BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	Docket No. 56765
Fuel Cost Recovery (FCR-27)	)	

Volume II

Hearing in Room 110
244 Washington Street
Atlanta, Georgia

Wednesday, May 6, 2026

The hearing was called to order, pursuant to Notice at 9:30 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TRICIA PRIDEMORE, Commissioner - (via Zoom)
PETER HUBBARD, Commissioner
DR. ALICIA M. JOHNSON, Commissioner - (via Zoom)

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P R O C E E D I N G S

CHAIRMAN SHAW: All right. Good morning, everyone. Welcome to the Commission this morning.

This is the second day of hearings on Docket No. 56765, Georgia Power Company's Fuel Cost Recovery FCR-27.

We will start by calling for appearances. Georgia Public Service Commission.

MR. COLLADO: Chris Collado and Justin Pawluk on behalf of Staff.

CHAIRMAN SHAW: Good morning.

Georgia Power Company.

MS. PRYOR: Good morning. Allison Pryor, Steve Hewitson and Holly Ingram on behalf of Georgia Power Company.

CHAIRMAN SHAW: Good morning.

Georgia Association of Manufacturers.

MR. JONES: Clay Jones on behalf of GAM.

CHAIRMAN SHAW: Good morning, Clay.

Georgia Interfaith Power & Light and Southface Institute.

MR. KAMANI: Good morning. Amitav Kamani, Jennifer Whitfield, and Bob Sherrier on behalf of GIPL and Southface.

CHAIRMAN SHAW: Good morning.

Metropolitan Atlanta Rapid Transit Authority, MARTA.

MR. BAKER: Good morning, Chairman. Bob Baker.

CHAIRMAN SHAW: Resource Supply Management.

(No response.)

Sierra Club, Southern Alliance for Clean Energy, and the Natural Resources Defense Counsel.

MS. ARIZA: Good morning. Isabella Ariza on behalf of Sierra Club, SACE, and the NRDC.

CHAIRMAN SHAW: Good morning.

It looks like we're all here. We can begin. Are there any housekeeping matters to take up before we get started?

(No response.)

All right. We're going to start with our public witnesses. I do have a sign-up sheet. So if there's anyone here that wants to speak and hasn't signed up, just let us know if we miss you.

But we're going to start. I have a short list this morning. We'll start with Mr. Dan Chappuis.

Good morning, Mr. Chappuis. How are you doing? All the way from Moultrie, Georgia; right?

MR. CHAPPUIS: All the way from Moultrie, Georgia, yes, sir.

CHAIRMAN SHAW: I've heard of you. I -- I don't think I've ever met you. Good to --

MR. CHAPPUIS: We've spoken on the phone.

CHAIRMAN SHAW: Yeah. Good to see you.

MR. CHAPPUIS: Yes, sir. You, too.

So, good morning, Chairman Shaw and fellow Commissioners. Again, my name is Dan Chappuis. I'm the superintendent of the Colquitt County School District in Moultrie, Georgia.

Every day in public education, our responsibility is pretty straightforward, but very important to the long-term success of our community. Our job is to provide students with a safe, stable, and effective environment where they can learn, grow, and prepare for the future.

And in our district, our first pillar is to provide a safe and positive learning environment. Our schools must be places where children are comfortable, secure and ready to learn, where classrooms are bright, technology works, our cafeterias function to serve meals, our buses run, and especially in south Georgia, our heating and air systems keep students comfortable and focused regardless of the season. And all that takes reliable electricity.

Reliable power is something that many people take for granted. But in education, we can't. When the lights are on, the technology is working, and our schools are fully operational, our students benefit. We are really very dependent on reliable energy in our schools today. This gives our parents peace of mind and our teachers can teach and do their jobs effectively.

Georgia Power has helped provide that reliability for our schools and community. Like any family, school system or business, we also understand that affordability matters. And every dollar matters in education.

And we work very hard in our system to be very responsible stewards of our taxpayer resources. We keep our property taxes as low as we can, being very mindful of our -- our community and their budgets, but also providing enough revenue to give our students the quality education they deserve.

And that's -- part of that is why predictability and stability in energy costs are so critical. Georgia Power's three-year base rate freeze has provided our families and communities with a measure of certainty during a time when many other costs have risen.

And as fuel costs are reviewed, we're encouraged by the possibility that potentially lower fuel costs and lower fuel expenses could create downward pressure on customers, including us, as a school system. So that balance, reliability, and affordability is very important to us in how we operate in our budget process.

We all want power to be available when we need it, and especially in our schools. But we also want it delivered responsibly -- responsibly and as affordably as possible. Maintaining that balance requires thoughtful planning. And Georgia Power must be able to secure fuel, maintain infrastructure, and prepare for future demand so that schools like ours are never left questioning whether we can fully serve our students.

In education, we plan ahead because our children's future depends on it. Reliable energy providers must also do the same. A practical fuel recovery framework helps support the dependable service we rely on, while also allowing the benefits of lower fuel costs to be reflected when possible.

CHAIRMAN SHAW: Don't worry about that. We don't have many today.

MR. CHAPPUIS: From an educator's perspective, reliable and affordable power helps create the kind of consistent, safe, and positive learning environment that our students deserve.

So we thank you for your time and consideration today.

CHAIRMAN SHAW: Thank you for taking the time to drive all the way up here. Because I know y'all are in the homestretch with the end of school year and a lot going on, I'm sure.

MR. CHAPPUIS: We are, yes, sir. I'm going to Honors Night tonight. We've got graduation in a week. And so we -- yeah, we've got -- it's a busy time in the school district, but this is important.

CHAIRMAN SHAW: Colquitt County is sort of just a good model for what, you know, rural Georgia looks like. It's just -- it's a heavy agricultural-based economy, a lot of great people, a lot of diversity.

But what y'all do, you're -- it's the -- public education is the backbone of our -- of our -- of our current and our future. And what y'all are doing is a lot like what we try to do here in balancing -- striking that right balance.

Because, like you said, you've got to have the resources you need, but you don't want to burden your taxpayers. Yes, but thank you for what y'all do. And appreciate it again for taking the time to come all the way up here.

MR. CHAPPUIS: Yes, sir. Thank you for the opportunity.

CHAIRMAN SHAW: Yes, sir.

MR. CHAPPUIS: All right.

CHAIRMAN SHAW: And our next two public witnesses are two that I have a lot of respect for, that are probably as passionate and thoughtful as any two that ever come down here.

And Dr. Preeti Jaggi is next. Good morning.

DR. JAGGI: Good morning. How are you?

CHAIRMAN SHAW: Good.

DR. JAGGI: I'd like to speak to both the docket that is undergoing and then the one for next week, if I can, because I'm not going to be able to be here this next week.

Georgians are estimated to have lost at least $5 billion in economic losses during Hurricane Helene. And there were priceless losses; farmers' livelihoods devastated, twin one-month-old babies that died in the bed with their mother during the storm, and approximately 250 people that died during the storm in the southeast.

Helene formed over record warm Gulf waters that have been made 200 to 500 times more likely due to the burning of fossil fuels. Georgians, along with others in the southeast, paid a cost. Homes flooded, restaurants closed from downed wires, hospitals across the country had shortages of critical saline because the Baxter plant in North Carolina was devastated and they produce about 60 percent of our saline. People lost their homes. They relied on their insurance coverage to put their -- the pieces of their lives back together.

Georgia Power is asking you to ask everyday Georgians to bail them out from these damages. I think you should say no to corporate welfare. Ten years ago, the PSC allowed for Atlanta Gas & Light to merge with Georgia Power, making an already powerful monopoly even more consolidated.

Now, Southern Company owns Georgia Power and much of the gas infrastructure. And that is why they want to keep us hooked on dirty, volatilely priced, polluting gas, instead of cheaper, cleaner solar that we can generate on our own properties.

If they felt the business decision was so great to merge with the gas company, then their shareholders to shoulder the cost of rising fuel costs, not Georgia Power customers. You are literally the only people that are able to balance the greed of a giant monopoly.

Consumers do not have a choice in their utility provider. We have been asking consistently for cleaner, cheaper sources of electricity for years. I have been here for years. And what we get is more gas and coal.

Georgia Power already charges us 10 percent of our rates towards an environmental compliance cost for energy sources that we don't want. We are asking for cleaner sources that do not require these extra costs and are better for our health.

I really do notice that when -- in 2016, when they merged Atlanta Gas & Light and Georgia Power, there was a three-year rate freeze. We didn't raise rates for three years.

And then guess what happened from 2019 to last year? Massive increase in our bills. We know what's happening. We're going to get a rate freeze for a few years and then it's going to go right back up.

I believe that it is time for the PSC to start acting in the best interest of Georgia and not as the puppets of Georgia Power. Thank you.

CHAIRMAN SHAW: Lisa Coronado.

Good morning, Ms. Lisa.

MS. CORONADO: Good morning. Nice to see you. Nice to see you.

CHAIRMAN SHAW: You, too.

MS. CORONADO: Yesterday there was a lot of talk about how the massive expansion of natural gas electricity generation that Commissioners recently approved -- not the new Commissioners. You voted to reconsider that decision when you took your seats.

How that massive expansion will bring substantial additional costs to transport gas into our state. Costs that Georgia Power does not plan to require data centers to absorb, even though data centers will consume nearly all of the new gas-generated electricity. Instead, residential ratepayers will foot the bill.

You know what energy source doesn't have to come from out of state and doesn't have a transportation cost? Solar. Georgia doesn't

produce natural gas, but we are one of the top ten sunniest states.

There was also a lot of talk about Georgia Power's request to increase its hedging amount to provide insurance against natural gas price spikes for this additional gas. Commission staff and other experts have pointed to national -- natural gas pricing volatility over the years. And we just experienced a large rate hike due to Russia's invasion of Ukraine as a reason to decrease, not increase, our reliance on this fossil fuel.

You know what energy source doesn't have these volatile pricing concerns? Solar. The sun provides all its energy for free. Now, I get it. Georgia Power gets a great deal when they generate our electricity with more natural gas.

When they send money out of our state to pay for gas, they send a significant portion of it into the pockets of Southern Company, their parent company. And they are making an enormous profit due to a Commission-approved return on equity that is far above industry average when they build gas pipelines and those big, expensive, polluting gas plants. And they don't carry any of the risks for the volatile pricing of the natural gas needed to

run those expensive plants. The Commission has allowed them to pass all those costs and risks on to ratepayers.

But relying more on natural gas is not in the best interest of Georgians. What is? Solar. More solar panels on the rooftops of houses, warehouses, schools, churches, hospitals, and small businesses would mean less demand on the grid and extra electricity sent back to the grid. It would mean -- it would mean less need to build those expensive gas plants.

More rooftop and utility-level solar would mean that we would keep money in our state, not sending it out of state to pay for gas. Instead, supporting a thriving solar and battery manufacturing and installation industry in Georgia, one that would provide thousands of jobs across our state.

And what's great, on top of all that, is that solar and battery is now cheaper than gas. And costs for both solar panels and batteries keep going down with advancing technology. And there are so many other co-benefits, including the fact that solar power doesn't contribute to changing our climate in ways that will cost our grandchildren and children dearly. And all future generations dearly.

But Georgia Power has fought tooth and nail against Commissioners setting fair policies that would support this growth in solar. And, in response, the Commission has failed to set those needed policies.

So as you are deliberating about who is going to pay for the costs associated with the large additional amount of gas that will be mostly used to pay for data centers and how much they're going to pay, know that ratepayers and voters across Georgia are thinking about how we just need one more Commissioner who will vote to reconsider this massive, not in the best interests of Georgians, but great for Georgia Power and data centers, fossil fuel gas expansion.

Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

Was there anyone else that wanted to address the Commission that did not get signed up on the sheet?

(No response.)

All right. Well, while the -- while Georgia -- the last panel that we have is Georgia

Power. The rebuttal panel.

Oh, so that's a separate panel? It's not showing up like that on mine.

Well, while you're preparing for your first panel, which is the larger panel -- right? -- we are going to take a quick break and allow IT to just kind of set everything up and allow you all to get your witnesses in here.

So we will take a five-minute break. Thank y'all.

(A recess was held from 9:46 a.m. until 9:52 a.m.)

CHAIRMAN SHAW: All right. We will get -- continue where we left off with our first panel -- rebuttal panel this morning.

So, Ms. Pryor, go ahead and swear in your panel, if you would.

MS. PRYOR: Thank you.

At this time, I'd like to call Georgia Power's first panel of witnesses on rebuttal, Mr. Adam Houston, Mr. Matthew Berrigan, Mr. Lee Evans, and Mr. John Ohlson to the stand.

Gentlemen, would you please raise your right hands.

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Thereupon,

MATTHEW S. BERRIGAN,
ADAM DUNCAN HOUSTON,
RICHARD JOHN OHLSON, JR.,
LEE EVANS,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. PRYOR:

Q. Mr. Houston and Mr. Berrigan, you previously testified in this FCR-27 docket; correct?

A. (Witness Houston) Yes.

A. (Witness Berrigan) Yes.

Q. Can you please remind us -- please state your name, employer and your responsibilities for the record?

A. (Witness Houston) Yes. Adam Duncan Houston, Georgia Power comptroller.

A. (Witness Berrigan) Matthew Berrigan, Georgia Power assistant comptroller.

Q. Thank you.

And, Mr. Evans and Mr. Ohlson, you did not previously testify in this docket yet; correct?

A. (Witness Evans) Correct.

Q. Mr. Evans, please state for the record your full name, your employer, and your responsibilities.

A. (Witness Evans) Lee Evans. Director of pricing and rates, Georgia Power Company.

Q. And, Mr. Ohlson, can you do the same?

A. (Witness Ohlson) Richard John Ohlson, Jr., Southern Company Services. Coal transportation, logistics and fuel assurance management.

Q. Mr. Houston, on April 23rd, did you prefile or cause to be prefiled 36 pages of rebuttal testimony in question-and-answer format in this case?

A. (Witness Houston) Yes.

Q. Are there any changes you need to make to your prefiled rebuttal testimony at this time?

A. (Witness Houston) No.

Q. If I were to ask you the same questions today under oath, would your answers be the same as if given here today?

A. (Witness Houston) Yes.

MS. PRYOR: Chairman Shaw, the court reporter has been provided a copy of the panel's prefiled rebuttal testimony. And I now ask that the rebuttal testimony be copied into the record as if given here today.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Matthew S. Berrigan, Adam Duncan Houston, Richard John Ohlson, Jr., Lee Evans, follows:)

REBUTTAL TESTIMONY OF

ADAM D. HOUSTON, MATTHEW S. BERRIGAN, LEE EVANS, AND R. JOHN OHLSON, JR.

ON BEHALF OF GEORGIA POWER COMPANY

GEORGIA PUBLIC SERVICE COMMISSION DOCKET NO. 56765

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Adam D. Houston. I am the Vice President and Comptroller for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

A. Matthew S. Berrigan. I am the Assistant Comptroller for Georgia Power. My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

A. Lee Evans. I am the Director of Pricing and Rates for Georgia Power. My business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

A. R. John Ohlson, Jr. I am the Transportation, Logistics, and Fuel Assurance Manager at Southern Company Services ("SCS"). My business address is 3535 Colonnade Parkway, Birmingham, Alabama 35243.

Q. MR. HOUSTON AND MR. BERRIGAN, DID YOU PRESENT DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?

A. Yes.

Q. MR. EVANS AND MR. OHLSON, DID YOU PRESENT DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?

A. No.

Q. MR. EVANS, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Financial Management from Clemson University and a Master of Science degree in Finance from Georgia State University. I have also served as an Adjunct Instructor of Finance for the University of West Florida and am a Certified Public Accountant licensed in Georgia. I have been employed for the past 19 years by Georgia Power and the Southern Company system in a variety of pricing, costing, and analysis capacities. My responsibilities include administering the Company's Rates, Rules, and Regulations as well as overseeing the billing operations for our largest Commercial and Industrial customers. I am responsible for administering the Georgia Territorial Electric Service Act of 1973, as it applies to Georgia Power. Additionally, I direct the Company's development and implementation of new tariffs to meet our customers' current and evolving energy needs.

Q. MR. EVANS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before this Commission in Docket No. 44160, Georgia Power's 2022 Integrated Resource Plan ("IRP"); in Docket No. 44280, Georgia Power's 2022 Rate Case; in Docket No. 55378, Georgia Power's 2023 IRP Update; in Docket No. 56298, Georgia Power's Certification of the 2029-2031 All-Source Capacity RFP; and in Docket No. 56310, Georgia Power's Certification of Supplemental Resources for 2028-2031 Capacity.

Q. MR. OHLSON, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Electrical Engineering from Mississippi State University in 1996 and a Master of Business Administration from Vanderbilt University in 2000. I began my career at Southern Company as a System Planning Engineer in 2000 and then transitioned to Long-Term Structuring Project Manager in 2003. From 2006 to 2008, I represented Southern Power Company in commercial transactions with wholesale customers in North Carolina and South Carolina. From 2008 to 2011, I served as the Enterprise Risk Management Manager for Southern Company. Beginning in 2011, I led teams and supported the cost forecasting for the Vogtle Units 3 and 4 in my role as Nuclear Development Financial Strategy, Analysis, and Budget Manager. I transitioned to my current role of Coal and Transportation Procurement Manager in 2015, where I support the development and implementation of Southern Company's coal and transportation procurement strategy.

Q. MR. OHLSON, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF THE PANEL'S REBUTTAL TESTIMONY?

A. The purpose of our rebuttal testimony is to respond to the testimony of the Public Interest Advocacy Staff ("PIA Staff"), the Georgia Association of Manufacturers ("GAM"), the Natural Resources Defense Council ("NRDC"), Sierra Club, and Southern Alliance for Clean Energy ("SACE"), and Georgia Interfaith Power and Light and Southface Institute ("GIPL & Southface") related to Georgia Power's Fuel Cost Recovery (FCR-27) Application, filed in Docket No. 56765. Our testimony focuses on several key issues without attempting to address every issue or recommendation raised in Staff or Intervenor testimony. However, the fact that the Company may not respond to a particular position of Staff or an Intervenor should not be construed as acceptance of such position.

Q. HAS THE COMPANY FILED UPDATES TO THE MINIMUM FILING REQUIREMENTS IN THIS PROCEEDING AND RESPONDED TO ALL PIA STAFF DATA REQUESTS DUE AS OF THE DATE OF THIS FILING?

A. Yes. The Company has filed Minimum Filing Requirements ("MFR") updates for the months of January and February 2026. In addition, the Company has responded to all 14 data request sets, containing approximately 300 questions and 600 subparts, issued by PIA Staff and its consultants and due as of the date of this filing.

Q. HAVE THERE BEEN ANY CORRECTIONS TO THE DIRECT TESTIMONY OR MFRs INITIALLY FILED BY THE COMPANY?

A. Yes. While there were no corrections to the Direct Testimony, the Company filed revised schedules MFRH-10, MFRH-11, MFRP-6.4, and MFRP-7.2 on February 23, 2026, due to the change in trade secret designations as agreed to with PIA Staff. The Company also made an errata filing to schedule MFRH-7.3 on March 17, 2026, to correct a formula error discovered by PIA Staff.

Q. HAS THE COMPANY INCLUDED UPDATES TO ITS FUEL COST PROJECTIONS AND FCR OVER/UNDER-RECOVERY BALANCES BASED ON LATEST ACTUAL DATA?

A. Yes, the Company has incorporated the latest natural gas price forecast as of April 2026 in the update to the FCR-27 budget. The latest price forecast, on average, is 2.8% lower over the projected test period compared to the price forecast embedded in the FCR-27 Budget filed on February 17, 2026. The update impacts the projected fuel cost of natural gas generation for Georgia Power-owned units and power purchase agreements ("PPAs"), including hedge gains and losses. The Company also incorporated the impact of lower natural gas prices on projected real time pricing ("RTP") fuel revenues. It is important to note that the Company did not model a redispatch of all of its generating resources as part of this update as that would require significant time to update, review and verify the energy budget model results.

In addition, the Company reflected the actualized FCR under-recovery balance as of March 2026 of REDACTED, which is REDACTED higher than previously anticipated in the FCR-27 Budget primarily as result of the Winter Storm Fern in January 2026. The combination of the two updates results in the projected FCR-27 Part B balance as of May 2026 of REDACTED.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Our rebuttal testimony addresses Georgia Power's responses to certain Staff and Intervenor testimony regarding: the Interim Fuel Rider ("IFR"); the strategy behind the Company's coal procurement, coal inventory management, and dispatch of coal units; generation unit outages and corresponding replacement power costs; the Commission-approved natural gas hedging program; renewable resource procurement and program cost recovery; RTP fuel credit methodology; fuel cost sharing and transparency; and the treatment of nuclear Production Tax Credits ("PTCs").

As it pertains to the IFR, we explain why the Company's requested modifications to the IFR will provide greater rate stability for customers and why PIA Staff's recommendation to maintain the IFR in its current form does not recognize the reality of the Company's growing system. We also describe the Company's coal procurement strategy, including contracting, and address unit dispatch and coal purchases, as requested by PIA Staff. While the Company's economic dispatch methodology is designed to minimize the total cost of serving native load across the system, we also provide additional context on the various types of operational limitations and constraints that impact the Company's unit commitment decisions.

Regarding fossil unit outages, PIA Staff recommends a disallowance of $10.0

million related to two outages at Plant McDonough Combined Cycle ("CC") Units 5B and 6B, which it alleges were imprudent, along with an outage at Plant McIntosh Combustion Turbine ("CT") for which there were no replacement power costs. We provide additional context and information for these three events and explain how the Company's actions were reasonable before, during, and after each event.

As it relates to fuel hedging, our rebuttal testimony reiterates the importance of the Company's Commission-approved natural gas hedging program in response to PIA Staff's recommendation that it be terminated, or alternatively reduced. We explain how customers benefit from the continuation of the hedging program, which protects against volatility and provides customers with the benefits of rate and cost stability. Regarding renewable procurement and program cost recovery, our rebuttal testimony explains why the Commission should continue its long-standing practice of allowing such costs that are not offset by participant fees to be recovered through the fuel cost recovery ("FCR") mechanism.

We also address PIA Staff's testimony regarding RTP fuel credit methodology, which the Company has not proposed changing, and respond to Intervenor recommendations regarding fuel cost sharing mechanisms. Our rebuttal testimony disputes the premise that the Company does not have any incentives to lower fuel costs for its customers, and we detail several activities the Company has proactively undertaken in recent years to optimize fuel costs for the benefit of customers.

Next, we address GAM's recommendation to use nuclear Production Tax Credits ("PTCs") to offset fuel costs recovered through FCR-27 and explain why these are appropriately a base rate component and therefore should not flow through fuel.

Finally, we conclude by describing the Company's ongoing actions that provide the Commission and the public with insight into the fuel costs, including the monthly over- or under-recovery status of its FCR balance filings made with the Commission as well as monthly operating and hedging reports.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Our rebuttal testimony is organized as follows:

- Section II discusses the IFR.
- Section III discusses the Company's coal procurement, inventory management, and economic dispatch.
- Section IV discusses fossil unit outages and replacement power costs.
- Section V addresses the recommendations related to the Company's natural gas hedging program.
- Section VI discusses renewable resource procurement and program cost recovery.
- Section VII responds to recommendations pertaining to RTP methodology.
- Section VIII discusses fuel cost sharing.
- Section IX discusses nuclear PTCs.
- Section X addresses fuel cost transparency.

II. INTERIM FUEL RIDER

Q. DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDATION TO MAINTAIN THE IFR AT ITS CURRENT THRESHOLD AND VARIANCE AMOUNT?

A. No. For context, the $200 million threshold was established and approved by the Commission in 2012 in the FCR-23 proceeding. The increase in the IFR threshold from the current amount of $200 million to $300 million is more appropriate given the relative size of the total fuel expenses incurred and to be incurred by the Company on an aggregate basis. The higher threshold provides greater rate stability for customers and allows increased capacity to absorb natural fuel price fluctuations and the normal swings of over- or under-recovery balances on a monthly basis. Further, the increase to a $300 million threshold provides a more appropriate balance between the frequency of the IFR trigger of potential rate adjustments and mitigating significant over- or under-recovery balances in the future.

Q. HOW WOULD THIS CHANGE TO THE IFR MECHANISM BE APPLIED?

A. Consistent with the currently approved IFR mechanism, the $300 million threshold will be applied in either direction of over-recovery or under-recovery with the current maximum percentage of +/- 40% of cumulative rate change unaltered from the current approved level. The Company proposes that the timing and the filing requirements remain the same. The increase in threshold will provide greater rate stability for customers and will allow increased flexibility to absorb natural fuel price fluctuations and normal swings of over- or under-recovery balances on a monthly basis.

Q. SHOULD THE COMPANY BE REQUIRED TO FILE FOR A RATE ADJUSTMENT IN AN IFR FILING?

A. No. There are numerous factors when considering whether a rate adjustment is needed in an IFR filing, which include but are not limited to, the projections of fuel over- or under-recovery balance, the latest fuel price forecast specifically for natural gas, incremental time required to implement the rate change, and the proximity of the next fuel rate case filing. Given those factors, the flexibility of whether to propose a rate adjustment is an important consideration with respect to rate stability for customers. As such, the Company and the Commission should maintain the current optionality afforded within the IFR mechanism to implement or forego a rate adjustment.

Q. SHOULD THE CURRENT IFR THRESHOLD BE RETAINED TO MAINTAIN FREQUENCY OF REPORTING FCR OVER/UNDER STATUS AS RECOMMENDED BY GIPL AND SOUTHFACE?

A. No. The Company files an update of its over/under status of the FCR balance with the Commission in Docket No. 3382-U as part of its monthly reporting requirement.

Therefore, even without the trigger of the IFR filing, the FCR over/under status and the associated details are publicly available to be tracked and reviewed on a monthly basis.

Q. DOES THE COMPANY AGREE WITH GIPL AND SOUTHFACE'S RECOMMENDATION TO LOWER THE MAXIMUM IFR RATE ADJUSTMENT WITHIN A FCR PERIOD FROM 40% TO 15%?

A. No. As evidenced in the prior periods when the IFR was set at the maximum percentage of 15%, the potential rate adjustment at that level may not adequately result in the desired impact to bring the cumulative FCR balance to a zero position, which is the primary goal of the IFR.

III. COAL PROCUREMENT, INVENTORY MANAGEMENT, AND ECONOMIC DISPATCH OF COAL UNITS

Q. PLEASE PROVIDE AN OVERVIEW OF GEORGIA POWER'S COAL PROCUREMENT STRATEGY.

A. Georgia Power's coal procurement strategy is designed to ensure reliable supply for generation while meeting system fuel requirements at the lowest reasonable total cost to customers. Procurement decisions are made using a disciplined portfolio approach that balances: (1) reliability of supply and delivery; (2) total delivered cost; (3) operational flexibility to respond to changing dispatch and burn requirements; and (4) risk management to address market volatility, supplier performance, and evolving environmental requirements.

1. **Reliability first, verified through performance history and due diligence**: Suppliers are evaluated economically and through technical and financial reviews; contract terms may include replacement-cost remedies and performance incentives, where appropriate.
2. **Portfolio contracting to manage volume uncertainty**: A portion of projected requirements is secured under long-term agreements to support dependable

supply and mitigate price volatility, with remaining needs met through spot purchases and negotiated volume flexibility to adjust to changing dispatch and burn requirements.

3. **Active price management**: Procurement maintains competitive pricing and limits exposure to market volatility through regular, formal, staggered solicitations. Awards are structured with competitive initial pricing, controlled escalation, and staggered expirations to avoid concentrated purchasing or renewal activity that could increase total delivered costs.
4. **Diversity of supply sources and transportation options**: Maintaining optionality across producing regions and transportation routes supports competition, mitigates supply disruptions, and allows the system to adapt as market and regulatory conditions change.
5. **Environmental and regulatory risk mitigation**: Procurement terms for longer-dated commitments may include environmental provisions intended to preserve flexibility to respond to current and future compliance requirements and to manage the risk of changing rules affecting unit operations.

Overall, the Company's integrated approach to coal-related procurement activities is planned and executed to support dependable fuel availability and prudent cost outcomes for customers under a range of market and operating conditions.

Q. WHAT DOES THE COMPANY CONSIDER WHEN NEGOTIATING AND ENTERING INTO COAL SUPPLY AND TRANSPORTATION CONTRACTS?

A. When negotiating coal supply and transportation contracts, the Company considers multiple factors, with the objective of meeting system fuel requirements at the lowest reasonable total cost while supporting safe and reliable generation. Some of these key considerations include:

- Fuel reliability and diversity to ensure dependable supply under varying market, operational, and regulatory conditions;
- Total delivered cost, including commodity price, transportation, handling, and environmental compliance costs, rather than focusing solely on Free on Board ("FOB") pricing;
- Volume and contract term flexibility, recognizing uncertainty in future dispatch, load, plant operations, and regulatory outcomes;
- Alignment between supply and transportation agreements to avoid mismatched commitments and unnecessary cost exposure; and
- Risk allocation structured to balance performance incentives, cost predictability, and protection against unbounded exposure from fuel unavailability or market volatility.

The Company evaluates these factors holistically and through competitive processes with appropriate cross-functional input to ensure procurement decisions are prudent, balanced, and consistent with Commission-approved strategies and system reliability obligations.

Q. PLEASE RESPOND TO NRDC, SIERRA CLUB, AND SACE WITNESS GOGGIN'S RECOMMENDATION THAT THE COMPANY SHOULD NOT ENTER INTO COAL SUPPLY OR TRANSPORTATION CONTRACTS THAT INCLUDE PENALTIES FOR FAILING TO MEET MINIMUM FUEL DELIVERY REQUIREMENTS.

A. Mr. Goggin's recommendation ignores the reality that coal suppliers and transportation providers typically require minimum delivery provisions in their contracts to secure commitments. The inclusion of minimum delivery requirement provisions is industry standard. Minimum delivery requirements and related performance provisions are a risk-management mechanism designed to reduce exposure to the much larger and less controllable costs associated with fuel unavailability, including emergency procurement and higher-cost replacement fuels. These provisions are not intended to compensate non-performance; they are structured to allocate performance risk to the carrier that controls execution.

Where applied, such provisions are bounded, transparent, and paired with other customer protections, including force majeure protections, performance standards, and remedies for repeated failure. Eliminating minimum delivery requirements, if even desirable, does not remove the underlying cost of securing transportation capacity. Rather, it shifts those costs into higher base rates or fixed charges with less direct correlation to performance. Accordingly, the Company's focus in contracting should remain on whether the overall contract structure reasonably minimizes total cost while meeting reliability obligations—not on the presence or absence of minimum delivery requirements in isolation.

Q. PIA STAFF TESTIFIES THAT THE COMPANY ENTERED INTO SUPPLY CONTRACTS FOR COAL THAT WERE HIGHER THAN COAL AVAILABLE FROM OTHER SUPPLIERS. CAN YOU ELABORATE?

A. The Company continues to pursue a diversified coal procurement strategy for Plant Bowen. While traditional Illinois Basin and Northern Appalachian ("NAPP") coals—generally the most economic sources—are expected to comprise a substantial majority of Plant Bowen's coal portfolio going forward, the Company incorporates other sources in its portfolio to enhance supply diversity and reliability.

The Company runs competitive solicitations for coal supply and uses price and non-price factors, including supplier performance history, production risk, transportation or rail risk, and the operational impacts of short falls, in making its supplier selections. Although lower-priced tons were available from certain Illinois Basin and NAPP suppliers during the relevant solicitations, increasing volumes within the same region or among a small number of large suppliers would have further concentrated Bowen's supply and transportation exposure. Accordingly, the Company limited the higher-priced volumes to a modest share of Plant Bowen's projected needs (less than 10% in the relevant years) and used those tons to mitigate supplier risk within the Bowen portfolio rather than as a replacement for the core Illinois Basin and NAPP supply. Including a historically reliable supplier from the Central Appalachian region enhances supplier/mine diversity, adds geographic diversity, avoids congestion along certain transportation corridors, and provides scalable capacity that can help mitigate the operational and market impacts of unplanned production issues at other mines as seen in recent years.

Q. PLEASE PROVIDE AN OVERVIEW OF GEORGIA POWER'S INVENTORY MANAGEMENT STRATEGY.

The Company's coal inventory management strategy is governed by SCS' Fossil Fuel Policy and is designed to ensure system reliability while optimizing supply chain performance by balancing on-site inventories and planned deliveries. Coal stockpiles are maintained on-site to protect against unanticipated demand changes and supply disruptions caused by factors such as weather, transportation issues, or production variability. Each plant operates under defined target, critical, and physical inventory limits that are reviewed annually by Georgia Power and SCS. SCS emphasizes steady, ratable deliveries while allowing inventories to draw down during high-burn periods and rebuild during low-burn periods to better accommodate changing burn requirements. To manage risk, SCS continuously evaluates coal burn scenarios and projected inventory levels. When critical situations are anticipated, SCS implements mitigation measures such as planned burn, load curtailment, accelerated or deferred deliveries, use of off-site inventory, or—subject to Georgia Power approval—coal buyouts or resales.

To ensure that coal supply continues to be available in the future, Southern Company has entered several coal supply contracts that provide a fixed and consistent delivery of coal on an on-going basis. As rail companies' ability to provide service flexibility has decreased, Southern Company has transitioned to a more proactive coal inventory management process to mitigate a more restrictive coal supply chain and ensure reliability of fuel supply to our plants. The intent of the coal inventory management program is to maintain greater flexibility with the stockpile at each unit so that the unit remains responsive to both higher demand periods and lower demand periods while still receiving regular shipments of coal.

A recent example that highlights the importance of this reliability of supply was Winter Storm Fern, during which gas prices increased significantly, and Southern's coal fleet was able to respond when called during this peak event due to ample supply of fuel, which helped reduce overall costs to customers during a winter event with extremely high gas prices.

Q. PLEASE RESPOND TO ALLEGATIONS THAT THE COMPANY DISPATCHES GENERATION UNECONOMICALLY.

A. Southern Company does not dispatch generation on an uneconomic basis. Generation resources are committed and dispatched based on system-wide production cost considerations rather than on unit-specific incremental energy cost alone. The system-side production costs are optimized considering many factors. As described more fully below, certain generating units as part of the overall optimization may be dispatched out of strict energy merit order when necessary to comply with binding transmission facility ratings, contingency constraints, voltage support requirements, reserve obligations, minimum operating levels, environmental or fuel-related operating limitations, avoidance of uneconomic start-up or cycling costs, or other power delivery limitations affecting the ability to reliably serve load across the interconnected system. Such commitments reflect the least-cost, feasible operating solution for the system as a whole and are undertaken to ensure reliable service to native load customers consistent with prudent utility practice.

Q. WHAT FACTORS INFLUENCE UNIT COMMITMENT DECISIONS?

A. Typically, generation units are dispatched in the pool to reliably meet customer demand at the lowest total production cost without regard to ownership.[1] Meaning, units are typically committed to serve customer load on the system based on which resources are least costly to run and most economic for customers. However, other factors independently, or concurrently, may impact the decision to commit a unit for reasons other than strict economics to meet system needs. For example, the types of operational limitations and constraints may include:

- System Reliability Requirements – Units are placed on "reliability must run" at the discretion of the Reliability Coordinator, not Fleet Operations, based on the Reliability Coordinator's assessment of operational requirements to maintain system reliability (e.g., voltage support, avoidance of transmission line overloads, etc.)
- Environmental Limitations – Certain units may be limited based on the number of hours of operation allowed in compliance with air permits or other environmental restrictions.
- Minimum Uptime / Downtime Constraints – Some units have a minimum run-time or down-time requirement. For example, a unit might be placed on transmission must-run for one day, but not the next. If the unit has not met the minimum up time or is expected to be needed again within the seven days, then it may continue to operate in the interim to be available when needed next.
- Testing Requirements – Various testing requirements often require a unit to run to demonstrate environmental compliance, capability, availability post outage, or to confirm operational health of a unit.

[1] Production cost minimization begins with unit commitment decisions based on operating characteristics (considering items such as startup times, fuel limitations, environmental constraints, minimum on/off constraints, etc.), together with unit specific operating costs. Thereafter, and again subject to the requirements of system reliability (e.g., units needed for transmission support), system resources are operated pursuant to a traditional economic dispatch model.

- Real-Time Constraints – Fleet Operations may start or shutdown a unit quickly to preserve system integrity and reliability in response to real time unit performance or changes in load.
- Fuel Management – Operational limitations on fuel supply may restrict typical usage or unit availability. For example, natural gas units may be held back during a portion of the day to ensure that enough natural gas remains available on the pipeline during the afternoon peak in the winter.

Q. CAN IT STILL BE PRUDENT AND IN THE BEST INTERESTS OF CUSTOMERS TO OPERATE A UNIT EVEN IF OUT OF STRICT ECONOMIC ORDER?

A. Yes. As described above, operational complexity, system needs, and unit characteristics all must be considered in how system operators determine which units are needed to run at a given time. In evaluating the various constraints that may impact unit commitment, it is important to frame the decision within the following context: (1) the fleet is operated as one portfolio to achieve the lowest cost of operation in lieu of any constraints; (2) an operating limitation or constraint is not necessarily indicative of uneconomic dispatch—a unit may be running for reliability reasons, while concurrently remaining economical; and (3) at any given time, a unit may be limited by a single constraint while at other times multiple constraints may be occurring simultaneously.

Q. PLEASE SPECIFICALLY ADDRESS NRDC, SIERRA CLUB, AND SACE WITNESS GOGGIN'S ANALYSIS REGARDING ECONOMIC DISPATCH.

A. Mr. Goggin's analysis compares a unit's committed and dispatched costs to a historical day-ahead lambda price and gives limited consideration to a single unit operating constraint—minimum up times—within a number of constraints that impact the operation of the units and the system as a whole. However, Mr. Goggin does not include the minimum downtime requirements for each unit as reflected in

Aurora inputs for Plants Bowen and Scherer. Minimum downtimes are important to consider because they reflect unit commitment risks, such as natural gas price, load volatility, and other ever-changing system conditions, over a week-long time period, compared to the day-ahead approach used in Mr. Goggin's analysis. That longer planning horizon requires managing operational and market risk over multiple days—a key consideration not reflected in Mr. Goggin's analysis. Furthermore, he does not consider constraints critical to the operation of the Company's generation system such as transmission reliability, and environmental or fuel-related operating limitations.

In addition, Mr. Goggin's analysis does not account for how removing large generators from the system would change overall system production costs and marginal costs, nor does it account for the resulting impacts to system reserves. The Company performs a production-cost optimization subject to all applicable system, and unit constraints to determine which units should be online and when. The marginal cost is an output of that constrained optimization—it is not an input that can be held constant while selectively removing generation. Therefore, using a historical day-ahead lambda, which does not assume the operation of a generating resource such as Plant Bowen or Plant Scherer, to determine the impact to fuel costs is inappropriate without considering the full impact of a scenario where the referenced plants would not have operated. This potential outcome could create additional constraints in the system and, in turn, drive up the system lambda. In addition, there are operating reserve considerations that must be considered in the economic dispatch of the units. A committed Plant Bowen or Plant Scherer unit provides regulating, contingency and additional operating reserves to the system as a benefit, which is not necessarily captured in the dispatch price.

IV. FOSSIL UNIT OUTAGES AND REPLACEMENT POWER COSTS

Q. PLEASE SUMMARIZE PIA STAFF'S RECOMMENDATION REGARDING GEORGIA POWER'S FOSSIL GENERATION UNIT OUTAGES.

A. PIA Staff recommends a disallowance of $10.0 million related to two outages at REDACTED REDACTED REDACTED during the historical period. PIA Staff also suggest that an outage at REDACTED CT was imprudent, but there was no replacement power cost related to the outage.

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT REDACTED.

A. On REDACTED REDACTED at REDACTED experienced a forced derate following an electrical fault that resulted in an automatic unit trip of Unit REDACTED. Immediately prior to the trip, on-site personnel observed indications of abnormal electrical activity within the REDACTED REDACTED. The root cause was found to be REDACTED REDACTED REDACTED REDACTED. An electrical arc occurred in association with that equipment, which progressed to a flashover condition. The installed protective systems performed as designed in response to the electrical fault, isolating equipment and initiating the trip to protect the REDACTED generator and associated systems. Following the trip, plant personnel focused on maintaining safe operating conditions and stabilizing REDACTED and the steam turbine. The incident resulted in a forced derate until corrective measures were completed.

Q. WAS THE OUTAGE A RESULT OF IMPRUDENT ACTIONS BY THE COMPANY?

A. No. The Company's actions were reasonable before, during, and after the derate. The Company performed routine preventative maintenance on the REDACTED generator during the REDACTED fall outage. As part of a preventative maintenance task, approximately 90 REDACTED were removed, inspected, and reinstalled. The task is considered routine work. The unit ran for approximately 69 hours before the electrical fault occurred. The REDACTED were inadvertently installed in a way that allowed the electrical fault to occur.

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT REDACTED.

A. On REDACTED REDACTED REDACTED experienced a forced derate after the REDACTED was removed from service due to a REDACTED REDACTED REDACTED. An REDACTED REDACTED prevented the automatic protective trip. REDACTED was removed from service by the operator. The condition occurred because a REDACTED REDACTED REDACTED change disabled REDACTED REDACTED REDACTED REDACTED, preventing the normal automatic trip response. After an initial inspection (including a borescope), the original equipment manufacturer REDACTED advised restarting the REDACTED on REDACTED REDACTED. REDACTED reported a risk of REDACTED failure, and the turbine was taken out of service for repairs, including replacement of REDACTED. Work was completed on REDACTED, and the unit was returned to Automatic Generation Control.

Q. WAS THE OUTAGE A RESULT OF IMPRUDENT ACTIONS BY THE COMPANY?

A. No. As explained below, Georgia Power acted prudently before, during, and after the event. The Company has a contract with REDACTED to perform preventative and corrective maintenance for the gas turbine, including support from REDACTED controls personnel for the event. The Company's decisions and actions were reasonable based on the information available at the time. The root cause was associated with REDACTED REDACTED modifications within a complex REDACTED environment, and the Company's oversight, operating practices, and corrective actions were reasonable and consistent with prudent utility practice. Accordingly, Staff's recommended disallowance is not warranted.

Following the event, Georgia Power conducted a root cause review in conjunction with REDACTED and implemented corrective actions consistent with the findings. The root cause of the REDACTED REDACTED was due to REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED. Immediate countermeasures were taken to REDACTED REDACTED REDACTED REDACTED REDACTED.

REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED. As per routine practice, simulation testing was performed on REDACTED REDACTED. In addition, REDACTED was performed on the unit during the outage. After the REDACTED was performed, the REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED from functioning properly. The design engineer assumed that REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED. The Company was unaware, and could not have been aware, that this process was not executed. Further, the retraining of the required REDACTED REDACTED within the causal product was in reference to training REDACTED employees REDACTED, and not employees of Georgia Power. The existence of an REDACTED REDACTED does not correlate to Georgia Power's pre-event practices or establish imprudence. These actions are intended to reduce the likelihood of recurrence and reflect the Company's commitment to continuous improvement. It is important to note that REDACTED provided all the replacement parts and performed all necessary repairs to REDACTED at no cost to the Company. In addition, REDACTED waived payment of extra work authorizations associated with the planned outage. REDACTED actions far exceeded what is recoverable per the long-term service agreement with Georgia Power.

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT PLANT MCINTOSH CT UNIT 7.

A. On REDACTED REDACTED REDACTED was dispatched and brought online at approximately 0300 EST. At 0311 EST, while performing equipment checks during start-up, one of the plant operators noticed REDACTED REDACTED REDACTED, located at the top of the turbine combustor section. The operator immediately used the emergency stop button (e-stop) to stop REDACTED and shutdown the unit. Based on the location of the REDACTED REDACTED, which is on top of the combustor, REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED. Due to the hot temperature REDACTED REDACTED REDACTED REDACTED REDACTED, eventually the insulation ignited. The CO2 fire suppression system automatically discharged. In addition, one of the outside plant operators initiated the manual discharge of the CO2 system to quickly extinguish the flames. It was determined upon further inspection that a REDACTED REDACTED REDACTED REDACTED at the top of the combustor developed REDACTED REDACTED REDACTED. The plant has updated the preventive maintenance strategy associated with the REDACTED REDACTED to address potential future issues with REDACTED.

Q. WAS THE OUTAGE A RESULT OF IMPRUDENT ACTIONS BY THE COMPANY?

A. No. Georgia Power acted prudently before, during, and after the event. As explained in the response above, the cause of the outage was related to the REDACTED REDACTED from an equipment failure, and the Company took prudent actions to remediate the event. PIA Staff's allegation that the REDACTED REDACTED REDACTED led to the outage and was the direct result of imprudent actions by the Company is unwarranted. REDACTED REDACTED is monitored and controlled by plant personnel using a distributed control system in a centralized control room for REDACTED REDACTED units. This system uses REDACTED REDACTED REDACTED

REDACTED and respond to emergent conditions using alarm screens. In addition to operating the unit from the control room, personnel perform assigned rounds in the field to identify and respond to abnormalities. While the REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED of the unit, they do not provide a REDACTED REDACTED REDACTED and are not considered the sole REDACTED to trigger an operator response. Operators are trained to perform visual inspections of equipment in the field, which occurred per design with the appropriate response on the morning of REDACTED.

Q. WHY WERE THERE NO REPLACEMENT POWER COSTS FOR THE REDACTED OUTAGE?

A. REDACTED REDACTED had a marginal dispatch price that was greater than the Associated Interchange Energy Rate ("AIER") in all hours during the outage. As such, the replacement power costs were zero since the unit was assumed to not be operating for economics during the entire outage duration.

Q. WERE THE COMPANY'S ACTIONS AND DECISIONS RELATED TO THESE OUTAGES CLEARLY IMPRUDENT?

A. No. Georgia Power's actions and responses to these outages were reasonable and prudent and do not evidence any repeated deficiencies or trends.

Q. PIA STAFF TESTIFIES THAT THE COMPANY'S AVERAGE GENERATION LOST PER PLANNING OUTAGE IS THE HIGHEST ON AVERAGE SINCE FCR-20. PLEASE EXPLAIN WHY THE COMPANY'S PLANNED OUTAGES HAVE INCREASED IN RECENT YEARS.

A. PIA Staff's analysis is fundamentally flawed because it does not take into account the Company's fleet optimization efforts, the varying length of planned outages, and the impact of extending the life of units within our existing coal fleet on the length of planned outages.

First, PIA Staff's analysis fails to consider the Company's fleet optimization efforts, such as reducing major planned outage frequency where applicable, that have benefited customers through extended operations. Through these efforts, the Company has continued to take steps to extend the interval period between outages in a manner that appropriately balances costs, reliability, and availability. However, these extended intervals also result in increased outage duration, as more extensive work is performed during the planned outages. Thus, while average MWh lost generation might increase for a particular outage as a result of these efforts, such metric does not capture or reflect the increased benefit to customers resulting from the available MWh during the extended availability of the units.

Second, all planned outages are not created equal. PIA Staff's analysis rests on a flawed assumption that, over time, the average lost generation per outage during historic periods of varying lengths should remain at some median value. This assumption simply does not reflect the realities of fleet operation or the variability of planned outages. For units larger than 500 MW, the Company plans outages on a cyclical basis generally over an eight-year period, based upon certain large equipment maintenance cycles, with a planned outage generally occurring every two years. Each outage during the eight-year cycle has a defined scope and includes tasks that are dependent upon the maintenance scheduled for that outage, and differing amounts of time are required to accomplish the specific scope of work identified for each particular outage. Given the fact that planned outages vary based upon the planned scope of work for each outage, it is unreasonable to expect that the average lost generation per outage will remain constant. In addition, due to the varying lengths of the FCR historic periods, there will likely be historic periods that happen to encompass a higher percentage of longer and more involved planned outages when compared to historic periods where planned outages happen to be smaller in scope and thus shorter in duration.

Finally, PIA Staff's analysis also fails to account for the fact that the Company is ensuring the units with recently approved extensions run reliably. Maintenance on units at Plants Bowen, Yates, and Scherer was deferred as the units were scheduled to cease operation at the end of 2028. After the life of the units was extended, capital projects and maintenance were necessary to support unit reliability. For example, Bowen Unit 2 had a planned outage in 2025 that required more extensive work scope on the Air Heater and Main Turbine beyond 2028. These work scopes drove the outage duration to be 108 days. The extended operation of these units has driven scope to support this effort thereby extending basic outage periods and skewing any attempt at averaging the duration of and lost generation during a typical outage during a given period.

V. NATURAL GAS HEDGING PROGRAM

Q. PLEASE PROVIDE A BRIEF BACKGROUND OF THE COMPANY'S NATURAL GAS HEDGING PROGRAM.

A. The Company has maintained a Commission-approved natural gas hedging program for over two decades as part of its fuel procurement practices. The program is intended to mitigate customer exposure to volatility in natural gas prices, which represent a significant component of the Company's fuel costs, by fixing or capping the price for a portion of the Company's projected natural gas burn.

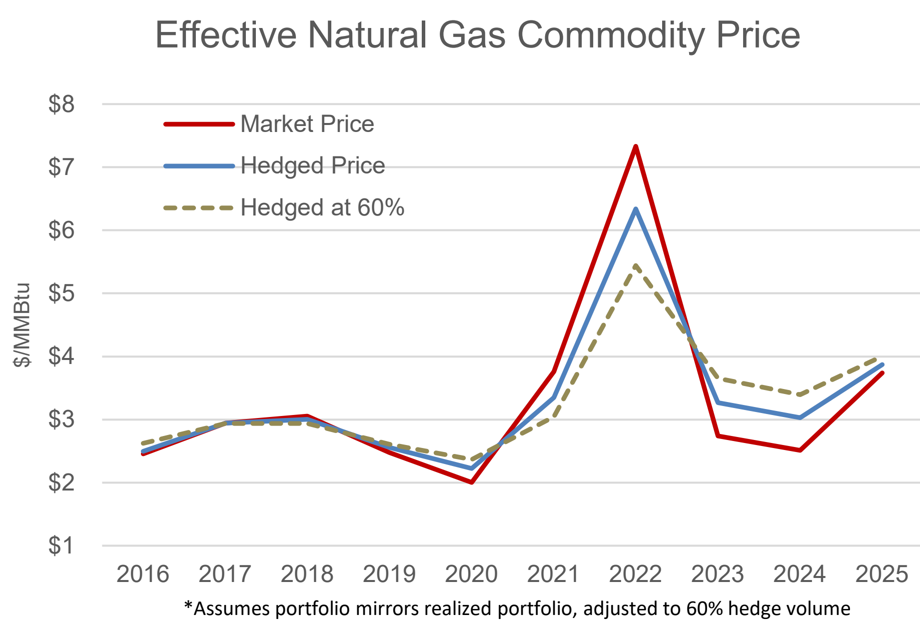
The Company's hedging activities are financial in nature and utilize instruments such as swaps and options, subject to parameters established through Commission orders in prior fuel cost recovery proceedings. The objective of the hedging program is to reduce exposure to adverse natural gas price movements and improve cost stability based on information available at the time hedging decisions are made, rather than to minimize realized fuel costs in hindsight. The structure of the hedging program has evolved over time as the Commission has adjusted allowable hedge volumes, tenors, and instruments in response to changing market conditions and policy considerations. The program is administered by SCS on behalf of Georgia Power, with hedging strategies and approvals established by Company management. All hedging activity is conducted within the parameters approved by this Commission. Consistent with Commission policy, all realized hedging gains and losses flow through the fuel cost recovery mechanism.

Q. PLEASE RESPOND TO PIA STAFF'S RECOMMENDATION THAT THE EXISTING NATURAL GAS HEDGING PROGRAM BE TERMINATED.

A. Georgia Power disagrees with this recommendation. The purpose of the hedging program is not to take speculative positions for gains or losses—it is to guard against volatility of natural gas prices in the market. The Company believes that rate stability for customers is an important consideration in setting regulatory policy. However, it's important to clarify the difference between rate stability and price stability as important customer protections. Rate stability refers to how often rates are changed, whereas price stability refers to whether the underlying costs upon which the rates are based are subject to volatility. The FCR over/under true-up mechanism and the adequate period between fuel cases provide *rate* stability for customers. The hedging program is the mechanism that provides *price* stability for natural gas purchases by locking in the future purchase prices today, as described further below. In combination, the Company's fixed fuel rates and the natural gas hedging program protect against volatility and provide customers with the benefits of rate stability and price stability, respectively.

Q. DOES THE COMPANY AGREE WITH STAFF'S ALTERNATIVE PROPOSAL TO REDUCE THE VOLUME AND HEDGING WINDOW FROM CURRENT APPROVED LEVELS?

A. No. An increase in the hedging volume is advisable at this time given the additional natural gas burn projected in the test period. Likewise, an increase in the hedging window to 48 months incorporates a longer-term natural gas price forecast into the mix of hedges, which provides additional diversity and stability of fuel price. As an illustrative example, the chart below shows the Henry Hub market price, the Company's actual price incorporating the hedges, and a hypothetical natural gas price assuming the hedge volume was increased to 60% as proposed by the Company in this filing on a historical basis over the last ten years.



As demonstrated by the chart above, the hedging program moderates price volatility by limiting exposure to extreme market movements. During periods of sharply rising prices, the program reduces peak costs, while during periods of rapidly declining prices, it results in higher prices than spot market outcomes. This reflects the intended function of a risk mitigation strategy, not an attempt to outperform the market on a realized cost basis.

Q. WITH RELATIVELY LOW NATURAL GAS PRICES, WHY IS HEDGING NATURAL GAS PRICES STILL REASONABLE?

A. Even at lower prices, natural gas prices are still volatile. Natural gas prices have an inherent level of volatility due to factors such as supply-demand imbalances, weather, and market dynamics. Given the Company's increased reliance on natural gas generation and corresponding increase in the volume of natural gas purchased, smaller changes in price can have a material impact on the Company's total natural gas fuel costs. For example, due to the Company's increased consumption, a $1 per MMBtu change in the price of gas today could cause a $260 million change in cost, whereas as recently as 2010, prices would have had to change over $2 per MMBtu to cause the same $260 million change. Continuing the Company's natural gas hedging program will mitigate the impact of this volatility.

Q. DO THE HISTORICAL HEDGE LOSSES REFLECT INEFFECTIVENESS OF THE HEDGES?

A. No, the hedge losses and gains are a function of the natural gas prices in the market compared to the hedged positions and should not be used to determine effectiveness of the hedging program. As mentioned earlier, the Company does not take speculative positions, and the intention of the program is to mitigate price volatility. Moreover, the cumulative hedge gains or losses depend on the time period for which they are measured. As seen in the table provided in PIA Staff's testimony, the hedge positions over the last ten years have resulted in a cumulative gain over that time period. On a long-term basis, the Company expects the hedge gains and losses to largely offset as natural gas prices typically fluctuate up and down.

Q. IS THERE A FUNDAMENTAL MARKET DIFFERENCE BETWEEN THE TIME PERIODS COVERED BY THE HEDGING PROGRAM IN THE EARLY 2000'S COMPARED TO THE LAST FIFTEEN YEARS?

A. Yes. The natural gas market has fundamentally changed as result of shale gas driven by hydraulic fracturing ("fracking") and horizontal drilling, which had a dramatic impact on the supply of natural gas within the industry. With the abundance of supply, the price pressure brought on by potential structural scarcity of natural gas was no longer a prominent force driving the market. In 2008, the average NYMEX prices for the following year were trading over $12/MMBtu during certain times, driven by a narrative that the country was running out of natural gas and would soon be dependent on liquified natural gas ("LNG") imports to meet its needs. The introduction of shale gas and fracking soon changed the natural gas outlook and prices dropped precipitously. As a result, the market is operating in a much different environment now given that there is no structural scarcity driving up prices. It is widely believed that the United States has decades of natural gas supply available at prices generally in the range of prices observed in the market today. However, while long-term supply abundance has reduced structural scarcity risk, natural gas prices remain subject to material volatility driven by weather-related impacts on both demand and supply, infrastructure constraints, and broader market dynamics.

VI. RENEWABLE RESOURCE PROCUREMENT COST RECOVERY

Q. HOW ARE RENEWABLE PROCUREMENT COSTS CURRENTLY RECOVERED?

A. As explained in our Direct Testimony, Georgia Power structures its renewable procurements to collect bid and winner fees to help defray the cost of the request for proposal ("RFP") process, including the cost of the Independent Evaluator, and to evaluate the submissions received in the RFP. Both the fees received from the RFP participants and the cost of Georgia Power's RFP administration and evaluation costs flow through the FCR. Therefore, any net revenues or costs are captured in the fuel balance, consistent with longstanding practice and direction from the Commission. Including any net revenues or costs in the same tariff where the customer benefits accrue from the low and fixed cost energy resources procured through renewable RFPs is fundamental to the Company and Commission's strategy to procure renewable resources and is consistent with cost causation principles.

Q. DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDATION TO PLACE COSTS IN EXCESS OF REVENUES ASSOCIATED WITH GEORGIA POWER'S RENEWABLE ENERGY RFPS AND SUBSCRIPTION PROGRAM INTO A REGULATORY ASSET TO BE ADDRESSED IN THE NEXT BASE RATE CASE?

A. No. These costs should be recovered through the FCR, consistent with current and past practice and cost causation principles. For more than ten years, the Commission has approved the Company's recovery of all Utility Scale and Distributed Generation RFP-related costs through fuel, along with any incremental renewable and nonrenewable resources costs and charges collected from customers participating in the Company's renewable subscription programs.[2] The Company proposes to continue this long-standing practice, while PIA Staff is recommending a change despite offering no reasons for this departure or justification why these costs should now be placed in a regulatory asset.

Notwithstanding the Company's request in this case, Georgia Power is actively reviewing the costs of conducting its renewable RFPs and the proposed

[2] *See Order Adopting Stipulation*, Georgia Public Service Commission, Docket No. 44160 (July 29, 2022) at 23-25; *Order Adopting Stipulation as Amended*, Georgia Public Service Commission, Docket No. 42310 (July 29, 2019) attached Stipulation paras. 3 and 5; *Order Adopting Stipulations*, Georgia Public Service Commission, Docket No. 40161 (August 2, 2016) attached Stipulation para. 3; *Order Approving Georgia Power Company's Request to Apply the Renewable Cost Benefit Framework to Behind the Meter Solar Technologies and to Adjust the Renewable Energy Development Initiative Distributed Generation Program Schedule*, Georgia Public Service Commission, Docket Nos. 40161 and 16573 (June 7, 2017); *see also Georgia Power's Application to Apply the Renewable Cost Benefit Framework to Behind the Meter Solar Technologies and to Adjust the Renewable Energy Development Initiative Distributed Generation Program Schedule (including the BTM Joint Recommendation as Attachment 1)*, Georgia Public Service Commission, Docket Nos. 40161 and 16573 (June 1, 2017).

procurement fees sought from RFP Participants to minimize the potential for RFP costs to exceed revenue collected, which will be presented to the Commission for consideration in upcoming RFPs.

Q. IS IT APPROPRIATE TO COMPARE COSTS AND BENEFITS FOR RENEWABLE PROCUREMENTS OVER A SHORT TIME FRAME AS STAFF DID TO SUPPORT THEIR RECOMMENDATION, WITHOUT CONSIDERING THE LONG-TERM BENEFITS THAT ACCRUE TO CUSTOMERS?

A. No. The fundamental value proposition for renewable resources is that they require significant upfront costs that are then offset by long-term low price and fixed cost benefits that accrue over the life of the asset. Further, the RFP administration costs and revenues are realized in blocks over time rather than on a regular cadence, as evidenced by the over-recovery of $21 million of revenues net of expenses in the historical period that reduced FCR costs as compared to the projected shortfall in the test period as noted in PIA Staff's testimony. Staff's characterization of Renewable RFP projected period costs as "excess" is inaccurate and misplaced.

VII. REAL TIME PRICING

Q. HAS THE COMPANY INTRODUCED A NEW RTP FUEL ACCOUNTING METHODOLOGY IN THIS CASE?

A. No. The Company continues to use the methodology approved by the Commission in the Company's 2010 base rate case (Docket No. 31958) and in practice for the last 15 years.

Q. PLEASE DESCRIBE THE CURRENT RTP FUEL CREDIT METHODOLOGY.

A. RTP incremental load is priced based on marginal cost. That revenue received from RTP customers is allocated partially to base and partially to fuel. The amount allocated to fuel is the average marginal replacement fuel cost of all Georgia Power resources operating in that hour plus Georgia Power's share of pool sales or purchases and off-system sales or purchases.

Q. WHY WAS THIS METHODOLOGY UPDATED IN 2010?

A. The RTP fuel credit methodology was updated in 2010 to better mirror the overall RTP rate and more quickly reflect changes in fuel costs incurred by the Company. The revised methodology better aligns fuel revenues and expenses attributable to RTP customers and limits wide swings in amounts credited to the fuel and base accounts during periods of fuel price volatility.

Q. ARE FIRM TRANSPORTATION OR NON-DISPATCHABLE PPA COSTS INCLUDED IN THE RTP FUEL CREDIT CALCULATION?

A. No. Firm Transportation ("FT") and non-dispatchable PPA costs have not been included under the current methodology. These fixed costs are, by definition, not marginal replacement fuel costs.

Q. WERE FT AND NON-DISPATCHABLE PPA COSTS RECOVERED THROUGH THE FUEL DOCKET PRIOR TO 2010?

A. Yes, FT and non-dispatchable PPA costs were recorded as FCR expenses prior to 2010, when the current methodology was approved by the Commission, and have continued to be since the implementation of the current methodology.

Q. DO RTP CUSTOMERS CONTRIBUTE TO FIXED COSTS INCLUDING FT AND NON-DISPATCHABLE PPAS?

A. Yes. The RTP incremental load is assessed a marginal cost-based rate. The price for RTP incremental load includes the marginal running cost of the system (lambda) even though most of the kilowatt hours sold are generated by plants with a lower running cost. As a result, most hours priced at RTP provide a contribution to the fixed costs of the system by lambda being greater than the underlying energy costs to serve them. Further, the Customer Baseline Load ("CBL") portion of an RTP customer's load is assessed the fully embedded base and FCR rate.

Q. WOULD CHANGING THE FUEL CREDIT METHODOLOGY CHANGE THE TOTAL REVENUES RECEIVED FROM RTP CUSTOMERS OR IMPACT TOTAL COSTS FOR OTHER CUSTOMERS?

A. No. As discussed in the 2000 Rule Nisi proceeding (Docket No. 11708-U) focused on RTP and Georgia Power's 2010 base rate case proceeding, where the RTP methodology was changed, a change in accounting practice would have no effect on the RTP price or the resulting revenues. It would merely shift base revenue to fuel to lower fuel costs, but the lost base revenue would need to be made up in increased base rates of those same customers who would now have lower FCR charges. This would have no lasting effect on the cost to customers.

VIII. FUEL COST SHARING

Q. WHAT IS FUEL COST SHARING?

A. Various intervenors suggested the Company adopt a fuel cost sharing mechanism, where the Company shares in the risk of the actual fuel costs in comparison to the forecasted budget on which the fuel rates are set. Based on their recommendation, the Company would absorb any over or under variance of fuel costs up to a fixed percentage. Any amounts over the fixed percentage amount are presumed to be captured through the over/under mechanism to be addressed in the next fuel rate case.

Q. DOES THE COMPANY AGREE WITH NRDC, SIERRA CLUB, AND SACE'S RECOMMENDATION TO IMPLEMENT A FUEL COST SHARING MECHANISM?

A. No. The Company does not earn a return on fuel costs and is already appropriately incentivized to keep fuel costs low. Fuel costs have always been designed as a direct pass-through on a dollar-for-dollar basis. Based on their proposal, the fuel costs will now potentially flow through as income for the Company. Fuel costs are often volatile based on market dynamics on both macro and micro-economic level, most of which are outside of the Company's control. Likewise, the Company's budget forecast of fuel costs largely depends on the inputs from independent sources from the industry and not derived solely by Company personnel.

Q. DOES THE COMPANY ACTIVELY TAKE STEPS TO LOWER FUEL COSTS FOR CUSTOMERS?

A. Yes. As a regular part of doing business, the Company seeks out opportunities to lower fuel costs for customers. In addition, there have been several activities the Company has proactively undertaken within its control in recent years to further optimize fuel costs for customers.

One such example is in its process of securing fuel transportation contracts. The Company has a demonstrated record of proactively negotiating coal transportation contracts to reduce fuel and production costs for customers, including at rail-captive generating facilities where no direct rail delivery competition exists. For REDACTED REDACTED, the Company negotiated transportation contract terms with REDACTED that resulted in approximately REDACTED in initial production cost savings over the REDACTED, with Company projections reflecting up to an additional REDACTED REDACTED in savings attributable to operational constraints and lower transportation rates secured through those negotiated arrangements. Similarly, for REDACTED, the Company negotiated transportation arrangements with REDACTED that produced no less than REDACTED in transportation contract savings over the REDACTED REDACTED period. Achieving these outcomes at rail-captive plants underscores the Company's proactive and disciplined approach to managing transportation costs on behalf of customers.

Another example is the implementation of an established, standardized heat rate program by the Company that directly links plant operational discipline and maintenance practices to measurable efficiency outcomes through defined Key Performance Indicators ("KPIs") and documented program tasks. Heat rate performance is evaluated using a consistent fleetwide methodology that focuses on controllable operational parameters and verified performance data, ensuring accountability. This operational discipline is further reinforced through centralized economic dispatch that commits and dispatches generating resources to minimize total system production cost, subject to reliability, environmental, and operational constraints. All else equal, units with better heat rate performance tend to be dispatched more frequently under this framework, while less efficient units tend to be utilized less. Because this framework already drives operator behavior, prioritizes efficiency improvements, and oversees heat rate performance through objective measurement and review rather than cost redistribution, the implementation of a separate fuel cost sharing mechanism would be duplicative and unnecessary.

Further, the Company retains natural gas storage inventory to ensure the reliability of fuel supply and for balancing daily pipeline requirements. When market prices are high, the Company can utilize that storage to provide additional benefit by offsetting high market prices with gas from storage. The Company's gas supply strategy, which includes optimization of storage, leveraging pipeline capacity that provides access to lower-priced supply, and capitalizing on gas market conditions, effectively reduces natural gas costs and maximizes value for our customers.

As evidenced by these examples, the Company takes its responsibility of prudent fuel management seriously and is consistently looking to optimize and lower fuel costs for customers whenever possible. Finally, intervenors that are advocating for fuel cost sharing have not provided sufficient evidence in their testimonies that the Company took specific imprudent actions that resulted in increased fuel costs. The current mechanism ensures that the customers only pay for the actual fuel costs incurred and there is no return earned on fuel costs. As such, any additional incentive to encourage the Company to lower fuel costs for customers is unnecessary.

Q. DO A MAJORITY OF STATES UTILIZE FUEL-COST SHARING MECHANISMS, AS INTERVENORS RECOMMEND?

A. No. As NRDC, Sierra Club, and SACE Witness Kalin indicates, there are less than 10 states with existing fuel-sharing policies.[3]

IX. NUCLEAR PRODUCTION TAX CREDITS

Q. WHAT IS THE COMPANY'S CURRENT PROPOSAL FOR TREATMENT OF NUCLEAR PRODUCTION TAX CREDITS?

A. In its Storm Damage Recovery Application in Docket No. 44280, the Company included 25% of 45U Production Tax Credits ("PTCs") regulatory liability generated in 2024 and 2025 as an offset to the revenue requirement of storm recovery costs as a benefit to customers.

Q. HOW DOES THE COMPANY RESPOND TO GAM'S RECOMMENDATION THAT NUCLEAR PTCS BE USED TO OFFSET FUEL COSTS RECOVERED THROUGH FCR-27 RATHER THAN AS AN OFFSET TO STORM EXPENSE?

A. Income tax credits, including PTCs, have always been a base rate component. The Company does not earn a return on fuel costs and, therefore, does not pay income taxes on fuel costs. Given the purpose of the income tax credits are to offset the Company's income tax obligation, they should rightfully be included as a base rate component and included in the Storm Damage Recovery Application.

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[3] See Direct Testimony of Jeremy Kalin on behalf of NRDC, Sierra Club, and SACE, Docket No. 56765 (Apr. 9, 2026) at 17.

X. FUEL COST TRANSPARENCY

Q. PLEASE RESPOND TO ALLEGATIONS THAT THE COMPANY IS LESS THAN TRANSPARENT REGARDING ITS FUEL COSTS.

A. Each month, under Docket No. 3382-U, the Company files an over- or under-recovery status of its FCR balance with the Commission, which includes actual fuel revenues and fuel costs as well as projections of the FCR recovery balance on a monthly basis until the date of the next expected fuel rate case. The Company also files monthly operating reports with the Commission, which provide general ledger details of all financial costs, including fuel costs. In addition, the Company files natural gas hedging reports monthly with transaction level details as part of the monitoring process of the hedging program.

Q. WOULD THE COMPANY SUPPORT A FUEL COST LINE ITEM ON CUSTOMER BILLS?

A. Interested customers can already request a detailed bill that provides an itemized breakout of bill components, including fuel. As such, it is not necessary for the Company to change its bill presentation.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

MS. PRYOR: In addition, with your permission, I'd like Mr. Houston to give a summary of the prefiled testimony.

CHAIRMAN SHAW: Yeah. Mr. Houston, go ahead.

MR. HOUSTON: Yes. Thank you.

Good morning, Commissioners. We appreciate the opportunity to be here again today in support of Georgia Power's FCR-27 application, our rebuttal testimony response to the critiques and recommendations of the Commission's Public Interest Advocacy staff and various intervenors. Specifically, we address feedback on the company's interim fuel rider, or IFR, the company's coal procurement, inventory management and unit commitment, fossil unit outages and replacement power costs, the natural gas hedging program, renewable resource RFP cost recovery, real-time pricing, or RTP, fuel credit methodology, fuel cost sharing, treatment of nuclear production, tax credits, and, finally, fuel cost transparency.

First, we explain why the company's requested modifications to the IFR will provide greater rate stability for customers and why maintaining the IFR in its current form does not recognize the reality of the company's growing system. We describe the company's coal procurement strategy, which is rooted in maintaining a reliable supply of coal for the generation fleet to ensure reliable and cost-effective generation when our customers need it most, and which works in tandem with our prudent inventory management practices.

We also addressed the company's approach to unit commitment. Although the company economically dispatches resources on its system to minimize the total cost of serving native load, there are several operational limitations and constraints that must be considered in the company's unit commitment decisions. Regarding fossil fuel outages -- regarding fossil unit outages, we respond to PIA staff's recommended disallowance related to the two outages at Plant McDonough combined-cycle units 5-B and 6-B, which it alleges were imprudent, along with the outage at Plant McIntosh combustion turbine, for which there were no replacement costs. We provide additional context and information for each of these three events and explain how the company's actions were reasonable before, during, and after each event.

Our rebuttal testimony also reiterates the purpose and importance of the Commission-approved natural gas hedging program. We continue to support the company's request of program modifications, given the exposure of our fuel costs to natural gas price market, net natural gas price in the market. We explain how customers benefit from continuation of the hedging program, which protects against price volatility, and explain why the effectiveness of the program should not be simply measured by historical gains and losses.

As it pertains to renewable procurement and program cost recovery, our rebuttal testimony explains why the Commission should continue its long-standing practice of allowing both the revenues and expenses associated with future requests for proposals, or RFPs, to be included in the fuel cost recovery mechanism to align with where the benefits of renewable programs are recognized.

Next, we address PIA staff's testimony regarding RTP fuel credit methodology, which the company has not proposed changing, and respond to intervenor recommendations regarding fuel cost sharing mechanisms. We dispute the notion that the company does not have an incentive to lower fuel costs for its customers. And we detail several

activities the company has proactively undertaken in recent years to optimize fuel costs for the benefit of our customers.

We also explain why using nuclear production tax credits, or PTC, to offset fuel costs recovered through FCR-27 are appropriately a base rate component, and, therefore, should not flow -- flow through the fuel costs.

Finally, we conclude by describing the company's ongoing actions that provide the Commission and the public with sufficient insight into the company's fuel costs. This includes the monthly over- or under-recovery status of the FCR balance filings made with this Commission, as well as monthly operating and hedging reports.

We continue to support the company's FCR-27 application and requested FCR rates as modified, which will result in a decrease to customer fuel rates. The company's proposed changes to the IFR and hedging program further support customers by providing greater rate and price stability.

The company has currently managed its generation resource fleet and the company respectfully requests the Commission to approve the FCR-27 application.

Thank you for your time and consideration.

MS. PRYOR: Thank you.

Chairman Shaw, the panel is now available for questions from Commissioners, as well as cross-examination.

CHAIRMAN SHAW: I would just ask that -- I know that staff has recommended, as well as other parties, to study -- further study the RTP model and how the large loads affect that, particularly around fuel costs.

I mean, does the company have a stance on that or do y'all object to looking at the RTP in a separate docket?

MR. EVANS: Commissioner, we always are happy to work with Commission and staff on any issue. Going into the next rate case, one of our primary objectives -- going into every rate case is to evaluate the effectiveness of all of our rates.

We're going to be doing that going into the next one with or without a docket. We're always happy to work with the Commission and staff and our customers on any issue that -- that's emerging.

CHAIRMAN SHAW: Well, what's -- the reason why staff is looking at this is because we are in a different situation now with the amount of load increase, just the overall impact, as far as costs alone. And it is complicated the way you price these -- these customers.

And particularly with the increase in -- I mean, we've heard it said that 98 percent of the load growth is from commercial industrial and large load customers. So it is -- it is complicated. It is something that I think needs to be looked at.

MR. EVANS: Yes. Yes, Commissioner. And we are. We will. We've been continuing to look at it -- right? -- and bring forward improvements as we saw fit.

The rules and regulation changes last year that this Commission approved are an example of that; right?

That we don't wait for -- for a rate case if we see something that needs to change; right?

We're going to continue to look at that and the effectiveness of it. We can talk today about how RTP was designed, how it is covering those costs, how the commitments we've made show that; right?

CHAIRMAN SHAW: Yeah. I mean, you're the expert. I've always -- I've always enjoyed listening -- hearing you, you know, when you're on the stand. Because you -- you are knowledgeable on the subject at hand. And so I know there will be some good questions around that today.

I just wanted to start out and say that I also have -- have concerns about that and look forward to hearing what you -- what you say.

MR. EVANS: Yes, sir.

COMMISSIONER HUBBARD: Yeah. Let me go ahead and jump in with a few questions, if I can. Let's maybe just pick up right where Chairman left off there on the large load customers.

They're on the time-of-use supplier choice monthly access charge. The large load customers that are 100 megawatts or larger; is that right?

MR. EVANS: The new ones.

COMMISSIONER HUBBARD: The new ones, right.

MR. EVANS: The new ones that have taken effect under the new rules and regs approved last year are on that rate; correct.

COMMISSIONER HUBBARD: And they're paying real time pricing rates on time-of-use supplier choice?

MR. EVANS: Yes. And be more -- a little bit more specific. Because that time-of-use supplier choice -- right? -- has a couple of different

options under it.

They're on what's called the monthly access charge option. And what that does is, as you said correctly, prices them at RTP for their energy usage, and then has a customized monthly access charge, a fixed charge that each of those customers pay that then cover the associated -- and make a contribution towards associated embedded and fixed costs, in addition to what the RTP rate would be.

COMMISSIONER HUBBARD: Got it. Okay.

Normally with an RTP customer, they have to have some history -- right? -- to establish a customer baseline. But in this case, what -- their application for electrical service, that's used as -- kind of to establish that baseline; is that -- is that right?

MR. EVANS: I would say existing customers have to have that. We have offered real time pricing with a customer baseline to new loads locating to the state for some time now for many years. That is -- like all of our real time pricing offers, regardless of whether it's on the monthly access charge option or the traditional RTP rate with a customer baseline, all of those have to still, one, cover their marginal costs, as RTP is

designed to do, make a contribution to embedded cost -- therefore, benefiting all customers -- and still pass the rate impact measure test and our associated economic thresholds.

So regardless of the option, whether -- because for new customers -- right? -- that are not on the rules and regs that are eligible for the monthly access charge rate, they could get an RTP offer and a monthly access charge offer together. Those are passing the same economic thresholds. One is not more advantageous to the customer than the other, and one is not putting less downward pressure on rates than the other.

COMMISSIONER HUBBARD: So they can choose between RTP or monthly access charge, you're saying?

MR. EVANS: The non-rules and regs new 100 -- or customers above 100 megawatts.

COMMISSIONER HUBBARD: Right. Well, help me then understand how you're accounting for that required firm transportation of fuel for these gas-fired power plants that the Chairman mentioned. You know, 98 percent of which at least, in terms of gigawatt-hours, the accounting for in this fuel cost recovery are attributed to those new large load customers.

How are you accounting for that firm transportation for fuel in the monthly access charge, or the RTP, whichever they select?

MR. EVANS: Certainly. And just this one -- I heard this stat a couple of times yesterday. The 98 percent is for all commercial and industrial, not large loads, not data centers and things like that. It's for all of our load growth in the commercial and industrial class.

Now, we know a lot of those are large loads and a good portion of those large loads are data centers. And so the foundation of RTP, it consists of five components; right?

One of those components that occurs in every single hour of every -- is lambda. And I heard a couple of things yesterday that I'd like to adjust and correct; right?

Lambda is the marginal operating costs of the highest economic unit running on the entire system; right?

That is higher than our embedded RTP fuel rate. It always is substantially higher. Those customers, hour by hour, are paying all of their energy based on the most expensive economic unit running; right?

That delta, which is -- you know, this is getting into our embedded cost of service studies and our rate-making treatment and things like that. But that delta between that highest economic unit running and our RTP fuel credit is that -- is what we have historically called capital substitution.

It's the revenue that these customers pay to reflect fixed costs, like firm transportation, like additional capital costs, things like that, that the company invests to result in lower fuel costs; right?

As you know, through our resource planning process, we're always looking for the most economical builds and most economical generation resources. Sometimes that results in additional fixed costs being incurred for a lower fuel cost over the operating life of that unit; right?

So by paying lambda, the highest operating cost on the system in every single hour, that delta that is above fuel for every year is then established to make that contribution to things like fixed costs, and like FT.

And to just give you an order of magnitude -- right? -- this is very clear in every one of our cost of service studies that we filed with the Commission in a rate case; right?

Those capital substitution costs are removed from every other rate and rate class and directly assigned to the RTP rate to bear. They have to bear all of those costs. And to give you an order of magnitude, I believe our last cost -- historic cost of service study filed with the Commission was 2021 test year. Or historic year. Pardon me.

In 2021, that capital substitution amount for lower loads than we're going to see was over $200 million. I believe staff's analysis of FT costs that RTP should bear were $19 million a year. So we're talking an order of magnitude more of what costs are recovered from RTP customers for fixed costs than what the FT was historically.

Now, we know those costs are going to go up for FT. We know the RTP load will also go up. And because the RTP load will go up, that's priced on lambda, that capital substitution amount that I mentioned will go up proportionally, too.

So as those FT costs rise, so does the recovery of those costs and recovered through -- and transparently shown in our cost of service studies.

COMMISSIONER HUBBARD: 19 million sounds awfully low for firm transportation costs, if that -- I realize that was back in 2021 and the last cost of service study that was done. And we didn't -- we didn't have -- we haven't had a cost of service study service done since that time.

Although, as the Chairman pointed out, there's been a pretty substantial shifting in the ground underneath us with respect to these large-load customers.

So that 19 million sounds awfully low. I -- firm transportation costs allocated to RTP customers, that's what you said?

MR. EVANS: So that is not our analysis. I was taking that directly from staff's testimony. I believe it's -- I can tell you the table, but they said $57 million a year.

They calculated over a three-year historic period. That's $19 million a year. I'm just taking their FT allocation and comparing it to the capital substitution amount in 2021 was over $200 million.

So the cost that we recovered from RTP customers for things like FT was $200 million in a single year, compared to staff's analysis that would indicate $19 million.

COMMISSIONER HUBBARD: Okay. And then take -- take-or-pay contracts. Can you talk to me about those?

I just need to understand. Do those include all renewables: biomass, solar, wind?

Is that what's included in take-or-pay contracts or what do you mean by those?

MR. EVANS: Certainly. So, yes, it is the contracts that have fixed -- that we -- that are not dispatchable. We cannot dispatch them. They do not come on the system economically.

For lack of a better word, they are economically unusable in our dispatchable system -- right? -- because those do not vary.

If a kilowatt-hour comes onto the system, we do not pay more. If a kilowatt-hour comes off of the system because of response to RTP prices, we do not pay less. They are not included and have never been included in the definition of average marginal replacement fuel costs, which for over 16 years has set the RTP fuel credit in the fuel docket.

But, now, one thing to mention is that that definition existed long before the accounting change in 2010. That's been part of how we dispatch the system. It's been talked to this Commission and staff for years and years prior to 2010. That was a well-established process that then was adopted to reflect the fuel accounting for RTP, but it did not drive it.

COMMISSIONER HUBBARD: Okay. Let me -- just a few more questions, if you don't mind.

MR. EVANS: Sure.

COMMISSIONER HUBBARD: Can you help me understand? So staff also did some analysis where they removed some of those large loads from a -- from their analysis and the dispatch and RTP rates went down 5, 11 percent, something like that. I also know that you're asking for an increase in the interim fuel rider. And there's a carrying cost to that.

So help me understand how you're accounting for some of those additional carrying costs for the increase in RTP rates and other things that are being driven by these large commercial customers. How you're accounting for those in -- in the monthly access charge, for example, in your time-of-use service supply choice.

MR. EVANS: Sure. So a couple of things there. One, I think -- I believe their analysis, which we had a -- I think in cross yesterday, we had some trouble mapping exactly where that data came from.

But I'll take it at face value because I think we can understand that fuel costs go up the more load you serve. That is -- that is true. We are serving more load. That is true; right?

COMMISSIONER HUBBARD: The quantity is going up, but also the -- the increase in demand is driving up the price of that, as well.

MR. EVANS: Absolutely. The cost is going up as the load goes up. That is one-half of the equation. I think with every kilowatt-hour we serve, whether -- regardless of who it's from, our costs will go up.

To look at cost in isolation is irrelevant without looking at the revenue associated with that load; right? So, yes, the fuel rate will go up. Also, the RTP fuel credit will go up. Also lambda, which they pay every hour, which is above both of those, will also go up.

The revenue will go up with this load associated that drives that cost increase, just like it always does for every kilowatt-hour.

COMMISSIONER HUBBARD: Okay. One or two more questions, then. Did -- was the company able to provide any kind of -- I saw a qualitative argument in the rebuttal on the price stability that's provided to ratepayers from the hedging program. Was there any kind of quantitative analysis on that hedging program?

Again, we talked about 17 years of losses, four years of gains. I know that that's not the intention, but is there any quantitative analysis that you provided to support the hedging program and the benefits that are provided?

MR. HOUSTON: I mean, I would say the quantitative analysis is the results of what we've seen over the last 20 years. There is a graph in our rebuttal testimony that shows if prices spike, having a higher hedge limit will put downward pressure on the exposure to natural gas, but no additional quantitative analysis.

COMMISSIONER HUBBARD: Okay.

MR. BERRIGAN: Commissioner, can I just add?

COMMISSIONER HUBBARD: Sure.

MR. BERRIGAN: The quantitative analysis backward-looking is one thing. The gas hedging program is not meant to be speculative. So any forward-looking analysis doesn't really apply to the purpose of the program; right?

The purpose of the gas hedging program is to be consistent, disciplined -- disciplined approach to providing stability, you know, for those fuel prices for our customers. So anything forward would be speculative and probably not tell you what you need to know about the benefits of the gas hedging program.

COMMISSIONER HUBBARD: And then maybe just one -- two more questions. So there was a pretty large identification of uneconomic coal dispatch to the tune of 152 million over the last three years. And -- now, I know that I asked about this at the end of the day.

There wasn't any analysis provided from the company, to my knowledge, about the security-constrained economic dispatch that would back up all of the things on page 14 of your testimony: binding transmission, facility ratings, contingency constraints, voltage support requirements, reserve obligations, minimum operating levels, all of that sort of thing.

My concern is that we are extending these coal plants for large load customers and others for at least another decade through 2038. And if we are uneconomically dispatching these coal units, we need to wrap our arms around that and understand what plan may be in place. Because 152 million over three years, if that is the right number, extended out another 12 years or so, we're talking about a large amount of money that may or may not be prudently spent.

So is there a plan in place to -- I mean, we don't know yet. We have someone who is saying that there's uneconomic dispatch and then you're saying there's not. But we don't have the data to kind of substantiate that.

So I'm just trying to understand: Should we expect more of the same of what intervenors are considering to be uneconomic coal dispatch or do you have any kind of attempt or plan to mitigate that, if there is uneconomic coal dispatch?

MR. OHLSON: If I could address that. I did listen yesterday. I did listen to the testimony that was provided on that analysis. And my opinion is that it's deeply flawed.

There was -- so I don't believe that it shows true uneconomic dispatch. Or, really, we could talk about the difference in commitment of coal units and dispatch of coal units. But, yeah, I did hear yesterday Mr. Hewitson talked about minimum downtimes. And it was argued that the minimum uptime and downtime of the units were different.

And, in fact, Mr. Hewitson was correct. Those units do have a seven-day minimum up and minimum downtime. That's a significant assumption to change in a model and will absolutely drive those results to be much higher, in terms of what he was looking for.

There's other issues, as well. When you remove these large loads from the analysis, since the lambda changes, there's a lot of different impacts that can occur that are not accounted for. Having those units committed also avoids things like CT startup costs and other reserve costs.

So I would respectfully submit that that analysis was flawed and I do not believe it shows economic commitment or dispatch. And I do not believe that we perform economic commitment or dispatch.

COMMISSIONER HUBBARD: But we don't -- we don't -- we have to take your word for it because we don't have that evidence of binding transmission facility constraints and other things of that nature; right?

MR. OHLSON: I'm sorry. Can you repeat?

COMMISSIONER HUBBARD: It's not a question. It's more of a comment that we have to take your word for it.

MR. OHLSON: And based on the questions and the -- the topics that we've been discussing over the last several months with staff, we have begun to implement some recording of unit commitment, and specifically coal units. It's very difficult from a system perspective to tell you why anything is committed at any given time. Many different units with many different constraints.

The electrical system has, you know, stability and reliability needs. And all those things are considered on a daily basis. But specifically to coal plants, there are, you know, a finite number of commitment reasons. And we're seeking to log those so we can explain them better.

COMMISSIONER HUBBARD: Okay. Last question. So I heard -- well, is it the company's position that there were zero imprudent actions taken by the company that led to forced outages?

These last three years were 100 percent prudent operations?

MR. BERRIGAN: Yes. Correct. I mean, yeah, I know there was discussion yesterday about whether or not there were -- maybe a mistake made or, you know, a reason for each individual outage. But we fully believe that the company was prudent in its actions before, during and after each one of those outages.

And so, yes, I mean, you know, we -- there was debate on the specifics of each one of those. But, yes, I mean, the company acted prudently in each of those.

COMMISSIONER HUBBARD: Okay. Thank you.

CHAIRMAN SHAW: All right. Any other questions?

(No response.)

All right. Georgia Public Service Commission.

MR. COLLADO: Good morning.

CHAIRMAN SHAW: Good morning, Chris.

MR. COLLADO: Good morning, Mr. Chairman.

CROSS-EXAMINATION

BY MR. COLLADO:

Q. Good morning, panel.

A. (Witness Houston) Good morning.

A. (Witness Berrigan) Good morning.

A. (Witness Ohlson) Good morning.

A. (Witness Evans) Good morning.

Q. I want to continue this conversation we started about coal, but I want to talk about procurement first.

And, Mr. Ohlson, that's sort of your realm; correct?

A. (Witness Ohlson) Yes.

Q. You work in coal procurement. Are you -- would you also be involved in decisions related to coal dispatch?

A. (Witness Ohlson) Not directly.

Q. Not directly, okay.

In your rebuttal on page 12 and 13, starting at line 27, you state: Accordingly, the company limited the higher price volumes to a modest share of Plant Bowen's projected needs, less than 10 percent of the relevant years, and used those times to mitigate supplier risk within Bowen portfolio, rather than as a replacement for the core Illinois Basin and the NAPP supply.

And by higher price volumes, this was discussing diversification of suppliers; correct?

A. (Witness Ohlson) Correct.

Q. Okay. Does the company have any internal policies or procedures in place that limits the amount of higher price volumes to a modest share?

A. (Witness Ohlson) If you're asking if we have specific restrictions on that, no.

Q. Okay. Then what drives the company's analysis on how much of the coal supply needs to be subject to this kind of diversification?

A. (Witness Ohlson) Okay. So our mission is to provide reliable and economic supply of fuel to our plants so that our plants can provide reliable and economic performance for our customers. And all of this is trying to maintain reliable and economic decisions, you know, for the customers, which are in the center of what we do.

Part of that reliability is diversification amongst coal producers. So this is specific to Plant Bowen. And specific to Plant Bowen, we buy from basins on the eastern side of the United States, like the two basins, two of which have proven recently to be lower cost, and the third has separated itself with a little higher cost.

All three are important to us for geographic diversity when it comes to our supply chain. So this is where we try to keep trains moving, avoid transportation congestion that can occur at the load-outs at the mines. It can occur from other natural issues, flooding, whatnot that can occur along the lines of the haul. And it can also occur from producers having issues at their mines.

So having a geographic diverse supply is important to us. That is part of our reliability column. But also on the economic side, we do recognize that this particular basin has separated itself with higher cost. And that's why it was limited to 10 percent.

So I would say that -- to your question about how we do that, it's through prudent judgment to maintain reliability, but also provide the coal supply at a reliable -- on a reliable basis at the least reasonable cost.

If I could point out, too, the -- the number, in terms of the volume that was included for that diversity purchase, is not indicative of the additional cost that it made; right?

So -- so when you look at the -- you call it a premium that we paid for that 10 percent component, when spread across the portfolio, that number is much less than the volume percentage.

Q. But the 10 percent isn't a limit. That's just how much it was used in a specific case; correct?

A. (Witness Ohlson) In this specific case, that was our prudent judgment limited to -- it's actually, I think, 9 percent, but we can say 10.

Q. Would the company be willing to establish a policy that limits the amount of higher-priced contracts that it enters into so that transparent policy could be implemented?

A. (Witness Ohlson) So I think that we would be willing, as we said before, to work with the Commission on anything, in terms of having some framework and guidelines. I would say that my hesitation on putting hard numbers to that is that we don't know what the markets will look like in the future.

And so putting bounded percentages or costs on that could preclude us from prudent decision-making in the future. A discussion on a framework or a guideline would be -- we would be acceptable to that.

Q. And moving further down the page, on page 13, line 26, you state: As rail companies' ability to provide service flexibility has decreased, Southern Company has transitioned to a more proactive coal inventory management process to mitigate a more restrictive coal supply chain and ensure reliability of our fuel supply to our plants.

Could you explain how the rail companies' ability to provide service flexibility has decreased?

A. (Witness Ohlson) Yes. So if we could go back to 2011, FCR-22, that's when the current inventory targets were established for our coal plants, the 40 to 50 days. At that time, the amount of coal generation, the capacity factors of coal units was -- was much greater. And, therefore, the -- we had a lot more producers to buy from and the railroads allocated a lot more resources to the coal industry. So that means they had a lot more locomotives, a lot more crews hired on the coal lines to haul.

Since 2011, we have seen a structural decline in the coal industry; right? A lot of unit retirements and across the board in the industry we're seeing about 70 percent reduction from that period of time into what the current coal industry looks like today. And Southern Company and Georgia Power is no different.

So, as such, the producers have rationalized their industry; right? There are far fewer producers for us to buy from. And the railroads have also rationalized their business. So fewer locomotives allocated to the coal or coal business, fewer crews hired and trained along these lines of haul. And so what that does is it reduces the flexibility that the supply chain has to meet our coal plants' needs.

So back at that time, the design was -- the units basically, quote, ran from the trestle, which means they were expecting trains to show up and support real-time operations. The railroads and the supply chain can no longer provide that service. And so we've had to adapt to that. So that's what I mean by the lack of

flexibility in the supply chain.

Q. Okay. Now, linking your explanation there to the company's new coal inventory management process, has this decreased flexibility increased the need to increase coal inventories at the plant?

A. (Witness Ohlson) So at times the answer is yes. At times it's the opposite. So in order for us to manage coal plant operations -- right? -- so coal plant operations are based on coal costs versus the kind of need for the plants at the time through whatever the load forecast or -- or the current load or natural gas prices are at that time.

So while the coal that's purchased, it's delivered fuel cost is -- is pretty consistent. We know what that's going to be. We're operating in a much more uncertain world, in terms of what the -- how often the coal plants will be called based on load fluctuations, natural gas volatility.

So given this more rigid supply chain, and on the other side, this more -- this need for flexibility of coal plant operations, we have had to use the pile as a bit of a flex point between those two. And so what that means is that we have a steady state of coal arriving at the plant through our transportation partners and coal producers. And we -- in times when the plant is not

called on operations, we are stockpiling that coal and sometimes building it above target.

The flip side is that when we have periods of high burn -- and we've seen those just prior to this test period and when the supply chain was not keeping up with the coal burn, we were supplementing that from the pile. And actually inventories drew down below the target.

So I would say that the rigidity in the supply chain has caused us at times to be above our targets. At times it can cause us to be below. And that's why the targets are always a long-term goal for us to -- to see, to move back to.

Q. If the company needs to maintain larger inventory levels because of this need for flexibility with inventory, will the company request a change to the target inventory levels from the Commission?

A. (Witness Ohlson) We are not currently suggesting a change to the target inventory levels. It has been common practice -- I think as long as I've been associated with it, for us to use the pile to build up before a summer peak season or a -- or a winter peak season in order to make sure that the plant is well supplied and can provide reliable service to our customers. So a little extra protection against supply chain disruptions.

That's been a standing practice. So we've tried to move a little high in the range or even above before those peak seasons. And then we anticipate that coming out of those seasons we may be a little below. And then we'll use the shoulder periods to build back up.

Again, I would say that at times we are -- when we are above target, it's because we're doing -- we're managing that supply chain in the interest of our customers and allowing them to choose cheaper generation options that are available at the time. And we'll stockpile that coal and hopefully wait until we're called upon to run those units.

Q. I want to switch over to staff's testimony on page 25 and 26. Is everyone there?

Okay. On page 26, line 13, staff states that the company standard operating procedures to commit and dispatch the lowest coast -- lowest-cost generation available, subject to identifiable constraints.

Mr. Ohlson, would you agree with that statement? Or anyone on the panel, sorry. I understand this is kind of moving to a different situation.

A. (Witness Ohlson) With the heavy emphasis on subject to identifiable constraints. So economics is clearly part of our goals. However, reliability and system constraints and unit constraints present real physical challenges that sometimes, you know, looking at a strict energy merit order or, you know, if you were just to look at the dispatch cost of a plant, that doesn't tell the whole story in any way.

Q. Sure. And with regards to those constraints, you guys have mentioned other -- you guys have mentioned other factors that come, which mean -- you guys have mentioned other factors that come into play, including reliability, production costs, coal supply availability, and coal inventories; correct?

A. (Witness Ohlson) I'm sorry. I had a little trouble hearing that question.

Q. Yes. Sorry.

And among the constraints that the company has identified in some of its data request responses, they've mentioned reliability, production costs, coal supply availability and coal inventories. Would you agree with that?

A. (Witness Ohlson) Can you repeat the four again?

Q. Reliability, production costs, coal supply availability and coal inventories.

A. (Witness Ohlson) And this was -- those are not all of the --

Q. No. No, no. This wasn't supposed to be an

exhaustive list.

A. (Witness Ohlson) Okay.

Q. These are just ones that are mentioned. I'm just trying to kind of identify some of these constraints that you mentioned.

A. (Witness Ohlson) I would agree that those are some of the constraints.

Q. Sure. Okay. So if a unit's coal inventory was running significantly above target, could that be a reason under Georgia Power's own procedures to dispatch that unit in order to draw the inventory down?

A. (Witness Ohlson) So, yes. Coal inventory management at times can include the curtailment of a coal unit when coal is scarce and we are holding the unit back in order for higher periods of -- of need. And it can also include periods of high inventory where we need to lessen the pile and -- for safety reasons and physical constraints at the plant, yes.

Q. Okay. And in those moments when that type of decision needs to be made, the company is sort of forced to move off of the lowest cost generation available, just, you know, factor it into one of these other constraining factors; correct?

A. (Witness Ohlson) Again, I think that question is misleading because you're comparing it to almost a

false choice. So we have made prudent decisions on the coal purchases, prudent decisions on the delivery schedule for those -- delivery schedules of those purchases.

And then that is all based on forecasts and -- of load and natural gas prices and -- and coal plant operations. So once those commitments are made, so -- to ensure that we have a reliable supply at a reasonable low cost for our customers -- once that plan is in place over the coming months or years, forecasts -- those forecasts can change and we have to manage those commitments.

Those commitments are still, in my view, very economic overall because it makes sure that our plants are reliable for those higher-cost needs when called upon. So if there's some, you know, small periods of time when we manage the coal inventory pile, that is the economic decision for the constraints that we see at that time. And it's all meant to ensure that the plant stays as a reliable source for our customers.

Q. So shifting our focus back to page 25, there is a graph in the trade secret version of staff's testimony, Figure 3.

A. Yes.

Q. Okay. And without getting into the actual numbers, do you see how the inventory of specifically

Plant Scherer specifically relate to the target inventory as -- as shown in that graph?

A. (Witness Ohlson) I do.

Q. Okay. Given the target versus actual in those plant's coal inventories, is it likely that Plant Scherer was dispatched because inventory was too high?

A. (Witness Ohlson) I do not think you can draw that conclusion from this chart.

Q. When a plant's inventory is above the target, does Georgia Power have an incentive to dispatch the unit more, even if it's not the cheapest unit available, in order to bring that inventory back down?

This is sort of what you said before in your previous answer; correct?

A. (Witness Ohlson) That is -- that is not based on the target phase. We do not invoke any coal inventory management in order to arbitrarily get to a target, no.

Q. Going to change gears to talk about outages, moving back to your rebuttal testimony on page 18. And also, this was also -- there's some redactions in this section of your testimony. A lot more than the redactions in the nuclear testimony. Is there a reason for that?

I'm just curious. It's okay. You don't have to answer that question. I was just --

On page 18, line 14, there's a discussion about McDonough 5-B outage on November 25th, 2023, talking about the root cause factor for that.

Panel, do you see that section?

A. (Witness Berrigan) Yes.

Q. Okay. On page 19, line 3, paraphrasing, the redacted or invert- -- inadvertently installed in a way that allowed the electrical fault to cure -- to occur.

With that statement, isn't the company saying here that there was a mistake that led to the outage?

A. (Witness Berrigan) Yes. And I think as we -- it was discussed earlier -- right? -- the definition and as we think about prudence -- a prudent decision or what was clearly imprudent, we're acknowledging that a mistake was made; right?

That the company and that the employee didn't act to a level of perfection in this case. But, you know, thinking about prudent and the training of that employee, the work that was performed before, during and after that outage -- right? -- it's an isolated incident, there's no history, this isn't an overly complicated task that was performed, and, yes, there was a mistake made.

But the company has provided training. The company has ensured that everything was corrected as a result of this. And so, from a prudence perspective, we believe that the company was prudent related to this outage.

A. (Witness Houston) Yeah. And I would also say that the protective systems operated in this case. So it's a -- it's a whole cascading level of work and protections that are put in place.

So as Mr. Berrigan pointed out, this was routine maintenance. The unit tripped offline based on the protective systems. And we have no history of issues as it relates to this type of work.

So you put all those things together between, leading up to this, what happened at the time, the quick response, and then the -- the analysis that was done afterwards. And we believe that this was prudent.

Q. You mentioned the mistake made by the worker. Would you also agree that maybe there's other mistakes that weren't -- that were from other people, including maybe the foreman or the supervisor who did not check the work of the installation on this part?

A. (Witness Berrigan) And, again, I don't -- I'm not sure what kind of work was performed outside of the one employee. Again, we're saying there was a mistake made by this employee. And, again, isolated incident and all the things that Mr. Houston mentioned.

A. (Witness Houston) Yeah. I mean, I -- I would add that certainly there was a mistake made, but it

was routine work. There was a work order that went along with that.

And supervisors, they do not check every piece of routine work. I mean, there's a lot of work that needs to be done on the plants. And not every single piece of work is checked off by a supervisor. That would be duplicative efforts.

Q. Okay. And moving down to page 20, there's discussion about an outage at McDonough on Unit 6-B on January 1st, 2025. Without getting into trade secret details regarding the outage, is this not a similar situation where a human error by the design engineer led to the outage?

A. (Witness Berrigan) Yeah. On this one, I would say it's -- it's not similar in that the -- the mistake that was made here was a result of contractors' work. And, you know, the -- the checks and balances that the contractor or the original equipment manufacturer has.

This -- this was not a mistake of a -- of a Georgia Power employee. And, further, again, I mean there's controls around, you know, oversight of the contractor.

The contractor has their own procedures that they're performing. You know, as a result of this, you know, there were -- there was an additional four -- the

first four rows of blades in the turbine were replaced by the manufacturer. That work was performed and no charge to the company.

And so there was -- I'll say, you know, the -- the contractor acknowledged this being their fault and that they then compensated through, you know, newer equipment as a result of that.

A. (Witness Houston) And I would also add, it's true, if we were using an unqualified contractor, that would certainly be imprudent. But this contractor knows this equipment better than anyone. So they're qualified, they're experienced. They've been on the site.

And -- and the issue at stake here was this was their work. And there's no way we could have known that they had not done this particular function. So when you put that all together, we believe that it was prudent.

I mean, I think of it as an analogy of, say, if you went to a board-certified surgeon; right? You went to the surgeon, the surgeon made a mistake on a technical error. That's not imprudent -- imprudence on behalf of the patient; right?

That's -- that's a technical error that the surgeon made. So this contractor is highly qualified, highly experienced. There was no way that we could have known.

Q. I understand the distinction you're making; the fact that it was a vendor, the fact that it was a contractor.

But doesn't GPC still have site access in the same way as if they had done it with their own crews?

Like, I'm just -- I fail to see the difference of why they would treat it differently because it was a contractor, in terms of evaluating prudence.

A. (Witness Houston) And, again, I think as Mr. -- Mr. Houston said, I mean, this contractor doing the work, that OEM is the expert on this equipment; right?

We are relying on their expertise to do the work. That's why we've hired them to do this work. And so, again, they made the mistake. And we are relying on them to do the work on our behalf.

Q. Mr. Evans, I know we've already discussed, sir -- you've already discussed with Commissioner Hubbard some matters about the RTP fuel credit methodology. I'd just like to follow up with some of those discussions you've mentioned.

Is it fair to say that the costs to RTP customers is based on one set of metrics, the marginal costs, but the allocation to the fuel and the base rate buckets is based on a different set of metrics and calculations?

Would that be a fair statement?

A. (Witness Evans) Can you repeat that?

Q. Sure. Is it fair to say that the cost to RTP customers is based on basically the calculation of marginal costs, but the allocation to the fuel and the rate buckets, which you say is part of this calculation, is based on a different set of metrics?

We're not using the exact same metric; correct?

A. (Witness Evans) So the RTP price is based on five components. The first, as I mentioned earlier, is lambda. That's included in every hour.

The next two are also included in every hour, which is line losses and a recovery factor. The -- the last two components are not included in every hour. It is a price signal to represent reliability costs for generation. That is represented on a weather-normal year over 50 hours.

The last component is a price signal to represent transmission costs. That on a weather-normal year is signaled 300 hours. So those components represent the marginal cost that the system incurs to serve an additional kilowatt-hour of load, or the cost avoided for a kilowatt-hour reduced from the system.

These components have existed for 35 years.

They have been modified and reviewed many, many times over that period of time. But they've always existed in some form or fashion.

RTP has been designed to provide overall benefits to the system of customers increasing or responding to price signals. That benefit has been substantial to Georgia Power in the state of Georgia over these decades.

It is not meant, nor has it ever been, to spread or average a preexisting cost to these customers. These customers pay their marginal costs that are incurred on the system and then some. So it's such that they always benefit and put downward pressure on existing customers' rates.

Q. Those marginal costs, would those be credited to the base revenues or to the fuel revenues?

A. (Witness Evans) Both. As we've discussed, there's an RTP credit that goes to fuel and the remaining revenues go to base.

Q. Okay. The $200 million recovered from RTP customers for firm transportation that you mentioned to Commissioner Hubbard earlier, would that be credited to base revenues or fuel revenues?

A. (Witness Evans) So the $200 million was referencing the capital substitution component. And that's the revenues received from lambda in every hour net of the fuel revenue that's booked to the FCR calls. So that is in base revenue. And that is downward pressure on base rates that every other customer benefits from.

Q. Is the FT costs included in the RTP fuel credit calculation?

A. (Witness Evans) No, no. As we said before, FT costs are recovered through the capital substitution component because they're fixed. The -- the RTP fuel credit recovers the marginal costs that result from an additional kilowatt-hour running or being added to the system or being reduced from the system.

If it's a fixed cost, it is not included in that, nor should it be. We would not want to credit a customer for FT avoided if we did not avoid it by them reducing a kilowatt-hour.

Q. And is that also a -- is that also true for the non-dispatchable PPA costs?

A. (Witness Evans) That's correct.

Q. Are there general principles or best practices of rate-making to try to match the costs and the revenues for the same types of costs and revenues in the same mechanism where you can, where it's possible?

A. (Witness Evans) So RTP has always -- and this was heavily discussed, I believe, in the 2010 docket

whenever this accounting methodology was approved; right?

In that docket, it put downward pressure on base rates because revenues were being removed from fuel and putting into base rates; right?

A -- a key consideration that we have to recognize here is that we are talking about the accounting methodology. We are not talking about changing the ultimate price that customers pay.

The RTP price is unchanged. It is just: Do the revenues show up in fuel or do they show up in base rate? Wherever they show up, customers benefit -- other customers benefit from that by putting downward pressure on those costs.

So in 2010, those revenues were removed from fuel and put into base revenue, resulting in downward pressure on base rates.

Q. But you would agree that the current methodology doesn't match those FT costs and PPA costs with the revenues; correct?

That's not the way it's currently designed?

A. (Witness Evans) That's correct. It's not meant to match fixed costs on an hour-by-hour basis because they do not fluctuate on an hour-by-hour basis.

Q. And the company currently believes that the revenues collected from RTP customers is sufficient to

cover both fixed and fuel costs; right?

A. (Witness Evans) The company is certain that it is recovering the marginal cost -- the incremental marginal cost to serve these customers, full stop, and put downward pressure on rates.

This has been shown for decades of RTP through our cost-of-service studies being the rate group -- the marginal rate group that is the closest to parity going back many, many rate cases. They are the closest ones to exactly covering their costs.

Rate groups are historically either over -- under parity or over parity. The marginal rate group has consistently been right at parity -- right? -- case after case.

Additionally, every one -- as I mentioned, every one of these offers, whether it be through the monthly access charge offer, traditional RTP offers with a customer baseline, every one of those go through the rate impact measure test that the company and the Commission have always relied on to ensure that that downward pressure on rates is occurring over the life of that project.

Q. For the RTP fuel credit, that's based on the average cost of fuel, not the -- the marginal cost of running the system; correct?

A. (Witness Evans) It is the average marginal cost of fuel. The average marginal replacement cost.

Q. Replacement cost?

A. (Witness Evans) Yes.

Q. Okay. That's the --

A. (Witness Evans) Sorry. I wanted to --

Q. It's understandable.

A. (Witness Evans) It's -- it's a long acronym.

Q. Yeah. Okay. How is it that the RTP fuel credit is so much lower than the overall supply cost on a per-megawatt basis, month over month, if the FT is supposed to be already covered there?

A. (Witness Evans) Sure. We would expect it to differ from the average. Whenever you're creating a cost -- an average cost over 2.8 million customers, the definition of an average is that groups will be above that average and groups will be below that average.

The marginal rate group RTP customers have a load factor nearly twice that of residential customers. That means they use more fuel during low-cost hours than everyone else. That drives down their price pay -- their average cost incurred.

Customers, like the domestic class rate group representing residential customers, have a load factor of less than, you know, 45 percent. I think it's 42 percent.

They use more fuel during high-fuel-cost hours. They use less fuel during low-fuel-cost hours. That drives up their average.

Q. Right. But they're also allocated more of the fixed costs; correct?

A. (Witness Evans) Can you repeat that?

Q. The -- you mentioned the -- the FCR customers, wouldn't they be allocated more of the fixed costs, though?

A. (Witness Evans) I'm not sure domestic's allocation of fixed costs in the fuel cost.

Q. Isn't it possible that one reason the FCR -- I'm sorry -- the fuel credit methodology allocates the fuel costs lower than the average supply -- I'm sorry.

Low compared to the overall supply cost is that this FCR -- the fuel credit methodology doesn't actually include the FT costs in the calculation directly?

A. (Witness Evans) Yes. I think it's important to go back to the underlying principles of the RTP rate and its existence to begin with.

Traditional rate-making methods in which average costs are spread over all customers is not and has never been how RTP is established. If we were to do that, we would not have or need an RTP rate.

RTP is meant to recover marginal cost to serve those customers and then provide downward pressure on existing costs. Existing costs, like fixed costs. If we now want to start averaging every cost on the system and spreading it over all load, including marginal load, then the RTP rate would not exist.

We have always made the distinction between marginal load existing and existing load. We've always made the distinction between embedded costs and marginal costs. That is, by design, for 35 years.

Q. I understand. Historically, I understand that, but with the -- with RTP customers having so much more of an incremental cost to serve them, do you see how it breaks down a little bit?

A. (Witness Evans) I don't. I only see it being reinforced over and over again by the company through our ARP extension, freezing base rates, with the exception of storm costs, through 2028, and then our commitment of a floor of revenue that produces substantial savings to all other customers.

Q. Is your testimony that you believe that RTP costs fully covers incremental FT costs caused by those customers?

A. (Witness Evans) Yes. And we've committed to benefits in excess of costs to this Commission through previous stipulations.

Q. What about QF costs, are they also included in the fuel credit methodology?

A. (Witness Evans) As I said --

Q. Are they included?

A. (Witness Evans) We're retreading our discussion -- my discussion with Mr. Hubbard -- Commissioner Hubbard. They are not.

Those fixed costs that do not vary -- again, if a kilowatt-hour comes onto the system, that does not change what our costs are. If a kilowatt-hour comes off, it does not reduce those costs. Therefore, they do not fluctuate in the recovery.

Q. And we've discussed that RTP customers, they pay the -- they're exposed to price utility and fuel cost. So they wouldn't pay hedging costs. That was mentioned yesterday.

But would you also agree to that statement?

A. (Witness Evans) Yes. I mean, I think we could fast forward-through -- unless it's the average incremental -- or the average marginal fuel costs, it's not covered in the fuel clause, which is a key distinction.

MR. COLLADO: All right. I have no further questions.

CHAIRMAN SHAW: All right. Thank you.

Georgia Association of Manufacturers.

CROSS-EXAMINATION

BY MR. JONES:

Q. Good morning, Mr. Chairman, Commissioners. Good morning, panel.

A. (Witness Houston) Good morning.

A. (Witness Berrigan) Good morning.

A. (Witness Ohlson) Good morning.

A. (Witness Evans) Good morning.

Q. All right. I just wanted to cover a couple of issues with you, if I could. And let's just start with hedging, which I think we've talked a lot about. So I'll try not to spend too much time on it.

But I understand from your colloquy with Commissioner Hubbard that you haven't done a strict -- a quantification of hedging benefits. Is that over any span of time?

Over 20 years, 10 years; you don't have a quantification of it?

A. (Witness Houston) No, we don't have a quantification.

Q. Okay. And when you're executing a hedging program, you purchase financial instruments of different kinds; is that right?

A. (Witness Houston) Yes. That's correct.

We -- the hedging program is not speculative in any way. I think the hedging program -- hedging instruments are well-defined. There's not a prop book or anything like that. It's purely to put a ceiling on the prices.

Q. And you're -- you're limited in the types of instruments you can choose?

A. (Witness Houston) Yes. That's right.

Q. Okay. Excuse me. And that effectively fixes the price of a certain amount of gas in future months; right?

A. (Witness Houston) Yes.

Q. And do you do that on a month-by-month basis?

A. (Witness Houston) Yeah. Continually, almost on a daily basis, looking at the market and then putting on hedges as appropriate to meet those thresholds.

Q. And so if the actual market price in the month that you buy the hedge settles below the hedge price, you record a hedging loss; right?

A. (Witness Houston) Yes. That -- that is true. But the flip side of a hedging loss, as we talked about yesterday, is a lower natural gas price, which benefits all customers.

Q. And if -- again, if the market price settles above that hedge price, then you record a hedging gain; correct?

A. (Witness Houston) Yes. That's right.

Q. Would you agree that the purpose of your hedging program, or any good hedging program, should be to allow you to meet the market, as we said, not beat it; right?

You're not trying to beat the market, so to speak?

A. (Witness Houston) Absolutely not. It's not -- this is not about beating the market, entering into sort of exotic or speculative-type transactions. Very vanilla-type instruments that are used and they are layered in over time in a disciplined way to give us the coverage up to the hedge percentage that we've agreed to with this Commission.

Q. Okay.

A. (Witness Ohlson) So can I just add to that?

Q. Please, yeah.

A. (Witness Ohlson) When you say meet the market, the hedging program is designed to not meet the market for a portion of it during certain market disruptions; right?

So it's designed to protect part of your fuel portfolio from meeting the market during those discussions.

Q. Are you saying "meeting" or "beating"? I'm

sorry.

A. (Witness Olson) I said "meet".

Q. Meeting, okay.

A. (Witness Olson) I thought you -- I thought I was using the words you used.

Q. No, you're right.

A. (Witness Olson) Okay.

Q. You're right. You're right. I wanted to make sure we were --

A. (Witness Olson) That's the --

Q. Too much rock and roll sometimes and I'm --

A. (Witness Olson) The hedging program is not designed to beat the market or...

Q. Right.

But -- so, in other words, to -- to simplify it, in the long run, the goal you should -- you should have a goal of offsetting hedging losses with hedging gains over a long period of time; correct?

A. (Witness Houston) Yeah. I think in the -- in the long run, maybe mathematically that's how it should work out, yes.

Q. Yeah. And so what is the company -- I think someone else asked this, but I wasn't quite clear on the answer. What does the company consider long term?

What would you consider long term when you're

sort of measuring the effectiveness of the hedging program?

A. (Witness Houston) Well, we're on a -- at the moment, we're on a 36-month. We can hedge out 36 months. So I would say -- I mean, there are a number of different periods you can look at the effectiveness.

You can look at each year cumulative. I think -- I think long term we try and manage to that 36-month horizon.

Q. Okay. Well, if you did that, though, it wouldn't look very good for the last three years, right, since you've had significant losses for the last three years?

A. (Witness Houston) Yeah. Certainly if you looked at the last three years, I think it's more losses than gains. In each period there are going to be individual transactions that are gains and losses.

If you look at a slightly longer period, I think you would maybe see more gains than losses, especially in 2022 when we needed those gains because of significant price increases.

Q. Right. So you could look -- you know, it all depends on the time frame you look over. Like the company's pointed out, if you look over the last ten years, it's more even out or a slight gain.

The staff has a chart in their testimony. You would agree that over the past 20 years would be losses again -- right? -- at those 21 years we keep talking about?

A. (Witness Houston) Yeah. Yep.

Q. Yeah.

A. (Witness Houston) That -- that graph is accurate, in terms of the numbers. But it doesn't acknowledge the change in the natural gas environment. Some of the years in there were pre-fracking -- right? -- and we all know what fracking has done to natural gas prices. More volatile perhaps than those earlier years.

And so, as I say, you can pick any time series. If you look at that 2025 year table, I think that's a little bit misleading. Because the earlier years where -- it's true that we did have some losses. Just the market is fundamentally different.

Q. Yeah. Okay. Fair enough.

So if we look at, though, like, just say the natural gas spot price -- Mr. Pollock had an exhibit in his testimony. Did you see it?

That sort of showed the history of that. I don't want to take the time to show it to you again.

A. (Witness Houston) Yes.

Q. But I will if you would like to see it,

but...

A. (Witness Houston) I remember there was a graph right in the back that had --

Q. Yeah.

A. (Witness Houston) -- a 50-year history of natural gas prices, but I suspect that's not what you're referring to.

Q. No. It's a little bit less than that.

So, I guess, let me just try it this way so we can save some time is the -- would you agree with me that a lot of the peaks in the natural gas spot prices come in the wintertime, over time?

A. (Witness Houston) I would not -- I would not be surprised if that's true. I just -- I don't have a --

Q. Yeah.

A. (Witness Houston) -- good enough memory of when the spikes come. Because spikes do come for reasons, other than just --

Q. Sure.

A. (Witness Houston) -- winter. There's summer.

Q. Sure.

A. (Witness Houston) Could be --

Q. Russia invaded Ukraine?

A. (Witness Houston) Yeah, yeah.

Q. Spring?

A. (Witness Houston) As we talked about, it could be macroeconomic events, so...

Q. Right.

A. (Witness Houston) If that's true, that doesn't surprise me. But --

Q. Yeah.

A. (Witness Houston) -- peaks also come in the summer and peaks also come at times you do not expect it. And that's part of the hedge program.

Q. Does the company on a month-by-month basis consider historical patterns like that?

In other words, are you trying to hedge more in January, February? Are you trying to maybe hedge less in some of the months where maybe hedging wouldn't provide as good a benefit?

Or are you just doing the same thing each month?

A. (Witness Houston) No, I think we're always looking at the market. And, obviously, seasons are very important for natural gas. Then there's the storage injection season, and then there's the withdrawal season.

So as we move through those seasons and you have an opportunity to look ahead based on a -- on a window -- that's currently 36 months. But we would -- we are requesting to extend that to 48 months.

As you look at that and you're seeing maybe fewer injections, more injections, I think that all informs the team about when to put hedges on.

Q. Do you think it would be a good improvement to the program?

I mean, I hear you're saying that you're doing that. Would it -- would it be an improvement or change the program?

And, if so, would it be a good one to focus on the winter pretty much for your hedging?

And some of these other events, like -- you can't predict. So hedging is really just more of a gamble then. But you have a pretty good sense that it's going to be high prices in the winter and maybe a better time to hedge?

A. (Witness Houston) I mean, I think we need to look at all market factors. And, you know, we -- if you -- if you put an element of trying to make a period you are trying to hedge against, then that goes a little bit against the hedge program.

I'm not saying that we shouldn't acknowledge that there are differences seasonally, but the purpose of the hedge program is over the hedge window to put enough insurance in place that if there's a sudden spike, which could be caused by something other than seasons, that there's coverage. But also acknowledging that seasons do exist, I guess.

Q. So factoring that in in some way?

A. (Witness Ohlson) Yeah. And can I -- if you have this three -- and we're asking for a four-year window look-ahead. When you're hedging natural gas, if there are patterns seasonally, those would be -- we -- they would be reflected in the forward curves that you are hedging against; right?

And it also goes a little against the -- the idea of hedging in general, which we don't know when the market disruptions will occur. I mean, we -- you can understand that seasonally gas prices will increase as demand goes up. But for reasons that you can find historically, a lot of the disruptions can happen for different reasons, as well.

So hedging is not meant to identify exact future disruptions and guard against them. It's meant to protect all the time and for what you don't know is going to happen.

Q. But you can still look at historical patterns and how you could design your system; right?

A. (Witness Ohlson) You could look at historical patterns. And, again, forward markets would -- would express those patterns, as well.

Q. Okay, okay. Moving to production tax credits. I believe on page 35 of your testimony, the panel states that there have always been base rate costs, but I'd like to ask a few questions about that.

Income taxes are based on taxable income; correct?

A. (Witness Houston) Correct.

Q. And income is the difference between your base revenues and deductible base rate expenses, which are base rate costs; is that fair?

A. (Witness Houston) Fair.

Q. But production tax credits and their value are not based on income. They're earned for every kilowatt-hour generated by a resource that's eligible for the credit; right?

A. (Witness Berrigan) And the production tax credits, or tax credits in general, are meant to be a reduction of income tax expense.

Q. Well, that wasn't my question. How are they generated?

They're generated based on kilowatt-hour usage, not on income; correct?

A. (Witness Berrigan) Correct.

Q. Okay. In other words, the same kilowatt-hour that causes Georgia Power to incur fuel costs is the same one that generates these nuclear PTCs that are issued?

A. (Witness Berrigan) Correct.

Q. Correct?

All right. And the ones at issue in this case were enacted after your '22 rate case; would you agree?

A. (Witness Berrigan) That's correct. The '22 rate case is the -- that is the -- the case that required the company to include those as a -- on the balance sheet and defer those for recognition in a future proceeding.

Q. But the specific tax credits here you're -- that you're using in the storm damages case to reduce base rates, those aren't the ones that were in existence when base rates were last set; right?

A. (Witness Berrigan) That's correct.

Q. They're in 2024 and '25.

And there's no Commission order regarding those specific tax credits as to how they should be treated; right?

A. (Witness Berrigan) The ones that we're proposing to use for storms?

Q. In '24 and '25.

A. (Witness Berrigan) The -- yes. Last summer's stipulation, the Commission -- part of that order was that the company would recognize those in income in

'26, '27, and '28 as part of the rate stay out.

Q. Well, but -- but there's nothing that would prevent the Commission from applying them here in the fuel case; right?

The Commission has the authority to do that?

A. (Witness Berrigan) The Commission has the authority to -- yes.

Q. Right. And applying -- as Mr. Pollock testified yesterday, applying those nuclear PTCs to lower -- lower fuel costs would actually benefit non-RTP customers -- right? -- because it would benefit the FCR rate?

A. (Witness Berrigan) I think from a -- a pure revenue requirement perspective, the impact would be the same. I think what he's -- what he spoke to yesterday was the allocation -- right? -- across customer classes, rate classes of how those would be beneficial to each of those different classes. But the actual benefit, the overall reduction in rates or revenue requirement would be the same under storm or -- or fuel.

Q. Yeah. That was my next question. So ultimately there's no difference in your net revenues whether you use them.

In this case, you're using them in the base -- for storm damage; right?

A. (Witness Berrigan) Correct.

Q. Okay. And of the -- the available credits that you have, the company is proposing to use 25 percent of them; is that a number I remember correctly?

A. (Witness Berrigan) In the storm case --

Q. In the storm case.

A. (Witness Berrigan) -- the company had proposed to use 25 percent of the ones that had been generated for tax years '24 and '25.

Q. And is there any consideration to using more than that since you have -- you have three times more that's sitting there?

Are there any -- any other thoughts of using additional amounts to help improve affordability?

A. (Witness Berrigan) As we -- you know, included in our storm filing, we believed that the 25 percent was the appropriate amount to include as a reduction to the revenue requirement.

Q. All right. Thank you.

So my last question goes to -- we've been talking about RTP a lot. And, Mr. Evans, you've been saying a lot about it this morning.

And you recall the chart in staff's testimony showing the difference between the average fuel cost and the RTP fuel credit?

A. (Witness Evans) Yes.

Q. And you were speaking to that earlier and explaining some of the ways that -- that RTP customers pay for FT through the capital substitution charge; right?

Is any of the difference that we see there -- and you were getting to this and I'm -- maybe I didn't hear it clearly enough. Is any of the difference there getting to the different types of load shapes that we see with RTP customers, as opposed to non-RTP customers?

A. (Witness Evans) Yes, yes. I -- I think I touched on it, but I'll -- I'll expand a little bit. RTP customers, I believe the marginal rate group's load factor is over 70 percent. I think it's about 72 percent. The domestic rate group's load factor, I believe, is 42 percent, subject to check, but I think those numbers are right.

That means that residential customers use energy during high-fuel-cost hours more as a -- as a percent of their total usage -- right? -- such that their average fuel costs incurred is higher.

RTP customers, because their load factor is 72 percent, they use energy much, much more throughout the entire year. That means that they use more kilowatt-hours during low-fuel-cost times.

We would -- as you would expect with, you know, 2.8 million customers, different load shapes, different types of businesses, manufacturing facilities, small commercial, residential, lots of customers use energy at different times throughout the year; right?

Whenever you're looking at an average, there will be rate groups that use -- whose cost is higher than that average. And then there will be some that are lower. By RTP's costs matching its actual price, they are lower.

MR. JONES: Mr. Chairman, that's all I have for today.

CHAIRMAN SHAW: Thank you, Mr. Jones.

Panel, do y'all need to take a break or are you ready to keep going?

MR. EVANS: Keep going.

CHAIRMAN SHAW: Ready to go. Good deal.

All right. We'll call up the next, and that would be Georgia Interfaith Power and Light and Southface.

MS. WHITFIELD: Chair, with your permission, I'd like Mr. Sherrier to hand out GIPL and Southface Exhibits 1, 2 and 14, which were used yesterday. He's really just handing them to Mr. Evans, who didn't receive them.

And good morning.

MR. HEWITSON: Good morning.

CHAIRMAN SHAW: Good morning.

MS. WHITFIELD: Good morning, Commissioners. Good morning, Panel.

CHAIRMAN SHAW: It is still morning.

BY MS. WHITFIELD:

Q. Let's talk about RTP, Mr. Evans. We've established that the RTP fuel credit reflects the money contributed by RTP to offset costs to everyone else in the FCR docket. Correct?

A. (Witness Evans) Yes.

Q. And RTP fuel credit is the hourly average marginal fuel cost, which is calculated using bottom of the -- bottom of stack unit costs and takes pooled sales into account as well; correct?

A. (Witness Evans) Sales and purchases, yes.

Q. The RTP fuel credit does not include any cost or compensation in the fuel docket for firm transportation; correct?

A. (Witness Evans) That's correct.

Q. It doesn't include any cost for non-dispatchable PPAs; correct?

A. (Witness Evans) That's correct. Those fixed costs that do not vary with kilowatt hour sales, but, in many cases, put lower -- put downward pressure on our fuel costs incurred; right? And I think FT is a great example

of that.

If there was no FT incurred, our marginal average replacement costs would be higher. So that's an example of a fixed cost, like there is a number of fixed cost incurred through prudent generation resource planning that we -- that the units selected have higher fixed costs at the benefit of lower operating costs and fuel costs.

Q. And the RTP fuel credit also does not include any costs or renewable program expenses, correct?

A. (Witness Evans) That's correct.

Q. Or hedging, correct?

A. (Witness Evans) Yes. Again, if it's not in the definition that you said, then it's not included in the FCR recovery.

Q. So the RTP fuel credit does not include any costs for the senior citizen fuel discount; correct?

A. (Witness Evans) Can you repeat that?

Q. The RTP fuel credit does not include any costs towards the senior citizen fuel discount, correct?

A. (Witness Evans) No. That -- that fixed cost again does not vary with kilowatt hour usage, is an embedded cost, and is not under the design of RTP in total. However, all of our RTP customers and our marginal customers have embedded cost allocation, right, and bear portions of the income-qualified discount program, which

it's now called, and that income-qualified program is spread out among all of our ratepayers.

Q. But not the senior citizen fuel discount that is specifically accounted for in the fuel docket; correct?

A. (Witness Evans) Not that portion of it; correct.

Q. Correct. So that means that everyone else, meaning non-RTP customers, are paying for 100 percent of those costs as part of their fuel charge in this fuel docket; correct?

A. (Witness Evans) Well, again, if we're talking about the accounting and splitting of base and fuel revenues, that is correct. However, it is widely known and known for many, many years, and when this accounting change was made, that it was recovered and putting downward pressure in base rates, and so the price in total is not changing. The costs are covered by these customers and it is producing well beyond the expenses incurred in the fuel clause through revenue in the basic side.

Q. You haven't provided any accounting as part of this docket for the benefit that you are describing in a rate case; correct?

A. (Witness Evans) Again, I think you can go back to the cost of service study filed in the last rate case. In all of them it's clearly identified. You see the amount of capital substitution removed from every rate group and rate. It's taking those costs away from them.

And then the next line -- and I can give you line references if needed. The next line shows all of those costs being directly allocated just to the marginal rate group. That benefit, as I mentioned in the last filed study, I believe was 200-plus million dollars for that single year.

Q. So $200 million a year is the total capital substitution costs that is allocated on an annual basis for the RTP rate in the base rate case?

A. (Witness Evans) No. That was a single year in 2021 based off of RTP loads, lambdas and costs in 2021. As you see those costs increase and those loads increase, that benefit will substantially increase. I would expect it to be far greater than that in the next filed study.

Q. Did you provide any accounting in this docket to reflect the costs that you're describing that you expect will be far greater in a future rate case?

A. (Witness Evans) No.

Q. So let's turn to firm transportation. I believe you've described today, but if not today, then certainly in your document responses, you've described that Georgia Power contemplates the RTP price as being designed to collect money from RTP customers to contribute towards firm transportation; is that correct?

A. (Witness Evans) Can you point me to where that was said?

Q. Sure.

(The document referred to was marked for identification as GIPL/Southface Exhibit 4.)

MS. WHITFIELD: Mr. Sherrier, could you please provide GIPL/Southface Exhibit 4, which is STF-PIA-3-5.

If he may approach.

MR. HEWITSON: Sure.

MR. EVANS: Just for me, or everyone?

MR. HEWITSON: Thank you.

BY MS. WHITFIELD:

Q. And do you see here that it is Georgia Power's position that RTP revenue is designed to contribute towards firm transportation?

A. (Witness Evans) That's correct.

Q. But, again, non-RTP customers are charged for 100 percent of firm transportation, correct, in this docket?

A. (Witness Evans) Again, the answer is in total benefits to customers through the total RTP revenue across basin fuel, RTP prices, which are designed in

total.

Again, the price components that I described earlier deliver a single price hour by hour to our customers that varies. On the back end, the accounting and split between base and fuel is done. So the costs are absolutely being covered through the RTP price.

Q. But you realize that by not accounting for those costs in this docket where 100 percent of the costs are charged, that means that non-RTP customers pay 100 percent of the firm transportation account; correct?

A. (Witness Evans) No, because they pay more than just the fuel costs. If they get to benefit on the base side of their bill, then they do not pay for 100 percent of the costs. They pay both fuel and base costs. They get a benefit on base that offsets fuel. They do not pay 100 percent.

Q. So your answer is no because of a future benefit that might happen concerning firm transportation in a rate case. But if we could for a moment focus on the accounting in this specific case.

A. (Witness Evans) Sure.

Q. You agree that 100 percent of firm transportation costs are charged in this docket; correct?

A. (Witness Evans) Firm transportation costs have existed beyond this case, beyond the historical year

and beyond when the accounting order changed fuel recovery in 2010. So no, I disagree. We have filed many rate cases that show those costs and benefits being recovered.

Q. I'm sorry. You disagree that yesterday your -- your co-panelists, I think we established that 100 percent of firm transportation costs of Georgia Power are accounted for to be recovered in this docket. Are you disagreeing with that?

A. (Witness Evans) No, I'm saying that that is not -- you cannot look at it in isolation, and that this is not a new issue that has come up. We have shown those benefits many, many times.

So -- and please forgive me if I have mischaracterized your question. It seemed as if you were saying that we have never shown those benefits to be offsetting, and I disagree with that.

Q. That's -- no, I'm -- I asked specifically about the costs in this docket. So let's break it down.

100 percent of firm transportation costs are charged in this docket; correct?

A. (Witness Evans) Correct. And offset by the associated revenues in the base case.

Q. And RTP revenue in this docket, as reflected in the RTP fuel credit, provides zero dollars towards firm transportation; correct?

A. (Witness Evans) And ten times the associated dollars in the base case.

Q. Correct. So you're agreeing with me?

A. That it provides substantially more in the base case, yes.

Q. Mr. Evans, I'll ask again.

A. (Witness Evans) I agree that it's not in this docket, but I disagree that you can look at the docket in isolation.

Q. That's okay. We can -- we can agree to disagree on that.

So Georgia Power is collecting those revenues from RTP customers designed for firm transportation in real-time, correct, in its monthly bills for RTP customers?

A. (Witness Evans) Yes.

Q. But the benefit that you're describing will arrive in a rate case?

A. (Witness Evans) Well, the benefit arrives as the revenue's received and goes through the accounting treatment and the regulatory process. So, I mean, the revenues show up in real-time.

Q. I'm sorry. That was a confusing question. I meant the benefit for residential and small business customers, not the company.

A. (Witness Evans) Not -- I think those benefits show up too. I mean, these revenues are not below the line revenues. They go through the rate-making process and are captured as part of the company's total retail revenues.

Q. But meanwhile, you agree that residential and small business customers are paying for one -- and not -- and other non-RTP customers, are paying for 100 percent of Georgia Power's firm transportation costs in their fuel rider; correct?

A. (Witness Evans) Again, yes, in that specific docket, that is correct. And the associated revenues in the base case are part of what also, right, as it goes through the ratemaking process and the benefits from RTP customers and large load and economic development that we have seen, are what helped us stay out of a base rate increase that customers have benefited from, with the exception of the fuel increase, and have resulted in us setting a floor of minimum revenues with substantial benefits and savings for those very customers.

Q. So I'd like to turn to non-dispatchable PPA costs, which we've covered, are not included in the RTP fuel credit. And I want to understand the scope of what you mean by non-dispatchable PPA costs.

MS. WHITFIELD: And for that, Mr. Sherrier, if you could provide, with the Commission's agreement, solar PPA tab of MFRP-1.

BY MS. WHITFIELD:

Q. And also, Mr. Evans, if you could take a look at GIPL/Southface Exhibit 14, which is MFRP Exhibit 1, line 27. These two exhibits are from the same document. One is a worksheet underlying the summary of Exhibit 1.

And recognizing, Mr. Evans, that we did not walk through MFRP Exhibit 1 together yesterday, if you need a minute to take a look at that too and sort of orient yourself, I understand. Otherwise, my question is the solar PPA tab calculates the monthly projected total costs of PPAs and QFs for solar that are recovered in this FCR docket; correct?

A. (Witness Evans) I'll take your word for it.

Q. Okay. Well, how about, then, we look at MFRP-1, line 27. Would you agree that that line item in the projected fuel expenses for the FCR-27 budget that says "Solar PPAs" reflects the total expenses in the test period for those solar PPAs to be recovered in this docket?

A. (Witness Evans) Again, I'm not familiar with the makeup or details of that MFR. I can't speak to it, what the underlying details are.

Q. Mr. Houston or Mr. Berrigan, could you confirm that?

A. (Witness Houston) Yes, that is -- that is correct, but I'm not sure if this schedule ties to the number we have there on the screen.

Q. Would it be fair for me to ask the company to correct me if that is not, in fact, the case, and let me know, so we could say that's subject to check and move forward.

Mr. Evans, the tab with a list of projects is provided to you to give you a sense of the kinds of things included in those overall numbers at the bottom of that sheet, and then the total on MFRP-1, Exhibit 1, are these the kinds of costs that are non-dispatchable costs, as you described?

A. (Witness Evans) You'll have to forgive me. This is six pages of really, really small font, and I'm not sure I can read it.

Q. That is -- that's fair enough.

A. (Witness Evans) And regardless, I'm not -- I would not be familiar with every single one of these 600 rows of data just provided to me.

Q. Are there any costs for solar PPAs or solar QFs that are considered anything other than non-dispatchable PPA costs?

A. (Witness Evans) Again, I'm hesitant to be -- to give an absolute answer, just because I do not know the ins and outs of every single one of our PPA agreements.

Q. Okay.

A. (Witness Evans) So I know the process that we go through in determination of what is or is not included in that average marginal replacement cost calculation, so that -- such that if a unit is not dispatchable, right, then it's not included. So if we have dispatchable PPAs, then I would imagine it would be included without knowing those details.

Q. Would that be something that the company could provide as part of a hearing request --

A. (Witness Evans) We can confirm that.

Q. -- which aspects of that line item and/or that itemized sheet are considered to be dispatchable versus non-dispatchable costs? Could you provide that as part of a hearing request?

A. (Witness Evans) We can certainly try. I don't know that -- this is not my area of expertise with the PPA, so I'm hesitant to commit to something that there might be nuances with, but --

MS. WHITFIELD: But, Mr. Chair, we'd like to make a hearing request for an itemization of which components of these solar PPA costs are considered non-dispatchable PPA costs.

MR. HEWITSON: Good.

BY MS. WHITFIELD:

Q. I'd like to ask you about wind generally. Is wind generally considered a non-dispatchable PPA cost?

A. (Witness Evans) Again, that would -- that would be dictated by the PPA terms of the agreement.

Q. How about biomass PPAs? Are those considered non-dispatchable PPA costs?

A. Same thing.

MS. WHITFIELD: Okay. Commissioner, I'd like to make a hearing request for an itemization of which of the costs included in MFRP-1, line 29, that's wind, and MFRP-1, line 28, that's biomass, are considered to be non-dispatchable PPA costs.

MR. HEWITSON: Very well.

BY MS. WHITFIELD:

Q. Mr. Evans, what do you consider to -- what -- what categories are generally considered to be non-dispatchable PPA costs as you testified to in your testimony --

A. (Witness Evans) Sure.

Q. -- at page 31.

A. (Witness Evans) It would be if -- if they are dispatchable, meaning we can control when they put energy on or off the system such that we are not obligated takers when they are economically unusable and therefore do not provide economic benefits to the system.

Q. So you testify that non-dispatchable PPA costs were recorded as FCR expenses prior to 2010, and, in fact, they're -- they're still recorded as FCR expenses. I think the question is about RTP's payment. But I'm curious how you offer that testimony. Is there someone else on the panel who can speak to what kinds of costs are non-dispatchable PPA costs?

A. (Witness Houston) No, I don't have any knowledge of that.

A. (Witness Evans) And help me here because, again, the process of determining it is based on the agreement, the underlying PPA agreements.

Q. Sure.

A. (Witness Evans) I'm not familiar with the 600 lines of PPAs and QFs and the agreements associated with them.

Q. Sure.

A. (Witness Evans) But we are -- our experts that review those and determine the appropriate treatment of them do those as those agreements come up.

Q. But I've also asked you about general categories of fuel, and no one's been able to answer that as well.

A. (Witness Evans) Can you repeat your question?

Q. Sure. Is anyone on the panel able to speak to what kinds of PPAs are considered non-dispatchable PPAs by Georgia Power?

A. (Witness Evans) I thought I answered that. It's those that we do not control when they dispatch and put energy onto the system.

Q. Like what kinds of fuel supply? Wind, gas, biomass, solar?

A. (Witness Evans) I believe we have some of each one of those categories that we view as non-dispatchable. Yes.

Q. Okay. You have non-dispatchable gas PPAs; is that right?

A. I'm not familiar with the details of those PPA. I'm not sure.

MS. WHITFIELD: I'd like to make a hearing request for any non-dispatchable gas PPAs that Georgia Power might have and an itemization of those.

MR. HEWITSON: Okay. The breakdown of the costs like you asked for in the other hearing requests?

MS. WHITFIELD: Yes.

MR. HEWITSON: Okay. Just wanted to make sure we're not asking for the PPAs. You're looking for a breakdown of the costs --

MS. WHITFIELD: Yes. I'd like to know how much of that specific line item. So the line items on MFRP-1, Exhibit 1, how much of each of those line items is deemed non-dispatchable for the PPAs.

Thank you.

CHAIRMAN SHAW: Wouldn't biomass be dispatchable?

MS. WHITFIELD: Well, that's a good question. I'm not -- I'm not sure, because I do know there were some real questions about offering it capacity credit, and its inability to perform. And when we -- when we did the last certification for biomass and there was some -- feels like it's a bit of a gray area, and so I'm not -- I'm not sure how that would be handled. It's one of the reasons I wanted to ask for how that's broken up here.

BY MS. WHITFIELD:

Q. So you testify that -- you testified that a number of non-dispatchable PPA costs were recorded as FCR expenses prior to 2010. Are you aware that as of 2013, at least, the amount of solar on line was nominal, less than

300 megawatts?

A. (Witness Evans) Yeah. I believe we have substantially increased our solar generation through PPAs significantly since then. Yes.

Q. Okay.

A. (Witness Evans) But that doesn't change the underlying treatment of it. I mean, I think that generation grows over time, but it doesn't change whether it's viewed as an average marginal replacement cost or not. It just means we have more of it.

Q. Sure. But surely you'd agree that larger line items in the company's budget get more attention from staff and commissioners and intervenors than smaller line items; correct?

A. I'll take your word for it.

Q. So I'd like to ask you about a few of the technicalities of the pricing structure. And as table setting, you've said multiple times lambda is a component of price. The RTP fuel credit is the credit that we see in the fuel docket specifically.

So you mentioned, I believe, in earlier questions or in your summation that lambda is based on the highest cost unit running to serve the system. Is it still true, as it was in 2000, that lambda is the marginal cost of the last resource used to serve the last increment of load?

A. (Witness Evans) Yeah, I think you misquoted me slightly at the beginning. I think I said economic unit running.

Q. Okay. And help me understand that distinction, please.

A. Sure. It's -- lambda is always dispatching our system in economics. There might be situations where a unit has to run outside of economics for a variety of conditions, for a variety of reasons, circumstances. But lambda is always capturing that highest economic unit running on the entire system.

Q. Sure. So if coal is in a must-run state, it would not be included. The price of that coal would not necessarily -- would not be included in the lambda calculation; correct?

A. (Witness Evans) That's correct.

Q. And if coal is dispatched out of economic order, due to some of the various operating constraints, it would not be included as lambda; correct?

A. (Witness Evans) I believe that's correct.

Q. You also mentioned, and, again, I may be misquoting you, so please correct me if it feels like I am.

I believe you said that lambda is higher than the embedded RTP fuel credit. Is that -- did I get that right? Is that what you said earlier?

A. (Witness Evans) Yes. Lambda, on average, is -- I'm going to get this a little bit wrong, but it's somewhere in the neighborhood of 50 to 60 percent higher.

Q. Than the RTP fuel credit?

A. (Witness Evans) That's correct.

Q. Okay.

A. (Witness Evans) Which makes sense because the RTP fuel credit is an average. You think about, like, the units running at a period of time; right? Lambda is always the highest one on the system running in economics.

RTP fuel credit essentially is an average of all those units that are cheaper than it for Georgia Power. So the RTP fuel credit is always cheaper than is -- than if you modeled and priced 100 percent of that load running at just the most expensive.

Q. If you could turn to STF-JKA-1-4, supplemental, which was handed out to you earlier and it has -- just for ease of reference, though you may know this at the top of mind, but this is the exhibit in which you describe the term lambda as the hourly running cost of incremental generation, and you describe the RTP fuel credit as the hourly average marginal fuel cost for the applicable hour.

Do you see that? It's on the second page.

A. (Witness Evans) What response number was that?

Q. It's JKA-1-4, supplemental. It's paragraph B, which is on the second page.

And my only question here is that you use the term "incremental" in the context of price, and you use the term "marginal" in the context of credit.

Could you please describe the difference between those two terms in this context and how you're using them.

A. (Witness Evans) In this context, I think they're interchangeable.

Q. Okay. Thank you.

The RTP fuel credit is based on the hourly average marginal fuel cost of Georgia Power's generation units, correct?

A. (Witness Evans) With the addition of -- of pool purchases and sales.

Q. Okay. Is lambda also calculated by -- based on the incremental generation of the same set of Georgia Power's generation units?

A. (Witness Evans) No. No. It's -- lambda is a system number. So Georgia Power very well could have no units running at the price lambda is set on, because

lambda is set based on another pool participant's unit that is being dispatched at a higher price.

Q. And when you say it's a system number, does that mean the Southern Company system?

A. (Witness Evans) The Southern pool. That's right.

Q. I want to turn to the history of the RTP fuel credit. You mentioned, page 31, line 3, that the RTP fuel credit that we use today was updated in 2010. And by using the phrase "update," you acknowledge that the RTP fuel credit was not originally designed the way it was used today; correct?

A. (Witness Evans) Can you -- was that rebuttal testimony?

Q. It was. It's page 31, lines 3 through 8.

A. (Witness Evans) Yes. I've got it.

Q. Oh, you got 3.

A. (Witness Evans) Yes, I got it.

Q. Okay. Great. Are you aware that when RTP tariff was originally designed, Georgia Power credited the fuel balance for RTP customers at the same FCR rate as charged everyone else?

A. (Witness Evans) Yes.

(The documents referred to was marked for identification as GIPL/Southface Exhibit 3.)

Q. And, in fact, in 1992, as you can see on GIPL/Southface Exhibit 3, Georgia Power testified that designing RTP to contribute the same rate for fuel as everyone else is the way Georgia Power would be sure, quote, that the fuel costs paid by non-RTP users is not affected by the existence of the RTP tariff.

A. (Witness Evans) Can you point me to that exhibit?

Q. Yeah. Well, hopefully you have Exhibit 3 in front of you.

A. (Witness Evans) I don't know that I do.

Q. If you don't -- I'm sorry about that, Mr. Evans. I'm going to fix it.

A. (Witness Evans) Thank you. Yeah.

I apologize. Looking at this exhibit, it says "Petition for rule nisi." Was that in 2004 or 2001?

Q. It's a document response from a hearing held in 2000.

A. (Witness Evans) 2000. Okay.

Q. And in response to a document request, Georgia Power quotes its own testimony from 1992.

A. (Witness Evans) Okay.

Q. And do you see here that Georgia Power believed when RTP was created in 1992, that reimbursing the fuel costs at the same rate that everyone else paid

was designed that way to be sure that non-RTP users would not be affected by the existence of the tariff?

A. (Witness Evans) Yes, I see that. I believe it was changed in 2010 because that proved not to be true, and that by charging the embedded FCR rate resulted in, for many, many, many -- I think it was for half the year, the FCR rate was greater than the RTP price.

And so the way that accounting worked is the fuel clause booked that revenue, regardless of what the overall price was, which resulted in negative base revenue being booked. And so when we went in for a base rate case, all customers were not held harmless because there was a substantial base revenue need to make up for that negative base revenue.

So in 1992, that was the belief, and I think for the subsequent 18 years, that proved not to be true, which warranted the 2010 accounting change.

Q. Thank you for explaining that so clearly.

What I just heard you say is that what the company realized is that if it didn't pull money out of the fuel cost docket and put it in base rates, when it came to a base case, its balances were going to be bad for the RTP tariff.

A. (Witness Evans) Well, I think that was the result. I think the driver of it was that we were

charging and recovering non-marginal costs through a marginal rate, and that whenever you try to do that, it will break.

And then, again, going back to -- and we can point to many, many dockets where we've said this along the way with RTP: It is not designed to recover fixed embedded costs that are spread among all customers.

If you try to do that, it will break, like it did, that led to the 2010 accounting change, and we don't need a marginal rate. It -- that -- it should go away then because you're not -- you're not sending the right price signals and you don't need it. It's done that way by design. Marginal costs recovered from marginal load.

Q. So you said that marginal cost is designed not to recover fixed costs, but --

A. (Witness Evans) No. I said existing.

Q. That's right. You did. Existing fixed costs. You agree, then, that fixed cost that an RTP customer is causing should be part of that rate, correct?

A. (Witness Evans) That's correct. Yes. Margin -- all marginal costs should be recovered.

Q. And do you agree that the RTP rate has been used since its inception as a promotional rate to attract new, large customers to Georgia?

A. (Witness Evans) I don't know about

promotional. I know it has been very successful in attracting customers to Georgia. It's also been very successful in allowing existing customers to utilize the rate for benefits, such as shifting their load from high-priced periods to low-priced periods, benefiting the system, or just reducing their load during high-priced periods.

While it is utilized by new customers locating to the state, it is also utilized by our existing customers. You do not have to have marginal load to participate in RTP. You could sign up for RTP with 100 percent CBO and reduce your load during high-priced hours and receive credits, which we have customers that do that and benefit from that load response from the -- from that dynamic pricing.

(The document referred to was marked for identification as GIPL/Southface Exhibit 8.)

MS. WHITFIELD: May Mr. Sherrier approach with what's been marked as Southface Exhibit 8, which is Georgia Power's testimony from 2013 in Docket 36989. And this exhibit includes excerpted pages. It's not the whole transcript.

BY MS. WHITFIELD:

Q. I'd like to turn your attention, Mr. Evans, to page 686, line 6 through 9.

A. (Witness Evans) I'm sorry. What lines did you say?

Q. It's lines 6 through 9 on page 686.

A. (Witness Evans) Yes.

Q. And here do you see that Georgia Power -- this is Georgia Power's witness, Mr. Robert, who was vice president or in charge of rates, but he was a rates guy. And do you see here he's asked: Would it be fair to characterize the RTP rates as a promotional device used to attract new, large customers?

To which he responds: It certainly has been used for that, absolutely.

Do you disagree with that?

A. (Witness Evans) No, it's been used to -- it's absolutely been used to attract customers to the state of Georgia.

(The document referred to was marked for identification as GIPL/Southface Exhibit 9.)

BY MS. WHITFIELD:

Q. I'd also like to turn your attention to GIPL/Southface Exhibit 9, which is Georgia Power's testimony in the 2022 rate case.

A. (Witness Evans) Pardon me. Do I have that?

Q. You don't yet, nope.

A. (Witness Evans) Okay.

Q. You will have it in just a moment.

This is Georgia Power's 2022 rate case testimony in Docket 44280, and GIPL/Southface Exhibit 9 is excerpted pages. And for this one, I turn your attention to what is page 12 of your testimony, Mr. Evans, lines 8 through 9 -- actually, lines 6 through 9, in which you describe here that if more costs were shifted to RTP, it would significantly decrease the appeal of the rate to current and future customers. And you call the RTP rate, quote, a critical rate for large economic development customers that are considering locating, relocating or expanding operations in Georgia; correct?

A. (Witness Evans) Yes, that's correct. I mean, I think it's simple as shifting costs, increasing the rate whenever you're competing against other jurisdictions and other states for new customers that locate to Georgia to bring jobs and economic development, that increasing the price --

Q. Are you also aware that Georgia Power is justified giving promotional rates to RTP customers, in part, based on the demand response value those customers provided?

A. (Witness Evans) Can you point me to that?

Q. Yes, I can.

(The document referred to was marked for identification as GIPL/Southface Exhibit 10.)

MS. WHITFIELD: Mr. Sherrier, if you could, please provide GIPL/Southface Exhibit 10. This is Georgia Power's testimony in the rule nisi Docket in 2000. That is Docket 11708-U.

A. (Witness Evans) I apologize if you said it. Could you point me to the page again.

BY MS. WHITFIELD:

Q. I don't think I did say it. It's page 9, lines 24 -- well, it's probably best if you start a few lines up from that. We're on line 21, where it says: As a result of this dynamic interaction of a large group of customers, Georgia Power can depend on a consistent level of response that effectively becomes the equivalent of a generating resource when conditions worsen and RTP prices rise.

Do you see that?

A. (Witness Evans) I do.

Q. And, in fact, at that time, in 2000, the RTP price response provided 328 megawatts for a typical peak day response; correct?

A. (Witness Evans) I see that.

Q. And that, Georgia Power testified, prevented the need to construct more generation; correct? That's line 28.

A. (Witness Evans) Thank you. And it says it prevents the need to construct similar megawatts of generation.

Q. Correct. And then if you go down the page to line 44, it further is talking about demand response and explaining how this demand response demonstrates that the concept behind the development of the RTP tariff is performing as it was intended.

Do you see that?

A. (Witness Evans) Yes.

Q. So at present day, RTP is still a promotional device; correct?

A. (Witness Evans) It's still a rate offered to both existing and new customers, yes.

Q. But the amount of demand response that it offers, which allows us to forgo buying new generation, is less than half of what RTP customers were providing in 2000.

A. (Witness Evans) Where do you -- can you help me with that math?

Q. Absolutely.

(The document referred to was marked for identification as GIPL/Southface Exhibit 11.)

Q. Take a look, please, at 11, what has been marked as GIPL/Southface Exhibit 11. This document is

Georgia Power's response to data request STF-PIA-1-7, in last year's All-Source RFP docket.

A. (Witness Evans) Yes.

Q. And if you turn to the third page of that exhibit --

A. (Witness Evans) Okay.

Q. -- you will see the demand response that is attributed to the RTP day-ahead customers and the RTP hour-ahead customers.

Do you see that?

A. (Witness Evans) I do.

Q. Okay. And in total, you see that the RTP tariff is credited with 127 megawatts of demand response to avoid buying new generation.

A. (Witness Evans) So these numbers are very different from what the 2000 testimony says. And they do not represent the same thing at all.

Q. Great. Explain that to me.

A. (Witness Evans) Sure. One is on a typical peak day, so that is a single day's response that's expected from the RTP rate.

This is the capacity equivalent on a winter and summer basis, which says when that response occurs throughout the year -- so it's a response throughout the entire year -- cross-reference with the capacity value of when that response happens. In addition, the response listed here is that response expected above the response seen in the historical forecast.

So this is a response beyond what we have seen historically. Responses seen historically for historical prices is already embedded in the load forecast itself. These numbers sit on top of that.

So there is a passive response, which is part of our regression models of load and price signals that bake into our standard forecast. This is looking at forward-looking RTP prices of the additional response we should expect on top of that that we've historically seen.

So one, the 2000 document, references a single day, and the total response seen. And again, that's 25 years ago. What we have here is a planning version that has to be viewed in combination with what's already seen in the forecast.

Q. So if you look back at the 2000 testimony, page 9, line 42, you'll see that the single-day value they actually describe as 864 megawatts.

A. (Witness Evans) Yes. That is a single year historical peak actual value.

Q. That's right.

A. (Witness Evans) And as we know, our forecasts are based on weather normal. And so if you were to look, going into the future, whenever RTP prices are going to be substantially more than they were in this year, and have been historically, we would expect the response to be more. However, if it is not -- and this is the key component of RTP -- they are paying the cost incurred for that.

A customer has the option. There is no obligation under RTP to respond. It is to send the appropriate price signal to customers such that they can evaluate that with their own economics of their business and make the determination whether they should shed load and avoid that cost or continue to produce and incur it.

Q. I also wanted to note that I realized that I should do this a bit out of context, but these demand response capacity numbers are the numbers that are included in Georgia Power's capacity tables, in which it includes all of its embedded costs, historic and projected, of how it's going to meet the needs of the system.

So I suppose I would ask, with a little more time, a hearing request if Georgia Power could provide updated numbers, if needed, to provide an apples-to-apples comparison, or not, if that's not appropriate.

A. (Witness Evans) Okay.

Q. Thank you.

Staff's analysis and their testimony, the Newsome panel, page 57, lines 3 through 4, demonstrated that when large data center growth was removed from Georgia Power's modeling software, Aurora, fuel cost per megawatt hour would be about 5 to 11 percent lower in 2028.

Are you familiar with that testimony?

A. (Witness Evans) I'm sorry. I was moving the stack of documents off my test -- can you repeat the page number in reference?

Q. Yes. It's the Newsome panel, page 57, lines 3 through 5.

A. (Witness Evans) Yes.

Q. Do you want me to repeat my question?

A. (Witness Evans) Yes, please.

Q. Are you familiar with staff's analysis that demonstrated when large data center growth was removed from Georgia Power's modeling software, Aurora, that fuel costs per megawatt hour were reduced by 5 to 11 percent in 2028?

Are you familiar with this testimony, you, Mr. Evans, or anyone on the panel?

A. (Witness Evans) I am.

Q. You didn't offer any rebuttal to this testimony in your prefiled rebuttal testimony, did you?

A. (Witness Evans) No. We had a hard time -- and I think this came across in cross yesterday. We had a hard time figuring out where it came from, I think, and it's helpful, the testimony yesterday. That was a different data request than the one referenced on 8 was used. So -- but, again, I think -- and I think I said this earlier. We understand that costs go up as you serve more load. So we'll take -- we'll take that foundation as -- as yes.

Q. Okay. Moving on from RTP, I think, if we could turn to page 4, lines 21 of your testimony. Here you describe -- essentially you're describing updates to your fuel costs expected in the projected period and the under-recovery balance in the projected period.

So at page 5, lines 7 through 8, you testify that the under-recovery balance is projected to be significantly higher than you -- than you would have expected during your direct testimony; correct?

A. (Witness Houston) Yes. If we were to actualize for natural gas prices and actualize for costs subsequent to when we filed, yes, that's correct.

Q. Okay. I think you may have answered my next question. Your testimony says that this update is a combination of two updates. Is that the -- primarily the cost from winter storm fern being one, and then the other

being the updated price in the intervening period?

A. (Witness Houston) Yes. Winter Storm Fern, we're just actualizing for all costs through that period, which included Winter Storm Fern and then the natural gas price update as well.

Q. What's the impact to the projected Part-B rate as a result of this change?

A. (Witness Houston) Well, I think the Part-B rate is stated here, but it's trade secret.

Q. I'm referring to the -- I see cost. I might be missing it. Can you point me to the line -- the page and line.

A. (Witness Houston) Well, understanding your question correctly, line 8, where we say FCR-27 Part-B balance --

Q. Oh, yes.

A. (Witness Houston) -- as of May?

Q. Yes. So I'm seeing the -- the total cost of that balance. I'm curious. You had provided earlier that the FCR-27 projected Part-B rate would be .1423 in the summer and .1415 in the winter. I'm wondering how that is shifted in light of this update. And if you've filed this and I've missed it, that's -- let me know that too.

A. (Witness Houston) Just to be clear, this update is not reflected in our request. This is just for

informational purposes.

Q. Okay. So you're not -- you're not changing the Part-B rate that you are requesting as a result of these updated costs?

A. (Witness Houston) That's correct. If we were to update for this number, that would actually be an increase in the rate.

Q. Correct. Okay. Thank you. And on page 4, line 20, same question, essentially. Here you say you've incorporated the latest natural gas price forecast, and the update to the FCR-27 budget, and that average price is 2.8 percent lower.

What is the impact of the Part-A rates as a result of prices being lower than you expected?

A. (Witness Houston) I don't have that information available, but if you were to update for all events that have happened, including the natural gas price decrease and the actualization of cost, you get this number here that's in line 8, which, if we were to update for that, would be an increase in the rates.

Q. I guess I'm wondering about the forward-looking cost, though. So you've suggested that the -- on page 4, line 21 to 22, you say that the latest price forecast on average is 2.8 percent lower. So what I'm wondering is, shouldn't that mean that the Part-A rate, the forward-looking projected rate, would then also be lower?

A. (Witness Houston) Yes, that -- that is correct. The forward rate would also be included. And I think, once you take that and meet it against the update to Part-B, you'd still have an increase in the request.

Q. I see. Okay. So when you cancel those two out, you lead to an increase. Have you provided an update of the FCR-27 budget reflecting these updated costs and the canceling out?

A. (Witness Houston) No, we have not.

Q. Could you please provide an updated FCR budget reflecting the updated projected costs? I would offer that as a hearing request. Perhaps not the whole -- not the whole budget, but the numbers behind the impact. There's a lot of play here and you are --

MR. HEWITSON: But that's not part of our request. That's what he just testified.

MS. WHITFIELD: But what I'm seeing is that you're projecting that prices are going to be 2.8 percent lower, and you're saying, but we're not going to lower our request. I'd like to know why.

MR. HEWITSON: Well, he just answered that question. Because when you net that out with Part-B, you get an increase, so we're not going to -- we're not going to update it, so that there isn't an increase to our request, so we're meeting our request at a lower level.

MS. WHITFIELD: But you've obviously done the financials to make that determination. Can you provide those financials that you did to make that determination that it nets out?

MR. HEWITSON: We can provide the netting --

MS. WHITFIELD: Because at the --

MR. HEWITSON: -- but we're not changing our request.

MS. WHITFIELD: I understand.

MR. HEWITSON: Okay.

MS. WHITFIELD: I understand. I got that.

MR. HEWITSON: You want to check our math.

MS. WHITFIELD: Yes. I want to -- I want to see the -- I want to see the math, yeah.

Thank you. Nothing further. Thank you.

COMMISSIONER HUBBARD: Could I ask a follow-up question, if I may, Mr. Evans? So a little bit of a preface. I mean, you mentioned that the firm transportation costs are not included in the RTP credit to fuel because it's a fixed cost, I think.

And then you also mentioned that the RTP credit exceeds costs because there's a delta between that system lambda and then the actual units set are dispatched. And so there's a delta there and that benefit accrues. And that's maybe one way that these firm transportation costs are accounted for.

You also mentioned, though -- and then they -- they come back into the base rates, and that's where that benefit flows to. But you mentioned that those benefits are in the form of a marginal average replacement cost, I think.

Do you recall that marginal average replacement cost for firm transportation? That's where that --

MR. EVANS: Let me -- and I might have -- I might need to clear that up a little bit.

COMMISSIONER HUBBARD: Please.

MR. EVANS: So the average marginal replacement cost is the calculation to determine the RTP fuel credit. The amount above that, that -- that -- the delta between lambda and that RTP fuel credit we refer to as capital substitution.

COMMISSIONER HUBBARD: Yes.

MR. EVANS: That's the amount, the

$200 million in 2001 that I referenced earlier. That amount is on the base set. So that is just our -- our highest economic unit running in every hour. That is not an average. The average of the marginal units occurs for the RTP credit calculation.

COMMISSIONER HUBBARD: Right. But in terms of calculating that benefit that -- that average marginal replacement cost, is that based on a -- on a gas peaker or what does that average marginal replacement cost? I mean, I guess it --

MR. EVANS: So the average marginal replacement cost is looking at every Georgia unit running in every hour, regardless of -- of gas, coal, every dispatchable unit running, plus system purchases and sales, because, in any given hour, we might be leaning on the system and making purchases on the system, or you might be a net seller to the system.

So we're taking into account those -- those pool purchases and sales hour by hour, plus the -- every Georgia unit running. And that is the average. So it's not related just to a gas peaker. It's -- it's our nuclear units running, right? It's our hydro units running. It's every Georgia

dispatchable unit running.

COMMISSIONER HUBBARD: For the firm transportation costs that are included in the base rates, that -- those firm transportation costs almost -- since we're talking about gas transportation, they're based on the premise that you would be adding -- the incremental or marginal unit that you would be adding would be a gas peaker; is that right? We're still working under that premise?

MR. EVANS: So the premise of the RTP rate in total, yes. Right? So it's looking at, as I mentioned earlier, the five -- the five components. That -- one of those components is our reliability cost, our marginal cost of generation; right? And that marginal cost of generation can get to, during times of scarcity, like we're in now, the cost of a CT.

Now, that does not mean, as we -- as we know, right, that through prudent resource planning that we're going to build a CT; right? But if you build something besides the CT that's going to lower your -- your lambda costs, right, at the expense of additional fixed costs, like additional capital costs for that CC or that firm transportation.

So that is where that capital substitution comes in to give credit to all of our other customers by the revenue received from RTP customers at lambda, which is above that fuel cost.

COMMISSIONER HUBBARD: Right. And that generation component was based on, what, the top 50 hours you mentioned, transmission 300 hours?

MR. EVANS: On a weather normal basis, that's how the price signal is sent. The cost itself is a -- is an annual cost, right? It's just in the design of RTP, how concentrated does that price signal need to be sent to reflect the underlying costs.

COMMISSIONER HUBBARD: Okay. Well, I guess what I'm getting at is that that benefit, that incremental capacity that would be needed is based on a gas peaker, but given all of the demand and the market for gas peakers, that cost is probably significantly more than you may be accounting for.

And I also know that dispatchable solar plus battery storage can also be that peaking unit.

So I think what I'm getting at is that there may be a need to update some of the information that's used to calculate the benefits from firm transportation, plus a gas peaker versus alternatives, or even that gas peaker and firm transportation with updated costs today.

MR. EVANS: Yes, sir. And our assumptions are updated annually. That cost of that capacity cost that I referenced is updated every single year, based on current projections. And as you would expect, right, during times of surplus, like we saw in the 2000s and 2010s, right, the cost of capacity was low; right? There's a variety of market conditions that resulted in that.

As we know right now, we are moving into a period of scarcity and those capacity costs are increasing, as you would expect.

COMMISSIONER HUBBARD: The last question. On the capacity for non-dispatchable power purchase agreements, are we still -- are you still including the value of any capacity in those power purchase agreements? I see RECs energy. Those are typically included in power purchase agreements. But are capacity values explicitly included as well in power purchase agreements for solar, for example?

MR. EVANS: Not familiar with how our PPAs are accounted for that have capacity payments.

MR. HOUSTON: Yeah, I'm not aware of any

solid PPAs that have capacity payments, but they made it. But I'm just not aware of that.

COMMISSIONER HUBBARD: I think I've seen -- it was just a few weeks ago when there was a transfer of a PPA. It included RECs energy and capacity, and this was an older solar PPA.

But I guess what I'm driving at is that there's a value to that capacity, apparently, if it's captured in a PPA, but it's not captured, for example, in an RFP, an All-Source capacity RFP. Those are not considered to be capacity-providing resources and are not included.

So I'm just drawing that distinction that PPA, solar PPAs and others that are non-dispatchable PPA as part of the FCR, appear to have a value capacity. It's included in some of the contracts, but then it doesn't appear, for example, in an All-Source capacity RFP. Not a question. Just a comment. That's all.

CHAIRMAN SHAW: All right. Any other questions?

MS. WHITFIELD: Mr. Chair, if I could move in GIPL and Southface Exhibits 1 through 4, 8 through 11, and 14 through 16, into the record, please.

CHAIRMAN SHAW: So marked.

(GIPL/SOUTHFACE Exhibits 1 through 4, 8 through 11, and 14 through 16 were admitted into evidence.)

MS. WHITFIELD: Thank you.

CHAIRMAN SHAW: I'm assuming that Mr. Baker and Ms. Ariza cross for this panel. So we'll go ahead and take a break and have everybody back at 1:00.

Panel, you can be excused.

(Whereupon, a lunch break was taken.)

CHAIRMAN SHAW: Welcome back. Hope everyone had a chance to grab a quick bite to eat. We'll continue with our hearing on the second day of Docket No. 56765.

We have -- Panel, I'll just remind you, you're still under oath. And we'll start where we left off, and I'll call up -- MARTA is up next.

MR. BAKER: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. BAKER:

Q. Good afternoon, Panel.

A. (The Panel) Good afternoon.

Q. It's going to be very quick for me, but I think, Mr. Evans, you may have answered this earlier today, but I just would like a clarification, just make

sure I get it absolutely clear.

The question is, is the cost of hedging recovered from all customers?

A. (Witness Evans) So the cost of hedging is not included in the RTP FCR calculation because it is not an average marginal replacement cost by definition.

Q. Okay. And that would be the only category of customers where it's not recovered; is that correct?

A. (Witness Evans) I believe so. I mean, it's included in the other standard FCR tariffs.

Q. Okay. All right. I don't know if this -- the Panel knows this answer, but I have a general question to the Panel is, do you know how many megawatts of the new large load contracts have been signed as of today, just approximately?

A. (Witness Evans) Yes. We have, I believe, around 9,600 megawatts of signed large load contracts.

Q. And this isn't just commitment. This isn't just the two-page commitment. This is a contract, full contract?

A. (Witness Evans) That's correct.

Q. Okay. All right. Thank y'all very much.

MR. BAKER: Thank you, Mr. Chairman.

CHAIRMAN SHAW: Thank you.

Resource Supply Management.

(No response.)

CHAIRMAN SHAW: Sierra Club, SACE, NRDC.

MS. ARIZA: Thank you.

CHAIRMAN SHAW: Afternoon.

MS. ARIZA: Good afternoon.

CROSS-EXAMINATION

BY MS. ARIZA:

Q. Good afternoon, Panel.

A. [The Panel] Good afternoon.

Q. For the record, my name is Isabella Ariza, and I represent Sierra Club, SACE, and NRDC.

Let me start by asking you some questions about coal diversity. You got some questions from Mr. Collado about your decision to pursue coal diversity, but, to be clear, the point of diversity in any competitive market is to take advantage of the lowest cost supply available, is it not?

A. (Witness Ohlson) Ask me that again. I'm sorry.

Q. The point of diversity in any market is to take advantage of lower costs from the resources that you're purchasing.

A. (Witness Evans) Actually, the point of diversity would be reliability. So if we were truly chasing lowest cost, we could single source our coal product and only purchase from the cheapest provider. That would be -- it would be very imprudent in terms of from a reliability perspective for a number of reasons.

So I think diversity is more of a reliability component. And then once we factor in diversity, then we absolutely seek to purchase, among that diverse group, at the lowest reasonable cost.

Q. So are you saying that in the name of diversity in your coal supply, you're willing to pay higher prices for coal indefinitely without a cap?

A. (Witness Evans) So I've not said anything about without a cap. But I have said that we would not want to buy from a single, sole, least cost producer, because we do think that diversity is important for a number of reasons: For the reliability of our -- of our deliveries to support the power plant which supports our customers, and it's an example of where reliability does have a cost.

I mean, no one has argued that purchasing from multiple suppliers was not a prudent decision. So I think we all agree that at some level diversity is important.

Q. I think you're right that staff agrees that some level of diversity is important. And you said before today that you limited your purchases to 9 percent of this premium priced coal, but that you were not comfortable with staff suggestion -- suggestion to set a percentage as a cap; is that correct?

A. (Witness Evans) That is what I said, yes, correct.

Q. Can you state which guardrails would you be comfortable with, or should the Commission expect you to continue to make these decisions on an ad hoc basis?

A. (Witness Evans) So I would not characterize it as ad hoc. I would characterize it as the responsibility to make prudent decisions in our purchasing across a number of suppliers and the multiple basins that we purchase from for each of the two coal facilities.

I'd be willing to have a conversation about guidelines and the reasons for the diversity, the importance of it. I can give many examples of transportation congestion concerns, supply chain disruptions in terms of flooding and rail lines. Producers that have either systematic or longwall moves, meaning that they move equipment in the mines, or just like the a roof collapse that occurred recently at one of the mines that caused there to be a loss of production.

Those are some of the reasons why having a diverse portfolio of purchases is important for our customers, so that we can continue to deliver coal to the plant in the timely manner that we do. And again, having that reliability does have a cost.

So having that conversation, I think we're very comfortable with in explaining the urgency of it, the way markets move, the way the price in the different basins can fluctuate. They're not necessarily related to each other at all times. Leads me to say that I'm not comfortable today telling you what percentage of diversity or what cost of diversity I think is prudent for our customers.

Q. Okay. Can we agree, at least, on the fact that you're not in the business of making sure that those particular coal mines stay in business?

A. (Witness Evans) So are you -- can you ask that a different way, please?

Q. Can we agree, at least, that it's not Georgia Power's objective mission or responsibility to make sure that each of the coal mines that supply you with coal stay in business?

A. (Witness Evans) I would say it this way: It is in Georgia Power's customers' best interest that they have a competitive, diverse supply of coal to purchase from. So I think the competitive solicitation process is important to driving costs down and making sure that we don't overpay for the price of coal.

So it is important for us to have viable partners in the different basins. And in that sense, I do think it's important that the mines stay viable and that there's multiple production facilities available.

Would we -- I think -- I think, to your question, to be fair, I think -- would we spend customer money in order just to keep one afloat? I mean, no, no, no, that that is not the intention at all.

Q. Okay. Thank you.

Now, I'll ask you some questions about coal generation. In your direct testimony -- and I'm asking you to -- in this rebuttal panel, because your colleagues yesterday said that this was a question for you, in your direct, you discuss Bowen's designation as a must-run unit; correct?

A. (Witness Evans) So I believe in the -- I believe in the direct testimony Bowen may have been referred to as a must-run unit at times.

Q. Can you state for the record what it means to designate a coal unit as must run?

A. (Witness Evans) So there could be multiple reasons. Are you asking me to name a specific time that it was a must-run?

Q. Just a definition of what having a unit designated as must run means. Does it mean it runs every hour of every day, or is there a time period?

A. (Witness Evans) This is how I would answer it: It's a common characteristic of electrical networks that, at times, generation is required in certain areas to maintain system reliability, system stability. And I'd say that's especially true near large load centers.

I would just make sure everyone remembers Atlanta is a very large load center, and Plant Bowen is in very close proximity. I mean 40, 50, 60 miles. So I think there would -- it would be a surprise if the system did not ask for Plant Bowen to be available to support system needs at times.

Q. So at times the company determines that a unit like Bowen, regardless of whether there's other cheaper options available, must run; is that correct?

A. (Witness Ohlson) So at times the system stability may require any generating unit on the system to be available in online. And that would be true for Plant Bowen as well, yes.

Q. Okay. And separately, your testimony recognizes that one of the primary drivers of higher fuel expenses is higher levels of coal generation; correct?

A. (Witness Ohlson) Can you say that a different way? I'm not sure -- I'm not sure I can say yes to the way you said that.

Q. Let me see if I can find the page.

But generally you've stated today and recognized, I think, in response to commissioners, that one of the primary drivers of higher fuel expenses in the historic period was higher levels of coal generation.

A. (Witness Ohlson) Are you referring to high prices or high inventory?

A. (Witness Houston) Yeah, I can answer that. That is correct. Also, higher coal generation in the forecasted period as well.

Q. Okay. And I was going to ask about forecast period too. You will continue to increase the percentage of coal that you will use over the next three years; correct?

A. (Witness Houston) Yes. That was in the direct testimony.

Q. It seems like if you have high fuel costs due to higher-than-expected coal operations, the last thing you would want is to categorize your coal units as must-run; isn't that correct?

A. (Witness Ohlson) So I would offer again that must-run would typically, to my knowledge, not be based on an economic -- true economic decision, but rather a system reliability, system stability decision, which, when we say not economic, that means outside of that constraint, it would not have been running.

But it is economic if you factor in the system reliability, what that would look like, if it called on a unit, like a Plant Bowen, and it was not able to meet the need. So the repercussions could be much greater.

Q. But just in putting aside reliability for a minute and assuming a perfect world in which other resources were available, you don't want to use a resource that is designated as must-run if there are cheaper options available?

A. (Witness Ohlson) I'm sorry, but I don't think I'm gonna answer a question that says "putting aside reliability for the moment," because that's not something that we can do.

Q. I don't mean ignoring the fact that you need to provide reliable services, just that to achieve your mission to ensure low rates, you would rather not have a unit that you -- that is expensive designated as must-run. Is that not adequate characterization?

A. (Witness Ohlson) Which is why I think we can -- we're going to consider reliability. We're going to consider system constraints and unit constraints. And then we're going to make the decision to commit units, which means have them on an -- online and available, or dispatch them, which means move them to their different load positions to achieve the lowest cost, once those are their characteristics have been met.

Q. Okay. I'll ask you some questions now about Bowen's minimum downtime in Michael Goggin's analysis.

A. (Witness Ohlson) Yes.

Q. Yesterday, during cross-examination, Mr. Hewitson stated -- and you stated earlier today that once Bowen comes online -- sorry -- offline, the minimum amount of time it needs to remain offline is seven days; is that correct?

A. (Witness Ohlson) That is correct.

Q. Does Bowen require a seven-day downtime because it's an older coal plant, or because it would otherwise require capital investment, or is there another reason why there's such a long downtime?

A. (Witness Ohlson) I'm not a plant operator. I can't answer that. I can tell you that as long as I've known about the minimum up and down times, it's been seven days for both.

Q. Are you aware of any other coal plants in the country that require such long minimum downtime?

A. (Witness Ohlson) I would not characterize that as long for a coal plant. I would characterize that is fairly standard.

Q. Are you aware that PJM's minimum downtime is eight hours?

A. (Witness Ohlson) I'm not aware of using PJM.

Q. And you didn't provide --

A. (Witness Ohlson) Can you just clarify? That was for a coal unit, a large central station coal unit had eight hours of minimum downtime?

Q. Correct.

A. (Witness Ohlson) Okay. I -- that would be surprising to me.

Q. Okay. And you didn't provide that minimum downtime constraint in discovery, did you?

A. (Witness Ohlson) You'd have to show me. I'm not aware of what we provided in terms of Bowen's characteristics.

Q. Okay. And did you happen to run Mr. Goggin's analysis, changing the minimum downtime to seven days?

A. (Witness Ohlson) No.

Q. Would it surprise you to learn that, with that change, the reduction in the disallowance is less than $1 million?

A. (Witness Ohlson) You're saying -- I'm sorry.

Q. Oh, Mr. Goggin -- are you aware that Mr. Goggin found that, given his analysis, $152 million should be disallowed from the uneconomic dispatch operations at the coal plants?

A. (Witness Ohlson) So a $1 million change from his original estimate?

Q. Right. That's my question.

Would it surprise you to learn that with the change of minimum downtime, seven days, the reduction in the disallowance is less than $1 million?

A. (Witness Ohlson) I don't think it'd be appropriate for me to comment on a model that he created outside of our purview. And, you know, we disagree with a lot of the assumptions and characteristics that we used in that. So I'd rather not comment on what changes he's made since then.

MS. ARIZA: Okay. No further questions.

Chairman Shaw, I just move my one exhibit entered into the record. I'll have it marked as Sierra Club, SACE, and NRDC Exhibit 12, since I marked the testimony and exhibits as Exhibits 1 through 11.

CHAIRMAN SHAW: So marked.

MS. ARIZA: Thank you.

(The documents referred to was marked for identification as SIERRA CLUB/SACE/NRDC Exhibit 12.)

(SIERRA CLUB/SACE/NRDC Exhibit 12 was

admitted into evidence.)

CHAIRMAN SHAW: Redirect.

MS. PRYOR: No redirect at this time. Thank you. I would just ask that the Panel be excused.

CHAIRMAN SHAW: All right. Panel, thank you for your time, and y'all can be excused.

THE PANEL: Thank you.

MS. PRYOR: To the extent I have not moved their testimony into the record, I would ask that it be moved into the record.

CHAIRMAN SHAW: So marked.

And I'll let you keep things going and call up your next panel, please.

MR. HEWITSON: Georgia Power calls Mr. Earl Berry.

Good afternoon, Mr. Berry. While you're here, will you please remain standing and raise your right hand.

Thereupon,

EARL BERRY,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HEWITSON:

Q. Mr. Berry, please state your full name, your employer and your responsibilities, for the record.

A. Yes. Earl Richard Berry, Vice President of Engineering for Southern Nuclear.

Q. Mr. Berry, on April 23rd, did you prefile or cause to be prefiled 17 pages of rebuttal testimony in question-and-answer format in this FCR-27 docket?

A. I did.

Q. And are there any changes you need to make to your prefiled rebuttal testimony?

A. There are none.

Q. If I asked you the same questions today under oath, would your answers be the same as are found in your prefiled rebuttal testimony?

A. Yes.

MR. HEWITSON: Chairman Shaw, the court reporter was previously given a copy of Mr. Berry's prefiled rebuttal testimony, and I now ask that the rebuttal testimony of Mr. Berry be copied into the record as if given here today.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Earl Berry follows:)

REBUTTAL TESTIMONY OF

EARL BERRY

ON BEHALF OF GEORGIA POWER COMPANY

GEORGIA PUBLIC SERVICE COMMISSION DOCKET NO. 56765

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Earl Berry. I am the Vice President of Engineering for Southern Nuclear Company ("Southern Nuclear"). My business address is 3535 Colonnade Parkway, Birmingham, Alabama 35243.

Q. MR. BERRY, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I began my academic studies at the University of Kentucky, earning a Bachelor of Science in Chemical Engineering in 2000. Following this, I pursued a Master of Business Administration at National University. I started my career in the energy industry in 2000 as a Process Engineer and Project Manager at Texaco (later Chevron), where I led and supported multiple energy and emerging technology projects, including gasification and hydrogen. Prior to joining Southern Nuclear, I held engineering leadership positions in advanced energy and technology organizations including Director of Engineering, Engineering Manager, and Process Evaluation Manager for a series of energy startup companies.

In 2009, I joined Southern Nuclear and served in a series of progressively responsible leadership roles including Chemistry Engineer, Rapid Response Engineer, Engineering Components Supervisor, Manager of Site Projects, and Engineering Systems Manager. I advanced to the role of Engineering Director in 2016, and Work Management Director in 2018. I hold an ANSI Senior Reactor

Operator certification, which further grounds my leadership experience in licensed nuclear power plant operations. Beginning in June 2019, I served as the Organizational Effectiveness Manager before I was seconded in February 2020 to the Institute of Nuclear Power Operators ("INPO") to serve as the Organization Effectiveness Leader supporting industry-wide performance improvement. I returned to Southern Nuclear in August of 2021 as the Governance and Oversight General Manager, and in June of 2022, I became the Vice President of Engineering. In this position, I am responsible for enterprise engineering governance, nuclear safety, equipment reliability, regulatory compliance, and executive oversight of engineering performance across the Southern Nuclear Fleet. I engage with the nuclear industry and am the executive sponsor of industry initiatives in accident tolerant fuel and digital modernization.

Q. PLEASE DESCRIBE SOUTHERN NUCLEAR OPERATING COMPANY.

A. Southern Nuclear is a subsidiary of Southern Company and operates two nuclear electric generating plants on behalf of Georgia Power Company ("Georgia Power") and its co-owners: the Edwin I. Hatch Nuclear Plant located near Baxley, Georgia; and the Vogtle Electric Generating Plant located near Waynesboro, Georgia. Plant Hatch and Plant Vogtle are co-owned by Georgia Power, Oglethorpe Power Company, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia through Dalton Utilities. Southern Nuclear has been licensed to operate Plant Hatch and Plant Vogtle since March 1997, when operating responsibility was transferred from Georgia Power to Southern Nuclear. Southern Nuclear also operates the Joseph M. Farley Nuclear Plant, located near Dothan, Alabama, for Alabama Power Company.

Q. MR. BERRY, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the Direct Testimony of Public Interest Advocacy ("PIA") Staff Witness Joseph R. Reynolds and provides additional context for the nuclear outages addressed in Mr. Reynolds' testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My rebuttal testimony responds to PIA Staff Witness Reynolds' testimony and his recommendations regarding five of the Company's unplanned nuclear outages by providing additional context and explanation for each event. Witness Reynolds' investigation did not consider the totality of the facts regarding each event and did not support his assertion that each outage was "clearly imprudent," as he defines the standard in his own testimony. With this background, my rebuttal testimony attempts to fill in the gaps and clarify the events surrounding the outages and the appropriateness of the Company's actions and responses in turn.

II. NUCLEAR OUTAGES

Q. PLEASE PROVIDE YOUR GENERAL FEEDBACK IN RESPONSE TO WITNESS REYNOLDS' TESTIMONY.

A. Witness Reynolds' recommendations in this proceeding are based on the information contained in certain reports written by Plant Hatch and Plant Vogtle personnel (Condition Reports, Apparent Cause reports, and Root Cause Analyses). However, in citing these reports, Witness Reynolds does not address the fundamental differences between the purpose of the analysis conducted for such reports and the determination of prudence that occurs in the context of this proceeding.

The reports relied upon were not written with the goal of analyzing whether the decisions in question were reasonable given what was known at the time. Instead, the reports utilize hindsight to identify the potential causes of the incident in question, whether such causes could have been avoided through the application of reasonable management decisions at the time of the event. The goal of identifying possible causes of an event is quite different from evaluating whether the actions or decisions in question were reasonable given the circumstances that existed at that time. Often, these reports are based on information that was not available at the time the underlying decisions were made or they omit key background information or other general issues that were considered by the decisionmakers.

Further, Witness Reynolds only presents selected portions of the material included in the reports, which provide insufficient context for the Commission's review. The terminology utilized in such reports often has meanings that are specific to the goals and ends of such reports. For example, "inadequate" connotes that the relevant actions or decisions did not result in the desired outcome but does not mean that the actions or decisions were unreasonable or reflective of a lack of diligence and care by Company employees. Thus, to use these reports as Witness Reynolds has, without proper context or independent analyses, risks misinterpreting or misconstruing such reports and the actions taken in response to certain events. In particular, the Root Cause and Apparent Cause reports typically do not delve into the underlying basis or rationale for a decision, such as why an engineer, technician, or operator took a particular action, but rather, summarily conclude that the decision did not lead to the desired result.

Q. DO YOU STAND BEHIND THE ACCURACY AND COMPLETENESS OF THE REPORTS?

A. Yes. I am extremely proud of the strength of our evaluative process as reflected in these reports. I, along with all of Southern Nuclear's leadership, encourage thorough and exhaustive analysis of these outages in order to identify every possible corrective action that could have been taken to better inform practice and process improvements to prevent such events from reoccurring. We apply a very high standard to our causal analysis findings and corrective actions consistent with nuclear industry measures of excellence. It is important to note, however, that the purpose of post-event causal analysis is to find opportunities for improvement using information that is available only after the event occurs. Accordingly, these analyses intentionally apply a high standard and benefit from hindsight and are not necessarily designed to assess whether decisions made prior to the event are reasonable based on the information available at that time. We acknowledge that not all processes are perfect and there are always opportunities for improvement and the causal analyses bear that fact. However, the Company's efforts to constantly improve our processes and performance should not be construed as evidence of imprudence.

Q. ARE THE CONCLUSIONS DRAWN IN THE REPORTS A SUBSTITUTE FOR MANAGEMENT'S DECISION-MAKING PROCESS?

A. No. Southern Nuclear management closely reviews the reports and engages in a deliberative process to implement any necessary corrective actions. Southern Nuclear management must also balance numerous other considerations and challenges in determining the appropriate course of action (*e.g.*, timing, technology interplay, cost, etc.).

Q. DOES SOUTHERN NUCLEAR EXPECT AND ACCEPT THAT FORCED OUTAGES WILL OCCUR?

A. No, absolutely not. Southern Nuclear expects complete operational excellence. We strive to have zero mistakes and no unplanned or forced outages, and our employees are consistently reminded of this objective, along with the overriding goal of safety that controls every decision made at the plants. This goal is exactly why Southern Nuclear conducts Root Cause and Apparent Cause analyses without regard for cost or what was actually or reasonably known at the time. Southern Nuclear intends to utilize every resource and every avenue for improvement that is available. My testimony is not intended to trivialize the outages that occurred or minimize the importance of the additional fuel costs incurred. Rather, the purpose of this testimony is to place each event in its proper context and focus attention on the facts and circumstances as they existed at the time of each incident, including key decisions leading up to these events.

Q. PLEASE ELABORATE ON THE SIGNIFICANCE OF THE FACT THAT PIA STAFF ONLY IDENTIFIED FIVE OUTAGES FOR RECOMMENDED DISALLOWANCE.

A. While it is the Company's position that none of these outages were the result of imprudent actions or decisions, the fact that Witness Reynolds only recommended disallowance of replacement fuel cost for five outages is a testament to the high level at which the Company operates these plants. Over the three-year period covered by this proceeding, Plants Hatch and Vogtle have contributed 64,802,106 megawatt hours ("MWh") of low-cost, emission free generation to Georgia Power's customers. Over that same time, Witness Reynolds only identified five outages for potential disallowance, representing 831,229 MWh of lost generation (or just 1.3% of the total generation during the historic period). I believe that the excellent operation of our plants over that time should be considered by the Commission as it reviews these particular outages.

Q. DOES THE EFFECTIVENESS OF SOUTHERN NUCLEAR'S FLEET FIGURE INTO THE CONTEXT OF THE INCIDENTS DISCUSSED IN MR. REYNOLDS' TESTIMONY?

A. Yes. Southern Nuclear's excellent and cost-effective performance provides the context necessary to truly understand why the decisions that Southern Nuclear made—based upon known facts and competing priorities at the time, as the prudence standard requires—were reasonable. In particular, Southern Nuclear has a demonstrated history of success in reducing the impact of unplanned outages. Although there are no criteria that measure "prudence," there are metrics for the reliability of nuclear plants. One of these metrics is called the Capacity Factor, a measure of how often a power plant runs over a specific period of time. The

Capacity Factor is expressed as a percentage and calculated by dividing the actual unit electricity output by the maximum possible output. This ratio indicates how fully a unit's capacity is used. The Capacity Factor of Southern Nuclear's Georgia fleet (not including Vogtle Units 3 and 4) over the previous three years is 93.63%. This is in line with the average of 93.2% for nuclear power generation in the United States.[1] Vogtle Units 3 and 4 do not have three full years of service at this point and, as previously discussed with the Commission, Unit 4 was operated at a lower power level to extend fuel life.

Q. WHY ARE THESE OBSERVATIONS NECESSARY TO ASSESS THE REASONABLENESS OF SOUTHERN NUCLEAR'S ACTIONS IN THESE INCIDENTS?

A. The success of Southern Nuclear's fleet on metrics of cost, production, efficiency, and safety could not be achieved without a culture of safety, reliability, and sensible decision making that benefits Georgia Power's customers. Each of these metrics (cost, production, efficiency, safety, etc.) is a priority that Southern Nuclear has an obligation to weigh for the benefit of customers. The Root Cause and Apparent Cause reports, which Witness Reynolds relies upon, are not written within this framework. Rather, these reports go above and beyond to find *any* possible causes of the incident analyzed, specifically with intent to identify means of improvement going forward.

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1 *See* Table 6.07.B Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels, U.S. Energy Information Administration, *available at* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b

III. PLANT HATCH

A. PLANT HATCH UNIT 2 EVENT 26 (09/13/2025)

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT PLANT HATCH UNIT 2 ON SEPTEMBER 13, 2025.

A. On September 13, 2025, Hatch Unit 2 Operators were performing required turbine valve testing. On the fourth and final test, the unit experienced a trip of both REDACTED REDACTED. A manual SCRAM was inserted per site procedure and industry norms.

Q. WERE SOUTHERN NUCLEAR'S ACTIONS LEADING UP TO AND DURING THE SEPTEMBER 13, 2025 HATCH UNIT 2 EVENT REASONABLE AND PRUDENT?

A. Yes, Southern Nuclear's actions before and during the September 13, 2025 Hatch Unit 2 event were reasonable and prudent when evaluated based on the information available at the time and consistent with industry standards and plant procedures.

Prior to the event, the unit was operating within its approved configuration, and turbine valve testing was being performed in accordance with established procedures. There was no indication that conditions existed that would have caused this event. Three of four turbine valves had been successfully tested. Following the event, Southern Nuclear conducted thorough causal analysis to understand all the factors contributing to the event and identify appropriate corrective actions. These reviews were undertaken not because the pre-event decisions were imprudent, but because Southern Nuclear holds itself to a high standard of continuous improvement. Notably, the Root Cause Analysis did not find that the Company had inadequate procedures in place at the time of the event. Further, the occurrence of the event does not show that management or operational decisions were unreasonable given the facts and circumstances known at the time.

Q. WHY SHOULD THE CONCLUSIONS OF POST-EVENT CAUSAL ANALYSIS NOT BE USED TO JUDGE THE PRUDENCE OF PRE-EVENT DECISION MAKING?

A. As stated above, the purpose of post-event causal analysis is to find opportunities for improvement using information that becomes available only after the event occurs. These analyses purposefully apply a high standard and benefit from hindsight. As such, they are not designed to evaluate whether decisions made prior to the event are reasonable based on the information available at the time the event occurred. In this case, Southern Nuclear's procedures, policies, and training reflect sound operational judgement and a conservative bias toward safety as three of four valves had already been successfully tested. The fact that improvement opportunities were found does not mean that the original procedures or policies were imprudent.

Q. DOES WITNESS REYNOLDS' CONCLUSION THAT THIS OUTAGE WAS IMPRUDENT FIT WITHIN HIS OWN DEFINITION OF IMPRUDENCE?

A. No. Witness Reynolds describes a plethora of factors to be evaluated in determining if an outage is prudently incurred or the result of clear imprudence. He testifies that if such analysis "indicate[s] that this was a one-time mistake by the plant operator, I would likely conclude that the operator was imprudent in that he did not take adequate care . . . . When I discover a pattern of similar events, and actions to prevent this type of event were inadequate or not timely, *I would likely conclude this outage to be clearly imprudent*." Here, Witness Reynolds' has failed to identify a pattern or similar events that would support a finding under his analysis of clear imprudence. He cites no similar events, and in fact, omits the fact that the Company had already performed three tests. In addition, on page 18 of his testimony, Witness Reynolds acknowledges that the Company's steps and procedures were adequate.

B. PLANT HATCH UNIT 2 EVENT 23, 11/01/2023

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT PLANT HATCH UNIT 2 ON NOVEMBER 1, 2023.

A. On November 13, 2023, Hatch Unit 2 had a REDACTED REDACTED REDACTED for the REDACTED REDACTED, which caused a leak. Operators secured one of the two REDACTED REDACTED to reduce the leakage. The second REDACTED REDACTED automatically tripped due to water from the leak. Operators inserted a manual SCRAM as Reactor water levels dropped. The impacted REDACTED REDACTED is not nuclear safety-related; therefore, the Maintenance team was deployed to fix the broken bracket.

Q. WERE SOUTHERN NUCLEAR'S ACTIONS LEADING UP TO AND DURING THE NOVEMBER 13, 2023 HATCH UNIT 2 EVENT REASONABLE AND PRUDENT?

A. Yes. Southern Nuclear's actions associated with the November 13, 2023, event were reasonable and prudent when evaluated based on the conditions and information known at the time. The event was started by a pipe failure. Once the leak occurred, Operators responded conservatively and in accordance with approved procedures. When water intrusion caused the second REDACTED REDACTED to trip and REDACTED water level to drop, Operators inserted a manual SCRAM per approved procedures and industry norms.

Q. DOES THE FACT THAT A REDACTED FAILURE LED TO THE OUTAGE MEAN THAT SOUTHERN NUCLEAR'S PRIOR DECISION WAS IMPRUDENT?

A. No. Equipment failures, particularly REDACTED REDACTED, can occur without prior warning notwithstanding the application of sound engineering, maintenance, and/or operational practices. Southern Nuclear has robust programs in place for system health monitoring, corrective actions, and continuous improvement, but the occurrence of equipment failures does not show that pre-event decisions were unreasonable. For this event, it is reasonable for Maintenance to fix a broken part and return it to the previous state.

Q. DOES THE FACT THAT THERE WAS EARLIER REDACTED FAILURE MEAN THAT SOUTHERN NUCLEAR'S ACTIONS WERE TO RESTORE THE BROKEN PART WERE IMPRUDENT?

A. No. In hindsight, our causal analysis noted a missed opportunity to find earlier failures and look deeper into the core issue. Although the causal analysis identified failures in 2007, notably there were no other failures until 2023. So, it is reasonable for Maintenance personnel to assume the needed fix was to reinstall the bracket given reasonable operation for a period of 16 years. Additionally, as noted in our causal analysis, both Maintenance and Operations personnel assumed simple vibration was the core issue. With that in mind, the Maintenance and Operations personnel assumed that reinstallation of the bracket was the right action.

IV. PLANT VOGTLE

A. <u>PLANT VOGTLE UNIT 3 EVENT 86 (09/17/2024)</u>

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT PLANT VOGTLE UNIT 3 ON SEPTEMBER 17, 2024.

A. On September 17, 2024, Vogtle Unit 3 experienced a REDACTED failure leading to a REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED opening completely instead of staying closed. This led to an automatic SCRAM and Safeguards actuation.

Q. WERE SOUTHERN NUCLEAR'S ACTIONS LEADING UP TO AND DURING THE SEPTEMBER 17, 2024 VOGTLE UNIT 3 EVENT REASONABLE AND PRUDENT?

A. Yes. Southern Nuclear's actions related to the September 17, 2024 Vogtle Unit 3 event were reasonable and prudent based on the information available at the time and were consistent with plant design, procedures, and industry standards. This event was caused by an unexpected REDACTED failure.

At the time of the event, Vogtle Unit 3 was operating within its approved configuration, and there were no indications that this particular REDACTED failure or valve response was imminent or reasonably foreseeable. The REDACTED were obtained as safety-related components consistent with industry standards. The plant's protection systems functioned as designed and intended and operators responded appropriately.

The vulnerability of this single REDACTED failure is part of the original plant design. The AP-1000 design is certified by the Nuclear Regulatory Commission ("NRC") in accordance with 10 Code of Federal Regulations Part 52. Per the terms of 10 C.F.R. Part 52, significant changes to the core design are not permitted without reapproval by the NRC. As noted in the causal analysis, following completion of construction, Southern Nuclear initiated a design change with the original equipment manufacturer (“OEM”).

As with other post-event reviews, these analyses benefited from hindsight and were conducted to strengthen long-term reliability and performance. The improvement opportunities identified after the fact do not indicate pre-event decisions or maintenance practices were unreasonable given the original plant design as approved by the NRC.

Q. COULD THIS OUTAGE HAVE BEEN PREVENTED BASED ON THE CRITICALITY RANKING OF THE REDACTED AS SUGGESTED BY PIA STAFF WITNESS REYNOLDS?

A. No. As stated in the Southern Nuclear causal product, the REDACTED were noted as a single point vulnerability (“SPV”) and the criticality of the part would not have prevented the REDACTED failure. Southern Nuclear utilizes the Electric Power Research Institute (“EPRI”) recommendations for REDACTED maintenance. These REDACTED were categorized as “Run to Maintenance” and the SPV plan lists replacement of the REDACTED with valve maintenance at no later than 10 years. The causal analysis noted this was not an issue or contributor to the failure of the REDACTED since these REDACTED were less than 10 years old at the time of failure. In fact, these REDACTED were replaced after construction was completed and prior to commercial operation to maximize the potential for satisfactory performance.

The Company’s response to this REDACTED failure was not clearly imprudent, nor was it imprudent. The REDACTED were installed as designed and approved by the NRC. Contrary to the statements of Witness Reynolds, additional or more regular maintenance on this type of component does more harm than good because it introduces infinitely more opportunities for failure. REDACTED fail when they are installed incorrectly. To check a REDACTED, the maintenance engineer must uninstall and reinsert it, which not only introduces oil from a human hand, it increases the likelihood that the REDACTED is reinstalled incorrectly. REDACTED like these are the type of component best left alone and not touched until a major system outage is scheduled.

B. PLANT VOGTLE UNIT 3 EVENT 66 (07/08/2024)

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT PLANT VOGTLE UNIT 3 ON JULY 8, 2024.

A. On July 8, 2024, Vogtle Unit 3 REDACTED REDACTED REDACTED failed to the open position due to foreign material in a positioner internal pressure regulator. This failure led to a loss of forward flow, causing the water levels in both Steam Generators to drop. Operators inserted a manual SCRAM due to low water levels in the Steam Generators.

Q. WERE SOUTHERN NUCLEAR'S ACTIONS LEADING UP TO AND DURING THE JULY 8, 2024 VOGTLE UNIT 3 EVENT REASONABLE AND PRUDENT?

A. Yes. Southern Nuclear's actions related to the July 8, 2024 Vogtle Unit 3 event were reasonable and prudent based on the information available at the time and consistent with plant design, procedures, and industry standards.

At the time of the event, Vogtle Unit 3 was operating within its approved configuration, and there were no indications that the REDACTED REDACTED within the REDACTED was present or that the REDACTED would fail in this manner. The positioner in question is located inside another component and not visible upon initial inspection without taking apart the surrounding component. Further, the REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED. The positioner was installed during plant construction and follow up inspections of similar positioners found no similar issues.

Even within Mr. Reynolds' own definitions of imprudence and clear imprudence, the failure to REDACTED REDACTED REDACTED component located inside of another component does not come close to imprudent decision making or conduct of the Company. Further, the REDACTED was introduced by the manufacturer, not the Company. No Company conduct, omission, or oversight contributed to this outage.

C. PLANT VOGTLE UNIT 4 EVENT 10 (06/05/2024)

Q. PLEASE DESCRIBE THE CIRCUMSTANCES OF THE OUTAGE THAT OCCURRED AT PLANT VOGTLE UNIT 4 ON JUNE 5, 2024.

A. On June 5, 2024, Vogtle Unit 4 Operators inserted a manual SCRAM after they responded in an unexpected manner following the trip of the REDACTED REDACTED. A faulty temperature probe gave a high REDACTED REDACTED REDACTED for the REDACTED REDACTED. This resulted in an automatic Turbine Runback and REDACTED REDACTED REDACTED. REDACTED buildup, due to the REDACTED, lowered the REDACTED REDACTED REDACTED. However, the REDACTED prevented the REDACTED from adjusting to respond to the lowering temperature.

Q. WERE SOUTHERN NUCLEAR'S ACTIONS LEADING UP TO AND DURING THE JUNE 5, 2024 VOGTLE UNIT 4 EVENT REASONABLE AND PRUDENT?

A. Yes. Southern Nuclear's actions related to the June 5, 2024 Vogtle Unit 4 event were reasonable and prudent based on the information available at the time and consistent with plant design, approved procedures, and operator training.

The event started with a faulty temperature probe that provided an erroneous high REDACTED REDACTED REDACTED REDACTED. This REDACTED REDACTED was installed during construction of the plant. There were no indications that the REDACTED was faulty prior to the failure.

Following the outage, Southern Nuclear conducted the causal analyses to fully understand the failure. As with other analyses, the causal product was the result of hindsight and was prepared with the intent of furthering continuous improvement. Southern Nuclear identified that this REDACTED was not installed correctly, but there were no indications of similar issues with other REDACTED. Also, it was found that none of the construction documents indicated any issues during installation.

Q. IS THIS COMPONENT SUBJECT TO ANY WARRANTY UPON WHICH THE COMPANY COULD DRAW TO BE COMPENSATED FOR THIS FAILURE AS SUGGESTED BY PIA STAFF WITNESS REYNOLDS?

A. No. Witness Reynolds' suggestion that this is a warranty item underscores his unfamiliarity with typical nuclear industry practice and the Vogtle Units 3 and 4 Project. In addition to the significant passage of time and the Westinghouse bankruptcy resulting in warranties no longer being available, warranties that were previously available would not cover the costs at issue here. Vendors will not agree to warranty terms where they agree to bear indirect damages due to unit outages and downpowers, or in the unlikely event they would it would render their components cost-prohibitive. A warranty of the kind Witness Reynolds discusses is not a standard or expected practice in the nuclear industry.

V. CONCLUSION

Q. WERE THE COMPANY'S ACTIONS AND DECISION MAKING REGARDING THESE OUTAGES CLEARLY IMPRUDENT?

A. No. The Company's actions and decisions related to the outages addressed above were reasonable and prudent and did not evidence any unaddressed reoccurrence trend or repeat deficiency. Witness Reynolds' testimony does not support a finding of clear imprudence for any of the five outages addressed. His attempt to identify a common thread among these outages is an overgeneralization that does not appropriately consider the full context of the circumstances impacting each outage.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

MR. HEWITSON: And with your permission, we'll let Mr. Berry summarize his testimony.

CHAIRMAN SHAW: Yes, sir.

Mr. Berry, go ahead.

MR. BERRY: Thank you.

So good afternoon, Commissioners. I appreciate the opportunity to support the Georgia Power's Fuel Cost Recovery Application. As I stated, my name is Earl Berry, and I'm the vice president of engineering for Southern Nuclear Company.

My rebuttal testimony addresses public interest advocacy staff witness Joseph Reynolds' testimony regarding the company's nuclear operations and outages.

I specifically respond to each of his recommendations regarding five of the company's unplanned nuclear outages by providing additional context and explanation for each event.

Witness Reynolds' recommendations in his -- in these proceedings are based on information contained in certain reports written by Plant Hatch and Plant Vogtle personnel, condition reports, apparent cause reports, and root cause analyses.

Importantly, the reports Witness Reynolds

relied upon were not written with the goal of analyzing whether decisions and questions were reasonable, given what was known at the time; rather, these causal reports utilize hindsight to identify any and all potential causes of the incident in question.

My rebuttal testimony explains how these reports are based on information that is not available at the time the underlying decisions were made, or they omit key background information on other issues that are generally considered by the decision makers.

With that context, I argue that Witness Reynolds' investigation did not consider the totality of the facts regarding each event, and did not support his assertion that each outage was clearly imprudent, as he defines in the standard.

My testimony seeks to fill in the gaps and clarify the events surrounding the outages and the appropriateness of the company's actions before, during, and after each of the five outages. I further describe how the company's actions and decisions related to the outages were reasonable and prudent.

Thank you for your time and consideration.

MR. HEWITSON: Mr. Chairman, Mr. Berry is available for questions from Commissioners, as well as cross-examination.

CHAIRMAN SHAW: Thank you, sir.

Commissioners?

COMMISSIONER HUBBARD: Mr. Berry, I have a question or two.

So you mentioned that there -- that there wasn't -- the decisions that you reviewed, the five different incidences that Witness Reynolds identified, one of which did have -- well, and to finish my thought -- that there was, at the time that the decision was made, the decision was prudent in your view. And so root cause analysis, the other things like that, are backwards looking and can't serve as a basis for this.

But isn't it true that one of those events had an incident that stretched all the way back 16 years of vibration, and a fix was found, but that fixed proved to last for a certain period of time, but then needed to be fixed again and ultimately resulted in an outage? Isn't that something that was known at the time, because there was past information that could have informed the decision that installing another bracket would lead to potentially an outage?

MR. BERRY: No, I do not agree with that if you look at the totality of the facts. So you're referencing the Hatch event.

So in 2007, a bracket was installed in the wrong location. From 2007 to 2023, there were no incidents. So why would you look at 2007 if there were no incidents?

The first additional failure happened in 2023, and our document, our causal product talks about -- and Witness Reynolds said on the stand something that was incorrect. He said that, hey, in all cases, vibration is a problem. You must go look at it.

I would ask you what rotating piece of equipment doesn't have any vibration? So a statement which may have been inadvertent was all -- all vibration. All pieces of equipment have vibration. And if you read the causal product, you will see that was actually what was in the mindset of the maintenance journeyman. They assumed vibration was the problem; thus their response was we put the bracket back on.

They also asked, and it was also in the causal product, they asked for vibration measurements, which we went out and took. And the vibration was acceptable. That is within industry standards and guidelines.

So vibration was not the issue. The fundamental mistake, as we pointed out in our causal product from 2007, was not the installation of the bracket. It was the installation of the bracket in the wrong location, which led to the cyclic fatigue that actually caused the failure.

That's a slightly different thing. So again, I ask you, in that mindset in 2007, what did they know versus what did we find out later?

And we -- again, we discuss that in our causal product the -- we called it an improper mindset. You know, again our standard in these causal products is pretty high. So it was in our mind and our belief an the improper mindset in the way that the organization looked at it.

It was the belief that vibration was the problem, and therefore they saw putting the bracket down as being the reasonable action. And that's why we determined it not to be fundamentally or clearly imprudent in this particular case.

COMMISSIONER HUBBARD: Based on the assumption of the journeyman to install that

bracket at the time?

MR. BERRY: That's correct.

COMMISSIONER HUBBARD: Okay. Then one other question, I think. Witness Reynolds kind of characterized -- well, there were five different events that -- events that he identified, each one that had a different root cause. And so there was no pattern there.

But what he did do is group them together, as, I think, what was it, either three or two were based on -- I think three were based on what he characterized as operator error or -- yeah, I don't know if operator error is what he characterized it as, but operator, you know, failed to follow code requirements or the vibrations, things that could have been caught by the operator versus, for example, there were two issues that were OEM related.

And so my question is, do -- in order to establish a practice or a pattern, does it have to be the exact same fault or error that happened, the piece of equipment that failed, or can it be simply operator error, if you will, and that be establishing that pattern?

You know, there's five different instances

here. Two are OEM related; three are related to operations. And so isn't that kind of -- isn't that establishing a pattern of operator error? Can you have two OEM incidences and three operator issues that can be classified together that show a pattern?

MR. BERRY: I understand the question. I'll just be clear. I'm not sure he used those exact words. I understand what you're saying, though, in general a question.

So I think that, you know, you can -- you can make patterns out of anything, but you're asking me a very theoretical question, right? If -- if -- if I go off and -- and, you know, hit somebody one day and then I go spit gum in other place does that show a pattern, it's -- I can say that both of them are patterns because they're related to me.

So where you draw the box to determine a pattern -- in our causal space, when we go look for repeat patterns, we do look for similar behavior. We don't necessarily look for or say, does the behavior have to be exactly the same? We would agree. Don't -- don't go. We teach our people not to go look for exact matches. That could be too dangerous.

We do ask them to look for same, similar behaviors. That's actually a specific question that we ask in our causal products. So we have a specific question, and it's worded slightly different in each of these products. But it'll be a repeat event-type question that we ask. Is this a repeat of that? None of these items were marked as repeat events.

COMMISSIONER HUBBARD: Okay. And last question. Is it -- we haven't built any AP1000s, but there was one issue that caused a SCRAM, I think, on day 36 of operations. Is that -- is that expected, growing pains, if you will, right after commissioning? Shouldn't commissioning catch a lot of these issues, if not all of them? So to expect something just 36 days after operations, I mean, is that surprising to you?

MR. BERRY: It is not surprising to me. My -- my goal is perfection. We want that for every one of our customers. But it is not surprising. If you look at data and compare, for example, Vogtle Unit 1 to Vogtle Unit 3, Vogtle Unit 1's availability that first year was about 70ish percent, low 70s percent. Vogtle Unit 3's was in the mid 80 percent. So much better performer. This is not unusual.

Again, if you compare the AP1000, you can use international data from, like, the Power Reactor Information System. So you have -- that's international data. But if you use that and you compare the Vogtle AP1000, or even the Chinese AP1000 to the other competitive new nuclear units, you will see that the AP1000's performance exceeded.

COMMISSIONER HUBBARD: Okay. Thank you.

CHAIRMAN SHAW: Any other questions?

(No response.)

All right. Georgia Public Service Commission.

CROSS-EXAMINATION

BY MR. COLLADO:

Q. Good afternoon, Mr. Chairman. Good afternoon, Mr. Berry.

A. Afternoon.

Q. I want to direct you to something you said in the beginning of your testimony, but you also mentioned it in your summary, so you may not need to reference it, but I'll just go ahead and quote you on page three, line 25.

You're talking about Witness Reynolds' recommendation. You stated that the reports utilize hindsight to identify potential causes of the incident in question, whether such causes could have been avoided through the application of reasonable management decisions at the time of the event.

Were you aware or are you aware that Witness Reynolds also reviewed Georgia Power and saw the company's processes and procedures when writing his testimony?

A. He reviewed some of our procedures. Yes.

Q. And a process and procedure would have been something that would have existed at the time of the outage; correct?

A. Correct.

Q. And we would expect that the -- or you would expect that the people working on Georgia Power's nuclear fleet are aware of the processes and procedures during operation of those units; correct?

A. Yes, I expect that.

Q. So we wouldn't consider that as a hindsight consideration. In fact, it would be foresight. It would be the company knowing that an outage could happen, creating a process or procedure to address that, to prevent it from happening, and something that was known by the workers at the time of the outage; correct?

A. That was an extremely long sentence. Can you restate that, please.

Q. Sure. You stated that Witness Reynolds relied solely on hindsight, but if you are looking at a process or procedure that the company has, that isn't really hindsight. In fact, it's foresight. It's the company thinking about how an outage could happen in the future, creating a process to address that, and then putting that process out there so its workers can follow them; correct?

A. You asked me two questions. I don't know if that was intentional. So you asked me -- the first question was, was Witness Reynolds looking in hindsight, yes. Even if you're reviewing the procedure, it's in hindsight because you already know what the event is.

The second question you asked me is, do we provide the procedures before an event to try to prevent an event? And the answer to that is yes.

Q. Okay. I understand the second -- your second answer. Going back to the first one, my point was, is Witness Reynolds depending on a hindsight report solely when he is looking at the processes that Southern Company and Georgia Power create relating to the outage?

A. Yes, because you already know the outage happened. But this is going to be a fundamental difference. If you know the outage -- by the way, they teach you this in root cause analyses, which Mr. Reynolds also, I believe, says he's an expert in, which is, when you already have the event in your head, even when you go back and review other materials that were known, you still have that. You have to try to split that.

So I cannot answer that question, that he split it, because I'm not in his head. That's why I'm answering the question the way I'm answering it.

Q.   How about this then: How would the people who write the processes be thinking about outages if they hadn't happened yet? They're not thinking backwards, they're thinking forwards; correct?

A.   We are thinking -- so thank you for asking that question. It's a wonderful question. Again, it tells us how robust we were and shows why we were prudent.

We go through and look at our plants and how they operate, and we assess what we consider the vulnerabilities of those plants and the risk. Based on that is how we go through our process of where do we think we need procedures, where do we need written instructions, what level of written instructions, and so on.

So all of that is based on not -- obviously not an event, but thinking through how our plants are designed, what we see as the vulnerabilities and the risks are, and where we believe we need written instructions or other instructions to be able to provide for our workers.

Q. Would you agree that although mistakes do happen, Southern Nuclear expects operation without any unplanned outages, either caused by procedural error or operational error?

A. We do expect that.

Q. And with that said in your testimony, did you or Southern Nuclear determine that all of the nuclear outages discussed were reasonable and prudent?

A. Based on the definition that has been given to me by the Commission and as highlighted in Mr. Reynolds' announcement, I find that they were prudent and they did not need that clearly improving guidance.

Q. And could any of the outages have been avoided through the application of reasonable management decisions at the time of the event?

A. Based on what we knew at the time of the event? No. Obviously, our expectations were not fully met in several of those outages. And I think, in particular, we mentioned or Mr. Reynolds may have mentioned the Hatch event where there was a clear miss in procedure steps. You know, that clearly did not meet our expectations.

Q. Let's talk about that outage.

Would you agree that the cause for this event was human error? And if you want me to just define human

error again.

A. Our causal product found it was human error.

Q. And do you recall saying in a meeting with staff in March that the cause of the event here was that our operators missed a critical step in their procedure?

A. Our causal product states that, yes.

Q. So this is consistent with, yeah, causal product.

Would you agree that this event was caused by human error of GPC personnel?

A. It was caused by a staff member of Southern Nuclear, that's correct.

Q. Would you agree that the root cause of this outage was that the operator failed to perform a sequential place keeping as required by the procedure?

A. Yes.

Q. And that operator was expected to know the procedure prior to showing up to work that day?

A. Yes.

Q. So although both you and Mr. Reynolds agree that the company's steps and procedures were adequate, this outage was not caused by inadequate procedures; correct?

A. Yeah, that is correct.

Q. And would you agree that the shutdown would

have been avoided if the procedures were properly followed?

A. Yes.

Q. And GPC took disciplinary action against the personnel due to this incident; isn't that correct?

A. Correct. We took discipline.

Q. Including termination?

A. For an individual. Yes.

Q. And is your testimony today that the operator's actions during this incident were both prudent and warranting employee termination?

A. By the definition used by our company, or the definition used here is for clearly imprudent.

For our company, we felt we took prudent and reasonable actions on behalf of the people of Georgia and our company, meeting the definition as outlined here for clearly imprudent, because I had good procedures and I know it followed correctly by that -- those individuals, which demonstrated that they followed it three out of four times correctly, I would say that they were prudent.

Q. And you were talking about the actions of the individual, not the actions of the company in disciplining the individual; correct, when you're talking about prudence?

A. When talking about prudence for that

discipline, that's correct.

Q. Okay. What about the prudence of the operator's actions?

A. The operator's actions by our definitions were not prudent.

Q. Okay. I want to talk about another Hatch outage event 23. This is going to be discussed in page 20, line 15 of your testimony. It's definitely not page 20. There's no 20 pages in this testimony. I think it's page 10.

A. Yes. Page 10.

Q. Page 10. Sir, I'm sorry about that.

A. Okay.

Q. I'm sorry, everyone involved. I'm talking about Mr. Reynolds' testimony. On page 20 of Mr. Reynolds' testimony, he's talking about the event 23 at Hatch 2.

I'm very happy with the last panel, by the way.

A. Okay.

Q. On page 20, line 15, Mr. Reynolds says, in response to the question, could this reactor manual SCRAM have been avoided, Mr. Reynolds' testimony reads: Yes. The company was aware that this -- of the issue and did not fully analyze the situation.

CHAIRMAN SHAW: We're still on the same incident at Hatch?

MR. COLLADO: We're on a different Hatch. This one happened on November 1st of 2023.

CHAIRMAN SHAW: Okay.

MR. COLLADO: So this is different than the incident I spoke to at first.

BY MR. COLLADO:

Q. And this was -- but you did discuss this a little bit with Commissioner Hubbard. You -- Witness Reynolds said an improper mindset contributed to the SCRAM as an ineffective U-bolt was installed and a pattern of vibration concerns were reported but never studied. Thus the reactor manual SCRAM could have been avoided.

Do you agree with that statement?

A. I explained that to the Commissioner Hubbard where that actually came from. Those words, "improper mindset," are our words that we determined afterwards. And I explained exactly the scenario to the Commissioner. If you'd like, I could go back over.

Q. Well, specifically would you agree that the reactor manual SCRAM could have been avoided?

A. All manual SCRAMS can be avoided. That's my standard of which you asked me earlier. My standard is -- is high.

In this particular case -- again, I would say all manual SCRAMS can be avoided. As I explained to the Commissioner, right, the 2007 event, the -- the improper mindset, which was the testimony of -- of Mr. Reynolds was vibration issue should all be resolved. Their -- their mindset was put a bracket on it. That stops vibration issues. That's what they were doing. In their mind, they were making actions.

That's what we knew. You know, that's what the maintenance journeyman knew at the time.

Q. And would you agree that the improper mindset or, I believe, in other places in your testimony you've said the words faulty mindset. Would you agree that they directly led to the failure to identify the cause of the problem that led to the outage?

A. They did. It was affirmative.

Q. Moving back to your testimony on page 13, you discuss the Vogtle outage in 2024. This is event 86.

In your testimony, when you state fuses fail when they are installed incorrectly, does this mean that the fuse was initially installed incorrectly by Georgia Power?

A. No, it does not. Again, our causal product goes off in investigating it. That was a direct response to a statement that was made in the -- in the testimony, of course, really related to maintenance.

Q. And do you know who installed this fuse? Was it Georgia Power personnel or someone else?

A. I do not know exactly who installed this particular fuse. I know we reviewed the work instruction, but I, off the top of my head, cannot answer that.

Q. Can you also state -- to check a fuse, the maintenance engineer must uninstall and reinsert it, which not only introduces oil from a human hand, it increases the likelihood that the fuse is reinstalled incorrectly.

Can you -- can you go a little further, deeper into that? How does oil from the human hand affect the fuse?

A. It increases the resistance on a fuse. That's -- that's a well-known failure mode and is discussed in -- in standard industry documentation for that item. No fuzes. Again, this was in reference to a direct question.

We did replace all of these fuzes right after construction. We wanted to make sure that there were no construction issues that -- that could have impacted them. But every time you touch a component, you're taking a risk. There's a risk of introducing human error, and things like oil on your hands or any other miscellaneous type materials will change the resistance to the fuse.

And this -- this changes that fuse characteristic.

In these particular fuses that are installed are designed to -- to protect part of the control circuitry for -- for this -- for this particular unit. And those are low voltage, low amperage-type systems, so they -- they do require a very clean source of power.

Q. Does Georgia Power provide gloves, or could gloves have been used by maintenance engineers in this process?

A. Certainly. And Georgia Power does provide gloves. Both.

Q. Does the company train personnel on how to perform proper inspections and maintenance regarding this operation?

A. Yes, we do.

Q. Is it prudent for the company to neglect to inspect and maintain items which must be removed and reinstalled due to risk of error during a reinstallation?

A. Yeah. Wonderful question. We weigh the risk of each and every application. Again, this has absolutely nothing to do with this case. I understand why you're asking it, but we would not, in any way, shape or form, remove anything before it is necessary, to not introduce other risk aspects.

Q. Is it true that the OEM has recognized that a

correction to the trip circuit software is being redesigned for NRC approval to correct the key problem of this single failure point?

A. That is not true. It is being redesigned because I directed it to be redesigned. The OEM does not -- did not do this, did not recognize this as any different. The OEM believes this is core to the AP1000. The AP1000s that they're selling overseas has this feature exactly as it is. Design change has been designated by us at Southern Company on behalf of Georgia, not by the OEM.

Q. Thank you for clarifying that.

Moving on to event 66, this outage occurred in Vogtle 3 in July of 2024, and as discussed on page 15 of your testimony, 14 and 15. But on page 2 of page 15, your testimony states that further, the foreign material was introduced by the manufacturer, not the company. And this is regarding the foreign material that led to the -- the failure.

Mr. Berry, in your opinion, who should be responsible for the replacement fuel cost caused by this outage?

A. In my opinion, I think that -- that's a tough question, and my opinion is -- is not really relevant here. But if you want to ask my opinion, it is traditional in our industry that the cost is borne by the organization and/or, you know, whoever -- whoever the ratepayers are.

Q. You said the organization and the ratepayers. This could be two different entities. Could you be more specific?

A. Yeah. There are different rate structures across the US, so I'm answering this question very generically.

Q. Mr. Berry, do you know if the company seeked relief from the OEM before requesting that ratepayers pay for the replacement power costs resulting from this outage?

A. I believe we answered that in a separate question, or I may be -- I may be mistaken in that, but I thought we answered that in a separate question for this one.

Now, this is, of course, an AP1000 and went through the bankruptcy proceedings, which I know many of the Commissioners are familiar with. So there are aspects of warranty that are not valid. They were discharged by -- by the bankruptcy proceedings that -- that the organizations went through.

Q. So, to your knowledge, the company has not sought relief from the OEM?

A. To my -- I know of -- no.

Q. Is it appropriate for the company to seek fuel costs recovery from ratepayers when the OEM is clearly and totally responsible for producing the contaminated product that caused the unplanned outage?

A. Yeah. As I stated previously, there are industry standards. No -- no OEM would sell us any component if they thought they were 100 percent on the hook for full fuel costs. Indeed, most of the materials when you buy a component and has a warranty, it specifically states that they will warranty certain aspects, but they will not warranty how you use that component. So you will not -- for example, if I go buy a screw and put into my plant and for some reason I say that screw caused the plant to trip, the manufacturer of that screw would say that their warranty does not cover our use.

Q. But the exact characteristics of the warranty, that would be a part of a contract that Georgia Power enters into with the OEM, correct?

A. Yeah. And I -- I failed myself. I probably should have asked you. When you say "OEM," I -- or you're talking about the bigger OEM, or are you talking about the specific supplier of this component?

Q. I can't say specifically. I -- I don't know exactly who would be responsible in this case. I'm saying

OEM and whoever the company would -- can and would be able to recover from.

A. Yeah. This particular component is not -- and I'll -- I'll try to answer it again.

The first one, the bigger one I referenced would be more of that bankruptcy-type item, right? That's the bigger OEM.

Now, the smaller OEM, in this case, the actual company that makes that particular component, we do not negotiate terms with them. It is -- it is like going to Home Depot and buying a part. It comes with a warranty that is a -- a standard-type warranty, and it is -- it does not cover the use of the component.

Q. And to your knowledge, this Commission does not review any kind of contract with an OEM, whether it's either type that you just described?

A. Yeah, I do not know what the Commission reviews.

Q. And discussing the last outage, Vogtle 4, that happened on June 5th of 2024. I believe it's on page 16 of your testimony.

Mr. Berry, do you dispute that the documents Georgia Power produced indicate in the equipment failure summary regarding this outage, that, quote, work practice during construction was less than adequate? And, quote, and, another quote, design was less than adequate, end quote.

A. Can you show me those words or point me to the -- the line number?

Q. So this would be in the equipment failure summary. I don't think you have it. And I don't know if you had it in front of you, but, to your knowledge and recollection.

A. Yes. I'll use the subject to check because I don't have the exact quotes in my words. They sound to be aligned with words that we would use in our call for products.

Q. And those comments were related to the root cause of the outage described as, quote, a loose wire on the termination block, end quote.

A. That's correct.

Q. So did the check. Subject checks. Yeah, I understand.

A. Yes, I know the loose wire part.

Q. Do you believe it's appropriate to place charges for replacement power on the -- on the ratepayer for inadequate work practices and design?

A. So again, to be clear, I know that the Commission will make the final determination on this particular item. As I started with to respond to the

Commissioners' initial questions, the Vogtle Unit 3 and 4 units operate better than Vogtle Units 1 and 2 upon startup. And, again, you can compare them to any other new nuclear project in the world using the PRIS date of the international data, and you will see that their performance is excellent and can be only categorized as excellent.

We expect in this -- you know, while our goal is perfection, are there issues that you see? There are -- our causal product talked about -- we reviewed in our extent of condition as discussing that causal products, every other wire next to it, and we also went to the opposite unit to check wiring. We did not find any other issues. We found this one.

So this was not a fundamental design issue; i.e., an issue that was so, you know, gross that it just should have been missed. This -- this turned out to be a singular location, an issue.

So I think it falls under what I consider a construction error, and one that was -- I don't want to say it was reasonable because there is no error that is reasonable. Our standard really is perfection, and we do endeavor to catch every one of those issues. But of the thousands of miles of cable and the thousands and thousands of terminations we did at Vogtle 3/4 to find one, I don't know that that's imprudent.

Q. And your answer was specifically talking about what the company found regarding this outage?

A. That's correct.

Q. Would you say generally, for outages that are -- that are due to inadequate work practices or design performed by the company or its vendors and contractors, do you think the ratepayers should be responsible?

A. I think our standard for what is adequate design and inadequate design change over time, and many of those are our responsibility as -- as owners, operators of the organization, and so ratepayers will be responsible for some of those items.

Q. The last question. On page 16, line 2, here you state: Southern Nuclear identified that this temperature probe -- I'm sorry.

A. Component.

Q. I apologize for the -- Southern Nuclear identified that "redacted" was not installed correctly, but there were no indications of similar issues with other "redacted."

Who was responsible for the vendors and installers who work on these plants, in general?

A. Who is -- can you repeat that?

Q. Yes. When vendors and installers work on the plants, is Georgia Power not responsible for their work?

A. Georgia Power is responsible for the work of that -- your question was -- sounded like a double negative, but Georgia Power is responsible for the work on these plants.

Q. Probably was a double negative. I apologize.

So is that substantially different than the level of responsibility Georgia Power would have for work done by its own personnel?

A. The standards are slightly different. I actually believe that came up slightly in other testimony. In areas where we bring in experts that may be beyond the expertise of our own personnel or others that we contract work, while we do maintain responsibility as it is our asset, or our asset on behalf of the people of Georgia and the other co-owners, of course.

You know, we do often sign contracts that allow those workers to work under theirs -- their -- their particular standards. So in this particular case, and I know it's been in front of the commission multiple times, right now some members may not have seen it, the construction of Vogtle 3 and 4 was done under contracts with organizations like -- like Bechtel, for example. And a lot of that was done under Bechtel procedures. And, again, I know those were separate proceedings.

So while, yes, we have those overall responsibility, particularly for the -- as the operators of this plant, the construction format was slightly different. And before this Commission, I know that that was completely laid out.

MR. COLLADO: Mr. Berry, thank you. I have no further questions.

CHAIRMAN SHAW: Thank you, Chris.

All right. Georgia Association of Manufacturers. He had to step out.

Georgia Interfaith Power & Light and Southface.

MS. WHITFIELD: No questions.

CHAIRMAN SHAW: MARTA?

MR. BAKER: No questions.

CHAIRMAN SHAW: Resource Supply Management?

(No response.)

CHAIRMAN SHAW: Sierra Club, SACE?

MS. ARIZA: No questions.

CHAIRMAN SHAW: Redirect?

MR. HEWITSON: Briefly, Chairman.

REDIRECT EXAMINATION

BY MR. HEWITSON:

Q. Mr. Berry, Mr. Collado, after each of the outages that he discussed with you, would ask you whether

you thought customers should be responsible for those costs. Do you remember that?

A. I do.

Q. Okay. Knowing you're not a lawyer and you don't practice in the regulatory aspects of the Public Service Commission, your understanding of the fuel cost recovery statute, is it your understanding that under the fuel cost recovery statute, Georgia Power is allowed to pass customers -- pass on its cost of fuel unless actions have been deemed or decisions have been deemed to be illegal or clearly imprudent?

A. Yes.

Q. Were any of the outages or any of the actions or decisions of the company during any of these outages illegal or clearly imprudent?

A. Not at all.

MR. HEWITSON: Thank you, Mr. Berry. That's all I have.

If there are no further questions for Mr. Berry, I ask that he be excused. We've moved his testimony into evidence, and I would ask that all of Georgia Power's exhibits be moved into evidence.(GPC Exhibits 1 through 21 were admitted into evidence.)

CHAIRMAN SHAW: All right. So marked.

Mr. Berry, thank you for your time. And you can be excused.

MR. BERRY: Thank you.

CHAIRMAN SHAW: All right. Was there any other housekeeping matters or anything to bring up before we adjourn?

(No response.)

Hearing none, I want to thank everyone for your patience and everything the last couple of days, and I appreciate all of the folks that came down here as public witnesses, and all of our panelists. And especially thank you to our hard-working staff for helping put this together. Thank y'all.

(Hearing concluded at 1:56 p.m.)

C E R T I F I C A T E

I, Brenda P. Elwell, Certified Court Reporter, do hereby certify that the foregoing transcript is an accurate record of the proceedings had in the above-entitled matter at the time and place therein set forth.

^Kelley Marie Nadotti, RPR, CCR
CCR 6256-8388-8026-4192

Brenda P. Elwell, RPR, CCR, B-2023