attributable to higher than projected economy power sales.

Q. What is the variance in retail (jurisdictional) FCR revenues?

A. As shown on Exhibit RBD-1, page 4, line 36, actual 2021 jurisdictional FCR revenues, net of revenue taxes, are approximately $13.7 million lower than the revised actual/estimated projection. This is primarily due to 189,217,636 kWh lower than projected jurisdictional sales (page 4, line 24, column 5) than the revised actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $13,855,504 as its 60% share of 2021 Asset Optimization Program gains over the $40 million threshold. When is FPL requesting to recover its share of the gains, and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2021 Asset Optimization Program gains through the 2023 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized gains amount in the calculation of the 2023 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2023 through December 2023 as a reduction to jurisdictional fuel revenues applicable to each period.

2021 CCR FINAL TRUE-UP CALCULATION - FPL

Q. Please explain the calculation of FPL's 2021 CCR net true-up amount.

A. Exhibit RBD-2, page 1 provides the calculation of the CCR net true-up for the period January 2021 through December 2021, an over-recovery of $3,634,686, which FPL is requesting to be included in the calculation of the CCR factors for the January 2023 through December 2023 period.

The actual end-of-period over-recovery for the period January 2021 through December 2021 of $8,551,683 shown on line 4 less the actual/estimated end-of-period over-recovery for the same period of $4,916,997 shown on line 8 that was approved by the Commission in Order No. PSC-2021-0442-FOF-EI, results in the net true-up over-recovery for the period January 2021 through December 2021 of $3,634,686 shown on line 10.

Q. Have you provided a schedule showing the calculation of the 2021 CCR actual true-up by month?

A. Yes. Exhibit RBD-2, pages 2 through 4, shows the calculation of the CCR true-up for the period January 2021 through December 2021 by month.

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

A. Yes. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 “Calculation of True-Up and Interest Provision” for the FCR Clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity costs and applicable revenues for 2021?

A. Yes. Exhibit RBD-2 pages 5 and 6 show the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2021 through December 2021.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 5, line 14, column 5, the variance related to total system capacity costs is a decrease of $4.3 million or 1.8%. Below are the primary reasons for the decrease.

<u>Transmission Revenues from Capacity Sales: $2.4 million increase (Exhibit RBD-2, page 5, line 5, column 5)</u>

Approximately $363,000 of the total variance is attributable to higher than projected revenues from capacity premiums associated with power capacity sales. The remaining variance of approximately $2,086,000 is attributable to higher than projected economy power sales which resulted in higher than projected transmission revenues from economy power sales. Higher revenues from capacity premiums, combined with higher transmission revenues from economy sales resulted in a total variance of $2,449,311.

<u>Incremental Plant Security Costs – O&M: $2.0 million decrease (Exhibit RBD-2, page 5, line 6, column 5)</u>

The variance for incremental plant security is primarily attributable to: (1) lower Nuclear Regulatory Commission ("NRC") fees than originally budgeted; (2) Force-on-force drill activities were minimized due to COVID, specifically contracted services were not needed to support these activities; and (3) deferral of work for the Control Center from 2021 to mid-2022.

<u>Incremental Nuclear NRC Compliance Costs (Fukushima) – O&M: $0.1 million decrease (Exhibit RBD-2, page 5, line 8, column 5)</u>

Incremental Nuclear NRC Compliance Costs were lower by $114,429 due to costs being lower than originally budgeted.

Transmission of Electricity by Others: $0.3 million increase (Exhibit RBD-2, page 5, line 4, column 5)

The variance is due to higher than projected purchases of third-party transmission service used to facilitate economy power sales during the period.

Q. Please describe the variance in 2021 CCR revenues.

A. As shown on page 6, line 28, column 5, actual 2021 CCR revenues (net of revenue taxes), are $1.1 million lower than projected in the actual/estimated true-up filing.

Q. Have you provided a schedule showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Exhibit RBD-2 as pages 17 and 18. Page 17 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2021 through December 2021. Page 18 provides the short-term capacity payments for the period January 2021 through December 2021.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the FCR and CCR Clauses?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2021 through December 2021 are included on page 19 of Exhibit RBD-2.

2021 FCR FINAL TRUE-UP CALCULATION – GULF

Q. Please explain the calculation of Gulf's FCR net true-up amount.

A. Exhibit RBD-3, pages 1 and 2 provide the calculation of the FCR net true-up for the period January 2021 through December 2021, which is an over-recovery of $21,938,913.

Page 1 shows the actual end-of-period true-up under-recovery for the period January 2021 through December 2021 of $81,780,862 on line 2. On December 7, 2021, the Commission approved FPL's 2022 mid-course correction petition, which included a revised 2021 actual/estimated true-up under-recovery amount of $103,719,775, which is shown on line 1. Line 2 less line 1 results in the final net true-up over-recovery for the period January 2021 through December 2021 of $21,938,913 shown on line 3.

The calculation of the FCR true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Page 2 shows the calculation of the FCR actual true-up by month for January 2021 through December 2021.

Q. Have you provided a schedule showing the variances between actual and revised actual/estimated FCR costs and applicable revenues for 2021?

A. Yes. Exhibit RBD-3, page 3 reflects that Gulf's actual total fuel cost and net power transactions expense was $420,504,523, which is $21,081,235 or 4.77% lower than the revised actual/estimated amount of $441,585,757 and jurisdictional fuel revenues applicable to the period were $338,003,815 which are $832,824 or 0.25% higher than the revised actual/estimated amount, which results in the $21.9 million variance.

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $21.1 million variance.

<u>Fuel Cost of System net Generation: $35.3 million decrease (Exhibit RBD-3, page 3, line 1, column 4)</u>

Fuel Variance	2021 Final True-up	2021 Actual / Estimated	Difference
<u>Oil - C.T</u>			
Total Dollar	$4,527,501	$4,483,618	43,883
Units	350,395	236,395	114,000
$ per Units	12.921	18.967	(6.05)
Variance Due to Consumption			1,473,009
Variance Due to Cost			(1,429,127)
Total Variance			43,883
<u>Gas</u>			
Total Dollar	$238,841,216	$254,112,128	(15,270,912)
Units	53,567,757	55,544,838	(1,977,081)
$ per Units	4.459	4.575	(0.12)

Fuel Variance	2021 Final True-up	2021 Actual / Estimated	Difference
Variance Due to Consumption			(8,815,162)
Variance Due to Cost			(6,455,750)
Total Variance			(15,270,912)
<u>Coal + Gas B.L. + Oil B.L.*</u>			
Total Dollar	$55,652,712	$75,710,068	(20,057,356)
Units	19,429,258	25,791,228	(6,361,970)
$ per Units	2.864	2.935	(0.07)
Variance Due to Consumption			(18,223,078)
Variance Due to Cost			(1,834,278)
Total Variance			(20,057,356)
<u>Other Adjustments to Fuel Costs</u>			
Total Variance	$686,016	$736,574	(50,557)
<u>Total Variance</u>			
Total Variance Due to Consumption			**(25,565,230)**
Oil - C.T.			1,473,009
Gas			(8,815,162)
Coal + Gas B.L. + Oil B.L.			(18,223,078)
Total Variance Due to Cost			**(9,769,711)**
Oil - C.T.			(1,429,127)
Gas			(6,455,750)
Coal + Gas B.L. + Oil B.L.			(1,834,278)
Other Adjustments to Fuel Costs			(50,557)
Total			**(35,334,941)**

*Note: B.L. - Boiler Lighter

<u>Total Fuel Cost of Purchased Power: $20.7 million increase (Exhibit RBD-3, page 3, line 5, column 4)</u>

Gulf Power's recoverable fuel cost of purchased power for the period was $236,011,683 or 9.60% above the estimated amount of $215,331,976. Total megawatt hours of purchased power were 6,023,582 MWh compared to the estimate of 5,532,000 MWh or 8.89% above estimates. The resulting average fuel cost of purchased power was 3.918 cents per kWh or 0.66% above the estimated amount of 3.892 cents per kWh. The higher total fuel cost of purchased power is due to higher megawatt hours purchased by Gulf at a higher purchased power price per MWh than estimated.

Total Fuel Cost & Gains on Power Sales: $6.2 million increase (Exhibit RBD-3, page 3, line 4, column 4)

Gulf's recoverable fuel cost of power sold for the period is $104,941,444 or 6.25% higher than the estimated amount of $98,766,525. The total quantity of power sales was 2,902,207 MWh compared to Gulf's estimated sales of 3,165,494 MWh, or 7.75% below estimates. The resulting average fuel cost of power sold was 3.594 cents per kWh or 15.18% above the estimated amount of 3.120 cents per kWh.

Stratified Revenue Credit: $0.251 million increase (Exhibit RBD-3, page 3, line 3, column 4)

The higher fuel prices in November 2021 drove an increase stratified revenue credit for the year.

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2021 gains?

A. No, this methodology is no longer applicable. As of January 1, 2022, Gulf no longer exists as a separate rate making entity. FPL and Gulf are one consolidated ratemaking entity.

2021 CCR FINAL TRUE-UP CALCULATION – GULF

Q. Please explain the calculation of Gulf's 2021 CCR net true-up amount.

A. Exhibit RBD-4, page 1 provides the calculation of the CCR net true-up for the period January 2021 through December 2021, an under-recovery amount of $3,937,996.

The actual end-of-period under-recovery for the period January 2021 through December 2021 of $2,250,303 shown on line 2 less the actual/estimated end-of-period over-recovery for the same period of $1,687,693 shown on line 1 that was approved by the Commission in Order No. PSC-2021-0442-FOF-EI, results in the net true-up under-recovery for the period January 2021 through December 2021 of $3,937,996 shown on line 3. This under-recovery amount of $3,937,996 will be included in the calculation of the 2023 CCR factors

Q. Have you provided a schedule showing the calculation of the 2021 CCR actual true-up by month?

A. Yes. Exhibit RBD-4, pages 3 and 4 provides the calculation of the CCR end-of-period true-up for the period January 2021 through December 2021 by month.

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

A. Yes. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the FCR Clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity costs and applicable revenues for 2021?

A. Yes. Exhibit RBD-4, page 2 shows the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2021 through December 2021.

The actual total capacity payments for the period January 2021 through December 2021, as shown on line 5 of page 2, was $82,573,570. Gulf's total estimated net purchased power capacity cost for the same period was $83,699,220, as indicated on line 5 of Schedule CCE-1B the Exhibit RLH-3 filed July 27, 2021 in Docket No. 20210001-EI. The difference between the actual net capacity cost and the estimated net capacity cost for the recovery period is $1,125,649 or 1.34% less than the estimated amount. Jurisdictional capacity clause revenue for the period January 2021 through December 2021, as shown on line 8 of page 2, was $80,591,303 or

$5,036,043 lower than the estimate of $85,627,346. Jurisdictional capacity clause revenue and expense variances were less than one percent for the period.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20220001-EI

JULY 27, 2022

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as Senior Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of FPL's Fuel Cost Recovery ("FCR") Clause actual/estimated true-up amount and to present for Commission review and approval FPL's Capacity Cost Recovery ("CCR") Clause actual/estimated true-up amount for the period January 2022 through December 2022.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

A. Yes, various schedules are included in Exhibits RBD-5 and RBD-6. Exhibit RBD-5 contains the FCR Schedules. These include Schedules E3 through E9 that provide revised estimates for the period July 2022 through December 2022. FCR Schedules A1 through A9 provide actual data for the period January 2022 through June 2022. The actual data was derived from the FCR A-Schedules A1 through A9 that are filed monthly with the Commission and served on all parties, which are incorporated herein by reference. The FCR schedules contained in Exhibit RBD-5 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2022 through December 2022.

Exhibit RBD-6 contains the CCR schedules, which provide the calculation of FPL's actual/estimated true-up amount and actual/estimated variances for the period January 2022 through December 2022.

Q. What is the source of the actual data that you present by way of testimony or exhibits in this proceeding?

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

Q. Please describe the data that FPL has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR actual/estimated true-up calculation compares actual data for January 2022 through June 2022 and revised estimates for July 2022 through December 2022 to the data reflected in FPL's 2022 FCR midcourse correction approved by Order No. PSC-2021-0460-PCO-EI, issued on December 15, 2021.

The CCR actual/estimated true-up calculation compares actuals for January 2022 through June 2022 and revised estimates for July 2022 through December 2022 to the data reflected in FPL's original projection for the period January 2022 through December 2022, which was filed on September 3, 2021 and approved by Order No. PSC-2021-0442-FOF-EI, issued on November 30, 2021.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-up amounts.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve-month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the projected months is the actual rate published on the first business day in July 2022, which reflects the interest rate from the last business day in June 2022.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2022 actual/estimated true-up by month?

A. Yes. Exhibit RBD-5, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2022 through December 2022.

Q. Please explain the calculation of the FCR 2022 actual/estimated true-up amount.

A. Exhibit RBD-5, page 1 shows the calculation of the FCR actual/estimated true-up amount. The actual/estimated true-up under-recovery for the period January 2022 through December 2022, including interest, is $1,658,287,443 (Exhibit RBD-5, page 1, lines 46 plus 47, column 15).

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the midcourse correction amounts for 2022?

A. Yes. Exhibit RBD-5, page 2 provides a variance calculation that compares the 2022 actual/estimated period data by component to the same components from the 2022 midcourse correction filing.

Q. Please summarize the variance schedule on page 2 of Exhibit RBD-5.

A. FPL's midcourse correction filing projected jurisdictional total fuel costs and net power transactions to be $3.828 billion for 2022 (Exhibit RBD-5, page 2, line 47, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $5.543 billion for that period (Exhibit RBD-5, page 2, line 47, column 3). The estimated variance is due to higher than projected costs combined with higher than projected sales and revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $1.715 billion, or 44.8% higher than the midcourse correction estimates (Exhibit RBD-5, page 2, line 47, column 5), and jurisdictional fuel revenues applicable to the period, net of revenue taxes are projected to be $71.082 million, or 1.9% higher than the midcourse correction estimates (Exhibit RBD-5, page 2, line 42, column 5). The net impact due to the increase in jurisdictional fuel costs and the increase in jurisdictional fuel revenues applicable to the period result in the actual/estimated true-up under-recovery of $1.648 billion (Exhibit RBD-5, page 2, line 54, column 5).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $1.715 billion variance in jurisdictional total fuel costs.

Fuel Cost of System Net Generation - $1.896 billion increase (Exhibit RBD-5, page 2, line 2, column 5)

The table below provides the detail of this variance.

Fuel Variance	2022 Actual/Estimated	2022 Original Projections	Difference
Heavy Oil			
Total Dollar	$79	$0	$79
Units (MMBTU)	6	0	6
$ per Unit	13.8762	0.0000	13.8762
Variance Due to Consumption			$0
Variance Due to Cost			$79
Total Variance			$79
Light Oil			
Total Dollar	$20,262,731	$1,431,439	$18,831,292
Units (MMBTU)	5,666,031	102,339	5,563,692
$ per Unit	3.5762	13.9872	(10.4111)
Variance Due to Consumption			$77,820,631
Variance Due to Cost			($58,989,339)
Total Variance			$18,831,292

Fuel Variance	2022 Actual/Estimated	2022 Original Projections	Difference
Coal			
Total Dollar	$80,055,769	$78,501,495	$1,554,275
Units (MMBTU)	24,307,379	28,549,433	(4,242,055)
$ per Unit	3.2935	2.7497	0.5438
Variance Due to Consumption			($11,664,246)
Variance Due to Cost			$13,218,521
Total Variance			$1,554,275
Gas			
Total Dollar	$5,611,368,724	$3,735,913,709	$1,875,455,015
Units (MMBTU)	682,372,501	640,630,550	41,741,951
$ per Unit	8.2233	5.8316	2.3917
Variance Due to Consumption			$243,423,181
Variance Due to Cost			$1,632,031,835
Total Variance			$1,875,455,015
Nuclear			
Total Dollar	$147,569,890	$147,539,060	$30,830
Units (MMBTU)	309,874,804	305,036,436	4,838,368
$ per Unit	0.4762	0.4837	(0.0075)
Variance Due to Consumption			$2,340,207
Variance Due to Cost			($2,309,377)
Total Variance			$30,830
Total			
Total Dollar	$5,859,257,194	$3,963,385,703	$1,895,871,491
Units (MMBTU)	1,022,220,721	974,318,759	47,901,962
$ per Unit	5.7319	4.0679	1.6640
Variance Due to Consumption			$311,919,772
Variance Due to Cost			$1,583,951,719
Total Variance			$1,895,871,491

Fuel Cost of Stratified Sales - $72.8 million increase (Exhibit RBD-5, page 2, line 4, column 5)

The variance for Fuel Cost of Stratified Sales is primarily attributable to significantly higher natural gas prices.

<u>Fuel Cost of Power Sold - $50.1 million increase (Exhibit RBD-5, page 2, line 5, column 5)</u>

The variance of $50,071,583 for the Fuel Cost of Power Sold is primarily attributable to higher than projected fuel costs on Associated Interchange and Economy Power Sales. The average unit fuel cost on Associated Interchange is now projected to be $20.80/MWh higher than originally projected, resulting in a variance of nearly $16.7 million. Similarly, the average unit fuel cost on economy power sales is now projected to be $12.73/MWh higher than originally projected, resulting in a variance of roughly $33.4 million. The increase in the fuel costs of power sold for both Associated Interchange and economy power sales has been driven by increasing fuel prices, particularly natural gas.

<u>Gains from Off-System Sales - $14.9 million increase (Exhibit RBD-5, page 2, line 6, column 5)</u>

The variance for Gains from Off-System Sales is primarily attributable to higher than projected margins on economy power sales. FPL now projects that margins on economy power sales will be $5.73/MWh higher than originally projected, resulting in a cost variance of $14,317,018. In addition, FPL now projects to sell 65,063 MWh more of economy power, resulting in a volume variance of $606,801. The combination of higher margins on economy power sales and a higher volume of economy power sales results in a net variance for Gains from Off-System Sales of $14,923,819.

<u>Fuel Cost of Purchased Power - $49.5 million increase (Exhibit RBD-5, page 2, line 7, column 5)</u>

The variance of $49,488,386 for the Fuel Cost of Purchased Power is primarily attributable to higher than projected costs associated with purchases from the Central Alabama (Shell) PPA and the Solid Waste Authority ("SWA"). FPL projects that purchases from the Central Alabama (Shell) PPA will be $21.75/MWh higher than originally projected due to the increase in natural gas prices. FPL projects that purchases from SWA will be $13.55/MWh higher than originally projected due to the overall increase in FPL's system fuel costs, which serves as the basis for the energy payment.

<u>Energy Payments to Qualifying Facilities - $6.4 million increase (Exhibit RBD-5, page 2, line 8, column 5)</u>

The variance of $6,353,054 for Energy Payments to Qualifying Facilities is primarily attributable to higher than projected fuel costs from As-Available Co-Gen facilities as a result of increased system fuel costs.

<u>Energy Cost of Economy Purchases - $13.0 million increase (Exhibit RBD-5, page 2, line 9, column 5)</u>

The variance for the Energy Cost of Economy Purchases is primarily attributable to higher than projected costs for economy purchases. FPL now projects that the average cost of economy purchases will be nearly $40/MWh higher than originally projected as a result of an increase in prices in the power markets due to rising natural gas costs.

<u>Variable Power Plant O&M Avoided due to Economy Purchases - $0.101 million decrease (Exhibit RBD-5, page 2, line 15, column 5)</u>

The variance is attributable to lower than originally projected economy power purchases.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2022 actual/estimated true-up by month?

A. Yes. Exhibit RBD-6, page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2022 through December 2022.

Q. Please explain the calculation of the CCR 2022 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-6, pages 4 and 5 shows the actual/estimated capacity costs and applicable revenues (January 2022 through June 2022 reflects actual data, while the data for July 2022 through December 2022 is based on updated estimates) compared to the original projection filing for the January 2022 through December 2022 period. The CCR revenues are projected to be $5.418 million (Exhibit RBD-6, page 5, line 29, column 5) higher than FPL's original projection filing.

Jurisdictional total capacity costs are estimated to be $8.355 million higher than the original projection filing (Exhibit RBD-6, page 5, line 23, column 5). The $8.355 million under-recovery due to higher jurisdictional capacity costs and the $5.418 million increase in revenues, results in the 2022 actual/estimated true-up under-recovery amount of $2.922 million including interest (Exhibit RBD-6, page 5, lines 31 plus 32, column 5).

As shown on Exhibit RBD-6, page 3, the 2022 end-of period net true up amount to be carried forward to the 2023 CCR factors is an under-recovery of $3,225,380 (line 16, column 15). This $3,225,380 net under-recovery is comprised of the actual/estimated true-up under-recovery, including interest, of $2,922,069 for the period January 2022 through December 2022 (lines 9 plus 10, column 15) and the 2021 final net true-up under-recovery of $303,311 (line 12, column 15). The $303,311 final net true-up under-recovery consists of pre-consolidated FPL's 2021 final net true-up over-recovery of $3,634,686 and pre-consolidated Gulf's 2021 final net true-up under-recovery of $3,937,996.

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this docket?

A. Yes.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-6, page 4, line 16, column 5, total system capacity costs are estimated to be $8,337,863 or 2.7% higher than projected in FPL's original projection filing. Below are the primary reasons for the estimated $8.338 million increase in total system capacity costs.

<u>Transmission of Electricity by Others - $12.4 million increase (Exhibit RBD-6, page 4, line 4, column 5)</u>

The variance for transmission of electricity by others is primarily due to transmission costs associated with the Central Alabama (Shell) PPA. Approximately $8.75 million in projected transmission costs were inadvertently omitted from the original projections. Approximately $3.20 million of the variance is due to higher costs than originally projected for the purchase of third-party transmission utilized to facilitate wholesale power activity during the period.

<u>Transmission Revenues from Capacity Sales - $4.2 million increase (Exhibit RBD-6, page 4, line 5, column 5)</u>

Approximately $3.1 million of the total variance for transmission of revenues from capacity sales is attributable to higher revenues from capacity premiums associated with power capacity sales. Higher than originally projected transmission revenues from economy sales resulted in a variance of approximately $1.1 million. Higher revenues from capacity premiums, combined with higher transmission revenues from economy sales resulted in a total variance of $4,230,063.

<u>IIC Payments/(Receipts) (Reserve Sharing and Santee Cooper) - $1.7 million increase (Exhibit RBD-6, page 4, line 6, column 5)</u>

The variance of approximately $1.66 million for IIC Payments is primarily attributable to reserve sharing costs associated with Southern Company Pool activity, which were inadvertently omitted from the original capacity projections. These ongoing costs terminated in July 2022 when pre-consolidated Gulf assets were no longer managed by Southern Company.

<u>Incremental Plant Security Costs - O&M - $4.6 million increase (Exhibit RBD-6, page 4, line 7, column 5)</u>

The variance for incremental plant security O&M costs is primarily attributable to costs associated with the addition of automation and compliance assessments to security centers and ongoing maintenance at existing plants, which were inadvertently omitted from the 2022 original projections.

<u>Incremental Plant Security Costs – Capital - $0.470 million decrease (Exhibit RBD-6, page 4, line 8, column 5)</u>

The variance for incremental plant security capital costs is primarily attributable to the deferral into 2023 of costs associated with the replacement of security fencing at the St. Lucie Plant, due to resource limitations and supply chain issues.

<u>Incremental Nuclear NRC Compliance Costs - O&M - $0.096 million decrease (Exhibit RBD-6, page 4, line 9, column 5)</u>

The variance for incremental nuclear NRC compliance O&M costs is primarily attributable to lower Fukushima emergency preparedness costs than originally projected. Additionally, one fewer Fukushima compliance-related leased truck at Turkey Point was required.

<u>Incremental Nuclear NRC Compliance Costs – Capital - $1.7 million decrease (Exhibit RBD-6, page 4, line 10, column 5)</u>

The variance for incremental nuclear NRC compliance capital costs is primarily attributable to equipment retirements, which were not included in the original projections.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20220001-EI

JULY 27, 2022

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as Senior Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of FPL's Fuel Cost Recovery ("FCR") Clause actual/estimated true-up amount and to present for Commission review and approval FPL's Capacity Cost Recovery ("CCR") Clause actual/estimated true-up amount for the period January 2022 through December 2022.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

A. Yes, various schedules are included in Exhibits RBD-5 and RBD-6. Exhibit RBD-5 contains the FCR Schedules. These include Schedules E3 through E9 that provide revised estimates for the period July 2022 through December 2022. FCR Schedules A1 through A9 provide actual data for the period January 2022 through June 2022. The actual data was derived from the FCR A-Schedules A1 through A9 that are filed monthly with the Commission and served on all parties, which are incorporated herein by reference. The FCR schedules contained in Exhibit RBD-5 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2022 through December 2022.

Exhibit RBD-6 contains the CCR schedules, which provide the calculation of FPL's actual/estimated true-up amount and actual/estimated variances for the period January 2022 through December 2022.

Q. What is the source of the actual data that you present by way of testimony or exhibits in this proceeding?

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

Q. Please describe the data that FPL has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR actual/estimated true-up calculation compares actual data for January 2022 through June 2022 and revised estimates for July 2022 through December 2022 to the data reflected in FPL's 2022 FCR midcourse correction approved by Order No. PSC-2021-0460-PCO-EI, issued on December 15, 2021.

The CCR actual/estimated true-up calculation compares actuals for January 2022 through June 2022 and revised estimates for July 2022 through December 2022 to the data reflected in FPL's original projection for the period January 2022 through December 2022, which was filed on September 3, 2021 and approved by Order No. PSC-2021-0442-FOF-EI, issued on November 30, 2021.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-up amounts.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve-month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the projected months is the actual rate published on the first business day in July 2022, which reflects the interest rate from the last business day in June 2022.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2022 actual/estimated true-up by month?

A. Yes. Exhibit RBD-5, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2022 through December 2022.

Q. Please explain the calculation of the FCR 2022 actual/estimated true-up amount.

A. Exhibit RBD-5, page 1 shows the calculation of the FCR actual/estimated true-up amount. The actual/estimated true-up under-recovery for the period January 2022 through December 2022, including interest, is $1,658,287,443 (Exhibit RBD-5, page 1, lines 46 plus 47, column 15).

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the midcourse correction amounts for 2022?

A. Yes. Exhibit RBD-5, page 2 provides a variance calculation that compares the 2022 actual/estimated period data by component to the same components from the 2022 midcourse correction filing.

Q. Please summarize the variance schedule on page 2 of Exhibit RBD-5.

A. FPL's midcourse correction filing projected jurisdictional total fuel costs and net power transactions to be $3.828 billion for 2022 (Exhibit RBD-5, page 2, line 47, column 4). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $5.543 billion for that period (Exhibit RBD-5, page 2, line 47, column 3). The estimated variance is due to higher than projected costs combined with higher than projected sales and revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $1.715 billion, or 44.8% higher than the midcourse correction estimates (Exhibit RBD-5, page 2, line 47, column 5), and jurisdictional fuel revenues applicable to the period, net of revenue taxes are projected to be $71.082 million, or 1.9% higher than the midcourse correction estimates (Exhibit RBD-5, page 2, line 42, column 5). The net impact due to the increase in jurisdictional fuel costs and the increase in jurisdictional fuel revenues applicable to the period result in the actual/estimated true-up under-recovery of $1.648 billion (Exhibit RBD-5, page 2, line 54, column 5).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $1.715 billion variance in jurisdictional total fuel costs.

<u>Fuel Cost of System Net Generation - $1.896 billion increase (Exhibit RBD-5, page 2, line 2, column 5)</u>

The table below provides the detail of this variance.

Fuel Variance	2022 Actual/Estimated	2022 Original Projections	Difference
Heavy Oil			
Total Dollar	$79	$0	$79
Units (MMBTU)	6	0	6
$ per Unit	13.8762	0.0000	13.8762
Variance Due to Consumption			$0
Variance Due to Cost			$79
Total Variance			$79
Light Oil			
Total Dollar	$20,262,731	$1,431,439	$18,831,292
Units (MMBTU)	5,666,031	102,339	5,563,692
$ per Unit	3.5762	13.9872	(10.4111)
Variance Due to Consumption			$77,820,631
Variance Due to Cost			($58,989,339)
Total Variance			$18,831,292

Fuel Variance	2022 Actual/Estimated	2022 Original Projections	Difference
Coal			
Total Dollar	$80,055,769	$78,501,495	$1,554,275
Units (MMBTU)	24,307,379	28,549,433	(4,242,055)
$ per Unit	3.2935	2.7497	0.5438
Variance Due to Consumption			($11,664,246)
Variance Due to Cost			$13,218,521
Total Variance			$1,554,275
Gas			
Total Dollar	$5,611,368,724	$3,735,913,709	$1,875,455,015
Units (MMBTU)	682,372,501	640,630,550	41,741,951
$ per Unit	8.2233	5.8316	2.3917
Variance Due to Consumption			$243,423,181
Variance Due to Cost			$1,632,031,835
Total Variance			$1,875,455,015
Nuclear			
Total Dollar	$147,569,890	$147,539,060	$30,830
Units (MMBTU)	309,874,804	305,036,436	4,838,368
$ per Unit	0.4762	0.4837	(0.0075)
Variance Due to Consumption			$2,340,207
Variance Due to Cost			($2,309,377)
Total Variance			$30,830
Total			
Total Dollar	$5,859,257,194	$3,963,385,703	$1,895,871,491
Units (MMBTU)	1,022,220,721	974,318,759	47,901,962
$ per Unit	5.7319	4.0679	1.6640
Variance Due to Consumption			$311,919,772
Variance Due to Cost			$1,583,951,719
Total Variance			$1,895,871,491

Fuel Cost of Stratified Sales - $72.8 million increase (Exhibit RBD-5, page 2, line 4, column 5)

The variance for Fuel Cost of Stratified Sales is primarily attributable to significantly higher natural gas prices.

<u>Fuel Cost of Power Sold - $50.1 million increase (Exhibit RBD-5, page 2, line 5, column 5)</u>

The variance of $50,071,583 for the Fuel Cost of Power Sold is primarily attributable to higher than projected fuel costs on Associated Interchange and Economy Power Sales. The average unit fuel cost on Associated Interchange is now projected to be $20.80/MWh higher than originally projected, resulting in a variance of nearly $16.7 million. Similarly, the average unit fuel cost on economy power sales is now projected to be $12.73/MWh higher than originally projected, resulting in a variance of roughly $33.4 million. The increase in the fuel costs of power sold for both Associated Interchange and economy power sales has been driven by increasing fuel prices, particularly natural gas.

<u>Gains from Off-System Sales - $14.9 million increase (Exhibit RBD-5, page 2, line 6, column 5)</u>

The variance for Gains from Off-System Sales is primarily attributable to higher than projected margins on economy power sales. FPL now projects that margins on economy power sales will be $5.73/MWh higher than originally projected, resulting in a cost variance of $14,317,018. In addition, FPL now projects to sell 65,063 MWh more of economy power, resulting in a volume variance of $606,801. The combination of higher margins on economy power sales and a higher volume of economy power sales results in a net variance for Gains from Off-System Sales of $14,923,819.

Fuel Cost of Purchased Power - $49.5 million increase (Exhibit RBD-5, page 2, line 7, column 5)

The variance of $49,488,386 for the Fuel Cost of Purchased Power is primarily attributable to higher than projected costs associated with purchases from the Central Alabama (Shell) PPA and the Solid Waste Authority ("SWA"). FPL projects that purchases from the Central Alabama (Shell) PPA will be $21.75/MWh higher than originally projected due to the increase in natural gas prices. FPL projects that purchases from SWA will be $13.55/MWh higher than originally projected due to the overall increase in FPL's system fuel costs, which serves as the basis for the energy payment.

Energy Payments to Qualifying Facilities - $6.4 million increase (Exhibit RBD-5, page 2, line 8, column 5)

The variance of $6,353,054 for Energy Payments to Qualifying Facilities is primarily attributable to higher than projected fuel costs from As-Available Co-Gen facilities as a result of increased system fuel costs.

Energy Cost of Economy Purchases - $13.0 million increase (Exhibit RBD-5, page 2, line 9, column 5)

The variance for the Energy Cost of Economy Purchases is primarily attributable to higher than projected costs for economy purchases. FPL now projects that the average cost of economy purchases will be nearly $40/MWh higher than originally projected as a result of an increase in prices in the power markets due to rising natural gas costs.

<u>Variable Power Plant O&M Avoided due to Economy Purchases - $0.101 million decrease (Exhibit RBD-5, page 2, line 15, column 5)</u>

The variance is attributable to lower than originally projected economy power purchases.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2022 actual/estimated true-up by month?

A. Yes. Exhibit RBD-6, page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2022 through December 2022.

Q. Please explain the calculation of the CCR 2022 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-6, pages 4 and 5 shows the actual/estimated capacity costs and applicable revenues (January 2022 through June 2022 reflects actual data, while the data for July 2022 through December 2022 is based on updated estimates) compared to the original projection filing for the January 2022 through December 2022 period. The CCR revenues are projected to be $5.418 million (Exhibit RBD-6, page 5, line 29, column 5) higher than FPL's original projection filing.

Jurisdictional total capacity costs are estimated to be $8.355 million higher than the original projection filing (Exhibit RBD-6, page 5, line 23, column 5). The $8.355 million under-recovery due to higher jurisdictional capacity costs and the $5.418 million increase in revenues, results in the 2022 actual/estimated true-up under-recovery amount of $2.922 million including interest (Exhibit RBD-6, page 5, lines 31 plus 32, column 5).

As shown on Exhibit RBD-6, page 3, the 2022 end-of period net true up amount to be carried forward to the 2023 CCR factors is an under-recovery of $3,225,380 (line 16, column 15). This $3,225,380 net under-recovery is comprised of the actual/estimated true-up under-recovery, including interest, of $2,922,069 for the period January 2022 through December 2022 (lines 9 plus 10, column 15) and the 2021 final net true-up under-recovery of $303,311 (line 12, column 15). The $303,311 final net true-up under-recovery consists of pre-consolidated FPL's 2021 final net true-up over-recovery of $3,634,686 and pre-consolidated Gulf's 2021 final net true-up under-recovery of $3,937,996.

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this docket?

A. Yes.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-6, page 4, line 16, column 5, total system capacity costs are estimated to be $8,337,863 or 2.7% higher than projected in FPL's original projection filing. Below are the primary reasons for the estimated $8.338 million increase in total system capacity costs.

<u>Transmission of Electricity by Others - $12.4 million increase (Exhibit RBD-6, page 4, line 4, column 5)</u>

The variance for transmission of electricity by others is primarily due to transmission costs associated with the Central Alabama (Shell) PPA. Approximately $8.75 million in projected transmission costs were inadvertently omitted from the original projections. Approximately $3.20 million of the variance is due to higher costs than originally projected for the purchase of third-party transmission utilized to facilitate wholesale power activity during the period.

<u>Transmission Revenues from Capacity Sales - $4.2 million increase (Exhibit RBD-6, page 4, line 5, column 5)</u>

Approximately $3.1 million of the total variance for transmission of revenues from capacity sales is attributable to higher revenues from capacity premiums associated with power capacity sales. Higher than originally projected transmission revenues from economy sales resulted in a variance of approximately $1.1 million. Higher revenues from capacity premiums, combined with higher transmission revenues from economy sales resulted in a total variance of $4,230,063.

IIC Payments/(Receipts) (Reserve Sharing and Santee Cooper) - $1.7 million increase (Exhibit RBD-6, page 4, line 6, column 5)

The variance of approximately $1.66 million for IIC Payments is primarily attributable to reserve sharing costs associated with Southern Company Pool activity, which were inadvertently omitted from the original capacity projections. These ongoing costs terminated in July 2022 when pre-consolidated Gulf assets were no longer managed by Southern Company.

Incremental Plant Security Costs - O&M - $4.6 million increase (Exhibit RBD-6, page 4, line 7, column 5)

The variance for incremental plant security O&M costs is primarily attributable to costs associated with the addition of automation and compliance assessments to security centers and ongoing maintenance at existing plants, which were inadvertently omitted from the 2022 original projections.

Incremental Plant Security Costs – Capital - $0.470 million decrease (Exhibit RBD-6, page 4, line 8, column 5)

The variance for incremental plant security capital costs is primarily attributable to the deferral into 2023 of costs associated with the replacement of security fencing at the St. Lucie Plant, due to resource limitations and supply chain issues.

Incremental Nuclear NRC Compliance Costs - O&M - $0.096 million decrease (Exhibit RBD-6, page 4, line 9, column 5)

The variance for incremental nuclear NRC compliance O&M costs is primarily attributable to lower Fukushima emergency preparedness costs than originally projected. Additionally, one fewer Fukushima compliance-related leased truck at Turkey Point was required.

Incremental Nuclear NRC Compliance Costs – Capital - $1.7 million decrease (Exhibit RBD-6, page 4, line 10, column 5)

The variance for incremental nuclear NRC compliance capital costs is primarily attributable to equipment retirements, which were not included in the original projections.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20220001-EI

SEPTEMBER 2, 2022

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Senior Director, Clause Recovery and Wholesale Rates in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- The Fuel Cost Recovery ("FCR") factors for the period January 2023 through December 2023;
- The calculation of the jurisdictional amount of FPL's portion of the 2021 asset optimization gains to be recovered through the 2023 FCR factors;
- The Capacity Cost Recovery ("CCR") factors for the period January 2023 through December 2023; and

- Proposed cogeneration as-available energy ("COG-1") tariff sheets, which reflect updated variable operation and maintenance expense and loss factors for the consolidated Company.

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

A. Yes. They are as follows:

Exhibit RBD-7

- Schedules E1, E1-A, E1-C, E1-D, E1-E, E2, RS-1 Inverted Rate Calculation, and page 4, Asset Optimization Gains, which support the calculation of FCR factors for January 2023 through December 2023;
- Schedule E10 presents the typical 1,000 kWh residential bill comparisons;
- Schedule H1 presents the historical generating system data by fuel type;
- Pages 9 through 13, which provide the 2023 Projected Energy Losses by Rate Class; and
- Pages 165 through 168, which provide updated COG-1 tariff sheets

Exhibit RBD-8

- Pages 1 through 4 provide the calculation of 2023 CCR factors;
- Pages 5 through 9 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments;
- Page 10 provides the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction;

- Page 11 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 12 provides the calculation of amortization and return on the regulatory asset related to the Indiantown Transaction;
- Page 13 provides the calculation of the amortization and return on the COVID-19 regulatory asset;
- Page 14 provides the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investments included for recovery through the CCR Clause for the period January 2023 through December 2023; and
- Pages 17 through 30 provide the calculations of stratified separation factors

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2023 FCR factors shown on Schedule E1?

A. The 2023 FCR factors include the following adjustments: (1) a consolidated 2021 final true-up, which reflects the sum of the 2021 final true-ups for both pre-consolidated FPL and pre-consolidated Gulf Power Company ("Gulf"), (2) a consolidated 2021 Generating Performance Incentive Factor ("GPIF"), which reflects the sum of pre-consolidated FPL and Gulf GPIF results, (3) the jurisdictional amount associated with FPL's share of the 2021 asset optimization gains and (4) the cost associated with the projected 2023 Subscription Credit for the FPL SolarTogether Program.

The consolidated final true-up amount to be included in the 2023 FCR factors is a \$10,256,384 over-recovery. The \$10,256,384 over-recovery, divided by the projected retail sales of 124,024,865 MWh for January 2023 through December 2023, results in an offset of 0.0083 cents per kWh.

The testimony of witness Charles R. Rote, filed on March 16, 2022, presents a GPIF reward of \$8,151,853 for pre-consolidated FPL and a penalty of \$1,157,234 for Gulf for the period ending December 2021. The total of these amounts, which represents a net reward of \$6,994,619, is reflected on line 37 of Schedule E1. This \$6,994,619 reward, divided by the projected retail sales of 124,024,865 MWh for January 2023 through December 2023, results in a charge of 0.0056 cents per kWh.

FPL is including \$13,178,912 for the jurisdictional amount associated with its share of 2021 asset optimization gains in the calculation of its 2023 FCR factors, as shown on line 39 of Schedule E1. As presented and explained in the direct testimony and exhibits of witness Yupp filed on April 1, 2022 in this docket, FPL's activities under the asset optimization program in 2021 delivered \$63,092,506 in total gains. Of these total gains, FPL is allowed to retain \$13,855,504 (system amount) per Order No. PSC-13-0023-S-EI dated January 14, 2013 and Order No. PSC-16-0560-AS-EI dated December 15, 2016. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount of $13,178,912, in each month's Schedule A2 for the period January 2023 through December 2023 as a reduction to jurisdictional fuel revenues applicable to each period. The calculation of the jurisdictional amount of the 2021 asset optimization gains is shown on page 4 of RBD-7. This $13,178,912, divided by the projected retail sales of 124,024,865 MWh for January 2023 through December 2023, results in a charge of 0.0106 cents per kWh.

FPL has included $143,020,130 associated with the projected 2023 Subscription Credit for the FPL SolarTogether Program, as shown on line 40 of Schedule E1. The Subscription Credit is based on the program's solar power plants' forecasted generation and the Subscription Credit rate as reflected in the SolarTogether tariff. This $143,020,130, divided by the projected retail sales of 124,024,865 MWh for January 2023 through December 2023, results in a charge of 0.1153 cents per kWh.

Schedule E2 provides the monthly FCR factors as well as the levelized FCR factor for 2023. Schedule E-1E provides the calculation of the 2023 FCR factors by rate group for each period.

Q. Please explain the fuel cost of the stratified sales amount reflected on line 2 of Schedule E1.

A. FPL has included a projected credit of $100,205,117 associated with stratified wholesale power sales contracts in effect in 2023. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel cost of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation. This adjustment was performed in the same manner that off-system sales are removed from the calculation, consistent with Order No. PSC-97-0262-FOF-EI.

CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested CCR costs for the projected period January 2023 through December 2023?

A. Yes. Pages 1 and 2 of Exhibit RBD-8 provide this summary. Total recoverable capacity costs for the period January 2023 through December 2023 are \$248,581,801 (page 2, line 33). This includes \$245,356,422 of 2023 projected jurisdictional capacity costs (page 2, line 28) and the net true-up under-recovery for 2021 and 2022 of \$3,225,379 (page 2, line 31 plus line 32).

Q. What adjustments are included in the calculation of the combined 2023 CCR factors included in Exhibit RBD-8?

A. The total net true-up to be included in the 2023 CCR factors is an over-recovery of \$3,225,379, as shown on page 2, line 31 plus line 32. This over-recovery is comprised of: (1) 2021 pre-consolidated FPL final net true-up over-recovery of \$3,634,686; (2) 2021 Gulf final net true-up under-recovery of \$3,937,996, which were filed on April 1, 2022; and (3) the consolidated FPL 2022 actual/estimated true-up under-recovery of \$2,992,069 filed on July 27, 2022.

Q. Please describe the Weighted Average Cost of Capital ("WACC") that is used in the calculation of the return on the 2023 capital investments included for recovery.

A. FPL calculated and applied a projected 2023 WACC consistent with the methodology established in Commission Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU, issued on May 20, 2022. The WACC was calculated using a 10.6% return on equity. This projected WACC is used to calculate the rate of return applied to the 2023 CCR capital investments. The projected capital structure, components and cost rates used to calculate the rate of return are provided on page 14 of Exhibit RBD-8.

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 3 of Exhibit RBD-8 provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. What are the effective dates that FPL is requesting for the new FCR and CCR factors for 2023?

A. FPL is requesting that FCR factors and CCR factors for the period January 2023 through December 2023 become effective starting with meter readings made on January 1, 2023. These factors should remain in effect until modified by this Commission.

PROPOSED 2023 RESIDENTIAL BILL

Q. What is FPL's proposed residential 1,000 kWh bill for the period January 2023 through December 2023?

A. The proposed residential 1,000 kWh bill for January through December 2023 for customers in the FPL's peninsular service area is $130.23. This proposed bill includes a base charge of $80.73, an FCR charge of $37.45, a CCR charge of $2.12, an environmental cost recovery charge of $3.12, a conservation cost recovery charge of $1.22, a storm protection plan cost recovery charge of $3.82, the transition rider credit of $1.58 and the gross receipts tax and regulatory assessment fee of $3.35. FPL's proposed 2023 residential 1,000 kWh bill is provided on Schedule E-10, which is page 161 of Exhibit RBD-7.

The proposed residential 1,000 kWh bill for January through December 2023 for customers in the NW Florida service area is $160.43. This proposed bill includes the same base charge, FCR charge, CCR charge, environmental cost recovery charge, conservation cost recovery charge and a storm protection plan cost recovery charge as customers in peninsular Florida. The bill for customers in NW Florida will reflect a storm restoration charge of $11.00, the transition rider surcharge of $16.85, and the gross receipts tax and regulatory assessment fee of $4.12. FPL's proposed 2023 residential 1,000 kWh bill for customers in the NW Florida service area is provided on Schedule E-10, which is page 162 of Exhibit RBD-7.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Curtis D. Young was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20220001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2021 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis Young, 1635 Meathe Road, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period January 2021 through December 2021.

Q. Have you included any exhibits to support your testimony?

A. Yes. Exhibit________ (CDY-1) consists of Schedules A, E1-B and C-1 for the Consolidated Electric Division. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period January 2021 through December 2021?

A. For the Consolidated Electric Division the final remaining true-up amount is an under recovery of $6,047,784.

Q. How was this amount calculated?

A. It is the difference between the actual end of period true-up amount for the January through December 2021 period and the total true-up amount to be collected or refunded during the January - December 2022 period.

Q. What was the actual end of period true-up amount for January - December 2021?

A. For the Consolidated Electric Division it was $3,790,314 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2022 period?

A. A consolidated over-recovery of $2,257,470 to be refunded.

Q. Were there any adjustments included in the Company's fuel true-up balance during 2021?

A. Yes. In response to related Orders approved by the Commission, the Company was allowed to apply amounts derived from settlement agreements to reduce its existing fuel and purchased power cost recovery balance and further reduce its fuel cost recovery factors in subsequent years. Order No. PSC-2019-0010-AS-EI in Docket No. 20180048-EI granted the Company permission to apply some of the income tax benefits associated with the Tax Cuts and Jobs Act of 2017 towards reducing its fuel and purchased power cost recovery balance. The amount applied during 2021 totaled $112,605.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Direct Testimony of Curtis D. Young (Estimated/Actual)

On Behalf of Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Curtis D. Young. My business address is 1635 Meathe Drive, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company")

Q. Describe briefly your education and relevant professional background.

A. I have a Bachelor of Business Administration Degree in Accounting from Pace University in New York City, New York. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. Have you previously testified in this Docket?

A. Yes, I have.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the Company's computations made in preparation

of the schedules being submitted in this docket.

Q. Which of the Staff's schedules is the Company providing in support of this filing?

A. I am attaching Schedules E1-A, E1-B, and E1-B1 as part of Exhibit CDY-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2022 – December 2022 based on 6 Months Actual and 6 Months Estimated data.

Q. Were these schedules completed by you or under your direct supervision?

A. The schedules were completed by me.

Q. What was the final remaining true-up amount for the period January 2021 – December 2021?

A. The final remaining true-up amount was an under-recovery of $6,047,784.

Q. What is the estimated true-up amount for the period January 2022 – December 2022?

A. The estimated true-up amount is an under-recovery of $15,143,447.

Q. What is the total true-up amount estimated to be collected, or refunded for the period January 2023 – December 2023?

A. At the end of December 2022, based on six months actual and six months estimated, the Company estimates it will under-recover $21,191,231 in purchased power costs, which will be refunded from January 2023 – December 2023.

Q. **In previous years FPUC explored other opportunities to provide power supply for its customers. Has FPUC continued to explore other opportunities?**

A. Yes. FPUC is continuing to look into other sources of power supply that will

provide low cost, resilient and reliable energy to its customers.

Q. **Would you please discuss the opportunities FPUC has been investigating?**

A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined Heat and Power (CHP) technologies with the goal of providing low cost, resilient and reliable energy to customers. Solar opportunities are being explored in both the Northeast and Northwest Divisions and are under consideration at this time. In our Northeast Division, significant effort has been focused on the development of a second CHP on Amelia Island. This project will be similar in size and operation to the existing Eight Flags Energy project that began commercial operation in 2016. Amelia Island Energy (AIE), as it will be named, will be located approximately one mile from Eight Flags Energy at a separate mill on Amelia Island. This CHP will provide electrical energy to the FPUC grid and thermal energy in the form of steam/hot water to the mill. Preliminary engineering has been completed, operating agreements and air permitting has been completed at this time. AIE will provide low cost energy to our customers while improving the resiliency and reliability to the FPUC grid on Amelia Island.

Q. **Has the Company incurred any costs during the preliminary stages of this project?**

A. Yes, the Company has engaged the consulting firms of Pierpont and McLelland LLC and Sterling Energy Services LLC and well as the law firm of Gunster, Yoakley and Stewart PA for their experienced expertise in the aforementioned processes. The Company incurred approximately $127,000 in the consulting and legal fees linked to this project in 2021 and another $105,000 to date in 2022. We roughly estimate to

spend another $116,000 by year-end.

Q. When do you anticipate construction to begin on the AIE facility?

A. It is anticipated that decisions can be finalized on these items later in 2022 with major items ordered in early 2023. Commercial operation should occur within 1.5 years of ordering the major equipment.

Q. Has the Company made any adjustments to its 2022 True-up computations?

A. Yes, pursuant to Order No PSC-2021-0266-S-PU in Docket No. 20200195-PU and beginning January 2022, the Company has been adjusting its monthly fuel true-up calculation by the amortized amount of Covid-19 regulatory asset. The amount of the adjustment is approximately $107,839 each month.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Direct Testimony of Curtis D. Young (Estimated/Actual)

On Behalf of Florida Public Utilities Company

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Q. What was the final remaining true-up amount for the period January 2021 – December 2021?

A. The final remaining true-up amount was an under-recovery of $6,047,784.

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A. The estimated true-up amount is an under-recovery of $15,143,447.

Q. What is the total true-up amount estimated to be collected, or refunded for the period January 2023 – December 2023?

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Q. **In previous years FPUC explored other opportunities to provide power supply for its customers. Has FPUC continued to explore other opportunities?**

A. Yes. FPUC is continuing to look into other sources of power supply that will

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Q. **Would you please discuss the opportunities FPUC has been investigating?**

A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined Heat and Power (CHP) technologies with the goal of providing low cost, resilient and reliable energy to customers. Solar opportunities are being explored in both the Northeast and Northwest Divisions and are under consideration at this time. In our Northeast Division, significant effort has been focused on the development of a second CHP on Amelia Island. This project will be similar in size and operation to the existing Eight Flags Energy project that began commercial operation in 2016. Amelia Island Energy (AIE), as it will be named, will be located approximately one mile from Eight Flags Energy at a separate mill on Amelia Island. This CHP will provide electrical energy to the FPUC grid and thermal energy in the form of steam/hot water to the mill. Preliminary engineering has been completed, operating agreements and air permitting has been completed at this time. AIE will provide low cost energy to our customers while improving the resiliency and reliability to the FPUC grid on Amelia Island.

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A. Yes, the Company has engaged the consulting firms of Pierpont and McLelland LLC and Sterling Energy Services LLC and well as the law firm of Gunster, Yoakley and Stewart PA for their experienced expertise in the aforementioned processes. The Company incurred approximately $127,000 in the consulting and legal fees linked to this project in 2021 and another $105,000 to date in 2022. We roughly estimate to

spend another $116,000 by year-end.

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A. Yes, pursuant to Order No PSC-2021-0266-S-PU in Docket No. 20200195-PU and beginning January 2022, the Company has been adjusting its monthly fuel true-up calculation by the amortized amount of Covid-19 regulatory asset. The amount of the adjustment is approximately $107,839 each month.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Amended Direct Testimony of Curtis D. Young (Estimated/Actual)

On Behalf of Florida Public Utilities Company

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provide low cost, resilient and reliable energy to its customers.

Q. **Would you please discuss the opportunities FPUC has been investigating?**

A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined Heat and Power (CHP) technologies with the goal of providing low cost, resilient and reliable energy to customers. Solar opportunities are being explored in both the Northeast and Northwest Divisions and are under consideration at this time. In our Northeast Division, significant effort has been focused on the development of a second CHP on Amelia Island. This project will be similar in size and operation to the existing Eight Flags Energy project that began commercial operation in 2016. Amelia Island Energy (AIE), as it will be named, will be located approximately one mile from Eight Flags Energy at a separate mill on Amelia Island. This CHP will provide electrical energy to the FPUC grid and thermal energy in the form of steam/hot water to the mill. Preliminary engineering has been completed, operating agreements and air permitting has been completed at this time. AIE will provide low cost energy to our customers while improving the resiliency and reliability to the FPUC grid on Amelia Island.

Q. Has the Company incurred any costs during the preliminary stages of this project?

A. Yes, the Company has engaged the consulting firms of Pierpont and McLelland LLC and Sterling Energy Services LLC and well as the law firm of Gunster, Yoakley and Stewart PA for their experienced expertise in the aforementioned processes. The Company incurred approximately $127,000 in the consulting and legal fees linked to this project in 2021 and another $105,000 to date in 2022. We roughly estimate to

spend another $116,000 by year-end.

Q. When do you anticipate construction to begin on the AIE facility?

A. It is anticipated that decisions can be finalized on these items later in 2022 with major items ordered in early 2023. Commercial operation should occur within 1.5 years of ordering the major equipment.

Q. Has the Company made any adjustments to its 2022 True-up computations?

A. Yes, pursuant to Order No PSC-2021-0266-S-PU in Docket No. 20200195-PU and beginning January 2022, the Company has been adjusting its monthly fuel true-up calculation by the amortized amount of Covid-19 regulatory asset. The amount of the adjustment is approximately **$56,422** each month.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Amended Direct Testimony (Estimated/Actual) of Curtis Young, has been furnished by Electronic Mail to the following parties of record this 5th day of August, 2022:

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By: Beth Keating

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(Whereupon, prefiled direct testimony of Michelle D. Napier was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2023 Projection Testimony of Michelle D. Napier

On Behalf of

Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Michelle D. Napier. My business address is 1635 Meathe Drive, West Palm Beach, FL 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as Director, Regulatory Affairs.

Q. Could you give a brief description of your background and business experience?

A. I received a Bachelor of Science degree in Finance from the University of South Florida. I have been employed with FPUC since 1987. Over the course of my employment at FPUC, I have performed various roles and functions in accounting, including General Accounting Manager, before moving to the regulatory department in 2011. As previously stated, I am currently the Director, Regulatory Affairs and in this role, my responsibilities include directing the regulatory activities for all regulated distribution companies of Chesapeake Utilities Corporation. This includes regulatory analysis and filings before the Florida Public Service Commission ("FPSC" or "Commission") for FPUC, FPUC-Indiantown, FPUC-Fort Meade, Florida Division of Chesapeake Utilities d/b/a ("CFG"), Peninsula Pipeline Company, as well as Delaware and Maryland Public Service Commissions.

Q. Have you previously testified in this Docket?

A. No, I have not but I have previously provided written, pre-filed testimony in a variety of the Company's annual proceedings, including Dockets for the Purchased Gas Adjustment, Docket No. 20170003-GU; the Gas Reliability Infrastructure Program (GRIP) Cost Recovery Factors for FPUC and our sister company, CFG, Docket No. 20120036-GU; and the Swing Service Cost Recovery for FPUC and CFG, Docket No. 20170191-GU; the Limited Proceeding for Hurricane Michael, Docket No. 20190156; the Storm Protection Cost Recovery, Docket No. 20220010, as well as the Rate Proceeding, Docket No. 20220067.

Q. What is the purpose of your testimony at this time?

A. My testimony will establish the "true-up" collection amount, based on actual January 2022 through June 2022 data and projected July 2022 through December 2023 data to be collected or refunded during January 2023 – December 2023. My testimony will also summarize the computations that are contained in composite exhibit MDN-1 supporting the January through December 2023 projected levelized fuel adjustment factors for its consolidated electric divisions. Additionally, these factors include costs incurred as a result of the COVID-19 pandemic and deemed recoverable in terms of the settlement approved by Order No. PC-2021-0266-S-PU, as amended, issued in Docket No. 20200194-PU. Finally, my testimony will propose that the Company be allowed to collect its 2022 true-up amount over a three-year period in order to mitigate the rate impacts to its customers.

Q. Were the schedules filed by the Company completed by you or under your direct supervision?

A. Yes, they were completed under my direction.

Q. Is FPUC providing the required schedules with this filing?

A. Yes. Included with this filing are the Consolidated Electric Schedules E1, E1A, E2, E7, E8, and E10. These schedules are included in my Exhibit MDN-1, which is appended to my testimony.

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up and projected amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel and purchased power clause. FPUC engaged Sterling Energy Services, LLC. ("Sterling") Christensen Associates Energy, LLC ("Christensen"), and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their purchased power rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2023 Projection factors, were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Mr. Cutshaw addresses these project assignments more specifically in his testimony.

Q. Please explain how these costs were determined to be recoverable under the fuel and purchased power clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the other fuel related costs included in the fuel clause are directly related to purchased power, have not been recovered through base rates.

Specifically, consistent with item 10 of Order 14546, the costs the Company has included are fuel-related costs that were not anticipated or included in the cost levels used to establish the current base rates. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of purchased power costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel and purchased power clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in more recent Dockets Nos.20170001-EI, 20180001-EI, 20190001-EI, 20200001-EI, 20210001-EI and 20220001-EI, the Commission determined that many of the costs associated with the legal and consulting work incurred by the Company as fuel related, particularly those costs related to the purchase power agreement review and analysis, were recoverable under the fuel clause. As the Commission has recognized time and again, the Company simply does not have the internal resources to pursue projects and initiatives designed to produce purchased power savings without engaging outside assistance for project analytics and due diligence, as well as negotiation and contract development expertise. Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. **Earlier in your testimony, you spoke of proposing that the Company be allowed to collect its 2022 total true-up over a three-year period. Could you elaborate further on that?**

A. The Company presently acknowledges that its 2022 true-up balance will substantially impact its customers' bills. Recent events, such as our nation's recovery from the pandemic and Russia's war against the Ukraine, have driven up natural gas prices by substantial measures. Given that natural gas is a key raw material for electric generation, it follows that FPUC's cost of purchased power would increase accordingly. FPUC's electric customers are already experiencing the bill impacts derived from the midcourse fuel rates that were effective as of August 1. Based on these events, FPUC is requesting approval to collect its 2022 under-recovery balance, $21,191,231 over the next three years and thereby include approximately $7,063,744 of that amount in its 2023 electric fuel rate calculations.

Q **Why does the Company propose collecting this under-recovery over three years versus one year?**

A. The Company is concerned that this under-recovery was driven by the increase in natural gas prices as a result of unusual circumstances rather than simply inflationary or normal expense increases. As a result of this unusual natural gas price spike, the Company feels that customers should be allowed to pay this over three years rather than one year. Customers will see lower monthly bills and will be allowed to pay this over a three-year period.

Q. **If recovered over one year, what would a residential customer using 1,000 KWH pay for the period January - December 2023 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier?**

A. A residential customer using 1,000 KWH will pay **$195.69**. This is an increase of **$52.89** above the previous period.

Q. **Is there any other related change to the fuel projections as a result of the proposed three-year amortization of the fuel under-recovery?**

A Yes, The Company proposes, pending Commission approval, to apply the parent Company's projected short-term cost rate to the under recovered balance of fuel costs, rather than the prescribed non-financial commercial paper rates.

Q **Why is it appropriate to use the weighted average cost of short-term debt rather than the prescribed method.**

A Short-term interest rates have increased dramatically, and the current non-financial commercial paper rates do not allow the Company to recover its actual cost of debt on the outstanding under recovery fuel cost balance. The Company should not be overburdened or penalized by recovering the under-recovery balance over three years without the ability to collect its actual cost of debt on that outstanding balance.

Q. **How does the Company intend to apply the use of short-term cost rates in its current and future filings?**

A. The Company is presently calculating its 2023 Projection factors utilizing the traditional non-financial commercial paper interest rates. However, the Company is requesting to be allowed to submit the calculation of its monthly and annual true-up and interest filings utilizing its short-term debt cost factor as an alternative towards mitigating the inherent burden of collecting its under-recovery over the extended period. The scheduling of this option would take place over the same three-year collection period of the outstanding true-up balance. If ever during that period the non-financial commercial paper rate surpasses the Company's short-term debt cost rate, the Company would then revert back to the traditional methodology for calculating the interest.

Q. In addition to the fuel-related endeavors mentioned above, has the Company included any other costs in your projected amounts?

A. Yes, the Company has also included costs related to the settlement agreement regarding COVID-19 regulatory asset in Docket No. 20200194 and approved in Order No. PSC-2021-0266-S-PU.

The settlement agreement, which was approved by the Commission on July 8, 2021, allows Florida Public Utilities Company to recover $2,085,759 of pandemic–related incremental expenses. Beginning with the factors established for the calendar year 2022, FPUC was allowed to amortize over two years and recover the allocated regulatory asset of approximately $1,354,120 for the electric division, through the Fuel and Purchased Power Cost Recovery Clause mechanism. The annualized amount, $677,060, is included among the Company's 2023 projected costs.

Q. What are the final remaining true-up amounts for the period January – December 2021?

A. The final remaining consolidated true-up amount was an under-recovery of $6,047,784.

Q. What are the estimated true-up amounts for the period of January – December 2022?

A. There is an estimated consolidated under-recovery of $15,143,447.

Q. Please address the calculation of the total true-up amount to be collected during the January - December 2023 year?

A. The Company has determined that at the end of December 2022, based on six months actual and six months estimated, we will have a consolidated electric under-recovery of $21,191,231.

Q. What will the total consolidated fuel adjustment factor, excluding demand cost recovery, be for the consolidated electric division for the period?

A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is **8.976¢** per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2023 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on consolidated Schedule E-10 in Composite Exhibit Number CDY-3, a residential customer using 1,000 KWH will pay **$172.89**. This is an increase of **$30.09** above the previous period.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of P. Mark Cutshaw was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 20220001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2023 Projection Testimony of P. Mark Cutshaw
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw, 208 Wildlight Avenue, Yulee, Florida 32097.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. Could you give a brief description of your background and business experience?

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering. My electrical engineering career began with Mississippi Power Company in June 1982. I spent nine years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the

Commission as well as other regulatory issues. During January 2020, I moved into my current role as Director, Generation Development.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case, addressed in Docket No. 20140025-EI, rebuttal testimony in Docket No. 20180061-EI and numerous dockets for Fuel and Purchased Power Cost Recovery. Most recently, I provided testimony in Docket No. 20190156-EI, in the Limited Proceeding to recover storm cost caused by Hurricane Michael and in Docket Nos. 20220049 and 20220010, in the Storm Protection Plan and Cost Recovery.

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

A. My direct testimony addresses several aspects of the purchased power cost for our FPUC electric customers. This includes activities to investigate the potential for reduced purchase power costs, execution/amendment of purchased power agreements with Gulf Power Company ("Gulf")/Florida Power & Light ("FPL"), Combined Heat and Power ("CHP") generation supply located on Amelia Island and investigation into the opportunities of energy provided from solar and battery installations.

Q. Given the current natural gas market and uncertainty with future projections, will this have an impact on future purchased power cost projections?

A. Yes. Currently, all generation resources used by FPUC utilize natural gas as the fuel source for the generation of electricity which ties purchased power costs directly to the costs of natural gas. As natural gas prices continue to fluctuate, so will the purchased power prices include in the FPUC cost projections.

Q. What actions has FPUC taken to provide accurate cost projections given the uncertainty in the natural gas markets?

A. FPUC, being predominately a natural gas utility, has utilized information from both inside the company and other external sources to carefully investigate the future of the natural gas markets as well as other energy sources that may provide future benefits. It is apparent that many outside factors could quickly change current market projects, however, estimated natural gas costs were determined and utilized to determine purchased power costs for 2023.

Q. What other energy sources are being investigated and what are some of the benefits anticipated?

A. FPUC has been investigating and testing the use of Renewable Natural Gas (RNG) and Hydrogen as future fuel sources for generation assets. The markets for both RNG and Hydrogen are still developing, however, both have the potential to provide environmental benefits compared to existing fuel sources. Although there are currently some operational and cost challenges being addressed, it is critical that FPUC continue to be involved in the development and testing of these resources.

Q. What new opportunities has the Company implemented with the intent of achieving energy resiliency and reducing costs for its customers in its consolidated electric divisions?

A. The Company regularly pursues opportunities to achieve energy resiliency and reduced purchased power costs for the benefit of our customers. During 2018, FPUC began by executing a transmission interconnection agreement and a new purchased power agreement with Florida Power & Light (FPL) for our Northeast Florida Division. During 2019, a purchased power agreement with Gulf/FPL for our Northwest Florida Division was executed along with an amendment of the existing FPL purchased power agreement for our Northeast Florida Division.

Q. What is the status of the existing purchase power agreements in place with FPL?

A. The existing agreement for our Northwest Florida Division with FPL became effective January 1, 2020 and will continue in effect through December 31, 2026 unless extended by FPUC. The existing agreement for our Northeast Florida Division with FPL which became effective January 1, 2018 was amended in 2019 to continue in effect through the December 31, 2026 unless extended by FPUC.

Q. Are there other efforts underway to identify projects that will lead to lower cost energy for FPUC customers?

A. Yes. FPUC continues to work with consultants, as well as project developers, to identify new projects and opportunities that can lead to increased energy resiliency and reduced fuel costs for our customers. We also continue to analyze the feasibility of energy production and supply opportunities that have been on our planning horizon for some time and noted in prior fuel clause proceedings, namely additional Combined Heat and Power (CHP) projects, potential Solar Photovoltaic ("PV") projects and associated utility scale battery projects.

More specifically, Pierpont & McLelland has been engaged to perform analysis and provide consulting services for FPUC as it relates to the structuring of, and operation under, the Company's power purchase agreements with the purpose of identifying measures that will minimize cost increases and/or provide opportunities for cost reductions. They have also been involved in the structuring of the most effective measures to ensure a reliable and resilient system on Amelia Island which may include additional transmission lines to the Island and using existing generation and the addition of natural gas fired generation. Locke Lord is a law firm with particular expertise in the regulatory requirements of the Federal Energy Regulatory Commission. Attorneys with the firm have provided legal guidance and oversight regarding the contracts and regulatory requirements for generation and transmission-related issues for the Northeast Florida Division. The Company's in-house experience in these areas is limited; thus, without this outside assistance, the Company's ability to pursue potential purchased power savings opportunities would be limited, as would its ability to properly evaluate proposals to meet our generation and transmission needs and ensure compliance with federal regulatory requirements. Sterling Energy and Christensen Associates have been involved to assist the Company in the most cost-effective means of incorporating additional energy sources, such as power available from certain industrial customers, existing and new Combined Heat and Power ("CHP") capability and improvements in the transmission system to Amelia Island to improve the reliability/resiliency on Amelia Island and further reduce the overall purchased power impact to all FPUC customers.

Q. Can you provide additional information on these CHP projects?

A. Yes. The success of the Eight Flags project has sparked interest in other CHP opportunities on Amelia Island. When coupled with industrial expansion in the area and the ability to do so within the context of the "Agreement" and "Amendment" with FPL, the already quantifiable benefits of the existing project has piqued the interest of others to contemplate partnering with a new CHP-based project on Amelia Island. Given that FPUC would again be the recipient of any power generated by such project, FPUC has been actively involved in the initial analysis, development and engineering of a possible new project located on Amelia Island. Significant efforts have continued to evaluate this CHP which, similar to Eight Flags, will be located on Amelia Island and would allow FPUC, along with transmission line upgrades, to provide additional reliability and resilience to its electricity supply for its customers on Amelia Island. This second CHP would provide competitively priced electricity for FPUC's customers while providing high pressure steam and hot water to a local industrial customer which is a critical component of the local community. Preliminary engineering, financial modeling, operating agreements and Florida Department of Environmental Protection permitting have been completed for this possible CHP unit. Although the final structure of the proposed CHP has not yet been finalized, when finalized FPUC anticipates purchased power agreements would be filed with the FPSC. Based upon approval of the purchased power agreements by the FPSC, construction would begin immediately on that project.

Q. Can you provide additional information on the PV and battery projects you referenced above?

A. Yes. FPUC is continuing analysis related to smaller PV systems within the FPUC electric service territory. Based on the results from the analysis, the economic feasibility of smaller PV installations has been difficult to achieve due to many different factors but work continues to investigate alternatives to improve the feasibility. At this time, FPUC is investigating opportunities involving larger PV installations which have proved to be more economically feasible. Not only will this increase the renewable energy available to FPUC, the cost is expected to complement the overall purchased power portfolio which will provide additional benefits to FPUC customers. The "Agreement" and the "Amendment" have provisions that allow for the development of PV installations by FPUC and provides for the possibility of a partnership between the parties that would allow for the development of a PV project.

Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. These projects have been difficult to justify economically at this point but are still under consideration by

FPUC. Nonetheless, the potential benefits of the PV and battery projects under consideration will be continued.

Q. Does this include your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of M. Ashley Sizemore was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

2021 FINAL TRUE-UP
TESTIMONY AND EXHIBITS

M. ASHLEY SIZEMORE

FILED: APRIL 1, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Political Science and a Master of Business Administration from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs Department working on environmental and fuel and capacity cost recovery clauses. During the last three years as a Program Manager in Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have over ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel clause and purchased power, capacity, and environmental cost recovery clauses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2021 through December 2021 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") and the Capacity Cost Recovery Clause ("Capacity Clause"), as well as the Optimization Mechanism gain sharing allocation for the period.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No. MAS-1, consisting of five documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2021 through December 2021?

A. The final true-up amount for the Capacity Clause for the period January 2021 through December 2021 is a recovery of $0.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric

Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2021 Through December 2021", provides the calculation for the final true-up of $0. The actual capacity cost under-recovery, including interest, was $39,496 for the period January 2021 through December 2021 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $25,180 actual/estimated under-recovery approved in Order No. PSC-2021-0442-FOF-EI issued on November 30, 2021, results in a final under-recovery of $14,316. Tampa Electric included the actual under-recovery of $39,496, to be recovered during the period of April 2022 through December 2022 in the company’s Mid-Course Projection filed on January 19, 2022 and approved in Order No. PSC-2022-0122-PCO-EI issued March 18, 2022 in Docket No. 20220001-EI. This results in a final net recovery of $0 for the period, as identified in Document No. 1, page 4 of 4.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2021 through December 2021?

A. The final Fuel Clause true-up for the period January 2021 through December 2021 is a recovery of $0. The actual fuel cost under-recovery, including interest, was $72,171,466 for the period January 2021 through December 2021. This $72,171,466 amount, less the $72,171,466 under-recovery included in the company's Mid-Course Projection approved in Order No. PSC-2022-0122-PCO-EI issued March 18, 2022 in Docket No. 20220001-EI, results in a net recovery amount for the period of $0.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2021 Through December 2021." It shows the calculation of the final fuel net recovery of $0.

Line 1 shows the total company fuel costs of $754,096,615 for the period January 2021 through December 2021. The jurisdictional amount of total fuel costs is $754,096,615, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $116,436,212 under-recovered fuel costs for the period, adjustments, interest, true-up collected, and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual under-recovery amount of $72,171,466 shown on line 9. The $72,171,466 actual under-recovery amount less the $72,171,466 under-recovery included in the company's Mid-Course Projection recovery amount to be recovered through the period April 2022 through December 2022 and as filed on January 19, 2022, shown on line 10, results in a final net recovery amount of $0 for the period January 2021 through December 2021, as shown on line 11.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 is entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Mid-course Estimates for the Period January 2021 Through December 2021." It shows the calculation of the actual under-recovery compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2021 through December 2021?

A. As shown on line A6 of Document No. 3, the fuel and net power transaction cost is $76,942,490 more than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2021 through December 2021?

A. As shown on line C3 of Document No. 3, the company collected $5,068,888, or 0.8 percent greater jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of transactions for each of Commission Schedules A6, A7, A8, A9, as well as capacity information on Schedule A12.

Optimization Mechanism

Q. Was Tampa Electric's sharing of Optimization Mechanism gains allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI, issued in Docket Nos. 20170210-EI and 20160160-EI, on November 27, 2017?

A. Yes. As shown in the testimony and exhibit of Tampa Electric witness John C. Heisey filed contemporaneously in this docket, the sharing of Optimization Mechanism gains was allocated in accordance with FPSC Order No.

PSC-2017-0456-S-EI. Total gains were $13,439,732. Under the sharing mechanism, Tampa Electric customers receive $8,619,866, and the company earned an incentive of $4,819,866 as a result of the company’s Optimization Mechanism activities during 2021. Customers received the gains from these transactions during 2021, and Tampa Electric requests Commission approval to collect the company’s $4,819,866 incentive in its 2023 fuel factors.

Q. Does this conclude your testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP
JANUARY 2022 THROUGH DECEMBER 2022

TESTIMONY AND EXHIBIT
OF
M. ASHLEY SIZEMORE

FILED: JULY 27, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates, in the Regulatory Affairs department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Political Science and a Master of Business Administration degree from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs Department working on environmental, fuel and capacity cost recovery clauses. During the last three years as a Program Manager in

Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have over ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel and purchased power, capacity, and environmental cost recovery clauses.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2022 through December 2022 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2023 through December 2023 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2022, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2023 fuel and purchased power and capacity cost recovery factors.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, I have prepared Exhibit No. MAS-2, which consists of two documents. Document No. 1 includes schedules E1-A, E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2022 through December 2022. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2022 through December 2022.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2023 through December 2023 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period of January 2022 through December 2022 is an under-recovery of $411,964,625.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2023 through December 2023 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2023 does not include the final true-up amount for the period January 2021 through December 2021 as this amount was returned to customers during 2022 in Tampa Electric’s fuel mid-course factors effective April 2022 through December 2022, as approved in Order No. PSC-2022-0122-PCO-EI, issued March 18, 2022, in Docket No. 20220001-EI. The actual/estimated true-up amount for the period January 2022 through December 2022 is included in the January 2023 through December 2023 fuel and purchased power cost recovery factors. This calculation is shown on Schedule E1-A of Exhibit No. MAS-2, Document No. 1.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2022 through December 2022?

A. The actual/estimated 2022 fuel true-up amount is an under-recovery amount of $437,178,107 for the January 2022 through December 2022 period. The detailed calculations supporting the actual/estimated current period true-up is shown in Exhibit No. MAS-2, Schedule E1-B on Documents No. 1.

Q. What are the primary drivers of the expected 2022 fuel under-recovery amount?

A. The primary reason for the expected 2022 under-recovery is a substantial increase in the price of natural gas, compared to the company's original 2022 mid-course projection.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2023 through December 2023 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2022 through December 2022 is an over-recovery of $3,967,826 as shown in Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2023 through December 2023 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2023 capacity cost recovery factors includes the actual/estimated true-up amount for January 2022 and December 2022. The final 2021 true-up amount was included in the company's mid-course capacity cost recovery factors effective April 2022 through December 2022, as approved in Order No. PSC-2022-0122-PCO-EI, issued March 18, 2022, in Docket No. 20220001-EI.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2022 through December 2022?

A. The actual/estimated true-up amount is an over-recovery of $2,397,141 as shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the net capacity cost recovery true-up amount for the period January 2022 through December 2022?

A. The net capacity cost recovery true-up amount for the period January 2022 through December 2022 is an over-recovery of $3,967,826. This calculation is shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

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Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2022 through December 2022 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2023 through December 2023 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2022, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2023 fuel and purchased power and capacity cost recovery factors.

Q. Have you prepared an exhibit to support your direct testimony?

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Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2023 through December 2023 fuel and purchased power cost recovery factors?

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Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2022 through December 2022?

A. The actual/estimated 2022 fuel true-up amount is an under-recovery amount of $437,178,107 for the January 2022 through December 2022 period. The detailed calculations supporting the actual/estimated current period true-up is shown in Exhibit No. MAS-2, Schedule E1-B on Documents No. 1.

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Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2023 through December 2023 capacity cost recovery factors?

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A. The net true-up amount to be recovered in the 2023 capacity cost recovery factors includes the actual/estimated true-up amount for January 2022 and December 2022. The final 2021 true-up amount was included in the company's mid-course capacity cost recovery factors effective April 2022 through December 2022, as approved in Order No. PSC-2022-0122-PCO-EI, issued March 18, 2022, in Docket No. 20220001-EI.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2022 through December 2022?

A. The actual/estimated true-up amount is an over-recovery of $2,397,141 as shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the net capacity cost recovery true-up amount for the period January 2022 through December 2022?

A. The net capacity cost recovery true-up amount for the period January 2022 through December 2022 is an over-recovery of $3,967,826. This calculation is shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY AND EXHIBIT
OF
M. ASHLEY SIZEMORE

FILED: SEPTEMBER 2, 2022

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220001-EI
FILED: 09/02/2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20220001-EI?

A. Yes, I submitted direct testimony on April 1, 2022 and July 27, 2022.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

A. No, they have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, and the proposed annual levelized fuel and purchased power cost recovery factors for January 2023 through December 2023. I also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2023.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. MAS-3, consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2023 through December 2023 as well as Schedule H1 for 2020 through 2023. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral.

Q. Are you requesting Commission approval of the projected fuel and capacity cost recovery factors for the company's various rate schedules?

A. Yes.

Q. How were the fuel and capacity cost recovery clause factors calculated?

A. The fuel and capacity cost recovery factors were calculated as shown on Document Nos. 1 and 2. These factors were calculated based on the current approved rate design and schedules as set out in the 2021 Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-2021-0423-S-EI on November 10, 2021 in Docket No. 20210034-EI.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. What payments are included in Tampa Electric’s capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. MAS-3, Document No. 1, page 2 of 4, Tampa Electric is refunding $3,123,211 after jurisdictional separation, prior year true-up, and application of the revenue tax factor for estimated expenses in 2023.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level effective beginning in January 2023 for which Tampa Electric is seeking approval.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	-0.018	
GS and CS Secondary	-0.017	
GSD, SBD Standard		

Secondary		-0.06
Primary		-0.06
Transmission		-0.06
GSD Optional		
Secondary	-0.014	
Primary	-0.014	
Transmission	-0.014	
GSLDPR/GSLDTPR/SBLDPR/SBLDTSU		-0.05
GSLDSU/GSLDTSU/SBLDSU/SBLDTSU		-0.04
LS1 Secondary	-0.003	

These factors are shown in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of (0.016) cents per kWh compare to the factor for April 2022 through December 2022?

A. The proposed capacity cost recovery factor of (0.016) cents per kWh beginning in January 2023 is 0.061 cents per kWh (or $.61 per 1,000 kWh) less than the average capacity cost recovery factor of 0.045 cents per kWh for the April 2022 through December 2022 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the period beginning in January 2023?

A. The appropriate amount for the period beginning in January 2023 is 4.832 cents per kWh before the application of the time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. MAS-3, Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2023 through December 2023.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF"), true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $546,170 and an Optimization Mechanism gain of $4,819,866, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up for 2022 to be $0.

Q. Do your 2023 factors include the projected under-recovery for 2022?

A. No. Natural gas prices remain highly volatile, and the 2022 under-recovery could change materially over the remainder of the calendar year. Consequently, the company did not include the currently projected under-recovery for 2022 in the factors for 2023.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric’s on-peak and off-peak fuel adjustment factors for January 2023 through December 2023. The schedule also presents Tampa Electric’s levelized fuel cost factors at each metering level.

Q. Please describe the information presented on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak, and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. MAS-3, Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for the period beginning in January 2023.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	4.832
Tier I (Up to 1,000 kWh)	4.525
Tier II (Over 1,000 kWh)	5.525
Distribution Primary	4.784
Transmission	4.735
Lighting Service	4.767
Distribution Secondary	5.179(on-peak)
	4.683(off-peak)
Distribution Primary	5.127(on-peak)
	4.636(off-peak)
Transmission	5.075(on-peak)

4.589(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 4.832 cents per kWh compare to the levelized fuel adjustment factor for the April 2022 through December 2022 period?

A. The proposed fuel charge factor of 4.832 cents per kWh is 0.706 cents per kWh (or $7.06 per 1,000 kWh) higher than the average fuel charge factor of 4.126 cents per kWh for the April 2022 through December 2022 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2023 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Optimization Mechanism replaced the short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2023 projection.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric’s proposed changes in its base, capacity, fuel and purchased power, environmental, and energy conservation cost recovery factors on a 1,000 kWh residential customer’s bill?

A. The composite effect on a residential bill for 1,000 kWh is an increase of $14.20 in the period beginning January 2023, when compared to the April 2022 through December 2022 charges. These amounts are shown in Exhibit No. MAS-3, Document No. 2, on Schedule E10.

Q. When should the new rates take effect?

A. The new rates should take effect concurrent with meter readings for the first billing cycle for January 2023.

Q. Does this conclude your direct testimony?

A. Yes.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court 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 28th day of November, 2022.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024