BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:	)	
	)	
Georgia Power Company's 2023 Integrated Resource Plan Update	)	**Docket No. 55378**
	)	**Volume 1**

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Thursday, February 29, 2024

The above-entitled matter came on for hearing Pursuant to Notice at 9:30 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman
FITZ JOHSON, Commissioner
TRICIA PRIDEMORE, Commissioner

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P R O C E E D I N G S

CHAIRMAN SHAW: All right. Good morning, everyone. Thanks for your patience this morning as we had to conduct some other business.

This is Docket Number 55378: Georgia Power Company's 2023 Integrated Resource Plan Update on February 29th and March 1st, 2024.

We'll start by calling for appearances.

Georgia Public Service Commission.

MR. THOMAS: Good morning. Preston Thomas and Ginny Davis on behalf of Public Interest Advocacy Staff.

CHAIRMAN SHAW: Thank you.

Georgia Power Company.

MR. MARZO: Thank you, Mr. Chairman. Brandon Marzo, Steve Hewitson and Allison Pryor on behalf of Georgia Power Company.

CHAIRMAN SHAW: Thank you.

Advanced Power Alliance.

MR. CARVER: Brad Carver. Hall, Booth, Smith on behalf of the Advanced Power Alliance.

Thank you, Mr. Chairman.

CHAIRMAN SHAW: Thank you, Brad.

Clean Energy Buyers Association.

MR. DUNBAR: Good morning, Mr. Chairman,

Commissioners. Scott Dunbar of the law firm Keyes & Fox here on behalf of the Clean Energy Buyers Association.

CHAIRMAN SHAW: Thank you.

Heelstone Renewable Energy.

MR. GALLOWAY: Good morning, Mr. Chairman, Commissioners. Newton Galloway and Terri Lyndall on behalf of Heelstone.

CHAIRMAN SHAW: Thank you.

Georgia Association of Manufacturers.

MR. JONES: Good morning, Mr. Chairman. Clay Jones for GAM.

CHAIRMAN SHAW: Thank you.

Georgia Center for Energy Solutions.

MR. HUBBARD: Peter Hubbard for the Georgia Center for Energy Solutions.

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: Good morning. Alicia Brown for the Georgia Coalition of Local Governments.

CHAIRMAN SHAW: Thank you.

Georgia Interfaith Power & Light.

MR. SHERRIER: Good morning. Bob Sherrier and Jennifer Whitfield on behalf of Georgia Interfaith Power & Light.

CHAIRMAN SHAW: Georgia Solar Energy Association.

Georgia Solar Energy Association.

(No response.)

CHAIRMAN SHAW: Georgia WAND Education Fund.

MS. SCOTT: Good morning, Mr. Chairman and the rest of the Public Service Commissioners. Kim Scott, Georgia WAND Education Fund, Inc.

CHAIRMAN SHAW: Thank you, ma'am.

Georgia Watch.

MS. COYLE: Good morning, Commissioners. Liz Coyle for Georgia Watch.

CHAIRMAN SHAW: Good morning.

Metropolitan Atlanta Rapid Transit Authority.

MS. STURM: Good morning. Kasey Sturm for MARTA.

CHAIRMAN SHAW: Microsoft Corporation.

Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: Robert Baker for RSM Energy.

CHAIRMAN SHAW: Good morning, Mr. Baker.

MR. BAKER: Good morning.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: Good Morning, Commissioners. Zach

Fabish for the Sierra Club. With me is Curt Thompson.

CHAIRMAN SHAW: Good morning.

Southern Alliance for Clean Energy.

MR. JACOB: Bryan Jacob on behalf of Southern Alliance for Clean Energy.

CHAIRMAN SHAW: Southern Renewable Energy Association.

You're not Simon.

MR. COX: Good morning. No, I'm not. But I'm Whit Cox. And myself, along with my colleague Simon Mahan, will be representing the Southern Renewable Energy Association.

CHAIRMAN SHAW: Good to have you. Thank you.

United States Department of Defense and all other Federal Executive Agencies.

MR. McNUTT: Good morning, Mr. Chairman. John McNutt on behalf of DOD.

CHAIRMAN SHAW: Good morning.

Walmart.

MS. EATON: Good morning. Stephanie Eaton here on behalf of Walmart, Inc. Thank you.

CHAIRMAN SHAW: Thank you.

All right. That's all of our appearances on the list.

Are there any housekeeping matters to take up at this time?

(No response.)

CHAIRMAN SHAW: I would just like to remind everyone that we have a lot of folks here to speak and a lot of different parties to be represented today. So please try your best to pay attention so that if a question has already been asked of a panel to try not to repeat that.

We're going to do our best to expedite this hearing and make sure that we get everyone out of here at a decent hour. Not today, but tomorrow. So that means -- gauging on how things are going today, we could be here for awhile.

We have instructed Georgia Building Authority to please leave the air on until 9:00 p.m., though. And we will take a couple of breaks. And we're going to try to move this thing along, but glad everyone is here. This is a very important hearing.

Now we'll move on to public witnesses. And I would just say that we have two sheets. And we have -- normally we try to get this done in one hour. So hopefully that will be the case.

So we're going to try to stick to the three-minute rule today as best as we can. But

thank y'all for being here. And we will start on page 1.

And if I pronounce your name wrong, just go ahead and repeat your name when you get up, as well. But I'll do my best.

Dr. Stanley Fineman.

DR. FINEMAN: Good morning. Yes, you pronounced it exactly right.

I'm Stan Fineman. I'm an allergist from Cobb County. I've been in practice here for over 40 years. I'm a product of the Atlanta Public Schools, also Emory College and Medical School.

And I'm here because I understand the Public Service Commission mission is to provide safe and reliable, reasonably priced electricity. And my comments are going to be on the safety, the safe aspects and the impact of fossil fuel and climate warming on allergies, which is my specialty.

Because I take care of patients with allergies and allergies are triggered by pollen. So we've studied pollen now for over 30 years. And the reason we've studied pollen is because it does cause allergies and it causes my patients to have more respiratory problems, especially respiratory problems.

Recently I published a study in collaboration with the CDC that, looking at data over 27 years, that the tree pollens here in Metro Atlanta have increased 5 percent a year. In other words, a pre-pollen count has increased 5 percent a year over that 27 years, which means that our pollen counts are higher.

We've also found that the length of the season is longer by almost three to four weeks over that 30-year period. Today's pollen count, by the way, is 67, which is in the high range. And in February, so far this year, we've had 16 of 21 days that we're counting pollen. We only count pollen in the winter during the weekdays.

And so we anticipate very, very high pollens. In fact, last year the pollen count was 1,600 on March the 6th. So we anticipate it's going to get worse in the next couple of weeks.

So what have I done with my patients? So when I started in practice, I was telling my patients to start their allergy medicine on St. Patrick's Day. Because that was before the pollen got worse and they were able to start their medicine and help them with their symptoms.

Now I'm telling patients start it on

Valentine's Day. So that's a month earlier because the pollen is starting earlier, it's higher. There are lots of studies that show it's more potent, as well.

But the bottom line is that the burning of the methane gas, oil and biomass is not safe for Georgians, especially those with allergies. And really the only safe prescription for the health of all Georgians is clean, renewable energy.

Thank you.

CHAIRMAN SHAW: Thank you, sir.

John Shackleton. And up next will be Brian Tolar.

Good morning.

MR. SHACKLETON: My name is John Shackleton. I live in the city of Atlanta. I'm a retired CFO with an undergraduate degree in science and a graduate degree in business.

Thank you members of the Georgia Public Service Commission for the opportunity to speak today. The supplemental request this year by Georgia Power is disconcerting. It bypasses the normal review process and calls for additional electrical needs to be furnished 70 percent by fossil fuels.

At a time when climate change effects are

dramatically increasing, Georgia has landed a substantial EV and solar manufacturing facilities that stand to be positive climate change solutions.

Thanks to Plant Vogtle, green energy is comparable to most other states. However, Georgia Power remains married to natural gas with 50 percent of our energy coming from fossil fuels. Meanwhile, other states are adopting goals of being carbon free.

While we may pat ourselves on the back for reducing the use of coal, natural gas is not a transition or green solution. Natural gas is composed mainly of methane, which is 28 times more potent as a greenhouse gas and carbon dioxide.

When burned to produce electricity, natural gas produces carbon dioxide that warms the plant. Natural gas can be considered worse than coal because its production and use allow for leaks that pollute the atmosphere with potent global -- potent warming effects.

Fossil fuel companies have lied about climate change and thwarted efforts to transition from fossil fuels. They think of themselves as energy companies and adapt, instead they double down on fossil fuels. Because climate disasters are

increasing dramatically in frequency and costliness, I can pre-see the day when fossil fuel companies will be sued and otherwise penalized for their conspiracy.

Those utilities and entities which enable their destructive product may also be called to task. This is a financial risk. The Public Service Commission has the opportunity to call on Georgia Power to reject their planned use of fossil fuels with this end run around the normal approval process.

Solar energy is cheaper than fossil fuels and getting cheaper with technological advances, does not cause planetary warming, does not fluctuate in price like fossil fuels. It saves lives, provides energy security and is a moral imperative.

Marriage of farming with fossil -- with solar is called agrivoltaics and provides a better return to the land user than if solar or farming were utilized independently. All of the typical objections to solar -- only works when the sun shines, can't be stored -- have been refuted.

The Georgia Public Service Commission is responsible for taking us down the energy path that is best for us. Please provide Georgia Power the

direction it needs to serve Georgians, our country, and the planet.

Thank you.

CHAIRMAN SHAW: Well, that timing was perfect.

Thank you, sir, Mr. Shackelton.

Brian Tolar and next is John Watford.

Good morning.

MR. TOLAR: Good morning, Mr. Chairman and Commissioners. It's good to be with you. This is my first trip to this facility and it's good to see a group of friends in the audience, as well as behind the bench. It's good to be with y'all.

CHAIRMAN SHAW: It's good to see you, Mr. Tolar.

MR. TOLAR: I'm Brian Tolar. I represent Tolar Capital Partners. And I want to speak to you today on behalf of the agriculture industry.

I've worked in this industry for over 30 years. And I've been very fortunate that during that time, I ran a trade association, Georgia Agribusiness Council, that allowed me to tour the state, which I know you-all have done, as well, and meet with businesses and the people that are in our rural communities, as well as those in the urban areas that benefit from the products that are produced by

our ag sector.

Now, you should know, if you don't already, the newest data shows from the University of Georgia -- it says $83 billion in economic impact is now where Georgia's ag economy is rated. And that's a growing number. And I would go as far as to say it's a big deal.

Much of what we have done in the ag economy is we have continued to grow, not only in our productivity, but also in the diversity of the crops that we have, the plants we produce, and the benefits that come from that, including our -- our livestock and our other protein sources.

Let me -- let me hit a couple of highlights for you. The industry of agriculture would not be where it is if it weren't for the adoption of new technology and the -- and the high importance of electricity in making those changes. They cannot be understated. I want to be clear about that.

Yesterday, at our state capitol, our Commissioner of Agriculture, Tyler Harper, held a ceremony where they looked at 150 years of the Department of Agriculture being in place. The oldest Department of Agriculture in our country.

And why that's important is it shows that the

State of Georgia has always seen the benefits of agriculture. And we've seen that prosperity that it's brought to every corner of our state. And I think it's important that we highlight that.

We have 11 million Georgians. We have a nation that we're very proud of. And we have a changing world that needs our industry to be productive. It needs to be -- certainty in how it produces that food. And, most importantly, it needs to be affordable. Electricity allows us to do that.

Technology, efficiency, and sustainability are our keys to being productive in this state. We have to meet all of those -- all of those metrics in order to deliver.

We've seen diesel pumps for irrigation have switched over to electric. We've increased bigger yields, which mean we have to have more product that has to be -- cotton has to be ginned, peanuts have to be dried, turf grass has to be harvested. And we can do all that with electricity.

I ask you today, please, continue to provide electricity. Dance with who brung you. Agriculture is the one that's been here. And we want your support to let us to continue to thrive.

Thank you so much.

CHAIRMAN SHAW: Thank you, Mr. Tolar. Thank you for representing Georgia's number one industry.

John Watford next. After him will be Bob James.

Good morning.

MR. WATFORD: Good morning. And good morning, Commissioners. My name is John Watford. I'm the president of South Georgia Technical College in Americus, Georgia. I have been there -- I'm on my 35th year at South Georgia Tech. I've been president going on eight years.

And I'm here to talk about our mission and one of our partners in that mission. Our mission is workforce development to further the economy of Georgia. That's why we are in the business of education is to see people get employed.

And that dovetails with the mission of Georgia Power. Georgia Power is a great partner of South Georgia Tech. About 16 years ago, they helped us start the first electrical line worker program in the state. And today we still have the -- one of the strongest -- we think the strongest line worker program in the state.

We keep a running waiting list and we run four classes, at minimum, per year to prepare line

workers. Georgia Power assists us with a lot of equipment, supplies, and other resources. They are on campus periodically to speak to students, to talk about safety, and to give mock interviews.

They also provide apprenticeship sites and workforce based learning sites for students in their last week of the program, whether they're going to work for Georgia Power or not.

Georgia Power has hired many of our diesel technicians. We carry the largest diesel enrollment in the state among the technical colleges for diesel students. And, of course, with as many bucket trucks as Georgia Power runs, they need diesel technicians. Our industrial electric program is very dependent on Georgia Power for hiring those students.

We serve seven counties in Southwest Georgia; Crisp County, Macon, Marion, Schley, Sumter, Taylor, and Webster County. And if you're familiar with our Georgia geography, those are all rural counties. But our rural parts of the state and those citizens deserve an opportunity for a strong economic future just like the rest of the state does. And working together with Georgia Power, we feel like we are meeting those goals.

We've had three major disasters in Southwest Georgia since I've been at South Georgia Tech; the flood of '94, the tornado that hit Americus in 2007, and most recently Hurricane Michael. And all three of those times our campus was a staging area for Georgia Power serving all of Southwest Georgia to get help to those in need.

We provided our truck driving pad as the staging area where the vehicles would be parked. And our dorms -- we're one of only two colleges that has campus housing. So we provided an opportunity for workers to be able to spend the night in a warm bed during those crises.

All that to say is: We have a lot of challenges in rural Georgia, but working with great partners like Georgia Power we're able to meet those challenges and we've got a promising future for the economic -- economy of Georgia.

Thank you for your time.

CHAIRMAN SHAW: How about -- how about GMC? That's Sumter EMC there; right?

MR. WATFORD: Yes, sir. That's correct.

CHAIRMAN SHAW: They do a pretty good job, too, don't they?

MR. WATFORD: They do a fantastic job. And so

does Flint Energies and Crisp County Power that also is in our service delivery area.

And let me say that all of those EMCs and power companies and Georgia Power all work hand-in-hand together to make sure that our citizens are getting what they need.

CHAIRMAN SHAW: Thank you for taking the time to come up today.

MR. WATFORD: Yes, sir. Thank you.

CHAIRMAN SHAW: All right. Bob James.

Next after him is Tara Overzat.

MR. JAMES: My name is Bob James. Thank you for this opportunity.

I've been concerned about carbon pollution for decades. Peer-reviewed climate scientists expect that the business-as-usual scenario could result in a 5.4 degree Fahrenheit increase in temperature. That will cause a lot of suffering, species extinction, loss of life and trigger social struggles, such as increased migration.

We all know we need to prudently transition away from fossil fuels. And I think I understand that you do, too. For that reason, I urge you to oppose Georgia Power's revised plan that adds more fossil fuels to handle increased demand.

We are not alone. The European Union's Carbon Border Adjustment will levy a tariff on goods imported from countries based on their carbon footprint. As a result, there is a bipartisan bill in the United States Congress today called the PROVE IT Act, Senate Bill 1863, which requires the Department of Energy to determine the carbon intensity of American goods. Charging will begin in 2026.

The Southern Company and Georgia Power ought to plan to reduce its carbon intensity to support the many clean energy manufacturers coming to Georgia and to enable more folks to benefit from the lowest costs for generating power.

While nuclear power reduces the carbon intensity, it is expensive and it's time-consuming. Renewables with batteries are great examples used by Texas and California to lower emissions and provide resiliency.

Please challenge Georgia Power's claims that increasing access to solar communities would raise rates. There is a lot of evidence that including solar communities would enable more folks to participate in the lowest cost for generating power. And our new sustainable industries, they need your

support as do all of us who care about our climate.

Thank you.

CHAIRMAN SHAW: Thank you, Mr. James.

I want to mention, too -- you know, I mentioned we've got the one-hour rule on public comments that we'll try to stick to. So if there's any -- and we're probably going to run over, but we're certainly not going to turn anybody away who has taken the time to be here today.

But if there's anyone that's signed up that is also planning to be here in the morning that would be willing to wait until in the morning so that we can maybe get closer to the hour, just let Sallie know. Sallie, raise your hand.

If not, we'll just keep going.

All right. Next, Tara Overzat. And behind her, Larry Heiman.

Good morning.

MS. OVERZAT: Good morning, Commissioners. My name is Tara Overzat and I'm a trauma therapist with a Ph.D in counseling education and supervision. I'm a licensed professional counselor in the State of Georgia, a national certified counselor, and approved clinical supervisor.

I'm a long-time Georgia resident and currently

live in Fulton County. I am concerned with the planned increase in the burning of fossil fuels in Georgia as this affects not only the physical, but mental health of all Georgians.

I have seen a marked increase in the amount of climate anxiety that my clients present with. Clients who were improving are suddenly asking themselves: What is the point if the planet becomes more unstable and less liveable?

The shift in our weather patterns has concerned young adults about their future, forcing them to wonder if they will live in a stable society, as did their parents and grandparents. Theirs is an uncertain future.

As temperatures continue to whiplash and extreme weather events become more frequent and severe due to the burning of fossil fuels, people are increasingly experiencing the traumatic aftermath of weather disasters. In the aftermath of these calamities, including tornadoes, extreme flooding and wildfires, survivors are plagued by myriad symptoms: Hypervigilance, panic attacks, sleeplessness, grief, and worry.

The constant fear of a worse event happening to them perpetuates a chronic cycle of psychological

distress. It is difficult for clients to attend to their needs and plan for their future with this growing sense of uncertainly. Parents tell me that they fear the world their children will inherit, that the opportunities they had once dreamed of for their children may vanish due to an unstable climate.

Continued effects of climate change have impacted the price of food, causing worries about their family's nutrition and making ends meet. They are feeling powerless and hopeless. People in sobriety stumble, wondering if the work of staying in recovery will be worth it if climate change worsens. Choices that decrease climate change will, in turn, increase resiliency and hope for all these Georgians.

In conclusion, I want to emphasize that the burning of coal, gas, oil, and biomass is not safe for Georgians. The only safe prescription for the health of all Georgians is clean, renewable energy.

Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

Larry Heiman. And up next, Roxana Chicas.

Good morning.

MR. HEIMAN: Good morning, Commissioners. My

name is Larry Heiman. I'm a resident of Dunwoody. I appreciate the opportunity to be here this morning to speak with you. I'm here today representing myself as a homeowner, as a parent, and as a citizen of the earth.

I wanted to be here last month in January to speak, but I wasn't able to. But I did take advantage of your wonderful Youtube Channel and binged watched all 12 hours of the hearing last month; all right?

So who needs Netflix -- who needs Netflix or Hulu anymore, right, when you have the PSC YouTube channel?

In watching that and in reading the IRP Update from Georgia Power, something really didn't seem right to me. The panel members from Georgia Power repeatedly used terms like: Unprecedented demand increases that we've never seen before, never seen before demand growth.

They used these terms over and over again. And stressed the race against time to meet the coming spike in demand. However, if these are unprecedented times, shouldn't they be thinking outside of their comfort zone, a little bit outside of the box in how they choose to address this?

Their plan relies largely on the same old technology; power from coal and gas-fired power plants. So my question is: Doesn't this unprecedented situation deserve some unprecedented thinking?

I was happy to hear Commissioner Echols' comment during -- in January about the possibility of launching, for example, managed charging -- managed EV charging to reduce demand.

You know, Georgia is the state I'm proud to call home and a state that's lauded for innovation. So I expect -- and I think all Georgia residents deserve -- innovative solutions -- more innovative solutions from Georgia Power to smooth out peak demand, reduce system-wide costs, and, importantly, reduce greenhouse gas emissions. We need Georgia Power to exhaust all of the clean and efficient solutions that they can before trying to use more fossil fuels.

Other utilities around the country are doing this, even in the southeast. I'm sure you're aware of what Duke is doing in North Carolina with some of their programs. I don't see why Georgia Power can't, as well. I know there's many, many very intelligent people in the company.

So EV charging virtual power plants that leverage residential and commercial battery storage systems. The list of possibilities goes on and on. Energy efficiency, on-bill financing. So many things can be done.

But only you, as elected Commissioners, can stand up for the rest of us and take -- and ask Georgia Power to take the actions that are appropriate for the times that we live in. Not just those that are convenient, easy, and profitable for them, which also happen to damage the environment.

Georgia Power can earn a rate of return, but they should be required to do the right things in order to earn that profit. Please require Georgia Power to do the right thing. I'm confident that you will.

Thank you.

CHAIRMAN SHAW: Mr. Heiman, you were talking about what Duke's doing. Are you referring to the virtual power plant?

MR. HEIMAN: Yes.

CHAIRMAN SHAW: Okay.

MR. HEIMAN: And I believe some EV charging programs, as well.

CHAIRMAN SHAW: Thank you.

VICE-CHAIRMAN ECHOLS: Mr. Heiman, could I give you my card? I'd like to get you on my podcast, if you don't mind.

CHAIRMAN SHAW: You have arrived.

All right. Roxana Chicas. And up next, Henry Slack.

DR. CHICAS: Good morning. My name is Roxana Chicas and I am a nurse researcher. I have a PhD and I live in Cobb County.

I research how heat affects the health of outdoor workers. And each year we are having longer and more stronger heat waves. Now, many of us enjoy the summer. We love doing outdoor activities. Perhaps we go outdoors with our kids or our grandkids.

And while you're outside enjoying the sun, at some point you may become uncomfortable. And it's just -- you're sweating and you may even get a little dizzy and you decide it's time to go back inside into the AC and cool down, have a cold glass of water or maybe even a cold beer.

But, you know, there are lots of workers that work outdoors that don't have that option to stop working. There's a million outdoor workers here in the State of Georgia. It's about 22 percent of the

workforce. And they have to continue to work through the scorching heat in the summers.

And many of them are having heat stroke. In fact, farmworkers, which is a big part of our Georgia industry, they're 35 times more likely to have a heat-related death, followed by construction workers, who are 14 times.

So they are dying to live. And these are jobs that we need, but we also don't want workers to die while they're working. And we're also seeing workers who are developing acute kidney injury just over the course of one workday.

And so with that said, I think that we are seeing a lot of association with chronic conditions that are associated with intense labor working outdoor in the heat. And outdoor workers are bearing the brunt of life-threatening and dehumanizing extreme heat health effects, which many more communities will face as heat waves worsen.

Therefore, the burning of coal, gas, oil, and biomass is not safe for Georgians. And the only safe prescription for the health of all Georgians is clean, renewable energy.

Thank you.

CHAIRMAN SHAW: Thank you.

Henry Slack. And up next, Dr. Greenwald.

MS. TANNER: Mr. Slack, is going to go tomorrow.

CHAIRMAN SHAW: Thank you, Mr. Slack.

Dr. Greenwald.

Are you keeping up with the hour, too, for me? What time did we start?

How you doing?

DR. GREENWALD: I'm doing well. Thank you. Good morning. Thank you for holding this.

I'm Michael Greenwald. I've lived in Dunwoody most of my life. I practice pediatric emergency medicine here in the Metro Atlanta area. And I wanted to talk to you just for a few minutes about asthma.

Asthma is one of the most common conditions that we see in medicine and it's been increasing now. Twenty-five years ago when I emerged from training, we already knew then the association between air pollutants and asthma triggers. That was established. It's not new information.

But other things have changed. The medicines haven't changed all that much, but the incidents has. It's growing. And, in fact, in this room we probably have lots of people who have asthma or

people who have family members with asthma.

And I get to see it every single day. There's not a shift that I work that I don't see a child struggling to breathe because their asthma medicines aren't sufficient. And when their asthma medicines don't work, then we have to admit them. And if admitting them and giving them oxygen doesn't work, then we have to intubate them.

These problems are getting worse. They're not getting better. We know the associations. We know the triggers. But we don't have control over the things that we'd like to. We have medicines that don't seem to prevent it.

I can take care of your pain. If you have severe pain, I've got medicines that can take care of that. But if you have shortness of breath, all I can do is provide a tube to intubate you.

I just ask that you consider this when you're making your decision because there's really no safe level of pollution. We need to do what we can now.

Thank you.

CHAIRMAN SHAW: Thank you, Doctor.

Kevin Kellner, followed by John Duke.

MS. TANNER: Mr. Duke is also going to go tomorrow.

CHAIRMAN SHAW: Okay. So followed by Sonya Doubledee.

MR. KELLNER: Hello, Members of the Public Service Commission of Georgia. My name is Kevin Kellner. And I'm currently a sophomore attending Kennesaw State University studying mechanical engineering.

As someone who has lived in Georgia all my life specifically in Cobb County, and recently in Roswell, I am truly honored to offer my insight at Georgia's energy policy with you today. I would like to start off my speech with a simple analogy. Imagine you could only eat one type of food every single day. Personally, I would probably go for an apple, but that would -- that -- but, let's face it, that would probably be dull very fast.

If we only rely on one piece of fruit, we aren't gaining the nutrients of the whole food pyramid. Just like food, having a balanced energy source is important for Georgia to supply energy to its residents. It is critical we consider all energy options, including renewables, nuclear, and even some fossil fuels. A combination of these energy sources would not only benefit citizens like me, but it would increase the economic drive.

Starting with solar, the energy innovations and falling cost of solar energy make it an evident choice to be a significant part of Georgia's energy mix. My peers and I are deeply passionate about the environment and we believe solar energy should play a major role in our future.

I've read that this Commission is considering battery technology paired with solar energy, which could be a game changer if implemented on a larger scale. Unlike Texas, we would be prepared for any disaster that would instill on our soil as the batteries would give us abundant source of already generated energy.

However, my professor -- professors have instilled in me the importance of pragmatism. Since renewable energies depend on weather conditions and might not always be available, Georgia needs to use other sources, like nuclear power, to make sure there's enough energy even when some of these renewables aren't working.

I had the opportunity to tour Plant Vogtle with my professor, Dr. Farfan, and it was a perfectly -- it perfectly aligns with many of the energy production requirements, including concentrated production, reliability, safety, and long-term

forward -- long-term affordability and environmental benefits, such as zero carbon dioxide emissions.

I am pleased that Georgia has recently added new -- new nuclear energy to our mix. As someone studying nuclear engineering, I believe nuclear generation should be considered -- if not now, then in the future -- for our state and our nation.

Although many believe nuclear power is dangerous, it is actually one of the safest forms of energy production. You get more radiation being outside in the sun than standing inside a nuclear reactor facility. One -- even 1 kilogram of natural radium -- uranium can produce about 20,000 times as much energy as the same amount of coal.

In the near term, natural gas generations may bridge -- may bridge the gap needed to ensure reliable energy source for our economy.

Now, just as an apple sparked Newton's insight, why not let the whole produce section fall and inspire the Georgia Public Service Commission.

Thank you.

CHAIRMAN SHAW: Thank you, Mr. Kellner.

VICE-CHAIRMAN ECHOLS: Mr. Kellner, I'll be speaking at Kennesaw on March 19th at noon. I would love to have you come over.

MR. KELLNER: Are you coming to the Marietta campus or the Kennesaw campus?

CHAIRMAN SHAW: The Kennesaw campus.

MR. KELLNER: All right. I'll be there.

When is it?

VICE-CHAIRMAN ECHOLS: March 19th on a Tuesday.

CHAIRMAN SHAW: Can I come?

VICE-CHAIRMAN ECHOLS: Of course.

CHAIRMAN SHAW: Sonya -- I'm going to let you pronounce this.

MS. DOUBLEDEE: Doubledee.

CHAIRMAN SHAW: I was right.

MS. DOUBLEDEE: Yeah. All right.

CHAIRMAN SHAW: Good morning.

MS. DOUBLEDEE: Good morning.

CHAIRMAN SHAW: And next is Martin Scott.

MS. DOUBLEDEE: Hello, Georgia Public Service Commission. My name is Sonya and I'm a sophomore at Emory University. For the next 30 years, my generation will have to deal with the effects of climate change in ways that we cannot predict.

Air quality has been increasingly diminished which we've heard from a number of people today. There were several instances over the summer in which we were advised to stay indoors. You could

visibly see the smog in the air whenever you went outside. And this is having serious health effects that several of my friends and family have been continuing to deal with.

If we continue to make decisions that enable the expansion of fossil fuels on the local level, this will only get worse. Georgia Power's request would build three new oil and gas-burning turbines at Plant Yates in Coweta County. The questions we have to ask ourselves is how far we are willing to go.

The federal government is already trying to provide funding to move away from fossil fuels through the Inflation Reduction Act. However, the proposal presented by Georgia Power would also continue buying 750 MW from Mississippi Power, which is postponing the retirement of a coal-fired power plant in that state.

The decision you make today will have spillover consequences across states, nationally, and ultimately for decades down the line. I would implore to ask yourself: When Georgia Power has already raised rates this year and is now saying that their initial projections for power are so off that they need an entirely new fossil fuel power

plant, what's to say that they won't do that again?

We'll continue seeing these rates go up and up. Georgia residents are already paying higher rates. There shouldn't be an additional environmental cost on top of that.

This new fossil fuel plant will last up to 40 years. In a world where we want to build up solar, wind, and other sources of renewable energy, locking Georgia Power into fossil fuel energy for the next 40 years makes any progress toward net zero impossible to reach.

Thank you.

CHAIRMAN SHAW: Thank you.

Martin Scott, followed by Randy Beall.

UNIDENTIFIED SPEAKER: I'm not Martin Scott.

CHAIRMAN SHAW: Martin Scott.

Maybe I'm saying it wrong. Is it Nathan or -- it's just hard to read.

I'll tell you at the end if I've left somebody off, it might be you.

Randy Beall, followed by Jaela Rivera.

MR. BEALL: Thank you, Mr. Chairman.

As an ordained, minister, man of God, three minutes is usually an introduction, but I will do my best here.

Good morning, all of you. My name is Randy Beall and every day I'm honored to represent the finest craftsmen and women in the construction industry with georgiaconstructioncareers.com.

The Bible tells us in Proverbs 29:18 where there is no vision, the people perish. With that verse in mind, let me take you back to a story I shared some years ago with this Commission about two cities that took divergent paths.

In Waynesboro, Georgia, our men and women in construction played a pivotal role in completing our state's nuclear plant, the first of its kind in 30 years in the United States. Something that could not have happened without the vision of this Commission.

That vision has proven to be prosperous for communities, families, and for our state attracting new businesses. Meanwhile, a town in South Carolina turned away from their nuclear project with consequences that were nothing short of devastating. That lack of vision resulted in communities and families' economic future to perish.

As you ponder the future of energy generation in Georgia, I'm here to remind you of the critical importance of maintaining a diverse fuel mix for the

economic and social well-being of our communities. Consider the closure of Plant Branch near Milledgeville in 2015.

It wasn't just a facility that was lost. It was 20 percent of the community's tax base, essential for funding public services from emergency rooms to schools. The closure sent shock waves through the community affecting everything from family stability to educational outcomes.

It's a stark reminder of the profound impact that job loss and economic shifts have on the very fabric of our communities. Jobs do matter.

We support building a gas generation plant at Plant Yates' site, but this is more -- about more than just building additional gas-generation facilities. It's about recognizing the role of good jobs and alleviating societal issues.

We're at a crossroads, in terms of energy production. We've relied on coal and should for some time in the future. However, the future is clear, natural gas and renewables must play a significant role.

Our organization supports the wise use of fossil fuels, alongside renewable energy, to ensure reliable, 24/7 energy supply for Georgia. We faced

extreme temperatures and peak demands that underscore the need for baseload generation to maintain grid reliability.

Imagine if every community could see the value -- the full value of hosting a power plant, a narrative of economic prosperity, job satisfaction, and upward mobility for generations to come. I work in ensuring a reliable energy grid even in the most challenging conditions as a testament to labor's commitment and capability.

In closing, the tale of two cities that I once told is more than just a story. It is a call to action. And like all good preachers, I'll go back to where I started, Proverbs 29:18. Where there is no vision, the people parish.

Have a vision for Georgia that we remain a leader in energy innovation and reliability. Have a vision that benefits all of our communities. Have a vision where families, workers, construction men and women economically thrive and don't perish.

Together we can build a future where every city thrives powered by the dedication and skill of our craftsmen and women and powered by your vision, a clear vision for the future.

Thank you, Mr. Chairman.

CHAIRMAN SHAW: Thank you, Mr. Beall. Thank y'all for what y'all have done to make Georgia a leader.

MR. BEALL: Thank you, sir.

CHAIRMAN SHAW: Jaela Rivera, followed by Isubel Li.

Good morning.

MS. RIVERA: Good morning, Commissioners. My name is Jaela Rivera and I'm a current undergraduate student at Emory University, here in Atlanta, Georgia.

I've lived in Georgia my whole life. Almost every significant memory I have from growing up is tied in the natural riches of our state. The lands and the people here are of the utmost importance to me. And with all of you being fellow Georgians, I hope you feel the same.

When I first became privy to the fact that Georgia committed to being one of the leaders of the renewable energy revolution, I was so happy and so proud of my state. I thought to myself: We can show the rest of the United States how important taking care of our natural resources are. And it gave me hope that we would keep moving in the right direction.

My pride turned into disappointment when I heard the request of the Georgia Power to increase their use of fossil fuels in Georgia. How can we be champions of renewable energy if we turn back to fossil fuels the moment that it's requested?

It's not necessary, no matter what Georgia Power claims that it is. It's just easier for them.

I'm also a military veteran and the daughter of two veterans. So the betrayal of Georgia Power's commitment to the Department of Defense is -- to the Department of Defense's sustainably goals is deeply disappointing.

In my time at West Point, I learned about the value of choosing the hard or right over the easy or wrong. The right choice here, however, is the easier one.

Don't let Georgia Power harm our state, our country, or our planet. Your duty is to the public, not to Georgia Power. The choices you make now will affect the present and future generations for years to come. Let's be on the right side of history. Let's be the Georgia that we know we can be.

And I just wanted to add: This is going to be my kids. This is going to be me. I'm going to be able to -- God willing, I'm going to be able to see

the end of this generation.

I'm going to be able to see the end of this century. And so the choice that you make today is going to affect everybody else that I have. So please, please make the right choice.

CHAIRMAN SHAW: Thank you.

Isubel Li. Please correct me if I --

MS. LI: You were perfect. Hi, my name is Isubel Li. And I'm a first-year student at Emory University studying environmental science and applied mathematics.

So this past September, flash flooding battered the very city we stand in now. The water displaced people, it injured students, it swallowed cars, and parking lots and roads. City mobility ground to a halt as Atlanta's infrastructure weaknesses were exacerbated and people were harmed. People were harmed.

The environment is inextricably linked to human well-being. And the data shows that catastrophic rainfall and extreme flooding events will only become worse if the city passes Georgia Power's fossil fuel proposal.

The greenhouse gases released from fossil fuels accumulate and accumulate over generations, which

heats the atmosphere. This warmer air increases evaporation and holds more water, which gets released in rapid precipitation events, destroying people's lives and sometimes even taking them.

We cannot allow temporary profits to take precedence over human life. These are our homes, our infrastructure, and our economic burden when it's time to recover from these environmental disasters.

I've heard a lot of comments about economic prosperity and job growth, but investing in green energy now sets us on the right track for further economic expansion and upward mobility.

Moreover, climate events disproportionally harm black and low-income communities. Environmental justice and social justice are so closely interrelated. And rejecting this proposal is a key first step in prioritizing the well-being of all people.

We need to release our hold on fossil fuels and the change starts now. Clean energy is the future. And as the late John Lewis once said: If not us, then who? If not now, then when?

I implore you to reject Georgia Power's proposal and prioritize human life over temporary

profit. The time is now.

Thank you.

CHAIRMAN SHAW: Thank you.

Dakota Tauteeq. You're going to have to help me. I'm sorry.

MS. TAUTEEQ: Good morning, Commissioners. Dakota Tauteeq.

My name is Dakota Tauteeq and I am a sophomore at Emory University. Like many other students, I am here today because I am concerned about my future. Georgia Power's request to increase their fossil fuel usage is in blatant disregard from what climate science has been telling us for decades.

Fossil fuels kill. They kill our ecosystems. They kill our people. And, more importantly, fossil fuels will kill our future generations.

How are we supposed to survive if corporations like Georgia Power keep making decisions that put profit over the well-being of our people?

I am here today to ask you to consider the people that call Georgia home, to consider a future where we can live equitably and safely. I'm asking you to use the power that the people of Georgia have placed into you to protect them. Please use your influence and your authority to say no to Georgia

Power increasing their fossil fuel use.

As a society, we are not doomed yet. It is still possible to make the shift to prioritizing clean energy methods that could help us reduce our global greenhouse gas emissions. As an environmental science major and a business major, I see that the possibility for innovation within this field is endless. We can prioritize clean energy and still make gains in furthering our general economy.

Georgia Power has the opportunity to set the standard by making major investments in clean energy that will not only propel them forward in the economy, but will also help protect our planet.

Thank you.

CHAIRMAN SHAW: Thank you.

Doug Miell, followed by Deanville Celestine.

MR. MIELL: Good morning, Chairman and Commissioners. My name is Doug Miell representing the Georgia Chamber of Commerce. And I thank you for this opportunity to speak in support of Georgia Power's 2023 Integrated Resource Plan Update.

The Georgia Chamber represents approximately 50,000 members who collectively employ over 2 million Georgians. We represent investors in

every county of our state and their membership includes small storefronts and large corporations of every size and business type.

Our organization believes in enterprise -- free enterprise and market forces. And at this time Georgia is experiencing exciting and unprecedented growth. The market is working overtime.

Across multiple industries, this is creating generational opportunity and changes in the growth projections for the state and is an overwhelmingly expression of the market's confidence in our state.

Alongside this growth and opportunity comes the need for reliable and affordable energy. To reliably and economically meet this demand, Georgia Power has proposed additional generational resources, including expansion of renewable energy resources, battery energy storage systems, new and expanded distributed energy resources, demand-response programs, as well as new and existing conventional power plants.

These initiatives align with the Chamber's all-of-the-above policy with regards to the importance of a diverse mix of energy generation sources. And as Georgia is recognized nationally as the leader in developing cost-effective renewable

energy, we are excited about Georgia Power's plans to add approximately 10,000 megawatts of new renewable energy resources by 2035.

With credit to all concerned, Georgia's energy utilities and policies have maintained competitive pricing and reliability critical for attracting new companies and supporting existing businesses in the state. As this Commission evaluates the need for future generation capacity to maintain Georgia's stellar energy network, the Chamber's members, investors, and listed partners request continuance of a strategy of a diversified energy mix that ensures reliability and affordability of this critical infrastructure.

Commissioners, in conclusion, the Chamber recognizes the unique challenges outlined by the projections that Georgia Power has outlined in its IRP submissions. We have confidence in this Commission and Georgia Power to bring these system expansions to a successful conclusion to the benefit of consumers and business and industries across the State of Georgia. The Georgia Chamber supports Georgia Power's proposed plan.

Thank you.

CHAIRMAN SHAW: Thank you, sir.

Deanville Celestine, followed by Dr. Jaggi.

MR. CELESTINE: Hello, and thank you. My name is Deanville. I am also a volunteer with a group called Citizens' Climate Lobby that builds political will for a livable climate.

And I would first like to thank the PSC for recognizing the need for renewables to be put in the Georgia Power IRP, but I'd also like them to focus specifically on making sure that residential solar and community solar are included, as EMCs, electric municipal cooperations, all across this state have many programs. They are, in fact, part of one organization called Green Power EMC since 2001, which has been working to get people to do more solar power, as well.

They have a program which lets people sign up and figure out how to get residential solar. As well as many EMCs, they have solar power and battery storage. My EMC, Coweta-Fayette, actually has that in Heard County, I believe. And hopefully Georgia Power can be a -- made to do the same.

Thank you for your time.

CHAIRMAN SHAW: Thank you.

Dr. -- Dr. Jaggi.

DR. JAGGI: I'm Dr. Preeti Jaggi. I'm a

pediatrician and infectious disease specialist and I live in DeKalb County.

Several healthcare workers and public health professionals are here today to specifically voice our concern about one of your core charges, which is to ensure that Georgians are provided safe electricity. Fossil fuels, including coal, methane gas, and oil have served our needs for reliable electricity in the past, but they no longer serve us. They are outdated and are harming our health.

The burning of fossil fuels causes climate change and air pollution and these things are killing us and making us sick. This article in the highly regarded journal, Nature Medicine, estimates that the cumulative death toll from climate change since 2000 will pass 4 million this year. That is more than the population of Los Angeles.

When we burn fossil fuels, we also know that air pollution is created. And this makes people sick and makes people die sooner than they should. And the closer you are to this burning of fossil fuels, the worse that air pollution is and its subsequent harms. We know that air pollution affects everyone, but especially children who breathe at a faster respiratory rate and whose

bodies are developing.

This is -- I'm going to leave you with this information from the American Academy of Pediatrics, which discusses the harms or air pollution in children, which includes low birth weight, prematurity, cancer, obesity, autism, asthma, and cognitive deficits, among other things.

And there are also health consequences from climate change which are so numerous that we could spend a whole hour discussing them. Severe weather fueled by climate change disrupts lives in ways that people don't realize.

For instance, we know that climate change is associated with more severe heavy rains and flooding events and this make diarrheal illnesses worse because our water supplies get contaminated with bacteria.

What does this mean? Well, for children, it means more trips to the emergency room to get rehydrated because their bodies are more susceptible to dehydration.

I will leave you with some information from the Infectious Disease Society of America, which details the infection risks that occur from climate change. And one of those things is an outbreak of Vibrio

vulnificus infections. That's sometimes called flesh-eating bacteria.

This was seen in Florida after heavy precipitation events. And it's actually being seen up and down the eastern seaboard right now.

What does that mean? It's a severe infection. This is from the Tampa Bay Times and it discusses the story of a lady who went boating and she got exposed to this organism in the water and she had to have her leg amputated.

There are lots of infectious complications of climate change. And many of them are indirect. So it's not something that you're going to typically think about.

The burning of coal, methane gas, oil, and biomass is not safe for the health of any Georgian. The only safe prescription for the health of all Georgians is clean and renewable energy.

Thank you.

CHAIRMAN SHAW: Thank you, Doctor.

All right. I've gotten some better direction here on the name. Let me go back and call Naturi Scott.

There we go. Good morning.

MS. SCOTT: Good morning, Chairman,

Commissioners. Okay. I'll keep this short and sweet so we can all go home; all right?

CHAIRMAN SHAW: You can stay with us --

COMMISSIONER JOHNSON: You can stay with us until tonight.

COMMISSIONER PRIDEMORE: Make a day of it.

MS. SCOTT: All right. My name is Naturi Scott. I am a junior at Emory University and I'm also a major in environment science. And I urge that you do not allow Georgia Power to expand Georgia's use of fossil fuels.

I am no expert, but the science shows that climate change here and climate disasters are happening each and every day. Climate scientists have reported on climate change for decades, far before I was ever born. It will be irresponsible to allow Georgia to invest in more natural gas and oil.

Climate change is not the only issue at hand, but environmental health and public health will inevitably be at stake as fossil fuels increase pollution in the state.

In addition, with the passing of the IRA Act, Georgia has become a leading state for an investment in renewable energy with an expanding job market, which will aid in deterring the climate crisis and

help Georgia's economy. Do not allow Georgia Power to undermine the progress that this state has made in just a few years.

As a member of the younger generation, I ask that you deny Georgia Power's plan. Instead, require that they invest in clean energy solutions.

Thank you for your time.

CHAIRMAN SHAW: Thank you.

All right. Next there's a translator involved, Flannery Childers. I'll let y'all come up.

And Ms. --

MS. TANNER: It's actually Soto --

CHAIRMAN SHAW: Soto.

MS. TANNER: -- before that one.

MS. SOTO: You said Jocelyne Soto?

CHAIRMAN SHAW: Excuse me?

MS. SOTO: I was just repeating the name.

CHAIRMAN SHAW: Yes. That's it. Soto.

MS. SOTO: Thank you. Hi, y'all. Thank you so much for the opportunity to speak with you today. I'm very excited to see all of you in person. I just did a presentation about y'all this past weekend so super happy to have this time here today.

CHAIRMAN SHAW: Good to have you.

THE WITNESS: Thank you so much.

My name is Jocelyne Soto and I'm the civic engagement director at the national nonprofit named Mi Familia Vota. Our organization is dedicated to empowering the Latino community through civic engagement. And I appreciate your time here today. There's a couple of different things I wanted to discuss.

The first thing I wanted to highlight is that here in the State of Georgia, we will be paying $35 billion over the next 60 years because of the needs of Georgia Power. And as our elected officials who regulate our electricity, gas, and telecommunications across Georgia, it is your responsibility to answer to the needs of our community.

What we know for a fact is that this plant poses a very real threat to our community. These power plants have polluted the area with radioactive materials that have leaked into our water, soil, and ecosystem, and have proven to have negative consequences on almost everything within the proximity to these power plants. What you are allowing is for these companies to pollute and kill the community members living here in the State of Georgia.

And I'm not sure if y'all have noticed, but we are quite literally barreling towards extinction. Everything that we do right now counts to not only the next generation of children and community members who will see the consequences of climate change, but, most importantly, humanity. If we don't fight for what's right now, we will not even exist long enough to really -- really understand the ramifications of what is to come.

By supporting and funding Georgia Power, you are allowing and are directly responsible for our collective demise. You all have a choice to make here today. Are you working for your constituents and for the people living in the State of Georgia or are you going to allow these companies to not only destroy our land, but to decide the fate of humanity?

Thank you for your time.

CHAIRMAN SHAW: Thank you.

Flannery Childers, followed by Sikiu Anez.

MS. CHILDERS: Good morning, Commissioners. My name is Flannery Childers and I am one of the 17 students who made public comments at the hearings in January.

The worldwide scientific community is saying

that we must rapidly phase down our use of fossil fuels and quickly transition to clean and renewable energy. If we don't, the consequences will be dire and significantly harder for humanity to handle. There would be much more disease, death, destruction, displacement of massive numbers of people and increasing global instability.

This is why Georgia Power's updated energy sourcing request is so alarming and distressing. Georgia Power is asking for your permission to do the exact opposite of what the worldwide scientific community is saying we must do. They are asking for greatly increasing our reliance on fossil fuels to build new infrastructure that will tie us to fossil fuels for decades.

That is a threat to our environment and our future. You must deny Georgia Power's request to increase the use of dirty, polluting, climate-warming fossil fuels in its energy sourcing.

Instead, require them to invest much more heavily in utility-level solar and battery storage, expand the RNR net metering program without a cap, expand energy efficiency programs, and explore and develop our offshore wind potential.

I would also like to add that I am proof of the

increasing struggles for those that have asthma. Over the course of the last two months, my asthma has progressed and left me in a state of constant wheezing, coughing, and struggling to breathe. I cannot do basic activities, such as running a short distance or laughing, without falling into a horrible, painful coughing fit.

Therefore, I hope that you take this into consideration when making a decision. Please -- please do not leave me and hundreds of thousands of other struggling even more to breathe.

Thank you.

CHAIRMAN SHAW: Thank you.

All right. Sikiu Anez. Is this the translator, too? Sikiu Anez and --

Sallie, I -- you've got some arrows on here. Is there a --

MS. TANNER: If you want to go to the next person, I'll check. She was in here.

CHAIRMAN SHAW: Is there a Laura I-y --

VICE-CHAIRMAN ECHOLS: Iyer, I-y-e-r.

CHAIRMAN SHAW: I-y-e-r. There we go. I'm sorry.

Good morning.

MS. IYER: Good morning. Thank you for having

me.

CHAIRMAN SHAW: What was your name?

MS. IYER: My name is Laura Iyer.

CHAIRMAN SHAW: Okay. Thank you.

MS. IYER: And I'm a --

CHAIRMAN SHAW: I'm sorry about that.

MS. IYER: No, no. Usually I get Laura Liar, so that -- you did good.

I'm Laura Iyer and I'm a resident and a small business owner in Athens, Georgia. And I really appreciate this opportunity to speak to you today. And thank you so much for fostering a robust and sustainable energy market for our great state.

For ten years, I have had the privilege to lead workshops for the Boy Scouts of America Sustainability Merit Badge, a required merit badge for young scouts aspiring to the rank of Eagle Scout. This past Monday, I began a brand-new session for the workshop ready to hear the fresh perspectives on our young minds have on sustainability.

When I asked the very first question of the merit badge, "Share in your own words the meaning of sustainability," an 11-year old fifth grader scout immediately responded: No fossil fuels.

This response sparked a discussion revealing an awareness among these youngsters that fossil fuels are a finite and a significant source of pollution. This recent incident underscores the urgency of our gathering here today.

You -- as you deliberate on Georgia Power's request for an off-cycle IRP plan to build new fossil fuel plants, please include in your considerations that we are making decisions that will resonate far beyond this room, this year, and into the lives of these young scouts and generations to come.

Georgia Power attributes the need for this expansion to unforeseen economic growth driven by data centers and clean energy manufactures necessitating an addition 6600 megawatts of power. However, this approach appears misaligned with the broader vision of sustainability and environmental stewardship that our community and our youth expect from us.

Our youth believes that fossil fuels, while historically central to our energy landscape, are not our future. They know that greenhouse gas emissions from fossil fuels are a potent contributor to climate pollution.

While they -- what they don't know is the financial implications of these fossil fuel investments, such as remedial costs, compliance with new regulations, and the risk of stranded assets; all significant burdens that will ultimately fall on Georgia's residents.

As you are well aware, the energy strategy, akin to a three-legged stool, must balance the cost, reliability, and environmental impact. The current proposal compromises this balance and contradicts the Southern Company's commitment to net zero emissions by 2050.

I urge the Commission to consider the long-term implications of this IRP. We have a responsibility not only to today's ratepayers but to the next generation of Georgians. I hope this path chosen aligns with the sustainable, reliable, and economically sound future reflecting on the values we strive to instill in our youth and who will inherit the outcomes of our decision today.

Thank you.

CHAIRMAN SHAW: Thank you, Ms. Iyer.

Next is Cary Ritzler. And we are right at the one-hour mark. So if -- if Mr. Slack and Mr. Duke want to go ahead and go today, that will be fine.

We're in good shape.

MS. RITZLER: Hi.

CHAIRMAN SHAW: Good morning.

MS. RITZLER: I'm Cary Ritzler. I am from Athens, Georgia. And I'm glad to -- I wasn't sure we would make it with all the traffic. So I'm glad to be able to speak.

In 2018, my city, Athens, committed to providing 100-percent clean and renewable energy to the city and community by 2050 in a unanimous vote. It was -- it was an ambitious goal that we felt we needed to work for to secure a safe and prosperous future for the families in our city.

At least seven other local governments, I believe, now in the state have made similar pledges. I was glad to see when Georgia Power made a similar pledge also net zero by 2050. That would be right in line with our goals. But I'm very puzzled by how this new request fits in to both the will of the people in these cities and communities throughout the state and the company's pledge.

Georgians do need reliable, affordable energy. I think all of us -- well, I'm not going to speak for everyone here. But I'm certainly in favor of electricity coming to my home. I have solar panels

which help.

There -- there may be a need for gas in -- in an energy mix, but I'd like to see Georgia Power come to this body with a plan -- and the people of Georgia, with a plan that shows what would it look like if we maximized energy-efficiency programs, if we maximized solar. And I'm talking about rooftop solar, distributed-generation solar, community solar. Use the policies that work, like net metering.

You know, develop these resources, maximize what we can do with battery storage. And then come to us and say what's left. There may be a need for gas.

But until we have maximized these less expensive, more healthy and clean sources, things that we can produce right here in our state -- we can produce batteries. We can produce solar panels. We do not produce natural gas.

We can produce these other things in our state. Let's maximize those and then let's talk about what's left to meet with the more harmful, more expensive energy sources for everyone in Georgia.

Your body -- you get to make the decision. You're in a seat of power in this decision. Please

make a good decision on behalf of the people of the state.

Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

Did any of the two I mentioned want to go ahead and go today? Mr. Duke or Mr. Slack?

MS. TANNER: You also had one addition, Christy York.

CHAIRMAN SHAW: Okay. All right.

Christy York.

MS. YORK: Hi, and good morning. My name is Christy York. I am a long-time Georgia resident. I'm a graduate of Georgia Southern University.

And I have also worked in chemistry in the field of polymers for six years. I've worked in Alpharetta at Allnex and I've worked in South Georgia at Brunswick. I have had the opportunity to see firsthand how much waste is generated from chemicals and just in the chemical industry. I've had an opportunity to see realtime effects of environmental issues.

I also am a very passionate person for the future. And I'm so proud of the people who have come before me today and before you, as well, and attested to the troubles of if the Georgia --

Georgia Power policy or resolution is passed what will become of the future and the future generations. So I would like to attest and to affirm to what the psychologist has said, what the doctors have said, what the students have said. All of those things are true.

Even what the last doctor said about the organisms affecting and impacting people's health. I got E. coli from a river two years ago. And I have no doubt that that was from environmental pollution.

There are so many beautiful minds in school right now who can engineer and innovate other ways to create sources of power. And I implore you to advocate and pass policy that would help support those types of scientific innovations.

We don't need to burn fossil fuels. We don't need to leach our grounds. We don't need to continue to damage this earth.

And the older people that are above 45 and 50 and 60 won't be here in 30 years. They won't be here in 40 years. They won't be here in 100 years. But our children and grandchildren will.

And I'm also -- would like to attest that the doctor -- the psychologist who spoke earlier is

right, as well. I have absolutely no desire to bring children into this burning world.

Because right now as it stands, it is devastatingly fearsome of what could become if we continue to support fossil fuels. It's a very scary time for my generation.

And you have the opportunity to support green and renewable energy. And I implore you to represent the people who have come before you today who represent Georgia.

It's not your job to help the people who have pockets and stocks in Georgia Power. It's your job to help Georgians.

Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

All right. Last call. If Mr. Duke or Mr. Slack want to ahead and go today, I will allow.

MR. SLACK: Good morning.

Good morning.

CHAIRMAN SHAW: Thank you for your willingness, though.

MR. SLACK: Yeah. Well, happy to. And I thank you for serving the public in this robust body. We're -- I mean, you make a giant difference.

And I know the work is not always fun and

sometimes, as we heard at 9:30 this morning, relatively boring. But I'm Henry Slack.

Yeah. Hey, this is the fun part.

I'm a mechanical engineer. Though, I have learned over time not to look at my feet, but to look at other people, unlike some engineers. I'm a native and resident of Decatur and I volunteer with a group called Citizens' Climate Lobby, which is people concerned about climate.

And I want to start off saying: I'm grateful for what fossil fuels have done for us. They've brought us to our current level of technology, which is, you know, pretty amazing.

My grandfather used to say: Awww, you kids are missing everything. You know, I watched it -- you know, we went from the horse and buggies to jet travel. And he had no idea what we can do now, that I can carry a computer in my pocket.

But the problem is the fossil fuel gasses that are left behind are causing warming on the planet. They wrap around the planet like a blanket. And so we have -- I don't call it global warming as much as I call it global weirding. Extremely weird weather and this leads to more disasters.

And you may or may not be familiar, but the

insurance reinsurers have big tables showing how the number of disasters have gone up. The simple numbers, in 1980s we averaged about three billion-dollar disasters a year. In the 2010s, we averaged about 18 billion-dollar disasters a year. So a sixfold increase.

In 2023, which is a smaller sample, we had 28 billion-dollar disasters. And that's what we're facing and that's why we need to phase out our use of fossil fuels.

Beyond that, I want you to consider what Southern Company has said publicly. We're going to be net zero by 2050. How do they square that with Georgia Power's going to build some 40-year equipment which will be running until 2064 or 2066 whatever? That's -- that bothers me greatly.

And, beyond that, I think Georgia Power's a little biased in its fuel choice here. That they can buy gas from a Southern Company subsidiary and so they're making money coming and going. And that has biased them against solar and battery storage as a cheaper alternative for them to meet this need.

Finally, I want to say: There's a story we can learn from -- you know, we -- one of our great things is that we learn from other states. And

Texas, that bastion of liberals, in February 13th met over 30 percent of its powers from solar power. Thirty percent. And that ran over seven hours that day. Yeah, I know it doesn't run all day. But pair it with the batteries, then it does good.

They have 22,000 megawatts of installed solar from what I've just read and more is coming in. You know, five times more than Georgia does. Why aren't we there? It's the wave of the future.

So I'm asking you to please reject this request of Georgia Power to install the fossil gas plants because solar with battery storage will clearly be better for people.

And one last note, we had an eloquent speaker talking about the effect of closing a plant on that rural county. Well, guess what? You build solar panels in any county you want to, and, lo and behold, the county wins from that tax base.

It's not just, you know, one county and seven wins and the others don't get the plant. But every county can benefit from having solar panels and additional tax revenue from those.

Thank you.

CHAIRMAN SHAW: Thank you, sir.

VICE-CHAIRMAN ECHOLS: Can I ask Mr. Slack a

quick question?

MR. SLACK: Please do.

VICE-CHAIRMAN ECHOLS: Just your opinion on this. It's good to see you again.

MR. SLACK: Thank you.

VICE-CHAIRMAN ECHOLS: Thanks for the great work --

MR. SLACK: Well, vice versa.

VICE-CHAIRMAN ECHOLS: -- that Citizens' Climate Lobby does and your approach to working with elected officials. I appreciate that.

So these CTs they're talking about building, they won't run that much. And I envision in the future, as we have more renewables, more batteries, more -- you know, more solar, possibly more nuclear in the future, that the CTs basically become an emergency generator; right?

That they're -- they maybe sit idle, except for when our solar is not working, like in Taiwan. They had CTs that they crank up as the sun's going down just for a little while.

Do you -- looking at it that way, do you see that they could be important for reliability?

MR. SLACK: I understand your point. And I would still reject them because the good folks at

Georgia Power know how to do -- you know, how to do batteries -- sorry -- how to do the turbines. And they're not thinking of the possibilities of solar.

They're biased because they can, you know, buy gas from another Southern Company. And, quite frankly, I expect we will have a more robust national grid before we expect it and that Georgia Power will be competing with wind turbines from Iowa and Illinois. And suddenly: Oh, that's so much cheaper.

Or if Texas actually connects into the rest of the country. You know, Texas makes a huge amount of wind and could make a lot more and furnish us with wind energy. And so I don't -- I don't see the need for this in that emergency.

VICE-CHAIRMAN ECHOLS: All right. Thank you.

MR. SLACK: Yeah. Thank you.

CHAIRMAN SHAW: Thank you, sir.

Mr. Duke, we'll just let you go ahead, if you want.

MR. DUKE: Well, I was hoping I could summarize everyone's comments from today and -- you know.

CHAIRMAN SHAW: Three minutes.

MR. DUKE: Yeah. Well --

CHAIRMAN SHAW: Go ahead.

MR. DUKE: Okay. Well, first of all, you know, I'm here to make the stance that, yeah, I think it's unacceptable to be, you know, building more fossil fuel power sources, especially in the situation that we're in.

But, you know, I've been taking notes from everybody. I've been trying to just listen to everyone and do less talking. And so four people out of everyone that spoke today are the only four people that did not come up here and say fossil fuels basically are unacceptable to be added to our power grid.

I could go on for an hour. That's -- three minutes is, like, just nothing. But, you know, I mean, first of all, I want to try to build a relationship with you, like, and let you know, you know, like I'm not standing up here as a wacko liberal; right?

I'd like to just, first of all, say my conservative credentials. For example, I own a 30-30 rifle and I deer hunt. And I'm married to a widow who had seven children. She's adamantly pro-life. I'm probably a little more pro-choice than she is, but we get along well.

I'm a Boy Scout, Eagle Scout. Someone up here

came up and talked about being an Eagle Scout. That's where I got my conservation and environmental ethics, besides the Catholic Church.

I'm a practicing Catholic. If you've seen the Pope Francis' Laudato si', an encyclical about climate, he specifically is saying: You know, we have to stop burning fossil fuels. We have to stop digging stuff out of the ground and putting it on fire.

But -- so -- and do I seem like I'm a far polarized person -- you know what I'm saying -- with that credentials that I'm trying to get across here? I'm not.

So, you know, the point is: There is a way forward without fossil fuels. I mean, just one example is, you know, the state of South Australia, 1.8 million people. 10 million in Georgia, not quite the same, but still, 1.8 million people.

By 2027 -- that's three years from now -- they will be 100-percent renewable power for all 1.8 million people in that state. They're doing it through wind, solar, and lots of battery storage.

State of Texas is putting in 2500 megawatts of batteries, you know, every year right now.

I mean, I don't want to just throw around

facts. Again, it doesn't matter if I throw around facts. I just think you -- you know, you need to be -- you should do the right thing and just know we're all in this together.

Thank you.

CHAIRMAN SHAW: Perfect. Thank you, sir.

All right. We're going to go ahead and just keep moving since we exceeded our hour a little bit. And we'll allow those that were just here for the public witness portion.

And we appreciate everyone that took the time to come here today. Thank y'all so much. You're welcome to stick around. We're going to start moving on with the hearing by allowing the Public Service Commission to call your first panel.

We're going to give -- you know, give y'all a couple of minutes here at least to let the room settle back down. Thank y'all again for coming down.

We are ready to move forward. Mr. Thomas, are you ready to swear in your first panel?

MR. THOMAS: Yes, Mr. Chairman. At this time I'd like to call the Panel of Rob Trokey, Kathy Kelly and Karan Pol to the stand.

Could you please raise your right hands.

Thereupon,

ROBERT L. TROKEY,
KATHLEEN A. KELLY,
KARAN A. POL,

having been duly sworn, testified as follows:

MR. THOMAS: Thank you. You can take a seat.

DIRECT EXAMINATION

BY MR. THOMAS:

Q Mr. Trokey, can you please state for the record your full name, by whom you are employed, and your responsibilities for the record.

A (Witness Trokey) Yeah. My name is Robert Trokey. I'm employed by the Public Service Commission. I'm the director of the electric unit and representing the Public Interest Advocacy Staff.

Q Thank you.

Mr. Pol, same question.

A (Witness Pol) My name is Karan Pol. I'm a senior analyst with Daymark Energy Advisors, consulting staff on this case.

Q Thank you.

Ms. Kelly.

A (Witness Kelly) Kathleen Kelly. I'm vice-president and principal consultant for Daymark Energy Advisors and staff consultant on this load forecast.

Q Thank you.

And, Mr. Trokey, on February 15th of this year, did you file or cause to be prefiled 73 pages of testimony in question-and-answer format, along with five exhibits marked as Exhibits TKP-1, TKP-2, KAK-1, RLT-1 and KAP-1?

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

Q And if you were asked the same questions today under oath, would your answers be the same as set forth in your prefiled testimony?

A (Witness Trokey) Yes.

MR. THOMAS: Mr. Chairman, the court reporter has been provided with a copy of the prefiled direct testimony. I would ask that the direct testimony be copied into the record, as if given here today.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as Staff Exhibits 1 through 5.)

(Whereupon, the prefiled direct testimonies of Mr. Robert L. Trokey, Kathleen A. Kelly and Karan A. Pol follows:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:

GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 55378**
2023 INTEGRATED RESOURCE PLAN	**)**	
UPDATE	**)**	

PUBLIC DISCLOSURE

DIRECT TESTIMONY AND EXHIBITS

OF

ROBERT L. TROKEY

KATHLEEN A. KELLY

AND

KARAN A. POL

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

February 15, 2024

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Staff Exhibit #	Description
RLT-1	Resume of Robert L. Trokey
KAK-1	Resume of Kathleen A. Kelly
KAP-1	Resume of Karan A. Pol
TKP-1	Winter Peak Demand Forecast Sensitivities
TKP-2	Proposed Large Load Tracking System

I. Qualifications

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

A. My name is Robert L. Trokey. I am the Unit Director of the Electric Section at the Georgia Public Service Commission (Commission or GPSC). My business address is 244 Washington St. SW, Atlanta, GA 30334.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My background and experience are provided in Exhibit RLT-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified in prior Integrated Resource Planning dockets and Rate Cases, including Docket Nos. 44160 and 44280 in 2022.

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

A. My name is Kathleen A. Kelly. I am a Vice President and Principal Consultant with Daymark Energy Advisors, Inc. My business address is 370 Main Street, Suite 325, Worcester, Massachusetts, 01608.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My background and experience are provided in Exhibit KAK-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. No. I have testified in other jurisdictions. A list of my testimony is provided in Exhibit KAK-1.

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

A. My name is Karan A. Pol. I am a Senior Energy Analyst with Daymark Energy Advisors, Inc. My business address is 370 Main Street, Suite 325, Worcester, Massachusetts, 01608.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My education and experience are provided in Exhibit KAP-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION OR OTHER COMMISSIONS?

A. No.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. We are testifying on behalf of the GPSC Public Interest Advocacy Staff (Staff).

II. Summary of Conclusions, Observations, and Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Our conclusions are as follows:

- Georgia Power Company (GPC or Company) filed a new load forecast in this docket, which is significantly higher than the forecast provided in the 2022 IRP. The new load forecast includes organic growth[1], but is driven primarily by GPC being selected, in 2022, to serve new large load customers. The Company identified a significant amount of future large load customer additions because of activities in 2023.

- The Company's tools and methods for the organic load forecast appear consistent with typical utility practice. Based on our review of the Company's analysis, we conclude that it has developed a reasonable organic load forecast. However, the Company should provide model results, variables, model documentation describing model structure(s), variable relationships and key formulae, and interactions between models, and regression statistics[2] in each future load forecast filing to ensure that Staff and its consultants can perform a timely review of model results without purchasing software to do so.

[1] "Organic Load Growth" refers to growth based on historical trends in the traditional classes of service and not including any new large load customers.

[2] Each regression equation used should be provided with coefficients, significance, measures of error, and any other relevant summary statistics that are typically generated when running a linear regression. Documentation should enable reviewers to understand how each model interacts as well as the underlying equations driving the forecasts.

- The largest portion of the change in the load forecast is from the large customer choice loads. The growth in customer choice loads increased noticeably in 2021. This trend continued with dramatic increases in 2022 and additional significant increases in 2023. Georgia Power developed a new tool to forecast the probability and timing of realization of this load. The Company's tool (Load Realization Model) for developing this forecast is highly sensitive to certain input assumptions, and the Company has not conducted sufficient analysis to justify those assumptions.

- The Company only tested one scenario, with one set of assumptions, in its large customer load forecast, indicating that it has not thoroughly and comprehensively examined the possible outcomes throughout the forecast time frame.

- The Company's overall methodology of forecasting new, large, customer choice loads is a reasonable approach, but based on our review, we believe the resulting forecast is skewed to show load realization sooner and in greater quantity than it is likely to materialize. The Company has not performed sensitivity analyses nor alternative forecasts that should inform capacity expansion planning or rate impact analysis.

- The Company estimated the incremental net cost to customers based on the load and capacity situation filed in October 2023. The Company's assertion that the new loads will result in "downward pressure" on rates, lacks context and may not apply to all customers. The testimony of Newsome, Hayet and Wellborn discusses this issue of rate impact. The Company's economic analysis is not sufficient because the impact on rates and bills for each customer class was not provided.

- We prepared an alternative forecast using uniform probabilities in the load realization assumption[3] and by extending the assumed length of potential project delays for Datacenters from a [redacted] approach to a [redacted] distribution. These changes are reasonable and lower the forecasted peak demand in the winter of 2028/2029 and throughout the forecast period by nearly 1,500 MW.

Q. PLEASE PROVIDE STAFF'S RECOMMENDATIONS TO THE COMMISSION.

A. Based on the conclusions of our review, Staff is making the following recommendations:

1. Multiple modifications to the Load Realization Model ("LRM").[4] The Company's current LRM is skewed to materialize load earlier and in greater quantity due to its assumptions. We recommend that the Commission require the Company to modify its assumptions in the LRM and use the results as inputs to the Peak model to produce a new forecast, as Staff did, in developing its forecast in the following manner:

- For the current LRM analysis, the Company should utilize uniform probabilities for all customer types in its Load Realization assumptions. The Company indicated that it relied on the "informed judgement" of its management as their rationale for the ranges and values utilized in the Model as well as for the higher datacenter values. However, the Company has not provided support for this differentiation. Due to a lack of empirical evidence, the Company should not make any

[3] Probabilities were assigned regarding when customers' load would come on the system and to what extent announced load would materialize. Staff used the same materialization probability assumptions ("uniform") across all customer types.

[4] The LRM is used to forecast large load growth for the Company. A more detailed description is provided later in Section IV and V of this testimony. In short, the LRM is added to a regression model based on historical growth (organic model) and eventually converted to peak load.

assumptions regarding how one industry may materialize differently from another. If empirical evidence is available to support its assumptions, the Company should provide it.

- Modify the assumptions for "Ramp-Up Delays" associated with datacenters from a most likely [redacted] delay and maximum [redacted] delay to a most likely [redacted] delay and maximum [redacted] delay. We base this recommendation on the public information available in the market related to delays and the time it takes to complete such projects, such as each facility owner working through the potential incentives offered to the facility, potential implications of supply chain interruptions, political uncertainty impacts, and construction delays.
- Increase the range of alternative futures considered by varying the key assumptions to produce a range of potential load additions along with a range of timing of those additions to assess risks for the Company and customers.

2. Staff recommends that the Company focus on the next ten-year period in its load realization model analysis to demonstrate the peak demand needs of the facilities and use the same time frame for the RIM analysis and the Estimated Net Impact to Customers analysis to inform an enhanced analysis of the potential short term rate impacts of the required investment in generation and transmission assets.
3. Given the uncertainty regarding the materialization of large load customers, Staff recommends that the Company update the Commission quarterly during this period of extraordinary load growth by documenting its interactions with potential new large loads, implications of changes since the previous update, and actions taken or actions requiring

modification to address changes in need. This will provide the Commission, Staff, and stakeholders with key information relevant to the investments proposed in this IRP Update.

4. To facilitate the recommendation in the preceding paragraph, and to support future load forecasts of new load, Staff recommends the Company be required to adopt a tracking system to monitor the market's activities and track the status and outcomes of potential projects. This tracking system will benefit the Company's modeling of new potential loads by providing trends, insights into decision making processes utilized by the new large loads relative to the planned project in Georgia, and support reporting both internally and to the Commission on activities in the market and those taken by the Company to address the new loads. The data collected in this tracking system will provide the foundation for the assumptions the Company may use in the LRM in future analyses. We offer a template for the Company to build from to address this recommendation in our testimony.
5. Staff recommends that the Company enhance the information provided in its load forecast filings submitted to the Commission as part of the regular and updated IRP submittals to include more detailed underlying assumptions and interactions that can facilitate Staff and Commission understanding of, and insights into, the drivers of energy and peak demand needs.

    - The information provided in the 2023 IRP Update requires Staff and its Consultants to acquire the software used by the Company to effectively analyze the Company's plan. The Company provided modeling information in technical sessions but without the actual tools, Staff and Consultants cannot adequately see behind the "curtain" of sophisticated and intertwined modeling assumptions and equations to understand how technology enhancements, economic changes, and efficiency

improvements impact energy consumption to produce a transparent review with which to advise the Commission. We offer specific modifications in this testimony regarding how the Company should modify its standard filing procedures. We request the Commission require Georgia Power to provide additional transparency enhancements for the next IRP filing. This recommendation is for both the "organic" forecast and the new "load realization model" developed to address the recent growth in large customer facilities.

III. Rules and Regulations of the State of Georgia

Q. WHAT IS THE ROLE OF THE LOAD FORECAST IN THE CONTEXT OF AN IRP?

A. Load forecasts are intended to project the energy (MWhs) and peak demand (MW) of customers over time so that the utility can assess its ability to serve those needs during the forecast period. It is standard practice in the industry to look at a range of potential futures, or forecasts, informed by different economic, technological, and policy assumptions. This allows the utility, Staff and the Commission, to assess the potential implications on need, risks, and costs and to monitor the market after the forecast is complete to identify changes that affect its planning. The Company identified a significant change from 2021-2022 resulting in the 2023 IRP Update with the acceleration of the expected large load projects.[5]

[5] The Company shows 2021 wins of 336 MW compared to an average of around 100 MW for the years 2017-2020. Based on information provided in Technical Appendix 7, "TS Load and Energy Forecast.docx"

Q. ARE THERE ANY REGULATIONS REGARDING ENERGY AND DEMAND FORECASTING?

A. Yes. Under Rule 515-3-4-.03 of the Rules and Regulations of the State of Georgia, there are specific requirements for energy and demand forecasting.

Q. HAS THE COMPANY MET THE REQUIREMENTS ESTABLISHED IN RULE 515-3-4-.03?[6]

A. No. Specifically relating to the new Large Load Forecast, the Load Realization Model fails to meet several requirements established under these rules. While this model cannot rely on historical data, and due to the unprecedented scale of this growth, some of the requirements do not apply to the model,[7] the model can and should incorporate the following requirements:

- 515-3-4-.03(4)(a & b): "The energy forecast shall include an analysis of the sensitivity of results to the major assumptions…[and] must include three levels of expected growth based on alternative assumptions…" The Company has only provided a single case of the Load Realization Model in its filing, which is assumed to be its "base case." Under this rule, the base case should "incorporate all assumptions that are likely to occur…" The Company has not demonstrated that its assumptions are "likely to occur" nor has it provided the requisite "high growth

[6] Office of the Secretary of State (2024), Rules and Regulations of the State of Georgia Subject 515-3-4 Integrated Resource Planning, https://rules.sos.state.ga.us/gac/515-3-4

[7] Commercial and industrial loads such as datacenters have no relevant demographic information, are relatively inelastic to the price of electricity once developed, cannot substitute electricity with alternate fuels, and typically operate 24/7. For this reason, many of the methodological requirements within Subject 515-3-4 may not apply to the Load Realization Model.

scenario" and "low growth scenario" that are required under this rule. Given the sensitivity of the LRM to individual model assumptions, and the fact that these loads have no historical precedent for their nature and size, the Company should have provided at least three plausible scenarios for evaluation. These alternate future scenarios should be developed to:

  - 1) comply with the Rules and Regulations of the state of Georgia,
  - 2) provide the Company, Staff, and the Commission with a set of alternative futures to understand the risks of faster or slower realization of these new large loads and support its capacity planning, and
  - 3) provide the Commission with appropriate context for the potential variability of load forecasts.

- 515-3-4-.03(3)(b & c): "Each utility…forecast shall include detailed descriptions of the source of all determinants…Where reliable data are not available, estimates should be used and justified." According to the Company, the source of several of the key assumptions in the Load Realization Model is the "informed judgement" of the Company.[8] The Company has not provided research or empirical evidence regarding the development delays associated with any industry segment nor any evidence that their materialization assumptions are representative of similar projects in the past. As such, the Company has not included detailed descriptions of the source of the determinants (assumptions) of this model, nor has it provided sufficient justification for its estimates.

[8] Responses to PD STF-DEA-2-1, PD STF-PIA-6-12, STF-DEA-1-8, and STF-DEA-1-9.

- 515-3-4-.03(2)(c)-5: "[The Forecast shall include the impact of…] Self generation and cogeneration by existing and future customers." Many of these customers have the capability to invest in collocated battery storage or other capacity resources that may mitigate their contribution to peak loads. The Company did not consider how these customers might address their total requested load needs in this manner.

We offer a more detailed analysis of the LRM and make recommendations for modifications to the projections and future analysis through the course of this testimony.

Q. ARE THERE OTHER WAYS IN WHICH THE 2023 IRP UPDATE HAS NOT MET THE CURRENT COMMISSION RULES AND REGULATIONS?

A. Though the Company has been relying on the same tools for some time in its organic forecast methodology and the Commission is likely quite familiar with the approach, Commission rules require the following:[9]

- 515-3-4-.03(3)(c) Data Requirements: Utility energy and demand forecasts shall be based on the best available data. Where reliable data are not available, estimates should be used and justified. Each utility shall develop a database of electricity consumption patterns by customer class and by end-use where applicable (e.g., classes for which end-use data have been collected within the most recent five years). When using end-use forecasting methodologies, each utility shall submit the most current data available on end-use appliance penetration and saturation rates and end-use electricity consumption patterns.

[9] Office of the Secretary of State (2024), Rules and Regulations of the State of Georgia Subject 515-3-4 Integrated Resource Planning, https://rules.sos.state.ga.us/gac/515-3-4

Each forecast shall include a detailed description of data used in making the forecast, an identification of the sources of such data, and a detailed explanation of specific techniques employed for gathering, organizing, adjusting, or interpreting the data, and

- 515-3-4-.03(3)(d) Econometric Forecasting Methods: Where statistical or econometric methods are used in developing forecast inputs or in the forecasting process, analyses of the reasonableness of such methods and models shall be presented, including computer outputs with parameter estimates…

The tools used to produce each portion of the Company's load forecast, except for the long-term load model, are proprietary[10]. Without access to these tools, it is difficult to understand the drivers of load growth without additional information and analyses provided by the Company. As required in the rules above, we would expect additional transparency regarding key forecast drivers and model results to facilitate the Commission and Staff review and understanding of the projections. Detailed recommendations are provided through the course of this testimony.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR ADDRESSING THE CONCERNS HIGHLIGHTED HERE?

A. The Company should provide further documentation that provides the results of any analyses or models to increase transparency of the results and underlying forecast drivers

[10] The Long-term load model uses an Excel Plug-in called "LoadMAP." An external consultant for the Company developed this plug-in.

as well as to enable Commission review and understanding as changes occur in the market. We make specific recommendations in Section VI of this testimony regarding the implementation of further scenarios. With respect to the issue of greater transparency to facilitate review of forecast drivers and changes from year to year we make recommendations in Section VII of this testimony.

IV. Company's Load Forecast Update

Q. PLEASE DESCRIBE THE OVERALL LOAD FORECAST METHODOLOGY EMPLOYED BY GEORGIA POWER COMPANY.

A. The Company's load forecast consists of two core pieces: the baseline, or "organic," load forecast and the large load forecast. The organic load forecast is a deterministic model used to estimate the growth of the residential, commercial, industrial sectors, and MARTA. It is notable that Georgia Power recorded large load customer growth wins as early as 2021 that, in MW terms, were three times the magnitude of wins in 2017-2020. In calendar year 2022, the Company recorded even more dramatic growth of large loads seeking to locate their projects in Georgia[11]. As a result of this large-load growth, the Company separated

[11] "..large load projects that Georgia Power was selected to serve in 2022 represented almost 2,200 MW. This is more than six times greater than in 2021 and nearly 22 times greater than the approximately 100 MW of large load the Company was selected to serve per year from 2017 to 2020. This growth has sustained in 2023. From January through August 2023, the Company was selected to serve more than 1,700 MW of new customer load and total Company selections in 2023 are estimated to be more than 2,500 MW." Based on 2023 IRP Update Load and Energy Forecast, page 1.

its large-load forecast from its organic growth forecast. The Company indicates that the organic growth model employs historical data in deterministic models to forecast future energy and peak demand. The large load forecast is a probabilistic model which specifically estimates the growth of large commercial and industrial loads based on individual project data.

The organic load forecast uses a set of linear regression models to estimate usage per customer and the total number of customers in each customer class on a short-term basis using a regression software called eViews.[12] Using these variables, the Company estimates total load in each year on an energy basis for each class. These model results are inputs into a long-term model called LoadMAP[13] which accounts for technology lifespans and replacement rates, costs associated with technology replacement, market saturation rates for given load sources, technology costs, and many more variables that are expected to impact long-term energy consumption.[14]

The large load forecast is produced by the Load Realization Model (LRM) and compiles every known potential large load customer considering development in the state of Georgia.[15] Unlike the organic load forecast, which is a fundamentals-based forecast relying on macroeconomic indicators and customer trends, the large load forecast is based on individual, known customers and project details. Each entry in the LRM is a specific

[12] Short-term in this context refers to the period from 2023 to 2027. Based on the Company's October 2023 Filing, PD Technical Appendix 7, Load and Energy Forecast Documentation.
[13] LoadMAP files are provided in TS Technical Appendix 7, LT Models.
[14] Long-term, in this context, refers to the period from 2028 to 2042. Based on the Company's October 2023 Filing, PD Technical Appendix 7, Load and Energy Forecast Documentation.
[15] A "large load" customer is any customer with a load greater than 45 MW for the Industrial class or 115 MW for the commercial class. Based on the response to STF-DEA-6-1.

potential customer that has expressed interest in initiating electric service with Georgia Power for a specific project or facility.

Each large load project is assigned a set of probabilities determining their likelihood of contracting with Georgia Power (Project Success assumptions), a set of probabilities to determine how much of their load might materialize (Load Realization Assumptions), and a set of assumptions regarding the extent to which that load might be delayed from the initial intended in-service date (Ramp-up Delay Assumptions). The assumptions are applied to a quarterly load ramping schedule provided by each project to produce a final peak load forecast using a Monte Carlo simulation. For this simulation, the Company has executed 100,000 iterations of the LRM, with each iteration representing a unique draw of project-specific probabilities for each potential large load customer.

For the large load forecast, the Company decided to use the P95 forecast level, meaning that of the 100,000 iterations, 95,000 of them produced a peak load forecast at or below the final forecast selected by Georgia Power.

This large load forecast is converted to an energy basis based on industry specific load factors and added to the organic load forecast as an "external adjustment." This total energy forecast is an input to a "Peak" model that accounts for industry specific load factors, coincident loads, and many other variables.[16]

[16] Due to issues procuring the relevant software and time constraints, the Peak model could not be accessed and was not reviewed. The assumptions used in the Peak model are likely reasonable, assuming they replicated similar assumptions as those used in the 2022 IRP and prior IRPs.

Q. HAVE THERE BEEN ANY CHANGES IN THE COMPANY'S LOAD FORECASTING METHODOLOGY IN THE 2023 IRP UPDATE LOAD FORECAST SINCE THE 2022 IRP FORECAST?

A. Partially. The organic model methodology, which estimates energy and peak demand growth from non-large loads in the residential, commercial, industrial sectors and MARTA, has not changed from the methodology explained above. The Company has updated the economic drivers in the organic forecast to more recent projections which has resulted in some increase in load more in line with historic growth in the residential sector and somewhat higher in the commercial and industrial sectors[17]. The LRM is a new method of calculating the impact of specific large loads on the Company's system.

In the past, the Company has performed "external adjustments" to its load forecasts to account for energy or peak demand not sufficiently captured in historical data or models.[18] However, the probabilistic framework used in the LRM is a novel approach, with the first iteration performed in January of 2023.

From January through the October 2023 filing, the assumptions underlying the LRM changed significantly in both structure as well as the specific values for a given industry segment.[19] The changes in the Load Realization assumptions have been described in Table 1. In total, 9 new industry segments were introduced with assumed values and distributions changing for every segment.

[17] TS Technical Appendix Figures and Data fil, CAGRs & Controls Tab
[18] 2023 IRP Update Direct Testimony of Georgia Power Company, p. 15 of 56, lines 4-7.
[19] Responses to TS STF-DEA-1-4, Attachments A through D.

Table 1: LRM Change in Load Realization Assumptions[20]

		January 2023 Assumptions			October 2023 Filed Assumptions			Change		
Class	**Segment**	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Commercial	[redacted]	[redacted]						30%	35%	10%
Commercial	[redacted]	[redacted]						30%	15%	0%
Commercial	[redacted]	[redacted]						10%	0%	-5%
Commercial	[redacted]	[redacted]						10%	0%	-5%
Commercial	[redacted]	[redacted]						40%	50%	75%
Industrial	[redacted]	[redacted]						40%	50%	75%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						0%	0%	-10%
Industrial	[redacted]	[redacted]						40%	50%	75%
Industrial	[redacted]	[redacted]						40%	50%	75%
Industrial	[redacted]	[redacted]						40%	50%	75%
Industrial	[redacted]	[redacted]						40%	50%	75%
Industrial	[redacted]	[redacted]						40%	50%	75%
Industrial	[redacted]	[redacted]						40%	50%	75%

Q. HOW DOES THE PEAK DEMAND FORECAST PRESENTED IN THE 2023 IRP UPDATE COMPARE TO PRIOR LOAD FORECASTS?

A. The peak demand forecast has changed significantly, adding nearly 7 GW of peak load by the winter of 2042/2043 when compared to the 2022 load forecast. Based on filed workpapers by the Company, the specific value is 6,865 MW by the end of the forecast period, with interim differences in 2028/29 and 2032/33 shown in Table 2.

Table 2: Filed GPC Winter Peak Demand Forecasts (MW)[21]

Filed Forecast	2028/2029	2032/2033	2042/2043
2022 IRP	15,760	16,250	18,169
Budget 2023	16,864	17,459	19,019
2023 IRP Update	20,551	22,353	25,033
Forecast Change			
2022 to Budget 2023	1,104	1,210	851
2022 to 2023 IRP Update	4,791	6,103	6,865

Figure 1 shows the peak demand forecasts filed for the 2022 IRP, the Budget 2023 forecast, and the 2023 IRP Update, within which the large load forecast is evaluated at the P95 level (2023 IRP Update, LRM P95).[22] The most significant projected increases occur between the winter 2024/2025 and the winter 2032/2033 – this excerpt is shown in Figure 2.

[20] Based on responses to TS STF-DEA-1-4 Attachment A and IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."
[21] Based on peak demand forecast data provided in the Main Document of the Company's 2023 IRP Update Filing. File: [Figures 4, 5, 6, & 9 - Capacity Needs Data for B22, B23, and 2023 IRP Update.]
[22] This testimony evaluates three filed forecasts: 1) the forecast filed with the 2022 IRP, 2) the annual forecast that is produced by the Company outside of the IRP (Budget 2023), and 3) the 2023 IRP Update forecast which the company filed in October 2023. The 2022 IRP forecast was developed in the second half of 2021. The Budget 2023 forecast was developed in fall 2022. The 2023 IRP Update forecast was developed in Q3 2023.

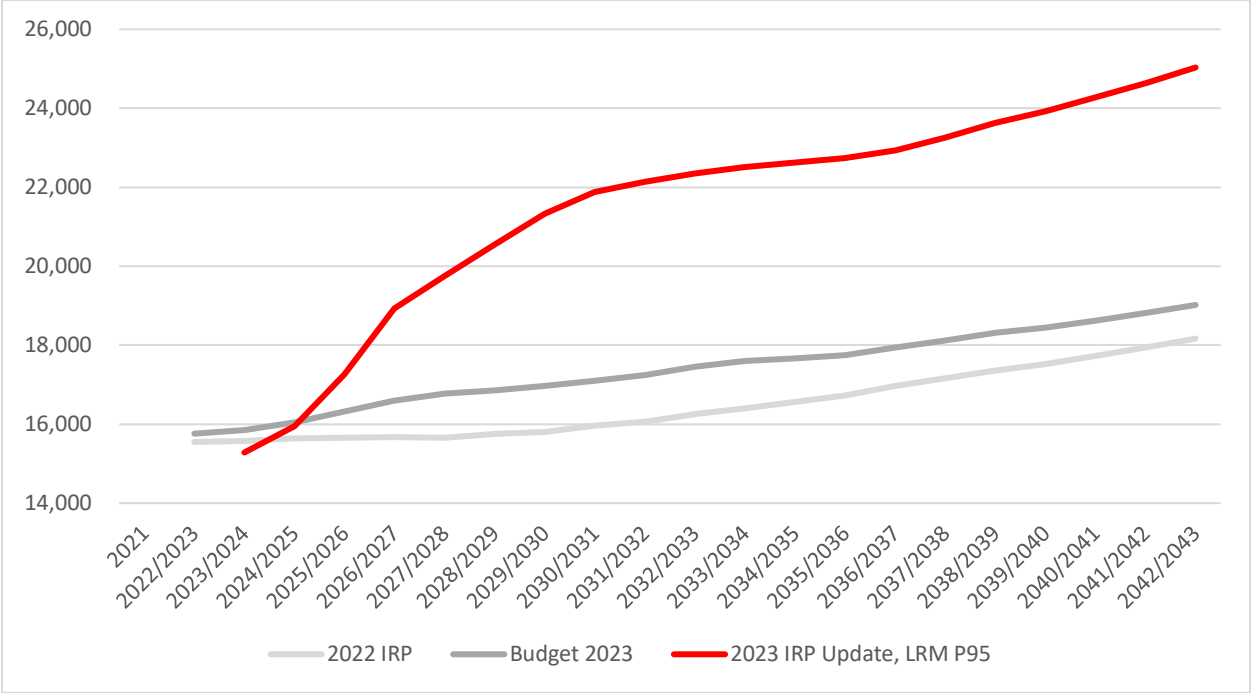

Figure 1: Selected GPC Peak Demand Forecasts and Adjustment for Large Loads[23]

V. Large Load Forecast – Load Realization Model Detailed Review

Q. PLEASE SUMMARIZE THE STRUCTURE OF THE LOAD REALIZATION MODEL. [24]

A. The Load Realization Model filed in October of 2023 evaluates a portfolio of 51 projects, which represented the known potential projects at the time of the analysis. The Company has indicated that since filing this IRP Update additional projects have expressed interest in using Georgia Power as their electricity provider.[25]

[23] Based on peak demand forecast data provided in the Main Document of the Company's 2023 IRP Update Filing. File: [Figures 4, 5, 6, & 9 - Capacity Needs Data for B22, B23, and 2023 IRP Update.]
[24] IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."
[25] Georgia Power Company, January 16 Hearing Transcript, p. 0165, lines 10-11 & p. 0381, lines 7-8.

Based on the initial information received by the Company from the potential customer, the LRM forecasts the amount and timing of the load that will ultimately materialize. For each project, the company estimates three sets of assumptions through a series of Monte Carlo simulations:

1) "Project Success" assumptions associated with the likelihood that a project will select Georgia Power as its service provider (0 or 1),
2) "Load Realization" assumptions associated with the extent to which said project's load will materialize ([redacted], dependent upon the industry), and
3) "Project Delay" assumptions associated with the extent to which quarterly peak demand might materialize in later quarters (ranging from [redacted]).

These assumptions are applied to a quarterly load schedule from Q1 2023 through Q4 2042. The annual load/ramp-up data are provided by customer/project. If the customer also provides an expected Commercial Operation Date ("COD"), the COD is rounded up to the nearest quarter end, and the initial load is assumed to materialize at the rounded-up COD. If an expected COD is not specified, the initial load is assumed to materialize at the end of the second quarter of the year in which it was reported, with load ramp up to full load occurring thereafter.[26] Linear interpolation is then used to create the quarterly load. The company provides an in-depth demonstration in the "Example" tab of "TS-STF-DEA-1-15 Attachment."[27]

[26] If a project reports that it will achieve peak demand of 60 MW in year 2030 and 70 MW in year 2031, the LRM will assume that the project reaches 60 MW at the end of Q2 2030.
[27] Response to Data Request STF-DEA-1-15

Using an Excel plug-in software called "@RISK," the Company then applies the Project Success, Load Realization, and Project Delay assumptions to these quarterly loads across 100,000 iterations of Monte Carlo simulations. As a result, a new quarterly load schedule is developed for each project 100,000 times. The company then selects the 95th percentile (P95) results from these simulations producing the resultant peak demand level. The P95 represents the forecast below which 95% of the simulations would fall and at which only 5% of the cases would exceed that value. This peak demand level is applied as an external adjustment to the organic peak load forecast.

While final values may fluctuate due to the probabilistic nature of the model, the total P95 level for end-of-year peak demand generally fluctuates around the values reported in Table 3, which demonstrates both LRM results rendered for this testimony as well as the results filed directly by the Company.

Table 3: Load Realization Model Results, P95[28]

Model	2023/2024	2024/2025	2025/2026	2026/2027	2027/2028	2028/2029	2029/2030	2030/2031	2031/2032	2042/2043
LRM Model Results, P95	[redacted]									
LRM Results, GPC Filed	[redacted]									

The forecasted results for each project calculated by the LRM should not be interpreted as the expected demand levels for each project in each year.[29] The LRM is a "portfolio-level" model which provides an understanding of the total level of peak demand that arises from

[28] Based on a 100,000 iterations @RISK simulation of the file from IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."

[29] Georgia Power would typically convert the values in Table 3 to an energy basis using established load factors and input these values into its Peak model. We were not able to perform this portion of the analysis due to software limitations and time constraints, but do not expect that this transformation will materially impact the conclusions of our analysis.

this set of projects. In each iteration and each simulation, the distribution of that peak load might vary between projects.

Q. WHICH POTENTIAL LARGE LOAD PROJECTS KNOWN TO THE COMPANY ARE INCLUDED IN THE LRM?

A. The Company's base case LRM is developed based on 51 known projects. Of these, datacenters constitute the majority of realized load, followed by Cryptocurrency and Battery Manufacturing. The total pipeline of 51 projects, referring to the total announced load data provided by customers, amounts to [redacted] by 2042. Table 4 illustrates how this announced load is spread across different industry segments.

Table 4: Load Realization Model Base Case, Industry Segment Analysis (% Total Announced Load)[30]

Row Labels	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	…	2042
Commercial												
Cryptocurrency	0%	24%	10%	4%	4%	3%	3%	2%	2%	2%		2%
Datacenter	0%	38%	61%	68%	73%	74%	75%	74%	75%	76%		77%
Placeholder	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%		0%
Industrial												
Battery Manufacturing	40%	15%	9%	5%	6%	5%	5%	4%	4%	4%		4%
Chemicals	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%		0%
Other Industrial	0%	10%	3%	1%	1%	1%	1%	1%	1%	1%		1%
Rubber & Plastics	0%	0%	2%	1%	1%	1%	1%	1%	1%	1%		1%
Solar	60%	15%	9%	6%	5%	5%	4%	4%	3%	3%		3%
Steel Manufacturing	0%	0%	0%	9%	7%	7%	8%	11%	10%	10%		9%
Transportation	0%	0%	6%	4%	3%	4%	3%	3%	3%	3%		3%
Grand Total	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**		**100 %**

[30] Based on a 100,000 iterations @RISK simulation of the file from IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."

The Company has testified that there are "14 of the 51…that we have won."[31] This value corresponds with the 14 projects in the LRM that have complete certainty of having selected both the state of Georgia as a site and Georgia Power Company as the service provider. Assuming these 14 projects in the LRM are the same projects the Company has "won," they have been consolidated in Table 5 below with industry data included as well.

Table 5: LRM Won Projects[32]

Project	Class	Segment	Announced Load
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
Total			[redacted][33]

Q. WHAT ARE THE KEY ASSUMPTIONS OF THE LOAD REALIZATION MODEL REGARDING PROJECT SUCCESS?

A. The Project Success assumptions are constructed of two core components:

[31] Georgia Power Company, January 16 Hearing Transcript, p. 0153, lines 12-13.
[32] Based on data from IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."
[33] We assume that this value corresponds with the Company's reference to a "won" 4,000 MW mentioned on Georgia Power Company, January 17 Hearing Transcript, p. 0472, lines 11-13.

1) A simple product of customer choice assumptions and

2) A Bernoulli distribution.

The customer choice assumptions are constructed of three probabilities:[34]

1) Probability 1: The probability that the customer has chosen Georgia as the site of the project ([redacted]),

2) Probability 2: The probability that the customer will choose GPC as the power provider ([redacted]), and

3) Probability 3: The probability that a project will materialize after the customer signs a contract with GPC, which is always set at [redacted] as signed contracts do fail to materialize sometimes.

A simple product of these three percentages is used to produce the likelihood that a given project would materialize. A Bernoulli distribution is then applied to this customer choice assumption through the @RISK software with independent correlation assumptions between projects to produce a value of either 0 or 1 across each iteration.[35] If a project receives a value of 0, then the project has "failed" and none of its load will materialize in each iteration. If a project receives a value of 1, then the project load will materialize according to the remaining assumptions in the model.

Q. ARE THE PROJECT SUCCESS ASSUMPTIONS APPROPRIATE?

[34] Based on explanations provided IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Model Sheet Description" and PD Technical Appendix 7 Load & Energy Forecast Documentation.
[35] Independent correlation in this context assumes that the success of Project A should not be correlated with the Success of Project B. This is a reasonable assumption.

A. The specific values are arbitrary as would be any alternate proposed values. For Probabilities 1 and 2, the Company seems to have based its confidence levels upon Requests for Electric Service, Contracts for Electric Service, Customer Baseline Load Agreements, Meter Totalization T&C Agreements, or Engineering Letter Agreements to Proceed, which are shown in Table 6. Evidence of any such agreement has only been provided for 16 projects of the total 51, largely consisting of Requests for Electric Service (RFS), as opposed to any firm contracts.

Table 6: Contracts and Agreements for External Load[36]

Customer	Request for Electric Service	Contract for Electric Service	Customer Baseline Load Agreement	Meter Totalization Term & Conditions	Engineering Letter Agreement to Proceed
[redacted]	Y	N	N	N	N
[redacted]	Y	Y	N	N	N
[redacted]	Y	N	N	N	N
[redacted]	Y	Y	Y	Y	N
[redacted]	Y	Y	Y	Y	N
[redacted]	Y	N	N	N	N
[redacted]	Y	N	N	N	N
[redacted]	N	N	N	N	Y
[redacted]	Y	N	N	N	N
[redacted]	Y	N	N	N	N
[redacted]	Y	N	N	N	N
[redacted]	Y	N	N	N	N
[redacted]	Y	N	N	N	N
[redacted]	Y	N	N	N	N
[redacted]	Y	N	N	N	N

[36] Based on responses to Data Requests JKA-4-7 (Attachments A & B) and DEA-4-7 (Attachments A though N).

Only three projects have anything firmer than a request for electric service as evidence of the Company's confidence level, as shown in Table 6. A request for service by a customer represents the customer's decision to take electric service at a certain location from Georgia Power rather than another load serving entity (MEAG or EMCs). It does not require the customers to start service at a certain date or require the customer to maintain a given load. Beyond the data in Table 6, the company has used what it refers to as "informed judgement" to set the levels at [redacted] for Probability 2 and at [redacted] for Probability 1.[37]

Ultimately, the Company must make some reasonable assumptions to develop this model, and for the purpose of reviewing this model, we would not be able to produce reasonable alternate assumptions without greater details on each of the project terms in the LRM. While these assumptions have been treated as reasonable, the Company should instead evaluate how different assumption values and different probability distributions (implementing fewer or more probability categories in each of Probabilities 1, 2, and 3) would impact the model results.

Q. WHAT ARE THE ASSUMPTIONS ASSOCIATED WITH LOAD REALIZATION, THE SECOND PARAMETER USED IN THE @RISK BASED LRM MODEL?

A. The Load Realization assumptions are constructed of a distribution of materialization likelihoods for each industry segment. A triangular distribution is assumed for each project's load realization, with a correlation matrix that is independent across segments and

[37] Response to Data Requests PIA-6-12

perfect within.[38] As a result, the load that is announced for each project by the potential customer accounts for some diversity factor, producing the values in column CR of the LRM: "Actual Max Load."

Most industry segments share the same Load Realization distributions, except for Datacenters and Cryptocurrency, as demonstrated in Table 7. These two industry segments have a [redacted], a [redacted], and [redacted] when compared to the other industries. As a result, the amount discounted from the max load of these two industries is typically less than that of the other industry segments in each iteration.

[38] This correlation assumes that the materialization of load in each segment (Datacenters for example) would not impact the materialization of load in another segment (Chemicals). However, the materialization of load for a single Datacenter *might* be correlated with the materialization of load for another Datacenter. This is a reasonable assumption.

Table 7: LRM Load Realization Assumptions, Base Case[39]

Class	Segment	Low	Mid	High
Commercial	Cryptocurrency	[redacted]	[redacted]	[redacted]
Commercial	Datacenter	[redacted]	[redacted]	[redacted]
Commercial	Miscellaneous	[redacted]	[redacted]	[redacted]
Commercial	Warehouse	[redacted]	[redacted]	[redacted]
Commercial	Distribution	[redacted]	[redacted]	[redacted]
Industrial	Steel Manufacturing	[redacted]	[redacted]	[redacted]
Industrial	Battery Manufacturing	[redacted]	[redacted]	[redacted]
Industrial	Chemicals	[redacted]	[redacted]	[redacted]
Industrial	Food Production	[redacted]	[redacted]	[redacted]
Industrial	Metals	[redacted]	[redacted]	[redacted]
Industrial	Other Industrial	[redacted]	[redacted]	[redacted]
Industrial	Pipeline	[redacted]	[redacted]	[redacted]
Industrial	Rubber & Plastics	[redacted]	[redacted]	[redacted]
Industrial	Stone Clay and Glass	[redacted]	[redacted]	[redacted]
Industrial	Textiles	[redacted]	[redacted]	[redacted]
Industrial	Transportation	[redacted]	[redacted]	[redacted]
Industrial	Beverage	[redacted]	[redacted]	[redacted]
Industrial	Brake Manufacturing	[redacted]	[redacted]	[redacted]
Industrial	Medical Microb Manufacturer	[redacted]	[redacted]	[redacted]
Industrial	Solar Manufacturer	[redacted]	[redacted]	[redacted]
Industrial	Housing	[redacted]	[redacted]	[redacted]
Industrial	HS Manufacturer	[redacted]	[redacted]	[redacted]
Industrial	Solar	[redacted]	[redacted]	[redacted]

Q. ARE THE LOAD REALIZATION ASSUMPTIONS APPROPRIATE?

A. No. Specifically, the assumptions associated with Datacenters and Cryptocurrency are not appropriate. The remaining industries' assumptions are appropriate.

The Company has demonstrated that it has considered multiple iterations of values for these assumptions. In the "Assumptions" tab of the response attachments to Data Request DEA-1-4, the Company demonstrates a testing of different industry segments and

[39] Based on a simulation with 100,000 iterations in @RISK of the file from IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."

different corresponding Low, Mid, and High realization rates. Specifically, the Company has moderated the modal probability distribution from [redacted] in its initial LRM version[40] to a modal distribution of [redacted] in the final filed version as demonstrated in Table 1.[41] This tighter distribution eliminates high rates of realization in the industry segment to which it is applied while eliminating lower rates of realization. This change is reasonable but should continue to be monitored and tested as loads are realized, suggesting that within an industry, load would not materialize at a level less than [redacted] of the total announced load, but it also would not materialize at a level greater than [redacted]. As a result, there is a minimum discount to each industry segment in each iteration of at least [redacted], for each project that receives a Project Success value of [redacted] denoting that the project has succeeded in materializing at all.[42]

This distribution of confidence is not the same, however, for the Datacenter and Cryptocurrency segments. The Company argues that these industry segments have a unique operational model:[43]

> "Due to the continuous operation of their equipment, Cryptocurrency and Datacenters are expected to use most of their connected load. Consequently, their percentage is higher than that of other segments included in the model. In contrast, industrial segments, which do not

[40] Response to TS STF-DEA-1-4, Attachment A
[41] IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."
[42] The product of each set of Project Success probabilities is input into a Bernoulli distribution to produce a value of either 0 or 1. If a project receives a value of 0 in a given iteration, the load will not materialize (it will be 0 MW for each year in the forecast and not contribute to the total portfolio load).
[43] Response to STF-DEA-5-3

operate their connected load simultaneously, are assigned a lower percentage."

The Company mentions this again in hearing:[44]

> "…when you ask for electric service, first you list all of the equipments that are behind the meter. Think about an industry that has motors, that has heaters, it has lighting; right? When they operate, they don't use every single device at the same time. They use something lower. That diversity in the usage is what we need to consider…for serving the load. And that number is coming as a portfolio and it's not something we can break down."

However, the Company has not demonstrated this claim empirically in its testimony, responses to data requests, or otherwise.

Since empirical evidence of the relationship between announced loads and materialized loads has not been provided for each industry, it would be more appropriate to assume uniform Load Realization assumptions for each industry segment and interpret these as the Company's level of confidence that announced load materializes. A uniform set of assumptions demonstrates that the Company does not expect varying levels of accuracy regarding peak load projection over time between different industry segments. Generally, it should be assumed that a customer's ability to provide an accurate demand

[44] Georgia Power Company, January 16 Hearing Transcript, p. 0153, lines 12-13.

projection for each quarter is similar and any set of assumptions suggesting otherwise should be defended more rigorously.

The company may find in the future that the materialization distribution is greater or lower than the levels assumed in this model. However, as an initial model for a novel growth situation, the [redacted] triangular distribution is reasonable, subject to future monitoring, testing, and revision. The Company should have evaluated alternative distributions to assess the sensitivity of model results and resource need to these assumptions.

Q. WHAT ARE THE ASSUMPTIONS ASSOCIATED WITH RAMP-UP DELAYS?

A. Similar to the Load Realization assumptions, the Company applies a Low, Mid, and High level of delay to each project. It then applies a triangular distribution to these values to produce an expected level of delay to the load schedule provided by each project. Table 8 illustrates the Ramp-up Delays applied to each industry segment.

Table 8: LRM Ramp-Up Delay Assumptions, Base Case[45]

		Ramp-up Delay (Months)		
Class	*Segment*	*Low*	*Mid*	*High*
Commercial	Cryptocurrency	[redacted]	[redacted]	[redacted]
Commercial	Datacenter	[redacted]	[redacted]	[redacted]
Commercial	Miscellaneous	[redacted]	[redacted]	[redacted]
Commercial	Warehouse	[redacted]	[redacted]	[redacted]
Commercial	Distribution	[redacted]	[redacted]	[redacted]
Industrial	Steel Manufacturing	[redacted]	[redacted]	[redacted]
Industrial	Battery Manufacturing	[redacted]	[redacted]	[redacted]
Industrial	Chemicals	[redacted]	[redacted]	[redacted]
Industrial	Food Production	[redacted]	[redacted]	[redacted]
Industrial	Metals	[redacted]	[redacted]	[redacted]
Industrial	Other Industrial	[redacted]	[redacted]	[redacted]
Industrial	Pipeline	[redacted]	[redacted]	[redacted]
Industrial	Rubber & Plastics	[redacted]	[redacted]	[redacted]
Industrial	Stone Clay and Glass	[redacted]	[redacted]	[redacted]
Industrial	Textiles	[redacted]	[redacted]	[redacted]
Industrial	Transportation	[redacted]	[redacted]	[redacted]
Industrial	Beverage	[redacted]	[redacted]	[redacted]
Industrial	Brake Manufacturing	[redacted]	[redacted]	[redacted]
Industrial	Medical Microb Manufacturer	[redacted]	[redacted]	[redacted]
Industrial	Solar Manufacturer	[redacted]	[redacted]	[redacted]
Industrial	Housing	[redacted]	[redacted]	[redacted]
Industrial	HS Manufacturer	[redacted]	[redacted]	[redacted]
Industrial	Solar	[redacted]	[redacted]	[redacted]

Q. ARE THE RAMP-UP DELAY ASSUMPTIONS REASONABLE?

A. Partially. These assumptions can be considered reasonable for most industries, except Datacenters. Since Datacenters comprise most of the load in the LRM, as demonstrated in Table 4, particular focus was given to analyzing this set of delay assumptions. A [redacted]

[45] IRP Models & Workpapers, TS Technical Appendix 7 – Load & Energy Forecast, "TS 2023.10.11 Load Realization Model."

[redacted] distribution of delay is not appropriate for this industry given recent industry trends. The Company should provide further evidence to support its Ramp-up Delay assumptions.

Datacenters have faced development delays due to supply chain issues, tight labor markets, and rising prices in 2022.[46] Supply chain issues continued through 2023, with semiconductor and server shortages impacting the datacenter industry.[47] A CBRE report suggests that construction timelines for datacenters range anywhere from two to six years, compared to an average range of one to three years for the 2015 to 2020 period, largely due to power availability.[48] This average timeline change represents a delay of 12 months on the low end up to a delay of 36 months on the high end. Specific project demands such as a new electricity substation or an upgraded transmission line could delay delivery by one to four years, per the report.[49]

While the Company could address many power availability issues, it could not address supply chain and procurement delays on the customer side. It is unclear how recent geopolitical developments may impact these supply chains. Local political uncertainty regarding favorable tax incentives for this industry segment may further impact the actual materialization of these loads.[50]

Furthermore, the Company has not tested different assumptions for the Ramp-up delay, as it did for the Load Realization assumptions. Since the initial LRM version in

[46] Sebastian Obando (2022), Supply chain issues threaten data center construction boom. Supply Chain Dive - https://www.supplychaindive.com/news/supply-chain-issues-threaten-data-center-construction-boom/625116/

[47] Blair Felter (2023), Navigating Data Center Market Challenges: A Business Guide. EVOQUE - https://www.evoquedcs.com/blog/navigating-data-center-challenges.

[48] Sebastian Obando (20230), Data center building boom shows cracks. Construction Dive - https://www.constructiondive.com/news/psmj-survey-data-center-construction/699469/.

[49] Sebastian Obando (20230), Data center building boom shows cracks. Construction Dive - https://www.constructiondive.com/news/psmj-survey-data-center-construction/699469/.

[50] Rob DiRienzo (2024), $10M tax break for X data center in Fulton Country face backlash. Fox5 Atlanta - https://www.fox5atlanta.com/news/tax-break-x-twitter-data-center-fulton-county-backlash-elon-musk.

January of 2023, the company has consistently used a [redacted] distribution.[51] This lack of testing suggests that the Company has not revisited these assumptions since January 2023 and has not considered modifying them.

Given the supply chain challenges and the lack of testing, it is possible that the datacenter industry, which is a key driver of the new large load demands, could face delays much greater than currently assumed. It is possible that other industries will also face different delays than assumed, but the [redacted] assumptions for non-Datacenter industry segments are reasonable estimates in the place of further research. Each of these delay assumptions should be monitored, tested, and reviewed over time to ensure accuracy and the Company should make an effort to research current trends for each industry. The Company should have evaluated alternative distributions in its analysis for this filing to understand the resource need of such alternatives.

Q. HOW DID THE COMPANY DETERMINE THE VALUES USED FOR THESE ASSUMPTIONS?

A. The company refers to "informed judgement" when explaining its methodology of selecting the values for each assumption. The values assumed in Project Success Probability 1 are based on information gathered by the Company's Customer Choice department and communicated to the Load Forecasting team.[52] The Project Success Probability 2 used "informed judgement based on the state of the negotiations with prospective customers."[53] Regarding the Load Realization assumptions, the Company

[51] Response to DEA-1-4, Attachments A through D.
[52] Response to PD STF-DEA-2-1.
[53] Response to PD STF-PIA-6-12.

"relied…on informed judgement."[54] Regarding the Ramp-up Delay assumptions, the Company also "relied…on informed judgement."[55]

Q. WAS THE COMPANY'S APPROACH TO SELECTING AND JUSTIFYING THE ASSUMPTION VALUES APPROPRIATE?

A. No. The Company has not provided sufficient justification for the approach used to select values for the Project Success assumptions, the Load Realization assumptions, and the Ramp-up Delay assumptions. Furthermore, the approaches used to produce [redacted] Load Realization assumptions for [redacted] customers as well as the [redacted] delay assumptions for Datacenters are not appropriate.

The company makes the point that the scope of growth in Georgia is "unprecedented," and as a result, it "cannot rely upon any historical data to serve as a guide for the forecast".[56] While it is true that the Company did not have historical data to inform every piece of this model, it did have the opportunity to research both publicly available and private industry data regarding construction/supply chain delays that might impact this model. The Company could improve its approach to specifying this model in the many ways outlined above.

[54] Response to STF-DEA-1-8.
[55] Response to STF-DEA-1-9.
[56] Response to STF -DEA-1-7.

VI. Incorporating Scenarios in the LRM forecast

Q. DID THE COMPANY PROVIDE ANY SENSITIVITY ANALYSES ASSOCIATED WITH THIS MODEL OR ANY POTENTIAL LARGE LOAD SCENARIOS AS PART OF THE UPDATED IRP?

A. No. The Load Realization Model was provided with a single set of assumptions. While the Company has modified the model over time with changes to assumptions in each version, the Company did not file multiple scenarios in its October 2023 filing. The Company's 2023 IRP Update provided only the P95 projection for the large load although the @RISK tool allows the user to select alternative probabilities. The Company selected the P95 level in response to "the unprecedented pace of economic development in the state of Georgia and because the Company has seen more increases in large projects interested in the state over the last several months than decreases."[57] Furthermore, the Company references "uncertainty surrounding future growth," as a reason to plan toward an "upper limit."[58]

Q. PLEASE CHARACTERIZE HOW SENSITIVE THE MODEL RESULTS ARE TO THE ASSUMPTIONS.

A. The model is highly sensitive to its assumptions, particularly those that impact the Load Realization or Ramp-up Delay of datacenters. The Company's failure to provide the Commission with alternative scenarios with which to evaluate the implications of LRM on the forecast is limiting. While numerous simulations have been rendered by Daymark

[57] Response to STF-DEA-1-5.
[58] Response to STF-DEA-1-5.

Energy Advisors in the process of reviewing the Company's filing, this testimony utilizes three core cases to demonstrate the sensitivity of this model to underlying assumptions:

1) 2023 IRP Update, LRM P95: This is the base case LRM filed by the Company,
2) Uniform w/Delays, P95: This scenario modifies the assumptions in two ways:
    a. The Load Realization assumptions are standardized such that every industry segment, including Datacenters and Cryptocurrency, have a [redacted] Load Realization distribution,
    b. The Ramp-up Delays for Datacenters are expanded from the original [redacted] distribution to a [redacted] distribution, to account for potentially longer delay times due to supply chain challenges, and
3) Uniform w/Delays, P80: This scenario uses the same assumptions as Uniform w/Delays, P95, but it evaluates the model at a P80 level, based on a suggestion from J. Kennedy & Associates regarding the Company's reserve margin planning methodology.

The results of these three scenarios are shown graphically for the period Winter 2022/2023 through Winter 2029/2030 and compared to the Budget 2023 forecast in Figure 2.

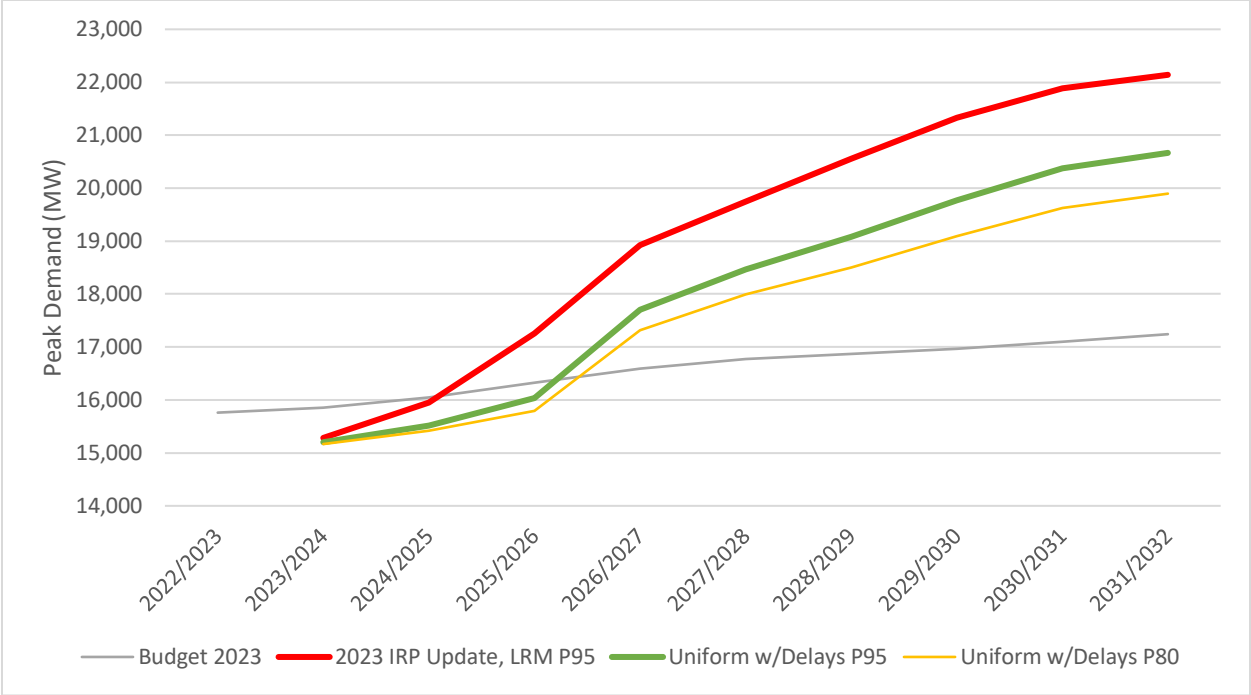

Figure 2: Peak Demand (MW), Selected LRM Sensitivities Winter 2022/23 – 2029/30[59]

The changes made in these two scenarios result in lower peak demand levels in each year as shown in Table 9. The total peak demand in the lowest case is more than 2,000 MW less by the end of the forecast period, with similar differences throughout, as demonstrated in Table 10. For the mid case, this difference is closer to 1,500 MW throughout the forecast period.

Table 9: Peak Demand (MW), Selected Sensitivities in Selected Years[60]

Author	Forecast	2028/2029	2032/2033	2042/2043
Company	2023 IRP Update, LRM P95	20,551	22,353	25,033
Staff	Uniform w/Delays P95	19,084	20,888	23,560
	Uniform w/Delays P80	18,504	20,109	22,765

[59] Based on values in Dir. Ex. TKP-1
[60] Based on values in Dir. Ex. TKP-1

Table 10: Peak Demand (MW) Change From Base Case, Selected Sensitivities, Winter 2028/29 to 2031/32[61]

Forecast	2024/ 2025	2025/ 2026	2026/ 2027	2027/ 2028	2028/ 2029	2029/ 2030	2030/ 2031	2031/ 2032
Uniform w/Delays P95	(204)	(571)	(840)	(1,019)	(1,203)	(1,349)	(1,417)	(1,440)
Uniform w/Delays P80	(527)	(1,464)	(1,613)	(1,760)	(2,047)	(2,231)	(2,253)	(2,244)

Q. PLEASE SUMMARIZE WHY THE TWO STAFF FORECASTS PRESENTED IN FIGURE 2 ARE REASONABLE ALTERNATE FUTURES.

A. The core issues identified in the Company's LRM are those of non-uniform Load Realization assumptions and likely inaccurate Ramp-up Delays for datacenters.[62] The Uniform w/Delays P95 case offers a reasonable alternative to the Base Case by standardizing the load realization assumptions and modifying the Ramp-Up Delays based on public research. The Uniform w/Delays P80 case replicates the assumptions above and plans to a P80 level, based on recommendations by J. Kennedy & Associates.

Beyond the modelling assumptions, we believe the Company has not provided sufficient evidence supporting the likelihood of these large load projects materializing in any firm manner. Of the various paperwork provided by the Company as proof of load materialization, most documentation simply demonstrates a request for service with no clear commitments from load itself.[63]

Due to these factors, we believe that the Company is likely over-stating the extent to which load will materialize in each year. Given the assumption that load will materialize at a lower rate, the two alternate forecasts proposed above are reasonable modifications.

[61] Based on values in Dir. Ex. TKP-1
[62] The inaccuracy of these Ramp-Up Delay assumptions is based on public research provided on page 34 of 46.
[63] This is demonstrated in Table 6.

Q. DESCRIBE THE BENEFITS OF USING ALTERNATE FUTURE SCENARIOS.

A. Developing alternate future scenarios aids planning by demonstrating the sensitivity of the forecast to changes in underlying assumptions. This allows planners to look at the costs and risks associated with meeting various capacity need levels produced under different forecasts.

The use of multiple scenarios establishes "reference points" for higher and lower growth. These alternative projections of need can serve as valuable information or trigger points at which the planners should begin to evaluate the need to modify its plans – either higher or lower. Should actual load differ from the forecast, but look similar to one of the alternate futures, then planners should investigate modifications to the original plan. Fundamentally, scenario analysis allows decision makers to weigh the risks and benefits of their decisions, and in this case should have been done to demonstrate the benefits and risks of planning to different P-levels and assumptions in the LRM. Furthermore, the Company could use these scenarios to assess implications for customer rates and rate allocations.

Q. IS THE COMPANY'S DECISION TO PLAN AT A P95 LEVEL IN THE LOAD REALIZATION MODEL REASONABLE?

A. The Company explains generally that there is significant uncertainty in this model and their goal is to ensure sufficient capacity to meet anticipated loads and ensure reliability.[64] By planning to a higher P-level, the Company is 1) preparing for the risk that loads may

[64] Response to STF-DEA-1-5.

materialize at a greater level than the most likely outcome of P50 and 2) ensuring that the system is robust to those higher levels. However, the use of a P-level only considers serving new customers reliably and does not consider the economic impact on all other customers. Using P95 level results in higher peak load than P50 or P80 levels and supports more capacity additions but it also increases the risk of constructing too much new generation capacity too quickly and increasing ratepayer cost unnecessarily. As the level of large-load growth changes or the Company's LRM becomes more accurate, the Company should monitor, test, and review this planning level to evaluate its accuracy.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING AN ALTERNATIVE LRM CASE THAT THE COMPANY SHOULD USE IN ITS FORECAST?

A. Yes. The most reasonable alternative LRM case is the Uniform w/Delays, P95. This scenario incorporates industry research on Ramp-up delays and standardizes Load Realization assumptions while acknowledging the high level of uncertainty surrounding this recent growth by relying on the Company's preferred P95 planning level. The Company should plan according to the load levels assumed in this scenario. We recommend the Company further evaluate alternative P levels and the impact of such planning on customer costs and company risks.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS REGARDING THE LOAD REALIZATION MODEL?

A. Yes. The Company should monitor, track, and review all assumptions made in the LRM. By tracking this data, the Company will be prepared to implement historical data if a similar

model or similar data are ever needed in the future. These recommendations are included in Section VII.

VII. Forecast Transparency, Tracking and Documentation

Q. HOW DO YOU RECOMMEND THE COMPANY MONITOR ACTIVITIES IN THE LARGE LOAD MARKET TO ENHANCE ITS NEXT LRM FORECAST?

A. The Company indicated during hearings that they plan to track activities which they had not needed to track prior to 2019.[65] In response to several questions during the hearing, witnesses indicated that the Company is tracking activity starting from initial contact and monitoring actions taken by potential large loads as they work through the process. Especially if this new large load activity occurs over a multi-year period beyond 2022 through 2024, it is important for the Company to implement a database with which to improve the key parameters of the LRM modeling or to modify the variables used should new information come to light. We propose that the Company database on new large loads incorporate at a minimum the information shown in Exhibit TKP-2.[66] This data intends to track each interaction or notification that occurs whether between the large load and the Company or within the Company or in the news. Monitoring the time it takes from initial notification, including the stage of the project at which the Company is notified, will enable the Company to fine tune the potential project timing, including potential for delays.

[65] Georgia Power Company, January 16th Hearing, p. 0157, lines 16-20
[66] Dir. Ex. TKP-2

We also propose in this exhibit that the Company institute tracking and verification of the actual loads during ramp up and beyond that time to enable the Company to have more data on which to develop its modeling tools capability. While this appears to require time to fulfill, the benefits to the accuracy of the forecast for such large load additions will be extensive – allowing better scenario considerations and hopefully accuracy of projections. Ideally the tracking system will enable the Company to report quarterly to the Commission on new large load activities ensuring that the next load forecast will have fewer surprises and also acting as an early warning system for both the Company and the Commission of changes in this market that might require an action on the part of the Company such as a delay in resource acquisition or a faster need for resource acquisition.

Q. HOW COULD THE COMPANY MAKE ITS FORECAST FILINGS MORE TRANSPARENT TO THE COMMISSION AND STAFF?

A. We recommend that the Company and Commission Staff work together to develop a model output reporting standard, in addition to the filing of all models, that allows reviewers to examine the outputs of models and the key drivers to load growth without purchasing access to any software. Understanding the key drivers of growth in each sector of the forecast is key to understanding what to investigate more deeply as one reviews a sophisticated forecast model like those used by the Company. For example, a tornado chart can help a reviewer understand the largest risks inherent in a PPA for example. As the Company and Staff develop this reporting standard, we recommend including the following items:

- **Overarching Model Structure Documentation**

- In its Technical Appendix, the Company should clearly explain how each model functions and interacts with the other. Based on the Company's filing, it is not clear a) how the short-term (ST) Model, long-term (LT) Model, and LRM are ultimately input to the Peak model. Documentation should make clear what transformations are taking place as the results from one model are fed into another. For example, the Company has not filed sufficient explanation of how the LoadMAP model produces long-term forecasts based on the results of the short-term models. Similarly, the current documentation does not explain key assumptions in the Peak model used to convert energy demand into peak demand.

- **Regression Statistics for All Regression Models and Associated Documentation**[67]
  - For each regression model used in the short-term models, the Company should provide regression statistics that show the variables used in the model and their coefficients, significance levels, definitions, and any associated error statistics.
  - Similar reporting should be provided for any other regression models.

- **Key Drivers Impacting Load Growth**
  - The Company should, in both the organic and large load forecasts, identify the key factors impacting load growth. For example, the Company could prepare data showing the contribution of each key variable to the total forecast of energy for that sector. In the residential class that could be a pie chart showing how customer numbers grow between select years of the forecast period and how

[67] Typically, regression software will produce summary tables to report these values to the user. This information should be readily available to the Company & provided to the Commission Staff and any supporting Consultants.

use per customer changes between those same years. This data enables the reviewer to identify key areas of investigation as the forecast review takes place. Another example is to show the breakdown of load growth for each section associated with economic factors as opposed to efficiency in usage and by increased electrification, again using a pie chart showing each factor's contribution to total growth.

Providing this level of analysis with the forecast documentation increases forecast transparency and enhances the understanding of drivers of load growth which may lead to identifying new policies to modify load growth to meet state objectives.

Q. DOES THIS CONCLUDE STAFF'S TESTIMONY?

A. Yes.

MR. THOMAS: And with your permission, the Panel would like to give a summary of their testimony.

CHAIRMAN SHAW: Go ahead, Panel.

MR. TROKEY: Thank you. Good morning, Chairman and Commissioners. Our testimony addresses the initial step in integrated resource planning, the energy and peak demand forecast used to assess resource needs, and reviews the methodologies used to forecast historic organic growth, as well as large-load growth in the load realization model.

We conclude that the forecast produced by Georgia Power is likely skewed to show load realization sooner and in greater quantity than is likely to materialize. We provide alternative forecast scenarios that reduce forecasted peak load by approximately 1000 to 1500 megawatt in winter '25/'26 and 1500 to 2200 megawatts by winter of 2030.

This alternative forecast informs decisions regarding the timing of capacity needs, investments, costs to consumers, and an alternative path forward for the Commission's consideration. We also provide suggestions regarding the format of future filings and regular reporting to track the development of

large-load growth. Our conclusions and recommendations are also included on pages 3 through 8 of our direct testimony.

We conclude that the organic load forecast is reasonable for this update; however, the company should fully document its inputs, variables, model structures, variable relationships, and key formulas. This documentation should fully identify interactions between models and regression statistics in each of the future load forecast filings to ensure that staff, its consultants, and intervenors can perform a timely review, model results without purchasing specialized software to do so.

Staff observes that the perspective load growth first increased noticeably in 2021. This trend continued with dramatic increases in 2022 and continuing into 2023, with the company projecting this load growth online through 2030 and beyond.

Georgia Power developed a new tool to assess the probability and timing of realization of this load. The company's load realization assumptions and ramp-up delay assumptions, however, should be modified.

The company's large-load model is highly

sensitive to input assumptions. The company has not conducted sufficient analysis to justify those assumptions. The company tested one scenario with one set of assumptions in its model. It has not comprehensively examined the possible outcomes throughout the forecast time frame.

The resulting forecast is skewed to show load realization sooner and in greater quantity than is likely to materialize. The company has not performed sensitivity analyses, nor alternative forecasts that should inform capacity expansion planning and rate impact analyses.

The company should utilize uniformed probabilities for all customer types in its load realization model assumptions, which constrain the extent to which certain industry loads materialize. The company indicated that it relied on the informed judgment of its management as the basis for these assumptions, as well as the decision to assume higher rates of materialization for data centers and cryptocurrency operations. However, the company has not provided direct or empirical evidence for that decision.

Due to this lack of evidence, the company should not assume one industry will materialize

differently from others. If direct or empirical evidence is available to support its assumptions, the company should provide that evidence.

The company should modify the assumptions for ramp-up delays regarding the timing of each project's load. The assumptions associated with data centers should be modified to assume longer delays based on public information related to the evaluation of potential development incentives, potential implications of supply chain interruptions, political uncertainty and construction delays.

The company should also increase the range of alternative futures considered by varying key assumptions. This will allow the company and Commission to assess risk for the company and customers.

Staff recommends in our testimony that the company focus on the next ten-year period in its load realization model analysis in order to demonstrate the peak demand needs of the facilities and use the same time frame for the rate impact measure analysis and the estimated net impact to customers' analysis to inform an enhanced analysis of the potential short-term rate impacts of the

required investments in generation and transmission.

Given the uncertainty regarding the materialization of this large load, staff recommends the company update the Commission quarterly, documenting its interactions with potential new large loads, the progress made, variances from estimates, and modifications needed to address changes in the capacity needs. This information will provide the Commission, staff and stakeholders with key information relevant to the investments proposed by the company.

To facilitate future load forecasts, staff recommends the company be required to monitor market activities and track the status of outcomes of potential projects. This tracking system will benefit the company's modeling of new potential loads by providing materialization data, delay data, insights into potential customers decision-making, a reporting system to the Commission for large-load activities, also a historical database of large-load activity. This tracking will provide the foundation for assumptions the company might use in future large-load analyses. We offer a reference template for the company in our testimony.

And, finally, staff also recommends that the

company enhance the information provided in its load forecast filing submitted to the Commission as part of the regular and updated IRP submittals to include more details, underlying assumptions, and interactions that can help staff and the Commission understand the drivers of energy and peak demand needs.

And that concludes our summary.

MR. THOMAS: Mr. Chairman, the Panel is available for questions from the Commissioners and cross-examination.

VICE-CHAIRMAN ECHOLS: All right. Commissioners.

Commissioner Echols.

VICE-CHAIRMAN ECHOLS: Mr. Trokey and the Panel, I can't imagine my life without Twitter. But if these data centers -- let's just start with Bitcoin mining. If Bitcoin mining -- and we've seen this happen to Dalton Utilities where a Bitcoin mining company up and left.

I just wonder as you evaluated this, and you've looked at the portion of this that might be related to Bitcoin mining, the portion that might be related to ChatGPT, and with all the social media that's streaming this -- maybe driving this data center

revolution, is it -- is it your opinion -- let's just start with data centers. Let's maybe just leave Bitcoin mining out of it for a second.

Is it your opinion that a data center load will be here in full -- whatever they're telling Georgia Power they're going to do -- for a long period of time; 10, 20, 30 years?

Have you looked at that part of the load?

MR. POL: Commissioner, so once a data center is expected to, you know, fully contract and get in place, the life span could go from 10 to 20 years, yes, especially for hyperscalers.

But I will point out that within the contracts that we've reviewed, we haven't seen that level of certainty from those data centers. We cannot say for certain that they will materialize fully or actually situate within Georgia Power's service territory.

VICE-CHAIRMAN ECHOLS: So on a hyperscale data center -- because, you know, certain social media platforms have enjoyed, you know, mass popularity and then they have subsided and they've had less users as another one comes along. I mean, Tik-Tok is, you know, really growing now and you see -- you see young people moving from one to another. Like

abandoning Facebook and moving on over to something else.

Did your analysis take into consideration any of that migration in social media?

MR. POL: We did not specifically comment on that. But, to your point, yes, there is uncertainty in general.

VICE-CHAIRMAN ECHOLS: Okay. Now on the Bitcoin mining piece of it, is it your opinion that Bitcoin miners -- who I don't have any problem with them and what they're doing in general, but are they here to stay?

MR. POL: We did not specifically spend much time looking into the cryptocurrency segment.

MS. KELLY: If I could add to that. I think one of the things that we did in looking at these is not necessarily look at social media per se, but take a look at what industry was talking about relative to data centers and how many data centers are actually being built and the fact that there is a boom. Not just in Georgia, but a boom regionally and nationally and data centers being brought to life and being brought into the industry. And utilities having to deal in the short term with immediate need from the data centers.

So there is a significant portion of commentary in the industry. Things like Standard and Poor regularly produce articles talking about the growth in data centers and the growth generally that's happening in manufacturing.

So we took a look at those things and looked at those for -- in particular, some of the assumptions that the company used in its load realization model. You know, how much delay there might be in a project, what kind of issues those projects must face as they're being constructed. So that was the information that we looked at.

MR. TROKEY: I'd just add, data centers are not an infant industry. They've been around. We expect them to be around.

I think staff's analysis really focused on: How soon will that materialize? How soon -- and we recommended that you -- using a uniform set of assumptions for that industry, in line with the other assumptions by Georgia Power, gives us a little bit more flexibility and gives us a different picture of how soon that will materialize.

VICE-CHAIRMAN ECHOLS: So a hypothetical, let's take a thousand megawatt hyperscale data center. They come, Georgia Power is supplying them with

power.

TVA builds 15 SMRs. The SMR price gets way down there. And the data center decides that they're going to build an SMR behind their meter to supply 300 megawatts of the power. And now the load that Georgia Power was hoping to have from the data center indefinitely is now dropped by a third.

Has your analysis taken into consideration anything like that? And, in your opinion, is it possible over the next 20 years something like that could happen?

MR. TROKEY: It seems like that's certainly a possibility. And a lot of these data centers, hyperscalers, will have backup generation. Some may or may not participate in the new programs that Georgia Power has offered.

However, as they expand, as they grow, as affordability becomes an issue, they'll make decisions based on their own economic interests.

So certainly I don't know what TVA will do. I did read that in TVA's territory a local community decided they preferred to not have the data center and did not approve an associated solar facility that would support that data center.

But that's the type of uncertainty that I think

we might see in the forecast and why staff focused really on the uniform set of assumptions, which provides a different perspective than what the company has provided.

VICE-CHAIRMAN ECHOLS: So if things in the future are -- I'm not going to call it volatile. I don't think it's volatile. Let's just say they are subject to change in the future.

And Georgia Power seems in a hurry to do -- to do this -- to do this now. Is there any -- is there any part of what we're talking about here that can wait one more year to the regular -- regular IRP in 2025 that we could evaluate it there?

Are you in agreement with their analysis that these things really need to be done right now?

MR. POL: Based on the alternative load forecasts that we've produced, what we see is load materializing much later and in lower quantity.

And, Rob, I'll let you speak to this more. But I believe other pieces of testimony specifically talk about the year of need in greater detail.

MS. KELLY: I might -- sorry. I might add to that. I think one of the things that we have recommended in our testimony is that the company provided one case. It did 100,000 potential

solutions through its use of the at-risk model and it shows only one solution and presented that.

Our recommendation, and what we tried to do in our analysis, is try to look at alternatives. If this happens, then this is what the company needs. If that happens, then this is what the company needs.

We see this as an opportunity for the company to look at alternatives, look at the risks of moving or not moving. Look at their ability to do something else, look at alternatives sources, look at maybe working with the customers to have them put in some backup already. Right as they start building the facility, let's put in some backup power now. That goes with one of their DER colocation programs that they proposed.

So there's lots of opportunities. I think it's a bit of a new phenomena that has come on very quickly. The company is trying to respond as quickly as it can.

And it's -- it's something where you have to sometimes just step back and say: Okay. Here's all the potential solutions. What do I need to do first and then what can wait?

And that, I think, is what we're trying to say.

There may be more time. You need to take a look at alternative solutions and then monitor things as they go forward.

MR. TROKEY: I just wanted to add real quick with respect to the timing and whether we can wait. And I think specifically the load forecasts that we've produced and provided to other staff witnesses indicates that we do have more time than is identified in Georgia Power's case.

A couple of things with that, the RFPs that are available for consideration, the all-source RFP that will have a bidders' conference on Monday, it's currently underway. That's an opportunity for the capacity needs to be acquired.

Also, the 500-megawatt battery energy storage system RFP, and even the CARES RFP. So all of those are avenues through which capacity can be acquired.

The other thing is that the PPAs -- the power purchase agreements that staff has recommended approving, those will be spoken to by the next panel, but they provide the additional cushion or additional time needed to fully conduct the 2025 IRP.

VICE-CHAIRMAN ECHOLS: I don't know if you heard me ask -- ma'am, go ahead.

MS. KELLY: I just wanted to go back to your question, which is if the data center goes in today and Georgia Power builds a thousand megawatts to serve it. If the data center then goes back in and puts in a certain percentage of load, SMRs, on their own facility so they can serve part of that load, one would hope or one would expect that load growth will continue in this region. So that it may provide the opportunity for Georgia Power to avoid something else because the customer has put something in during that time frame. So that's also a potential and something, I'm sure, most of us have thought about.

VICE-CHAIRMAN ECHOLS: I don't know if you heard my question in the first hearing about, you know, how can we do more with what we already have?

And let me -- let me just postulate the same question with recognizing part of what we have right now is this IRA money that's sitting out there for homeowners/businesses to be able to install a number of things. Not just solar, but batteries and geothermal and other things.

This money is not forever. It's going to go away eventually. And certainly it -- you know, there is -- you know, there's a good chance it

wouldn't be renewed in the future.

So if that asset is sitting there and we've got an opportunity to help customers on the Georgia Power system or encourage customers to get a battery, get those tax credits -- if they live in one of these coal communities from Milledgeville down to Albany, you know, Cartersville or other places, they're going to get an extra 10 percent.

And the utility can get visibility into that. Let them structure a program where they get visibility, even -- even to have the algorithm control it just like they're recommending for their Check Temp program.

Is that an asset that you're factoring in or that you believe that the utility could, just for now -- between now and next year's IRP, that the utility could quickly tap and partner with residents on this kind of thing?

Do you think that has any mitigating, you know, megawatts that could help us with this?

MR. TROKEY: It's not specifically identified in our testimony. However, that makes sense. We -- in this circumstance, really it's an opportunity to explore all of those alternatives, all of the assets that we do have available.

And even the data centers themselves have flexibility to be part of the solution. So although we don't speak to that directly in our testimony, we think that's an important part of this conversation.

VICE-CHAIRMAN ECHOLS: Thank you so much.

CHAIRMAN SHAW: Commissioners.

COMMISSIONER PRIDEMORE: I do. Thank you, Mr. Chairman.

So my first question -- other than Mr. Trokey, the other two witnesses, have you ever testified before this Commission before?

MR. POL: No.

MS. KELLY: No.

COMMISSIONER PRIDEMORE: Have you ever given prefiled written testimony for this Commission before?

MR. POL: No.

MS. KELLY: No.

COMMISSIONER PRIDEMORE: Okay, okay. Keying off something Mr. Trokey said, I want to challenge this assumption that you made in your oral summary where you state that Georgia Power has not supplied sufficient detail and information on the forecast.

Staff has submitted 34 data requests. It's on my counting. So subject to check, as they say, and

my ability to add.

Thirty-four data requests that have anywhere between 1 and 50 questions in each one. And those have been submitted over the life of the case. Those questions have covered everything from the Aurora modeling, to the forecast accuracy, to the capacity management or decision by which they chose to select capacity in their filing.

Has not the staff been given ample opportunity to go to the company and seek the questions that they need answers to?

MR. TROKEY: Thank you, Commissioner. Indeed we have had the opportunity. And I think our testimony is based on the responses that were provided indicating that only one sensitivity was provided. Based on the assumptions that we saw in those responses is what informed our recommendation to provide a uniform set of assumptions for the different industries.

So, yes, we definitely have had the opportunity to ask questions and we're now, through our testimony, asking Georgia Power to provide the additional information that we did not see and may have expected to receive in those responses.

COMMISSIONER PRIDEMORE: You used the word

"sensitivity." I believe that needs definition, clarification.

MR. POL: Yeah. Commissioner, when we talk about sensitives all we're really referring to are a separate set of assumptions in each model. The large-load model had a single set of assumptions that while over time were very defiled, the forecast only had that single set.

We would expect the company to produce multiple sets of assumptions and evaluate all of those and then present the Commission with a range of options that provide the full picture of the future situation.

COMMISSIONER PRIDEMORE: I would recommend then that staff and this panel go back and look at STF-JK-8 in particular and notice the different assumptions or the different realties that the company presented, which I think backs up probably why they are suggesting what they're suggesting to be able to deploy in this case.

So much of this is based upon not just the quantity of the capacity that's needed, but also the speed at which the capacity is needed. And so I would recommend you go there.

I found some other answers when I looked back

through at your response to your data request in four, as well.

Ms. Kelly, to that point, you mentioned SMRs just a few minutes ago. Has an SMR been constructed in the United States to date?

MS. KELLY: I'm sorry. I didn't hear the end of that.

COMMISSIONER PRIDEMORE: Has an SMR been constructed in the U.S.

MS. KELLY: I believe so. Only as a test site. But I don't believe one is producing any power anywhere.

COMMISSIONER PRIDEMORE: Can you tell this body what the construction schedule and time frame for that SMR that you believe exists -- can you tell us how long it took to build?

MS. KELLY: No. That would be somebody else on this -- the next panel's capabilities. I'm doing load forecast, not technologies.

COMMISSIONER PRIDEMORE: Okay. I would like this panel to go back and explore whether or not an SMR has been completed and its in service and the length of time of the schedule that it took to be able to construct?

MS. KELLY: In this country?

COMMISSIONER PRIDEMORE: In this country.

COMMISSIONER JOHNSON: Can we add cost to that?

COMMISSIONER PRIDEMORE: Thank you.

COMMISSIONER JOHNSON: Do you mind if we add cost to that, Commissioner Pridemore?

COMMISSIONER PRIDEMORE: Please add cost.

COMMISSIONER JOHNSON: Thank you.

COMMISSIONER PRIDEMORE: Thank you, Commissioner.

That's all for now. Thank you.

MR. TROKEY: Can we get a clarification just on how small modular reactor is being defined here?

COMMISSIONER PRIDEMORE: A small modular reactor --

MR. TROKEY: Anything less than 300 megawatts or --

COMMISSIONER PRIDEMORE: Less than 300 megawatts is fine.

MR. TROKEY: Okay.

COMMISSIONER PRIDEMORE: But to Ms. Kelly's point that she just made a minute ago.

MR. TROKEY: Okay.

COMMISSIONER PRIDEMORE: If -- this panel is trying to say that what the company has filed that includes natural gas units is -- there's other

methods and other means to be able to do that. Ms. Kelly said SMR is an option.

To my knowledge, an SMR has not been built in the United States yet. And if one has, I would like to know. And I would like the schedule and the time frame and the cost by which it took to build it.

MS. KELLY: If I could, I used the SMR as an example because Commissioner Echols mentioned it. And that was the only reason I used SMR.

I'd also like to go back to what the company provided in the forecast versus all of the information that we've been able to get from the company as a result of our IRs.

I think the company provided a good amount of information, but no insights into what was happening behind the models. And I'm not talking about just the LRM model. I'm talking about the organic forecasts that they've been doing for years based on history.

There's a lot of data, but the insights about what's driving the growth behind them are not there. It requires the staff, the consultants, and anyone who is trying to review those -- the forecast, to do a lot of digging on their own. And it might be a lot simpler for the company to present some of the

key forecast drivers and show how loads change over time so that it's simpler for a lot of folks to be able to see what they are seeing.

Because they're the experts here. They understand what's going on and they communicate it. And it's part of the rules of the Commission, as well, is that there should be a certain amount of information behind what's there. Our suggestions are designed to help in the future.

COMMISSIONER PRIDEMORE: I guess to that point, Ms. Kelly, I challenge the assumption that the insight has not been provided when during the Georgia Power portion of these hearings their witnesses sat in that box for hours and hours and were peppered with questions from Commissioners and intervenors, alike, driving to the very point as to why this capacity is needed.

I don't think that for a moment that there's anybody that has been in and out of this room that does not exercise the very knowledge that Georgia is growing and Georgia's need for energy is growing. So I -- I challenge that assumption. I believe that a great deal of insight has been provided.

I'll put it this way: This Commissioner is satisfied on the insight portion. I just -- I want

to make sure that we make the right decision on the rest of it.

MS. KELLY: And I just -- I agree with you they've been very upfront and forthcoming with us. I'm suggesting the initial filing. That's what we're going back to, not the whole process.

COMMISSIONER PRIDEMORE: Okay. Well, thank you.

CHAIRMAN SHAW: All right. Any -- any other questions, Commissioners?

(No response.)

CHAIRMAN SHAW: All right. We will move on.

We'll start with cross-examination from the parties going in alphabetical order starting with Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: No questions.

Clean Energy Buyers Association.

MR. DUNBAR: No questions, Mr. Chairman.

CHAIRMAN SHAW: Heelstone Renewable Energy.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. JONES: No questions, Mr. Chairman.

CHAIRMAN SHAW: Georgia Center for Energy

Solutions.

MR. HUBBARD: No questions. And I won't have any questions.

CHAIRMAN SHAW: Okay. Thank you, Mr. Hubbard.

Georgia Coalition of Local Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

Good morning -- well, afternoon, Ms. Whitfield.

MS. WHITFIELD: Oh.

CHAIRMAN SHAW: I almost said morning.

MS. WHITFIELD: Good afternoon, Commissioners. Good afternoon, Panel. Thank you for your testimony. I have just a couple of questions.

CROSS-EXAMINATION

BY MS. WHITFIELD:

Q I wanted to direct you to page 41, lines 2 through 6 of your testimony. And that's where you're describing the "P" level. Or, Ms. Kelly, I think, as you described it, the single solution of the 100,000 that were run by Georgia Power in its analysis.

Specifically, I wanted to ask you just to elaborate a little bit on lines 2 -- beginning on line 2 you say that the "P" level -- and you're just describing what that means, what that single point means -- only

considers serving new customers reliably and does not consider the economic impact on all other customers.

If you could just help me understand what you mean by that -- by that assertion.

COMMISSIONER PRIDEMORE: What line, Ms. Whitfield?

MS. WHITFIELD: Two.

BY MS. WHITFIELD:

Q Okay. Two to three on page 41.

A (Witness Kelly) Oh, the P95 level is looking at making sure that the peak that's served is only exceeded about 5 percent of the time. I just want to clarify that.

So what it's done is it's looking at making sure that the reliability of these new large customers is served. In the analysis that was done by the company and provided, it looked at the -- the rate impact or -- let me change that. The economic impact. And that was the incremental revenues covered the incremental costs.

But what we didn't see was what happens to the rest of the customers that already exist today at Georgia Power. And there was no rate impact analysis, per se, saying that there would be either an increase or no increase on residential customers or commercial customers.

So the implications of what they're doing does not look at the direct rate impact. It looked at, you know, a general downward -- downward rate impact or revenue impact. Excuse me.

A (Witness Trokey) I was just going to add -- and my fellow panelists can correct me here if I'm wrong. But because the load realization model is specifically for those large customers and new customers, it -- the existing customers are essentially covered under the organic forecast.

A (Witness Pol) That's correct.

A (Witness Trokey) So that's also what comes out of this. It only considers the new large-load customers. That's how it's applied.

MS. WHITFIELD: Thank you for those clarifications.

And may my colleague approach with an exhibit?

CHAIRMAN SHAW: Sure.

MS. WHITFIELD: I would like to introduce GIPL Exhibit 1, which is a stipulation in Docket Number 9355-U. And if you go a few lines forward, you'll see that there's an Attachment A to that stipulation. And what I'm ultimately getting at is Paragraph F of that Attachment A on the second to last page.

(The document referred to was marked for identification as GIPL Exhibit 1.)

BY MS. WHITFIELD:

Q So my question: On page 11 of your testimony, lines 8 through 9, you answer the question whether there's other ways in which the 2023 IRP Update have not met the current Commission rules and regulations.

And what I've handed you includes, pertinent to my question, the affiliate transaction standards for the company. Are you familiar with these standards?

Are any of you familiar with these standards?

A (Witness Trokey) I'm familiar with them, yes.

Q And I was just wondering if you had an opportunity in the course of your review to consider the -- to consider whether the company is in compliance with the affiliate transaction standards.

A (Witness Trokey) It's not something we looked at in preparing our testimony. I think -- what I'm reading here: For goods and services purchased by the utility from other affiliates.

In this case, they certainly have a power purchase agreement with Mississippi Power Company, an affiliate.

How this is specifically applied may need further consideration. I would say other panelists that

staff has addressing the additional sum may want to consider this, as well, as to whether or not this would support our position. It seems like it would support staff's position on additional sum.

Q Okay.

A (Witness Trokey) But, yeah, this was not specifically considered for our load forecast.

Q So the specific standard here, the one, (f), would you agree that the PPA with Mississippi Power is a lease with an affiliate company of Georgia Power?

A (Witness Pol) I think this question might be --

MR. MARZO: Mr. Chairman, I think this question is asked and answered. The panel just said to the extent of the knowledge that they have about applying particular standards. And they told -- they have told counsel that they didn't look at this.

So now counsel is going to go line by line through this document and ask them questions. I don't believe it's appropriate.

CHAIRMAN SHAW: Ms. Whitfield, do you think they have answered the question?

MS. WHITFIELD: Well, if Mr. Marzo's position is that it is an affiliate with a lease cost, then, yes, they have.

MR. MARZO: That's not my position. My position is she's allowed to ask witnesses questions. I'm not on the stand.

And to the extent these witnesses have told her already that they have not evaluated this, they have answered that question.

MS. WHITFIELD: Well, that's not -- I didn't ask if they evaluated it. Again, I heard them say they didn't.

I'm getting at the context of -- I expect that this document is newish to at least some of you. It was to me. So I'm trying to get at some of the context of this document.

CHAIRMAN SHAW: Okay.

MS. WHITFIELD: It's familiar -- Mr. Trokey is familiar with it. He indicated that.

CHAIRMAN SHAW: All right. Let's move on.

MS. WHITFIELD: Okay. That's it.

Thank you, Commissioners.

CHAIRMAN SHAW: Thank you.

All right. Georgia Solar Energy Association.

(No response.)

CHAIRMAN SHAW: Georgia WAND. Georgia WAND.

MS. SCOTT: Thank you.

CROSS-EXAMINATION

BY MS. SCOTT:

Q Thank you for being here today.

My first question is: Would you agree that the utility has had flaws in their forecast and calculations?

A (Witness Pol) I wouldn't describe them as flaws. I would rather say that the utility should have produced a larger range of alternate forecasts and filed them to provide a larger range of potential futures.

Q And what about their modeling?

A (Witness Pol) Their organic load forecast model, which is based off some pretty historically established methods regarding linear regression, was reasonable in our view.

We largely focused on the large-load model, the load realization model, which is what we were specifically talking about when we say we expect further alternative futures to be considered.

Q Okay. The company, Georgia Power -- your colleagues, I know they're coming up with another panel, but in some of their recommendations of Georgia Power's economic analysis of capacity resource study, one of the things that they said is that the study was deficient due to the company's overstated load forecast. Do you recall that from your colleagues?

And -- but you said that you agree -- or you

don't agree that the utility has had flaws in their forecast and calculations?

A (Witness Kelly) We reviewed their testimony just after -- after it was filed. We did not look at the company's record for load forecast. So I think you best ask them that question.

Q Okay. So on page 6 of your report, you -- there are a lot of blackouts. Can you please clarify your recommendation on the ramp-up date delay assumption?

A (Witness Pol) To the extent that it is allowable in the public session, I think we generally just speak to longer delays for data centers specifically.

A (Witness Trokey) We're really talking about the amount of time over which these data centers will be built up; right?

In staff's perspective, one of the adjustments we've recommended is to look at a broader period of time over which that ramp-up of the new load might be delayed. And so that's the essence of our recommendation there.

Q Okay. Mr. Trokey, you mentioned a downward pressure on rates for some customers, but not all. What do you consider to be downward pressure on rates?

A (Witness Trokey) Can you point me to where I mentioned downward pressure on rates?

Q So I don't have the report right here. I can get you the page number afterwards; okay?

But there was a mention in your report on downward pressure of rates. So what do you consider to be downward pressure on rates?

A (Witness Trokey) Staff's concerned with the cost to all Georgia Power customers. We do have panelists, including the next panel with Tom Newsome, Phil Hayet, Leah Wellborn, and, also, Ralph Smith and Dr. Deitchman, who will address this more completely.

Essentially we want a full picture of what the impacts will be. We don't believe that's been provided by the company. But wanting to ensure because -- because of our forecast, because we have additional options for the Commission's consideration, we think this is an opportunity that can be done that's still a win-win scenario and does not negatively impact existing customers.

COMMISSIONER PRIDEMORE: Ms. Scott --

MS. SCOTT: Yes.

COMMISSIONER PRIDEMORE: Page 4, lines 18 through 22, is where Mr. Trokey discusses downward pressure on rates.

MS. SCOTT: Thank you.

COMMISSIONER PRIDEMORE: And to that point, I

just want to make sure that everyone is still aware this is an IRP and not a rate case.

MS. SCOTT: Right.

COMMISSIONER PRIDEMORE: Thank you.

MS. SCOTT: So I'm only speaking to what was put in the report.

BY MS. SCOTT:

Q So since you mentioned it, Mr. Trokey, Georgia Power consistently said that their expansion requests would provide a downward pressure on rates and considering that would not cause any increases on our power bills again.

So, in your professional opinion, do you believe that to be true?

A (Witness Trokey) I will let the next panel speak to that. But their testimony -- we point to their testimony, but I -- I will only say that I'm aware that staff's position is that the company has not shown that to be the case.

Q Okay. So you point to their testimony there, but you didn't point to their testimony about the overstated load forecast?

A (Witness Trokey) That's right. Our panel is specifically addressing the load forecast.

Q Okay. All right. And then there is -- so, in

my opinion, we agree that there may be some potential cost implications with this request. So can you quantify the customer classes consistent with the request in this amended IRP?

A (Witness Trokey) I'm sorry. Did you say quantify the customer classes?

Q So your staff, colleagues -- again, I know that's on another panel, but I'm thinking that you-all are reading each other's reports.

They have a specific request that Georgia Power should quantify the rate impacts on all customer classes, consistent with the request in this amended IRP, much to what you just said about trying to look at it overall.

Can you speak on that or what is your opinion on that?

I know --

A (Witness Trokey) This panel hasn't attempted to quantify impacts. And we did not look at that from our -- for our testimony.

Q Okay. You also mention alternative resources. And so when we look at -- when we look at backup power, did the staff recommend, and the Commission approve, in both 2019 and 2022 IRPs, battery energy storage systems capable of generating almost a thousand megawatts of power?

Someone mentioned backup power. So I just wanted to bring that up since it is mentioned.

A (Witness Kelly) Can you point to where that is in our testimony or is that in somebody else's?

Q So you just said it earlier about alternative energy sources. And so I mentioned in the 2019 and 2022 IRP this Commission approved some additional battery energy storage systems capable of generating almost 1000 megawatts of power.

And so since you mentioned it, I wanted to ask about it, and then why so little.

A (Witness Trokey) There was a 2022 IRP. As a result of that, there's a Commission decision. It did include, for instance, directing Georgia Power to go to the market for a competitive solicitation of 500 megawatts of battery energy storage.

So, yes, there are battery projects that have been approved by the Commission and acquisition of future batteries.

Q Yeah. So if that's the case then, why aren't we moving to those alternative energy sources, instead of continuing with the fossil fuel, coal, gas and oil power plants?

A (Witness Trokey) Our testimony is focused on the load forecast and we've provided an alternative for

the Commission's consideration based on uniform assumptions. And that information can be used, for instance, by our expansion plan witnesses to inform their recommendations on supply-side resources.

MS. SCOTT: Thank you.

CHAIRMAN SHAW: Thank you.

All right. We're going to go ahead and take a break. You know, it's cross-over day at the Capitol today so I assume the cafeteria is probably buzzing.

So we're going to take a full hour because it may take awhile for folks to get served. So we're going to come back at 1:20.

(A lunch recess was held from 12:19 p.m. until 1:21 p.m.)

CHAIRMAN SHAW: All right. We'll go ahead and get started again after lunch. I hope everyone had a good lunch or had time to have lunch.

This is Docket -- again, Docket No. 55378. Are there any housekeeping matters to take up at this time before we move on?

MR. THOMAS: Mr. Chairman, staff would request that we change our order of witness panels due to one witness' travel schedule. We would ask that our fourth panel, Ralph Smith and Benjamin Deitchman, go third.

CHAIRMAN SHAW: Okay. Is there any objection

to moving the staff's fourth panel to -- swapping it with the third so that they can accommodate travel plans?

Any objections?

(No response.)

CHAIRMAN SHAW: Okay. That will -- that will be fine.

MR. THOMAS: Thank you.

CHAIRMAN SHAW: Sallie, please make note of that.

All right. We'll go ahead and get started again. I think -- I don't think Ms. Coyle is here, Georgia Watch, but she said she did not have any questions for this panel.

So we'll go to MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: No questions.

Microsoft.

Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

Mr. Baker, come on up. How are you doing?

MR. BAKER: I'm doing well.

Good afternoon, panel. I have some questions for you regarding your prefiled testimony.

CROSS-EXAMINATION

BY MR. BAKER:

Q I refer you to page 9, line 17. Referring to the company's large-load forecast and load realization model, you state, quote: The company has not demonstrated that its assumptions are "likely to occur."

How likely, in your opinion, is that; 50/50, 90/10, 10/90?

And you also make reference to that again, your dubiousness about the realization, on pages 39.

A (Witness Trokey) I believe there's -- in our testimony, and it may be trade secret, there's an order of magnitude, in terms of the probability of certain load materializing. And there's essentially a low, medium, and high case for data centers and -- and crypto mining operations that are set at a much higher level of materialization than the rest of the analysis. So it is quantified, but I would -- would need to check to make sure I'm not exposing the trade secret.

A (Witness Pol) And I'd like to make the point, I think the case we're making is that the company has not demonstrated empirical evidence that their assumptions are supported. Rather, they refer to informed judgment and don't provide further justification for their decisions.

Q Got that.

All right. Looking at page 10, line 15, you say: The company's source of several of the key assumptions in the load realization model is the informed judgment of the company.

Is informed judgment another way of saying educated guess?

A (Witness Pol) Sure. I -- that's a valid synonym.

Q All right. Page 11, line 19, you reference PSC Rule 515-3-4.03, subsection 3(c) dealing with: Each utility shall submit the most current data available on end-use appliance penetration.

Did the company provide this type of information for heat pump penetration, by any chance?

A (Witness Trokey) I don't recall that it was provided. I -- I don't believe so.

Q So what type of -- I mean, is the appliance penetration -- does it -- do they identify specific appliances, like -- I don't know -- refrigerators, heat pumps, air conditions?

A (Witness Pol) Yes, yes. There are specific pieces of technology that are identified with saturation rates and so on. I don't think we can speak specifically to which ones were and were not included. But, yes, the

company did provide some level of information to that -- to that end.

A (Witness Trokey) And those would be included in the organic growth model as opposed to the large-load customers.

Q Just recollect -- organic growth is basically natural customer increases just through people moving in, buying a house. When you talk -- what's the normal annual level of organic growth that the company has experienced before this boom in large-load customers?

A (Witness Kelly) The company provides historical load forecasts in its rate of growth in one of the documents that they submitted. And I can just take a look and see if I can find it quickly.

But they had lower load growth occurring before the latest IRP in 2022. They forecasted lower load than they are now forecasting going forward based on economic changes. And what the organic sectors really are are the traditional residential, commercial, and industrial, and MARTA as opposed to any other meaning of organic.

That's -- we just coined the term to kind of put them over in the corner and say: Okay. This is the traditional information that you have loads of history for, as opposed to the LR -- the load realization model, which is a new phenomena about which there isn't a lot of

information to fall back on and do regression equations and that sort of thing.

Q All right. Wasn't Georgia Power Company on notice of potential significant capacity shortfalls in 2022 when it was selected to serve almost 2200 megawatts of new load -- new load, which was six times greater than in 2021 and nearly 22 times greater than the approximately 100 megawatts of large-load growth the company was selected to serve from 2017 to 2022?

A (Witness Trokey) Yes. And I -- I would add 2021, they saw large-load customer agreements essentially that were three times higher than was identified in the prior five-year period. So even as early as 2021, but it's definitely in 2022, throughout the year, they were identifying these additional large loads.

A (Witness Kelly) And that's in the footnote on page 13 of our testimony.

Q Yeah. I know.

But, I mean, you go from 100 megawatts to 2200. Doesn't somebody -- you know, doesn't a red flag go up, you know, bells -- bells and whistles go off, something's really, really different from normal customer attrit- -- customer acquisition kind of thing?

And that was before the 2022 IRP. I mean -- yeah, IRP.

A (Witness Trokey) Right. The '22 IRP was conducted through, essentially, July of 2022. And -- and these new large-load customers were being identified and -- and Georgia Power Company was aware of these throughout all of 2022. And certainly to a much greater degree than they even saw in 2021.

Q All right. All right. Turning to page 19, the company's load realization model filed in October of 2023 evaluates 51 large-load projects.

Does the company assume all these projects will be developed and become operational?

A (Witness Pol) No.

Q Okay. And is that -- based on your evaluation, is that most are likely, most are not likely to be developed?

A (Witness Pol) It's not a straightforward question to answer. If the company's large-load realization model -- it takes a portfolio approach and it sums up the total capacity demand of all these projects across industries and then -- let's say a portion of that materializes, we can't speak to specific numbers on how many projects might or might not materialize.

Q And Table 6, page 25, reflects the actual construction of the listed projects. Doesn't Table 6 only show what contracts or agreements have been signed

with the company?

And only one has an engineering letter agreement to proceed; is that correct?

A (Witness Pol) That is correct.

Q So aren't these -- aside from -- the engineering letter agreement, is that a little bit more involved, as far as a commitment goes, as opposed to these other -- they're just contracts; right?

With -- with basically saying: We want to -- we want to select Georgia Power. We think our -- our load is going to be X megawatts and we think we're going to be operational on X date. And that -- that's all those contracts say; is that correct?

There's no commitment we're going to turn a shovel of earth or anything like that?

A (Witness Pol) That's -- if you are referring to the requests for electric service, yes, that's correct.

Q Should there be something a little bit more defined, more committed, rather than just contracts -- signed contracts?

Shouldn't there be some commitments, such as a purchase agreement for property, a contract with a -- a developer to build the facility?

A signed contract with a developer to build a facility to show the real commitment and likelihood that

a project will actually be -- come to fruition?

A (Witness Pol) I'll let my co-panel members add, but I think we point to in our testimony that, yes, this is a source of uncertainty.

A (Witness Kelly) I would also add that it's -- it's one of the -- the kinds of things that you're talking about are some of the suggestions that we made about a quarterly report to the Commission identifying what's happening as these loads move through the process of getting to finalization.

Q Well, based on your recommended -- recommendation to the Commission, when would, in the staff's opinion, a load be considered one load?

One that could be committed -- that could be relied upon with a sure -- with a relatively certain degree of certainty that will be developed?

A (Witness Kelly) The company considers it one when they're told that the customer is going to locate in the state. And -- and that's fine.

The question becomes then: How much more information comes in as you go forward? It's a process. It's a long process.

Q But at what point do you then make the -- then you have to -- does the company then have to come to the realization that we need additional capacity to meet this

actual load, rather than this hypothetical?

And it's, like: Oh, we want to come to Georgia and we want Georgia Power to be our electric provider. And we want to use 500 megawatts.

Okay. That's nice.

A (Witness Pol) Point -- point taken. We have not defined a specific contract type or anything of this sort at which we consider that to be firm, nor did we make any discounts in our analysis based on this thinking process.

All we're saying that this is an additional sort of uncertainty, in addition to the other assumptions that we've modified in the load realization model. So whatever forecast we've -- alternative forecast that we've provided, it's possible that this uncertainty could impact those values, as well.

Q Okay. At page 28, you indicate that -- you say -- refer to data centers and cryptocurrency facilities and you -- why aren't the load realization assumptions for data centers and cryptocurrent facilities appropriate?

Why aren't they appropriate?

A (Witness Pol) So the argument we make in our testimony is that they are different from all of the other industries and the company has not provided

sufficient justification, in our opinion, to support that decision. We interpret these assumptions simply as the company's confidence that the announced load from each project will meet actual load -- actual metered load; right?

So we don't think the company has empirical evidence showing a different -- differing level of confidence between industry segments. Because of that, whatever assumptions they make should be uniform.

Q Okay. And y'all have provided to -- as part of your testimony a list of additional information that you would request the company provide to you in the future. Is this the -- going to provide more detailed information to determine the viability and the reliability of a project being developed?

MR. MARZO: Mr. Chairman, I let the friendly cross go for awhile. I mean, Mr. Baker just asked him a question that is in his testimony with an answer and asked the witness basically to restate the response. And now we're, once again, asking a witness about something that's clearly in his testimony.

MR. BAKER: All right. If he wants to make an objection, I -- I hear the objection and I don't --

MR. MARZO: Well, he rules. I don't think you

rule.

CHAIRMAN SHAW: We'll just -- we'll just refrain from -- from friendly cross.

MR. BAKER: Well, it's my -- my last question.

BY MR. BAKER:

Q Is this -- that's your recommendation to the Commission; to help provide more detail, as far as the reliability of the projects in the future?

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

MR. BAKER: Okay. Thank you, Mr. Chairman. Thank you, Commissioners.

CHAIRMAN SHAW: All right. Thank you. Thank you, Mr. Baker.

Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: No questions.

Southern Alliance for Clean Energy.

MR. JACOB: No questions.

CHAIRMAN SHAW: No questions.

Southern Renewable Energy Association.

MR. COX: No questions.

CHAIRMAN SHAW: United States Department of Defense.

MR. McNUTT: No questions, Mr. Chairman.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions. Thank you.

CHAIRMAN SHAW: All right. Georgia Power.

MR. MARZO: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. MARZO:

Q Good afternoon, Panel.

A (Witness Trokey) Good afternoon.

A (Witness Kelly) Afternoon.

Q I've got a few questions for you this afternoon related to your testimony. I'd look to talk first about what I -- what I think we agree on. So, hopefully, this will be the happy part of our cross-examination.

Now, you agree --

CHAIRMAN SHAW: No friendly cross.

MR. MARZO: It won't be friendly. It won't be friendly.

I just want to make sure we agree. Want to make sure we agree on a few things.

BY MR. MARZO:

Q You agree that the company developed a reasonable organic load forecast in this case; correct?

A (Witness Trokey) That's right.

A (Witness Pol) Yeah.

Q Okay. And you agree that the practices utilized by the company in this case to develop that

forecast are consistent with typical utility practice; correct?

A (Witness Pol) Yes.

Q And I believe you also agree that the company's overall methodology for forecasting new large-load customers for -- is reasonable?

A (Witness Pol) Could you repeat that, please?

Q Sure.

You also agree the company's overall methodology of forecasting new large customer choice load is reasonable?

A (Witness Trokey) Overall method, not all of the assumptions.

Q Okay. And I realize we're going to have differences in assumptions and I'm -- I'm going to address those momentarily.

But the methodology is essentially the same methodology you use, just tweaking assumptions?

A (Witness Trokey) Correct.

A (Witness Kelly) Yes.

Q Okay. And do you agree with me that besides the large forecast for large customers, the forecasting process used in this case is the same process that was used in the 2022 IRP and the 2022 rate case?

A (Witness Trokey) That's correct. And -- and by

saying we think it's reasonable for this case, it certainly doesn't preclude further analysis in -- in the next case.

Q Yeah. And to that -- to that extent, we can agree that, you know, as we gain experience here that they'll all -- there is no debate with the company that there's an ability to add and -- additional information and value over the time.

Is that what the staff's general position is?

A (Witness Trokey) That's right.

Q Okay. Now, you're aware that the load realization model is the tool the company developed to forecast new economic development load; correct?

A (Witness Pol) Could you repeat the last portion of that, please?

Q Yeah. You're aware that the load realization model, which you've been talking about today, is the tool that the company developed in this case to forecast the new economic development load; correct?

A (Witness Trokey) Yes.

A (Witness Pol) Sure.

Q And can we agree that one of the assumptions that's been given some scrutiny by parties in this case is the load value to use when forecasting economic development loads?

A (Witness Pol) Are you referring to the materialized versus announced load?

Q I'm referring to the P values.

A (Witness Pol) I see. Yes.

Q Okay. And load value is the external adjustment for large loads for any given certainty level; is that correct?

A (Witness Pol) Yes.

Q Okay. And you understand that Georgia Power selected a P95 load value to respond to this unprecedented pace of economic development in the state and to ensure sufficient capacity to meet loads; correct?

A (Witness Trokey) We understand the P95 was selected by the company, yes.

Q Okay. And you understand that's the reason the company gave in its data responses to the -- to the Commission?

A (Witness Trokey) What -- did you say the reason?

Q Yeah.

A (Witness Trokey) Repeat those for me.

Q Sure. That Georgia Power selected a P95 load value to respond to the unprecedented pace of economic development in this state and to ensure sufficient capacity to meet loads?

A (Witness Kelly) I might add that during the hearings we probably heard a little more than that.

Q Okay. But the -- at least, at a minimum, that was provided to the staff in response to the data requests; correct?

A (Witness Pol) Well, yeah, we agree in general --

Q Okay.

A (Witness Pol) -- the company provided that reasoning.

Q Okay. And staff's recommendation is also to use a P95 load value; correct?

A (Witness Pol) Yes. That does not preclude any further consideration or analysis of the P level.

Q Of course. But in this case, I understand that you have recommended what you refer to as a P95 with delay scenario; correct?

A (Witness Trokey) Uniform assumptions and -- and different delay scenarios, yes.

A (Witness Pol) So, yes, for the purpose of our alternate forecast, P95 was reasonable.

Q Now, the company's load realization model is based upon specific known customers; is that correct?

A (Witness Pol) Yes.

A (Witness Kelly) Yes.

Q And -- and you're aware that the load realization model considers 51 known projects totaling 15,958 megawatts; is that correct?

A (Witness Pol) Yes, subject to check.

Q And are you aware that the number of projects that have expressed interest in using Georgia Power has grown to 19,580 megawatts since the company finalized its load realization analysis?

A (Witness Pol) I don't know that we were aware of that specific value, no.

A (Witness Kelly) No.

Q Okay. Now, in your testimony you talk about three primary set of assumptions that impact the results of the load realization model. And I think you refer to those as project success, load realization, and project delay; is that correct?

A (Witness Pol) Correct.

Q Okay. Now, I want to talk first about project success, if we could. Project success is defined as the assumptions associated with the likelihood that a project will materialize and be served by Georgia Power; is that correct?

A (Witness Pol) Yes.

Q And as it pertains to the assumptions of project success used in a load realization model, you

stated on page 26 of your testimony that the company's assumptions are treated as reasonable; is that correct?

A (Witness Pol) Yes. I'd make the caveat we did not think it would be impactful for us to go through multiple iterations of different categories for this project success assumption cat- -- setting. So we took them as reasonable in order to focus on the other assumption levels. These assumptions could also warrant further scrutiny.

Q Well, would you agree with me that the company who is on the ground and in regular conversations with these potential customers is in the best position to determine the likelihood of project success?

A (Witness Pol) That's a reasonable statement, but the company should also provide justification for their decisions.

Q Okay. But we can agree that the company is in the best position to determine that; right?

Correct?

A (Witness Pol) Yes.

Q Okay. Now, you state on page 25, lines 5 through 7, that -- and I'll let you get to that. That the evident -- well, I'll read the question, but let you get to the line.

You state on page 25, line 5 through 7, that

the evidence the company has provided largely consists of requests for electric service forms as opposed to any firm contracts; is that correct?

A (Witness Trokey) That's what's stated.

Q Yeah. And I believe Mr. Baker was walking you through some of that momentarily -- moments ago when he was doing his cross.

But let me ask you this: Are you aware that requests for electric form -- service forms are relied upon by this Commission as evidence of a contract in territorial cases that come before this Commission?

A (Witness Trokey) I'm not sure.

Q Okay. Well, let me ask you this: Are you aware that the Appellate Court of Georgia has found that requests for electric service forms, together with Georgia Power's publicly available rates, rules, and regulations, are sufficiently definite to comprise a contract?

A (Witness Trokey) I'm not aware of the --

Q Okay. So you didn't -- that wasn't taken into consideration as you did your evaluation in this case?

A (Witness Trokey) I think our focus was on the assumptions and lack of support for those assumptions.

Q Okay.

A (Witness Pol) And I'll make the point again, we

identified this as an additional source of uncertainty. That doesn't ultimately impact the alternative forecast that we suggested.

Q I hear that, but I just want to be clear that requests for electric service forms are indeed evidence before this Commission and has been treated as such in prior cases before this Commission; correct?

A (Witness Pol) Yeah.

Q Now, understanding the treatment of requests for electric forms in front of this Commission, are you suggesting that the company shouldn't begin planning for customers who have executed those forms?

A (Witness Kelly) No.

A (Witness Pol) No.

Q Okay. Good.

One last question along these lines. Now, are -- are you aware that the historical project failure rate for those who have been selected Georgia Power through requests for electric forms?

A (Witness Pol) Subject to check, I don't believe we've been --

Q Made aware of that?

A (Witness Pol) No.

Q Okay. Well, let me -- let me provide you with --

MR. MARZO: Mr. Chairman, could I approach the Commissioners with a data request?

CHAIRMAN SHAW: Sure.

MR. MARZO: What I'm handing the witnesses, Mr. Chairman, is Staff DEA 1-13, which is a response to a data request submitted by the company to the Commission staff. And I'll let the witnesses have an opportunity to review that.

And you -- you just tell me when you're ready.

MS. KELLY: Yep.

MR. TROKEY: Go ahead.

BY MR. MARZO:

Q Now, this data request describes the company's historic experience with choice projects that are won and how many materialize. And if you look at Question B, do you acknowledge that the historical project failure rate is low?

A (Witness Pol) We -- we see that it has been rounded to 95 percent, which, sure, we could characterize that as a high project success rate. I -- I would make the point that, as the company has stated, the -- this recent growth is unprecedented and we don't really have an understanding of how these projects might behave.

Q But if we look at just what the company has experienced with the request for electric service forms

and when they are executed and they're chosen -- the company's chosen, am I correct that the project completion rate is nearly a hundred percent?

A (Witness Pol) It is nearly 95. It's 96.5.

Q Okay. Well, I was trying not to use a trade secret numbers. So that's why I was --

A (Witness Pol) Oh, I'm so sorry.

Q Yeah.

A (Witness Pol) I apologize.

Q That's why I was asking the question in that form. But I -- to the extent it's available to the Commissioners, they can see those numbers.

Now, you're aware that of the 14 projects that have executed requests for electric service forms in this case, eight customers have broken ground and two customers will break ground soon pending on final permitting?

A (Witness Kelly) No.

A (Witness Trokey) Not aware of that. I think it -- we have to take into consideration the fact that so many have not signed that request for electric service yet.

Also, I'm assuming that the response here is -- is not specific to data center and cryptocurrency. So these customers are treated the same as other customers

who put in requests for electric service. So I believe that's a distinction here.

Q Well, yeah, this response is the aggregate customer choice response; correct?

A (Witness Trokey) Right.

Q And let me just say -- this is a question to you: Is you would agree with me that involved in that would also include -- or do you have any reason to believe it wouldn't include some data center load?

A (Witness Trokey) It's quiet likely, too. And I would say that to the extent that we don't have that granular detail of which portion of this -- it could be higher or it could be lower for -- for the data centers for materialization.

But it -- it doesn't also address the question of which of those customers will ultimately select Georgia Power and continue to build out their projects and have that load materialize on the time frame that Georgia Power has requested.

Q Okay. Let's talk about that because --

A (Witness Trokey) Or as identified.

Q I'm sorry, Mr. Trokey. You finish.

A (Witness Trokey) That's all right. I -- that Georgia Power has identified in its case.

Q Okay. And let's talk about that. Because I --

I think to cut to the chase, I mean, the primary disagreements between the company and staff regarding the appropriate load forecast is really the -- the LRMs, load realization, and project delay components; correct?

A (Witness Kelly) That's correct.

A (Witness Pol) That's correct.

Q Okay. And let's talk first about load realization.

Now, the load realization refers to how much these specific potential customers' loads will materialize; is that correct?

A (Witness Trokey) Correct.

Q And on page 28 of your testimony you have a table that depicts load realization assumptions used by the company; is that correct?

A (Witness Pol) Yes.

Q And can we agree that although staff takes issue with both data centers and cryptocurrency, data centers are, in this case, the great majority of the projected load increase; is that right?

A (Witness Pol) Yes.

Q Okay. And so for purposes of these questions, I'm primarily going to refer to data centers.

Now, staff's recommendation is essentially lower the load realization percentage for data centers;

correct?

A (Witness Pol) Correct. But it's not so simple as a lower. We are suggesting that they be uniform with the other industries.

Q Okay. But the -- the effect of that is to lower it; correct?

A (Witness Pol) Correct.

Q Okay. And lowering the load realization percentage for data centers has the effect of reducing the forecasted load; is that correct?

A (Witness Pol) Yes.

Q Now, staff did not provide any industry-specific support in their testimony for the proposition that the load realization percentage for data centers used by the company was unreasonable, did you?

A (Witness Pol) No, nor did we feel it was necessary. Our prime contention was that these assumptions should be uniform because there is no evidence to suggest otherwise.

Q Well, let me ask you this: Can we agree that with the pace that economic development load is coming to Georgia, it's important that we be accurate as we can to ensure that we have adequate capacity to serve load?

A (Witness Pol) Yeah.

Q Okay. And in your section on load realization,

you refer to this IRP update as a novel growth situation. And you do so on page 31 of your testimony, lines 4 through 5.

And I believe you're referring that assuming load realization that is uniform across all the industries is reasonable in that particular case; is that correct?

A (Witness Pol) Right. Absent of any evidence otherwise.

Q And let's talk a little bit about some of the evidence that's impacting us right now.

Now, you understand that the novel growth situation you're referring to is roughly 17,000 megawatts of economic development projects potentially coming to Georgia?

A (Witness Pol) Potentially, yes.

Q Okay. And, in fact, the company has experienced an average of 1953 megawatts of load growth since 2022, which is more growth than the company's experienced in four decades?

A (Witness Pol) In potential projects.

Q And this novel growth includes 4189 megawatts of new projects announced since the company filed this case. Are you aware of that?

A (Witness Pol) Maybe not that specific number,

but it sounds --

Q Okay. You know it's growing is my point?

A (Witness Pol) Yes, uh-huh.

Q Okay. Now, you're familiar with -- or are you familiar with DEA 5-3?

A (Witness Pol) I -- I would not recall off the top of my head, no.

Q There is a lot of discovery in this case; right?

So let me provide you with --

MR. MARZO: Mr. Chairman, can I approach?

CHAIRMAN SHAW: Sure.

BY MR. MARZO:

Q Let me provide you with --

MR. MARZO: And, Mr. Chairman, for the record, if I could mark the prior request, which was DEA 1-13 as Georgia Power Number 10.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GPC Exhibit 10.)

MR. MARZO: And if I could mark DEA 1-5 as Georgia Power Number 11.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GPC Exhibit 11.)

BY MR. MARZO:

Q Now, you cited excerpts of this particular response in your testimony on page 29 and 30; is that correct?

A (Witness Pol) Do you have specific line numbers that you're referring to?

Q Yeah. If you look at page 29, line 15, carries over to page 30 -- top of page 30.

A (Witness Pol) Looking at our testimony, that seems to be citing 5-3.

Q Which is what I -- what I --

A (Witness Pol) I believe we have 1-5 in our hands.

A (Witness Kelly) Right. We do.

Q Okay. Well, hold on to that one, but let's work through your testimony. So in your testimony you say: Due to continuous operation of their equipment -- do you see that line starting on line 15 through 18?

A (Witness Pol) Yes.

Q Now, logically -- let me ask this. Logically, a data center customer will more likely than not use their service 24/7; is that correct?

A (Witness Pol) We -- we can't speak to the specific operations, but that sounds reasonable for the industry.

Q Okay. And unlike manufacturers, there are -- there are not multiple processes and different equipment that requires starting and stopping throughout the day; is that correct?

A (Witness Pol) That seems like a reasonable general comment.

Q Okay. And if you're -- are you aware that the company has 60-plus data center customers currently on the system from which to pull comparable operational data assumptions?

A (Witness Pol) We were not aware of the specific number. And from what I understand, when we requested information specifically regarding how data centers operated in the past, I think the response was that the growth is not comparable to the current -- or the new data centers. So we were unable to get information regarding their operability.

Q The -- the quantity of data centers was not comparable, in terms of the -- in terms of the amount of load; is that what you --

A (Witness Pol) Per data center, correct.

Q Okay. But what I'm asking you is: Are you aware that there are 60-plus data centers, even if they're not in comparable load sizes?

A (Witness Pol) Yes, we are aware that there are

data centers in Georgia.

Q Okay. And do you understand that the experience is part of what informs the company's judgment regarding how data centers will operate?

A (Witness Pol) That's a fair statement. But I believe the company should, when requested, provide evidence then.

Q Okay. And let's talk about -- let's talk about the evidence.

Well, let me ask you this. I mean, we talk about informed judgment. And we talked earlier that it's the company who is in constant contact with these customers. It's the company who has gotten the request for electric service forms executed and gone through the process to deal with preliminary work with these customers.

Isn't that, indeed, information in regards to how these customers are going to come online, how this load will materialize?

A (Witness Trokey) It's -- it's information, but I don't know that it specifically informs whether or not Georgia Power will ultimately be selected or that -- the timing of that load developing.

So I -- I think that's getting to staff's analysis is that the company's prior experience --

although, it's appreciated -- it has not been identified or there have been no empirical data provided to support the assumptions that staff has modified.

And the other thing I would say is that the -- the newer data centers may be different in -- than prior data centers. So although typically they may run 24/7, they also will have the advantage of -- of backup; right?

So they will have their own ability to provide for their own power needs when -- when it's necessary. And they are actually potentially a flexible load. So the new data centers and the magnitude of these data centers can actually provide an opportunity for the system to benefit all customers.

But it's a -- although I appreciate the company's experience with its existing customers and -- and those existing data centers, I think the -- the growth and the magnitude that you're seeing -- although these customers have not all selected Georgia Power, that's one thing we're considering -- but there's also that flexibility from these data centers themselves. They don't always have to run at a hundred percent of their -- of their own peak demand.

Q Okay. So let me ask you this. I mean, I think earlier it was agreed that data centers would likely use their service 24/7.

Have you spoken to any of these potential customers to be able to opine that that's not the case, that they are going to have flexible loads?

A (Witness Pol) I -- I don't think we've suggested in our testimony otherwise beyond the 24/7 assumption. I think the point we're trying to make is that we can't double check informed judgment. And our role as reviewers is that -- is to double check those assumptions.

A (Witness Kelly) I think you --

Q Well, you are checking informed judgment because you made a material change to our -- an assumption the company's made. And so in that regard, you've decided that assumption is incorrect.

And I guess my question is: Is that based on any particular conversation with the customers that we're talking about coming to the state?

A (Witness Kelly) If -- if I could just jump in a minute here. We asked the company to -- to give us information that backed up the informed judgment. And basically we were informed it was informed judgment and that's it.

With all the information that you're sharing here today, that would have been better to have had during the analysis. But at this point, when the company

decided to use different parameters here, there was no evidence for why. It just said informed judgment.

Our thought here is that since you don't know a lot about these new loads, it's better at this point to use uniform assumptions than to assume something is going to be like the other smaller data centers that you have now as opposed to what's -- what's coming in in the future.

Q Okay. Let me ask this. Not agreeing necessarily with what's previously been communicated, but it sounds to me that what staff is saying is that to the extent they understand that informed judgment is actually more meaningful than what they characterized to Mr. Baker earlier, it could change your position in this case; is that correct?

A (Witness Kelly) Not necessarily, but it depends on what you would share.

Q Okay. Let me -- let's jump over to ramp-up delays, if we could. Ramp-up delays is essentially the extent to which expected loads might be delayed from the initial intended in-service date; is that correct?

A (Witness Pol) Yes.

Q And your Table 8 on page 32 of your testimony includes the ramp-up delay assumptions used by the company in the load realization model; is that correct?

A (Witness Pol) Yes.

Q Now, in the -- in this case, in the case of the ramp-up delays, the staff once again is taking issue with the assumption the company has offered for data centers; is that correct?

A (Witness Pol) Yes.

Q And staff's recommendation is to lengthen the data center delay assumption, further reducing the near-term forecasted load growth; is that correct?

A (Witness Pol) Yes.

Q And as the basis for support for staff's change to the company's ramp-up assumption, the staff refers to two articles from Construction Dive, a blog post, and a Fox 5 story about tax breaks for Elon Musk; is that correct?

A (Witness Pol) Those seem to be the citations on that page.

Q Okay. Well, let's look at those specific articles.

MR. MARZO: Mr. Chairman, can I approach again?

CHAIRMAN SHAW: You may.

MR. MARZO: I'll let -- I'll let you get those.

For the record, Mr. Chairman, I would like to have this marked as Georgia Power Exhibit 3 [sic]. This article is a "Construction Dive" article. It's

marked -- it's titled "Supply Chain Issues Threaten Data Center Construction Boom," which is a June 8, 2022, article.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GPC Exhibit 12.)

MR. MARZO: And for reference, it also appears in staff's testimony as a citation.

CHAIRMAN SHAW: Okay.

BY MR. MARZO:

Q You let me know when you've had a chance to review that.

VICE-CHAIRMAN ECHOLS: That's 10, 11, 12.

MR. POL: I think we're -- we're ready.

BY MR. MARZO:

Q You ready?

A (Witness Pol) Yeah.

Q Okay. Now, if you turn to page 2 of the article, would you mind reading the highlighted language?

A (Witness Pol) Sure. Operators who focus on procuring key materials and equipment early, have good relationships with vendors, and can secure warehouse space for storing equipment and products offsite are the ones with making headway in this challenging environment, the report said. Smaller companies that build the

2-megawatt to 4-megawatt data centers, they're probably not going to have that relationship with the vendors. Supply chain is definitely still an issue right now.

Q Okay. And if you would for me, could you turn to Table 5 on page 23 of your testimony.

A (Witness Pol) Page 23, you said?

Q Yeah. Page 23 of your testimony. It should be Table 5.

A (Witness Pol) Yes.

Q And this is the table that staff uses to depict projects that the company has already won. Both data center and non-data center projects are on it; is that correct?

A (Witness Pol) Yes.

Q Okay. Now, are there any projects on this list that are 2 to 4 megawatts?

A (Witness Pol) No.

Q And there's no data center projects on this list below 100 megawatts and the average load for data centers on this list is about 375 megawatts; is that correct?

A (Witness Pol) We haven't done the math, but that seems reasonable.

Q And if you look down further on page 2 of the article that I gave you -- and this is the article that's

cited in your testimony as support for the change in assumptions -- one of the articles that is cited, do you see where it says about one paragraph from the bottom, it starts: Through the first quarter of 2022 --

A (Witness Pol) Uh-huh.

Q -- data center construction has been on a tear, according to Dodge. Starts reached 1.4 billion during the three months of 2022, a 29.2 percent increase from the first quarter of 2021.

A (Witness Kelly) Uh-huh.

A (Witness Pol) I do.

Q And it says -- it goes on to say that doubles the pace of construction starts in general.

Now, you also referred to an article titled "Navigating Data Center Market Challenges: A Business Guide," for the proposition that supplies -- you used this as a part of the proposition that supply chain issues continue in 2023; is that correct?

A (Witness Kelly) Uh-huh.

A (Witness Pol) That seems right.

Q Let me provide you --

MR. MARZO: If you could give me a moment, Mr. Chair, I'm going to give Mr. Hewitson a couple of exhibits to prevent him from having to walk around several times.

The first one that Mr. Hewitson is going to provide you is the blog article titled "Navigating Data Center Market Challenges." And that's the first one I asked you questions about.

And I'll bring up the second one, which is called -- titled -- Mr. Chair, it's titled "Navigating Data Center Market Challenges: A Business Guide." I would like to get them both marked as GPC 13 and 14.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GPC Exhibit 13.)

MR. MARZO: Yeah.

(The document referred to was marked for identification as GPC Exhibit 14.)

BY MR. MARZO:

Q These two are 13 and 14. Are you ready?

A (Witness Pol) Yes.

Q Okay. If we look at the first article titled "Navigating Data Center Market Challenges: A Business Guide," could you turn to page 2 under heading 2?

And under that heading, would you read the highlighted section.

A (Witness Pol) Sure. Post 2020, the echo of supply disruptions is palpable in the data center realm.

With semiconductor and server shortages, project timelines are stretched and costs escalate. The key to resilience is diversifying supplier networks and considering alternative components. By expanding supplier connections and being agile in component choices, data centers can regain control.

Q I mean, would -- would you agree with me this article -- that article itself talks about the ways data centers can respond to any supply chain issues; correct?

A (Witness Pol) Yes. But I -- I wouldn't say it's indicative of what practices incoming data centers might have taken.

Q Okay. Did you happen to click on the supply chain's disruption link there on the page?

A (Witness Pol) I don't recall.

I do not recall.

Q Okay. So -- so are you aware or did you know if you click on that link, it says that only about one-fifth of supply chain operators report experiencing supply delays?

A (Witness Pol) I do not recall.

Q Okay. So that means that four-fifths of data centers are not reporting experiencing supply chain delays; correct?

A (Witness Pol) That math checks out.

Q Okay. Now, you reference the other article, which is "Data Center Building Shows Cracks." And that was GPC 14.

And I believe that's for the proposition that specific project demands, such as new electricity substations or an upgraded transmission line, could delay delivery by one to four years; is that correct?

A (Witness Pol) Yes. That sounds right.

Q Okay. Now, can we agree that having the capacity needed to serve these customers, as has been requested in this case by the company, addresses the power delivery issues that you're referencing?

A (Witness Pol) Yeah, it -- it could. Georgia Power does have the capacity to address those issues. And I think we address that in testimony, as well.

Q Okay. And does the staff have any evidence or reason to think that data center customers seeking to be served by Georgia Power haven't already included potential supply chain issues in their estimated time frames to construct and receive service?

A (Witness Pol) We have no reason to assume one way or the other.

Q Okay. Now, where staff relied on Google searches to support its load ramp assumptions, are -- are you aware that the company has relied upon real-world

information provided directly from new economic development customers?

A (Witness Pol) I don't think we are aware of any of that, no.

Q Okay. You're not aware that the company has communicated -- the requests for electric service forms are indicative of the communications between the company and those --

A (Witness Trokey) Could you --

Q -- customers; correct?

A (Witness Kelly) Could you restate that?

Q Sure. I said: Where the staff used Google searches, and we've kind of gone through the doc- -- the articles that come out of Google searches to support a significant change in assumption in this case, are you aware that the company is relying upon real-world information it's receiving directly from the new economic development customers?

A (Witness Pol) What is the real-world information you're referring to?

Q The real-world information is the conversations with the customers, the work that's done to get to the request for electric service form execution, the work that's done postexecution, the continuation of that work even now today with customers, and the customers who are

now signing up or want to sign up with Georgia Power?

A (Witness Trokey) I would just say that the -- the plans, the conversations, they -- they do lay out a timeline. For those customers that have selected Georgia Power, I -- I think it's important to have those schedules and to understand the -- the ramp that is the request of the customers. And -- and the company will try to meet those.

That -- that doesn't mean Georgia Power will have the ability to control all of the circumstances or risk for those data centers, even whether or not those data centers will continue or at some point down the road decide that their business model doesn't work.

A lot of this building may materialize. And staff's not opposed to that. I -- I think that the assumptions that we have in our testimony are really to identify the fact that there are risks, that there are challenges to meeting what these data centers are -- are seeking to do in Georgia.

Some of that is political risk and, you know, whether or not there will be tax credits available. There's a lot of things that are outside of the control of Georgia Power, outside of the control of these data center customers.

Some of these customers may select an EMC

ultimately. They may select to go to another state. They may decide that their business model is not appropriate.

So although I think the conversations that you're having with your customers are important, I don't think that it necessarily means that every single area of potential risk is going to be eliminated.

Q Well, Mr. Trokey, let me ask this. I mean, there is -- staff in this case has done more than just identify risk. You've made a substantive change to the load forecast that if you are wrong, there will not be enough capacity available to serve new economic development load. So it has a real-world consequence.

Are you suggesting that all staff was doing was identifying risk in --

A (Witness Pol) Subject to --

Q -- this case?

A (Witness Pol) Subject to check, I believe what we say in our testimony is that we propose a reasonable alternative. And the company should go back and examine multiple alternatives to produce a range of outcomes that then the Commission could review again.

Q Is it -- is it a reasonable alternative to adjust an assumption based upon reading a few Google articles without following up with the actual customers

that are coming to Georgia?

A (Witness Trokey) I think if the market trend and -- and it's a known that there are delays, that there are challenges in this market, that it's not just Georgia where these data centers are seeking to build their projects. I think by recognizing all of the variables, I -- I do think this information, a CPRE report or -- yeah, a lot of these articles are substantiated with additional studies.

So I -- I think that that data and that information helps inform the -- the decision to make the adjustment. So the staff is suggesting in our testimony that Georgia Power's assumptions, beyond the informed judgment of its employees, has not provided that empirical data.

Q Well --

A (Witness Kelly) If I could add, the -- the reasons that these alternatives are in our testimony is that Georgia Power came in with a single case. We believe strongly that if you're going to make a decision to invest the money that you are planning to invest and asking the Commission for approval for that, that the company should have come in with an -- an analysis that shows what happens if the assumptions are different.

How much is at risk? What happens to the

investment you are making? What happens to the customers who have to pay for it?

So it's more an analysis of looking at the potential futures for these data centers for all these new customer loads, which are not a certainty.

Q Well, do you -- yeah.

A (Witness Kelly) And it's -- it's our suggestion, our strong belief, that the analysis should have been broader and not just been: Here's what's going to happen and here's the solution. These are our assumptions.

We went want back and said: Okay. If the assumptions are not the ones the company said they're going to be, what happens then?

Q Well, you understand, Ms. Kelly, that what the company has put before this Commission is what it believes to be the likely load that it will serve or need to serve in terms of economic development load.

Now, are you suggesting the company should provide alternative cases to the Commission that they don't believe to be true in an IRP Update case where they're trying to get specific resources put in place to serve this load?

A (Witness Kelly) I don't -- I don't want words put in my mouth.

Q Sure.

A (Witness Kelly) What I'm suggesting is that what the company should do is enable the Commission to make a clear decision and understand what's happening. So if you are saying that the future is going to be point A, then you should say: If it doesn't happen, there is minimal risk. Or if it's even greater than what we're saying, this is the risk.

So the -- it's a decision that is made understanding what's going to happen to the rest of the customers of Georgia Power, as well as what kind of other, you know, issues can happen.

Q So what case is your P95 with delays?

Is -- is that the risky case that you put before the Commission, or is that, in your position, a case the Commission should actually adopt?

A (Witness Kelly) We think that case is as probable as your case.

Q Okay. And you believe that and that's -- I'm not trying to be argumentative. But your belief in that, in part, in terms of one of the assumptions, at least, is based entirely upon Google articles without any additional backup, Mr. Trokey.

So, you know, I heard you say there were additional studies, but there weren't anything additional

that these Google articles provided.

You changed an assumption based upon that; correct?

A (Witness Kelly) We modified an assumption that is pretty common in the industry that there are delays in construction projects all the time.

Q Okay. And --

A (Witness Kelly) And --

Q Go ahead, Ms. Kelly. I'm sorry.

A (Witness Kelly) And those delays can be longer than the ones that the company assumed.

Q Okay. Now, you're aware that the three data center customers have requested -- or are you aware that three data center customers have requested their load ramps be accelerated from what was filed in 20- -- in the IRP Update?

A (Witness Pol) No.

Q Okay. Are you aware that the accelerated role lamp -- load ramp, sorry, equates to an additional 433 megawatts of load that will appear in 2027?

A (Witness Pol) No.

Q Are you aware that almost 2315 megawatts of data center load has broken ground and begun construction?

A (Witness Pol) No.

A (Witness Kelly) No.

Q Okay. Now, one of the staff's -- well, let me ask this question as a follow-up, Mr. Trokey, to something I heard earlier. I think earlier, in response to Commissioners, you had said something to the effect that the RFP could be utilized to meet loads in the future.

Would you agree with me that the -- the only way the RFP can be utilized is if the Commission accepts that your forecast is, in fact, the right forecast?

A (Witness Pol) The Commission may also accept an alternate forecast that Georgia Power produces. It doesn't have to be our forecast, by any means.

We're, again, suggesting that the company produce multiple forecasts and file all of them to the Commission to show the range of possibilities.

Q But you understand that under the company's forecast that it's recommending this Commission adopt, the company's position is there is not time to do an RFP. And I just want to confirm that Mr. Trokey's comments were related to the adoption of the staff position; is that correct?

A (Witness Trokey) I would say that the staff's position on the RFP is that there is time to do that. There's time to expedite it.

There is more than one RFP. There's the CARES RFP, there's the all-source RFP, and there's the 500-megawatt battery storage RFP, all of which could be expedited and can provide capacity to the company to -- to meet its customers' needs.

Q But staff's position on that availability is built entirely upon your changes in assumptions to the company's load forecast; correct?

A (Witness Trokey) I wouldn't say entirely. There's other recommendation that staff has in our testimony. And the next panel will share with you that they're recommending acceptance of the two PPAs.

But we believe that our forecast is a reasonable alternative and provides the time for, as you'll hear from the other witnesses, competitive solicitations and to procure the -- the most economic resources for customers and still be able to serve your -- your new large-load customers.

Q And that's because under your forecasts, you shifted the load out via these assumption changes to 2029. Some of the load. Not all of it, but some of the load is being shifted out to 2029; is that correct?

A (Witness Trokey) Because we believe the assumptions are reasonable that --

Q Okay.

A (Witness Trokey) -- we've provided.

COMMISSIONER PRIDEMORE: So to be clear -- do you mind? So what -- what these witnesses are saying is that you don't -- you don't believe that this quantity of capacity that the company has filed is going to come within the schedule that they filed it in?

MR. POL: We believe that's a -- a possibility, yes.

COMMISSIONER PRIDEMORE: How great of a possibility?

MR. POL: We think it's prob- -- very likely. I don't think we can attach a number to that value.

COMMISSIONER PRIDEMORE: But to Mr. Marzo's point, you believe it's very likely based upon Google searches and articles that you're finding off the internet without talking to these customers or working with the Georgia Department of Economic Development.

MR. TROKEY: So our -- our assumptions with the load realization, for instance, are in line with all of the other assumptions Georgia Power made. So we believe those are reasonable. And, in fact, are supported by Georgia Power's assumptions for all of the other industries.

And what we haven't seen is empirical evidence that their assumptions for data centers and cryptocurrency operations should be that much higher. And because the model is so sensitive to those assumptions, Georgia Power could come in with almost anything that they haven't supported with empirical evidence.

And so it's -- the same is true with the delay situation. There are a lot of factors. And because we have accepted the P95 approach with a uniform set of assumptions that are in line with Georgia Power's, we think that essentially what it comes down to is we do believe the load will materialize over a longer period of time and that there are certainly some risks involved with Georgia Power's approach. And -- and one of those risks is the cost impact of doing everything we can now without competitive solicitation for these resources.

COMMISSIONER PRIDEMORE: Okay. So you believe that the quoted capacity that the company has filed is going to materialize. You just don't believe it's going to materialize in the time frame they set forth; correct?

Correct, okay.

So why would an all-source -- why would an

all-source RFP, or the means by which to go outside in a pure PPA environment -- why is that going to be faster when we have RFP processes that last here multiple years?

MR. TROKEY: So -- and that's what we're saying is. Is because the RFP has already started, it's an avenue through which the capacity can be acquired.

COMMISSIONER PRIDEMORE: But the all-source RFP is not -- is not the same level of capacity that's needed in this filing.

MR. TROKEY: That's within the Commission's authority. There's no specific number of megawatts in the all-source RFP --

COMMISSIONER PRIDEMORE: But to my point, Mr. Trokey, what you're saying is that you just think that all of it has to go out to an all-source RFP. And that you want the Commission to reset or validate the filing of the megawatts that they put in the filing and then put it all out for an all-source RFP, without ever assuming that the company could build -- could build assets faster or build the assets that they need that are in the filing.

MR. TROKEY: I appreciate the question. Just one distinction that the next panel can speak to is

we have accepted the power purchase agreements that Georgia Power acquired --

COMMISSIONER PRIDEMORE: Yeah. The two PPAs.

MR. TROKEY: -- with an affiliate and another independent power producer. So I think -- although in an ideal situation those would compete with the market to -- to ensure that Georgia Power's customers are getting the most economic resources, it's because we have accepted that and in line with our load forecast that you do have the ability to use the existing RFPs to address the load.

And the next panel can identify the specific years in which you would need to address that. But you do have time to use those RFPs.

COMMISSIONER PRIDEMORE: All right. I think I've -- that was a lot of words. I think I'm following you.

Thank you, Mr. Marzo.

MR. MARZO: Thank you, Commissioner.

BY MR. MARZO:

Q Mr. Trokey, just to close this out, I mean, it sounds to me that -- would you agree with me that the Commission can consider the information that staff has used to justify its changes to the assumption, it can consider the information that Georgia Power has garnered

through its informed judgments from its customers, and it can make a determination as to which of us is using the better set of information in regards to what the proper load forecast is to adopt?

A (Witness Trokey) The Commission certainly can consider and -- and we recommend the load forecast that's in our testimony.

But beyond that, I -- I don't want to lose sight of the fact that Georgia Power has the ability and -- and should be directed to provide follow-up from these customers because you are interacting with them. And as these projects are being built out, the company should be reporting back on the progress and variances and whether there are delays. So there's a lot of information that I think that should be provided to staff and the Commission for its consideration.

Q And to close out on that, Mr. Trokey, I mean, one of staff's recommendations is that given the uncertainty regarding the materialization of large-load customers, staff recommends that the company update the company's quarterly -- update the Commission quarterly during the period of extraordinary load growth by documenting interactions with potential new large customers.

Is that what you're referring to?

A (Witness Trokey) Correct.

Q Okay. Now, do you understand that given the extraordinary growth we're seeing, if the Commission were to adopt staff's P95 with delays forecast, it's likely -- very likely that the company will be reporting that it can no longer serve potential economic development load customers for some duration of time?

A (Witness Trokey) I don't know that to be the case.

Q Okay. You're just asking the Commission in this case to trust you in this assumption?

A (Witness Trokey) I -- I think we have a 2025 IRP that will inform that. And I think the -- the quarterly reporting from Georgia Power to the Commission will help inform that.

That said, I think the forecast accepting the PPAs will enable Georgia Power to -- to serve the load.

Q Okay. But, Mr. Trokey, if you are wrong, the 2025 IRP does nothing to address the duration of the time that the company will not be able to serve economic development load?

A (Witness Trokey) I'm not sure that's the case, given what could be available through an RFP.

MR. MARZO: Okay. Well, we'll agree to disagree on that. But thank -- I thank the Panel

for their time.

COMMISSIONER PRIDEMORE: Mr. Marzo --

MR. MARZO: Thank you, Commissioners.

COMMISSIONER PRIDEMORE: Mr. Marzo, before -- or you can go.

Mr. Chair --

MR. MARZO: I'll take questions.

COMMISSIONER PRIDEMORE: I just -- sorry. I just -- I like answers.

Do you mind?

CHAIRMAN SHAW: Go ahead.

COMMISSIONER PRIDEMORE: Okay. So -- so I've heard everything that you've had to say back to the company, Mr. Trokey, but let me just ask you like a very -- in a specific way. We're the number one state for business for 11 years in a row.

Lots of intervenors come in here and they -- they shoo that, but they don't live it. And I can guarantee you when you live it, you know it.

Because you know all of the infrastructure and all the work that the state agencies put forward, everything that goes on behind the scenes, and then you realize the jobs and the economic growth from it.

Are you suggesting that we tell Governor Kemp

and the people that do this modeling that consistently prove year after year that they can make this -- and do -- make this possible, they're wrong, you're right, because of some articles, which were compelling -- I've sat up here and read them all -- but some article said: We just don't know. It's unknown. So let's not do anything?

MR. POL: Can --

MS. KELLY: I --

MR. POL: Sorry. Go ahead.

MS. KELLY: Sorry. I just wanted to add the point, it's not just these four articles. There's -- it's history with utilities. It's history with construction. It's -- we all want to get everything done --

COMMISSIONER PRIDEMORE: But not relative to data centers, though, Ms. Kelly. I mean, it's -- this proliferation in data centers we're seeing, it's -- it's new. And we all know that it's --

MS. KELLY: This -- this is new. I agree.

COMMISSIONER PRIDEMORE: That it's -- it's being powered by AI. And as we're seeing --

MS. KELLY: Okay.

COMMISSIONER PRIDEMORE: -- businesses -- I mean, two years ago I didn't even know what ChatGPT

was.

MS. KELLY: Yeah.

COMMISSIONER PRIDEMORE: And now it's -- it's everywhere. Can't swing a dead cat without hitting it.

So I just think that to some extent we just don't want to be in a position to make an assumption just because something's never happened before that: Well, all right. Well, we're just not going to do anything and we're going to sit and let the tidal wave take us over.

MR. POL: Commissioner, if I may, two points to make. The load realization model, from my understanding, this is the first time this probabilistic model has been used by Georgia Power. So while they may have a couple more months of experience than we do, it's not that many more. It is a novel model in and of itself.

And, second, our proposed alternative load forecasts doesn't preclude significant growth. We still show a pretty large level of growth, I would say, that is larger than historic growth, as well. So we don't disagree with that story; right?

There is a lot of economic growth in Georgia and will probably continue to come to the state for

many years to come. All we're saying is there is risk if we overestimate that growth. And that risk is going to be borne by existing customers.

COMMISSIONER PRIDEMORE: All right. Thank you.

CHAIRMAN SHAW: All right. Any more questions?

(No response.)

CHAIRMAN SHAW: Redirect.

MR. THOMAS: Thank you.

REDIRECT EXAMINATION

BY MR. THOMAS:

Q Ms. Kelly, you said that you used SMR as one example of an alternative for data centers. What -- what are some of the other options that you pointed to?

A (Witness Kelly) Can you restate that?

Q Yes. I think -- I think you were asked about the small modular for data centers. And you said that that was just one example, that there were alternatives that data centers could turn to.

What are those other alternatives?

A (Witness Kelly) There's -- there's plenty of other technologies. I am not a technology expert, as I said earlier this morning.

But you can look at BESS. You can look at other large nuclear. But there's all kinds of solar, there's all kinds of solar-plus-storage or

storage-plus-solar. There's wind projects. I mean, there's a plethora of such technologies.

A (Witness Pol) And -- and if I may add, the decision to speak on SMRs was not to give a specific example. It was a hypothetical, I think, prompted by Commissioner Echols' prior comment.

A (Witness Kelly) Yes.

A (Witness Pol) That shouldn't be indicative of a recommendation on our part. It's just completely in the air.

A (Witness Trokey) And if it's behind-the-meter, I think most data centers are using diesel generators as their backup.

Q You were asked a lot of questions around the articles you cited. What was staff's point in citing these articles?

And to what extent did staff rely on them and -- along with other things in creating their assumptions?

A (Witness Pol) So our -- our intent in citing these articles was just to demonstrate that there is uncertainty regarding the specific assumptions that the company chose for ramp-up delays. That is not to say that they're the best and most accurate references. There could easily be more detailed studies that prove

otherwise.

But I think our intention is to say: Look, there's variability here and uncertainty that the company has not referred to when asked to provide clarification, you know, on their decision-making process for the assumptions.

And if we could so easily find some other reference points, the company should be expected to provide more detailed evidence for their assumptions, as well.

Q Mr. Marzo stated that the company relies on real-world data. Would you consider conversations with potential customers as data?

A (Witness Pol) I think we would contend that is not empirical evidence. While the company may have some general sense of these assumptions, it is not empirical evidence.

A (Witness Kelly) I would also add, it is -- it is data of a sort from the customer's perspective. The customer is always hopeful that they're going to get things done in a shorter time frame as possible. But we always run into real-world issues and that needs to be considered and at least assessed as you go through this to see what kind of implications there are for the company and the rest of the customers.

Q Mr. Marzo suggested in his cross that rather than the company providing details behind its informed judgment, staff should call prospective customers. And I suppose staff could do this, but would it be easier for the company who's already had those discussions to provide that information?

A (Witness Kelly) Yes.

A (Witness Pol) That would be most appropriate.

Q If the company overestimates load growth and, therefore, overbuilds, the cost of that overbuild will have to be paid by existing ratepayers; is that correct?

A (Witness Pol) To our understanding, yes.

Q Okay. And is the staff suggesting that the Commission do nothing or is the staff simply suggesting that the Commission look at alternatives?

A (Witness Pol) The latter. Look at alternatives.

MR. THOMAS: That's all I have, Mr. Chairman. I would ask that the panel be excused.

CHAIRMAN SHAW: Okay. Panel, thank y'all.

MR. POL: Thank you.

CHAIRMAN SHAW: You're excused.

Mr. Newsome, you are ready, aren't you? All right. We will go ahead and let Public Service call your next panel.

MS. DAVIS: Good afternoon, Commissioners.

CHAIRMAN SHAW: Go ahead. Good afternoon.

MS. DAVIS: And, Mr. Chairman, in the interests of administrative efficiency, I am calling a panel and an individual witness together. So at this time, I call the panel of Tom Newsome, Phil Hayet, and Leah Wellborn. And I also call to the stand John Kaduk, who will give a separate summary from the rest of the panel of his own prefiled testimony.

CHAIRMAN SHAW: Okay.

Thereupon,

TOM NEWSOME,
PHILIP HAYET,
LEAH WELLBORN,
JOHN KADUK,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. DAVIS:

Q Starting on the end with Mr. Newsome, could you all please state your full name, by whom you are employed, and your responsibilities for the record?

A (Witness Newsome) Tom Newsome, director of utility finance, Georgia Public Service Commission staff.

A (Witness Hayet) Phil Hayet, vice president, J. Kennedy and Associates.

A (Witness Wellborn) Leah Wellborn. I'm manager of consulting at J. Kennedy and Associates.

A (Witness Kaduk) John Kaduk. I am a staff member at the Georgia Public Service Commission in the Energy Efficiency and Renewable Energy Unit.

Q Thank you.

Mr. Newsome, on February 15th of this year, did you file or cause to be prefiled 116 pages of testimony in question-and-answer format, that includes six exhibits marked as Exhibits STF-NHW-1 through STF-NHW-6?

A (Witness Newsome) Yes.

Q Thank you. Did you also file or cause to be prefiled errata on February 22nd and February 23rd of this year?

A (Witness Newsome) Yes.

Q Okay. If I were to ask you the same questions today under oath, would your answers be the same as set forth in your prefiled direct testimony, as corrected by your errata?

A (Witness Newsome) Yes.

Q Okay. Thank you.

Mr. Kaduk, did I say that right? I am sorry.

A (Witness Kaduk) Kaduk. Yes.

Q On February 15th of this year, did you file or cause to be prefiled 15 pages of testimony in question-and-answer format?

A (Witness Kaduk) I did.

Q If I were to ask you the same questions today under oath, would your questions be the same as set forth in your prefiled testimony?

A (Witness Kaduk) They would.

MS. DAVIS: Mr. Chairman, the court reporter has been provided with a copy of the prefiled testimony and the errata. I would ask that the direct testimony, as corrected by the errata, be copied into the record as if given here today.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as Staff's Exhibits 6 through 11.)

(Whereupon, the prefiled direct testimonies of Tom Newsome, Philip Hayet, Leah Wellborn, and John Kaduk follows, including erratas:)

PUBLIC VERSION

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE	**)** **)** **)**	**DOCKET NO. 55378**

DIRECT TESTIMONY AND EXHIBITS

OF

TOM NEWSOME, PE, CFA

PHILIP HAYET

LEAH WELLBORN

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

FEBRUARY 15, 2024

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Exhibit STF-NHW-6 – Staff Ranking Iteration Results

I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. My name is Tom J. Newsome. I am the Director of Utility Finance with the Georgia Public Service Commission ("Commission"). My business address is 244 Washington St., Atlanta, Georgia 30334.

My name is Philip M. Hayet. I am the Vice President and a Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

My name is Leah J. Wellborn. I am a Manager of Consulting at Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. MR. NEWSOME, WHAT ARE YOUR PRIMARY RESPONSIBILITIES WITH THE COMMISSION STAFF?

A. I am responsible for economic, financial, and cost of equity analysis and evaluations at the Commission.

Q. WHAT CONSULTING SERVICES DOES KENNEDY AND ASSOCIATES PROVIDE?

A. Kennedy and Associates provides consulting services related to electric utility system planning, resource analysis, production cost modeling, ratemaking, finance, accounting, and industry policy issues.

Q. PLEASE PROVIDE SUMMARIES OF YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. Summaries of our education, experience, professional certifications, and testimony appearances are provided in Exhibits STF-NHW-1, STF-NHW-2, and STF-NHW-3, for Mr. Newsome, Mr. Hayet, and Ms. Wellborn, respectively.

Q. HAVE YOU ALL PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, we have all testified before this Commission.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. We are presenting testimony on behalf of the Georgia Public Service Commission's ("GPSC" or "Commission") Public Interest Advocacy Staff ("Staff").

Q. PLEASE OUTLINE THE ROLES STAFF AND ITS CONSULTANTS PLAYED IN THIS PROCEEDING.

A. The primary focus of this panel has been to address Georgia Power Company's ("Georgia Power" or "Company") supply-side capacity requests. Staff and its other consultants evaluated Georgia Power's Distributed Energy Resource ("DER") tariff proposal and Demand Side Management ("DSM") program modification requests. Daymark evaluated Georgia Power's proposed load forecast and transmission load flow analyses, Grid Strategies considered the Company's transmission requests along with the need to integrate renewable resources, and Larkin Associates evaluated the Company's financial regulatory requests.

II. FINDINGS AND RECOMMENDATIONS

Q. WHAT ARE GEORGIA POWER'S SPECIFIC REQUESTS IN THIS PROCEEDING?

A. Georgia Power's requests are presented in the Summary Section of the 2023 IRP Update Main Document, beginning at page 28 and are repeated here. The specific items that this panel addresses are shown in **bold** text.

1. ***Authorization to procure the supply-side resources described in items 2-6 and 9 below in accordance with Commission Rules through the exceptions to the Commission's RFP process set forth in Commission Rules 515-3-4-.04(3)(f)(3), 515-3-4-.04(3)(f)(6), and 515-3-4-.04(3)(f)(7).***

2. ***A certificate of public convenience and necessity for the PPA Between Georgia Power Company and Mississippi Power Company as described in Attachment A and the Technical Appendix.***

    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of the wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, including an executed system sale to a regional electrical service provider during that time, for recovery in the next base rate case.

3. ***A certificate of public convenience and necessity for the PPA Between Georgia Power Company and Santa Rosa Energy Center LLC as described in Attachment B and the Technical Appendix.***

    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of any wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, for recovery in the next base rate case.

4. ***Authority to develop, own, and operate up to 1,000 MW of BESS at various sites as described in this IRP Update and the Technical Appendix.***

   a. *Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.*

5. ***Authority to develop, own, and operate up to 1,400 MW from three simple cycle CT resources at Plant Yates as described in this IRP Update and the Technical Appendix.***

   a. *Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.*

6. *Approval of two new customer-sited DER programs as described in this IRP Update.*

7. *Approval of one new tariff-based demand response program as described in this IRP Update.*

8. *Approval of an amended certificate for one existing demand response DSM program as described in this IRP Update and Attachment C.*

9. ***Approval of the Flex Capacity framework as described in the Flex Capacity section.***

   a. *Regulatory asset treatment to defer any developmental costs for such activities that would otherwise be expensed for recovery in the next base rate case.*

10. *Expansion of the transmission system to accommodate the above-requested resources and the Company's Load and Energy Forecast as described in the Technical Appendix.*

Q. PLEASE SUMMARIZE THIS PANEL'S FINDINGS AND RECOMMENDATIONS.

A. Our findings and recommendations are:

1. Based on Staff's load forecast and Target Reserve Margin ("TRM") assumptions, Staff agrees there is a need for additional capacity, beginning in 2027 and subsequent years to meet winter peak demands.[1] Staff recommends approval of the Mississippi Power Company ("MPC") Power Purchase Agreement ("PPA") and the Santa Rosa PPA to mitigate reliability risk, as these resources are the only ones currently in operation certain to be available at the time of the 2027 winter peak period.

2. Staff's Proposed Plan recommends approval of the MPC and Santa Rosa PPAs, which results in the Company's next need date for additional capacity occurring in 2029.

3. Staff recommends the Commission direct the Company to expedite its currently ongoing Request For Proposals ("RFPs"), the 2029-2031 All-Source RFP and the 500 MW Energy Storage System ("ESS") RFP, to provide for competitive procurement of additional resources to meet the need in 2029 but expand the start date of resource selection to begin as early as 2027. Staff believes that by accelerating the ongoing competitive processes, the Company and Commission could assess the economic merit of all proposed resources, and all start dates in the widened time band.

4. Staff recommends that the Commission deny the Company's request for certification of the Yates Combustion Turbine ("CT") Units 8, 9, and 10. The Yates capacity is not required until 2029 and should be bid into the 2029 – 2031 capacity RFP to determine whether this capacity is least-cost and the most reliable compared to other options.

5. Staff recommends the Commission deny the Company's request for approval of the proposed Moody and Robins BESS projects, and the Co-located BESS/Solar resources. This capacity is not needed until 2029 and these resources should be bid into the 2029 – 2031 All-Source capacity RFP and/or the 500 MW ESS RFP to determine whether these resources are least-cost and the most reliable compared to other options.[2]

[1] The 2027 winter peak includes possible peak demands in December 2026.
[2] The Company's Request For Information ("RFI") provided with the Supplemental Filing provides evidence of the availability of BESS PPA resources at potentially lower cost than the Company's proposed self-build options.

6. Staff recommends the Commission not give blanket approval for 1,000 MW of Company developed BESS capacity at this time. Staff recommends that new BESS resources be selected based on a competitive procurement process, such as the 2029 - 2031 All-Source capacity RFP or the 500 MW ESS as approved in the 2022 IRP.

7. Staff recommends the Commission deny the Company's request for approval of the Flex Capacity Framework, which could authorize the Company to develop even more capacity without going through a competitive solicitation process. This capacity is not needed until 2029 and should be bid into the 2029 – 2031 capacity RFP and/or the 500 MW ESS RFP to determine whether the capacity is a least-cost option.

8. Staff's independent Aurora Resource Mix Study tested the validity of the Company's proposed resource additions. The results indicate that the proposed Company-owned BESS, BESS plus Solar, and CT projects are not economic in 2027 and would not be selected as part of an optimal mix study, given the availability of lower cost generic resource alternatives. This supports Staff's recommendation that Company-owned resources should be evaluated in a competitive RFP process.

9. In the 2022 IRP (Docket No. 44160), the Company proposed a 26% System winter TRM while Staff proposed 24.5%. The Commission postponed a decision on the TRM to a later time when new resources would actually have to be acquired, though the Commission stated that no party would be foreclosed from presenting arguments for a TRM in a future IRP. Staff used a 24.5% TRM for this IRP.

10. Staff recommends the Company perform a new TRM study in the 2025 IRP that incorporates the Load Realization Model ("LRM") impacts as an evaluated variable along with other variables already modeled by the Company (weather, load forecast error, and outages).

11. Staff finds that the Company's notice of the 70% rule for owned capacity should not be considered as part of the rationale for acquiring Company-owned resources in this proceeding. The 70% rule should be evaluated separately outside of the context of this "extraordinary" load growth dominated IRP proceeding to consider impacts on ratepayers.

12. The Company provided an Economic Analysis of Capacity Resource Study ("Economic Analysis Study")[3] to support approval of its proposed contracts and resource additions. Staff finds the Company's study was deficient due to the Company's overstated load forecast, failure to consider PPA options, use of outdated fuel and carbon tax forecasts, and other problems.

13. In the event the Commission does not accept all the Staff recommendations, and determines more capacity is required earlier, Staff presents a ranking of the proposed Company-owned resources to guide the selection of approved resources. However, Staff continues to believe a competitive procurement process such as an RFP, is the best means to rank and evaluate the Company's proposals against market alternatives.

14. Given the significant impact new large customers loads could have on other customer classes, Staff recommends the Company file a Cost of Service Study in rebuttal testimony consistent with the Company's requests in this 2023 IRP Update to quantify the rate impacts on all customer classes. Furthermore, the Company should be required to file a Cost of Service Study with its 2025 IRP filing to demonstrate potential rate impacts considering all costs on all customer classes consistent with the Company's proposed 2025 IRP plan.

Q. WHAT LED THE COMPANY TO FILE ITS 2023 IRP UPDATE?

A. Georgia Power states that since the 2022 IRP was approved by the Commission in its Order issued on July 29, 2022, Georgia has experienced "extraordinary growth [that] requires Georgia Power develop new supply- and demand-side capacity resources to meet substantial increases in customer demand and energy needs of our state."[4] The Company believes it will require quick action on the part of the Commission to enable Georgia Power to serve these new large customer loads when they are ready for operation.

[3] Technical Appendix, Section 9.
[4] Direct Testimony of Jeffrey Grubb, Francisco Valle, Lee Evans, and Michael Bush, Docket No. 55375, December 4, 2023, ("Georgia Power Direct Testimony"), p. 6, l. 5.

According to the Company, the dramatic increase in load accelerates the Company's need for capacity resources. At the time of the 2022 IRP, the Company projected it would have a capacity need in the winter of 2028/2029, but now the Company is projecting that it will have a capacity need three years earlier, in the winter of 2025/2026. Georgia Power has identified resources to satisfy the earlier capacity need. Georgia Power is required to conduct an RFP process; however, the Company is seeking an exception to that requirement pursuant to the Commission's IRP Rules 515-3-4-.04(3)(f)(3), (6) and (7). Rule 515-3-4-.06(5) requires an amended IRP be filed when Georgia Power anticipates acquiring a resource that will be excepted from an RFP process, which is the subject of this proceeding.

Q. WHAT IS STAFF'S UNDERSTANDING OF THE EVENTS THAT HAVE OCCURRED RELATED TO THE SIGNIFICANT GROWTH IN THE LOAD?

A. The following timeline provides Staff's understanding of the events that occurred around the time the Company became aware there would be significant growth in large customer loads:

- ***January 31, 2022*** – Georgia Power filed the 2022 IRP.
- ***March 2022*** – By the end of March 2022, Georgia Power knew that [redacted] of large customer loads had selected to be served by Georgia Power.[5]

[5] STF-JKA-4-9 Attachment.xlsx

- ***July 29, 2022*** – The 2022 IRP was approved, and the Company was ordered to conduct an All-Source RFP for winter of 2029-2031 resource needs.
- ***December 2022*** – By the end of December 2022, Georgia Power knew that an additional [redacted] MW of Economic Development Load had been selected to be served by Georgia Power.[6]
- ***March 2, 2023*** – Staff reached out to Georgia Power for an update on when the All-Source RFP would be issued. On March 29, 2023, the Company communicated to Staff it would provide an update no later than June 2023 of its plans, including its proposed RFP schedule to meet winter 2029 – 2031 needs.
- ***June 27, 2023*** – Georgia Power met with Staff and discussed the All-Source RFP and load forecast increase, which led to an earlier capacity need year. Georgia Power first notified Staff of the large increase in customer choice load at this meeting.
- ***July 10, 2023*** – Georgia Power met with Staff and continued All-Source RFP and load forecast discussions with Staff.
- ***August 2, 2023*** – Georgia Power met with Staff to discuss the Company's plans and schedule for the of upcoming 2023 IRP Update and continue discussions regarding the 2029-2031 All-Source RFP. On August 22, 2023, Staff proposed to the Company a schedule for the 2029 – 2031 All-Source RFP that would expedite the RFP and expand the time period when capacity could be acquired to cover December 1, 2025 to the end of 2031.
- ***September 12, 2023*** – Georgia Power met with Staff to discuss final capacity needs that would be addressed in the 2023 IRP, and continued discussions regarding the 2029-2031 All-Source RFP. Staff continued to advocate for the 2029-2031 All Source Capacity RFP to be expedited and expanded to 2027-2031.
- ***October 27, 2023*** – Georgia Power filed the 2023 IRP Update.

Q. HOW DID THE TIMELINE ABOVE IMPACT THE COMPANY'S REQUEST IN THIS PROCEEDING?

[6] *Id*.

A. The Company was aware of an increase in new load in the first half of 2022 and won significantly more load in the second half of 2022. Given the large increase in load in 2022, the Company should have started the capacity RFPs approved by the Commission in the 2022 IRP Order earlier such as in January 2023 rather than December 2023. An earlier start of the RFPs would have provided an opportunity to test the Company's self-build generation proposed in this filing against the market and could have resulted in market proposals for the Commission's consideration in the 2025 IRP.

Q. IS GEORGIA POWER REQUIRED TO FILE AN AMENDED IRP WITH THE SAME AMOUNT OF DETAIL AS IS REQUIRED IN A FULL IRP?

A. No, as the Commission's Procedural and Scheduling Order ("PSO") states, "Commission Rule 515-3-4-.06(6) provides that the Commission may limit the scope of issues it will consider in the review of subsequent plans to those issues directly related to material changes."[7]

III. RESOURCE NEED AND RFP TIMELINE

Load Forecast and Need Date

Q. HOW DID THE COMPANY'S LOAD FORECAST CHANGE BETWEEN THE 2022 IRP AND THE 2023 IRP UPDATE?

[7] Georgia Public Service Commission Procedural and Scheduling Order, Docket No. 55378, November 21, 2023, p. 5.

A. The Company's latest load forecast is significantly higher than what the Company forecast in the 2022 IRP, as seen in the following table.

Table 1: Company Winter Peak Forecast Comparison
2022 IRP vs 2023 IRP Update

MW	2024	2025	2026	2027	2028	2029	2030
2022 IRP	15,581	15,636	15,657	15,674	15,659	15,760	15,799
2023 IRP Update P95	15,283	15,947	17,256	18,928	19,751	20,551	21,326
Delta	-298	311	1,599	3,254	4,092	4,791	5,527

Q. WHAT CAPACITY NEED HAS THE COMPANY IDENTIFIED IN THE 2023 IRP UPDATE?

A. The following table presents the Company's load, total capacity resources, and capacity need that the Company identified in the 2023 IRP Update (without new proposed resources). The Company developed a new probabilistic model to evaluate the likelihood of new economic development load being added to Georgia Power's system. As discussed in more detail by the Daymark Panel, the Company's forecast, including new large customer loads, is referred to as the P95 forecast, which essentially assumes that with respect to the new large customer loads, there is only a 5% chance that the load could possibly exceed the identified forecast. In the 2022 IRP, the Company determined that its need for additional capacity would not occur until 2029, while in this 2023 IRP Update, the Company has determined that its need for additional capacity resources has

advanced by three years to 2026, as seen in the following table.[8]

Table 2: Georgia Power's Load and Resource Balance without Proposed Resources [9]

Year	Peak Demand (MW)	Total Capacity (MW)	Capacity Required to Meet GPC Target (MW)	GPC Reserve Margin (%)
2024	15,283	19,980	(964)	30.7%
2025	15,947	21,196	(1,352)	32.9%
2026	17,256	21,296	175	23.4%
2027	18,928	21,785	1,875	15.1%
2028	19,751	22,088	2,601	11.8%
2029	20,551	20,882	4,807	1.6%
2030	21,326	20,885	5,774	-2.1%
2031	21,880	18,864	8,487	-13.8%
2032	22,141	18,901	8,776	-14.6%
2033	22,353	18,883	9,059	-15.5%
2034	22,515	18,917	9,228	-16.0%
2035	22,630	16,948	11,340	-25.1%

The "Total Capacity" column contains all Georgia Power firm capacity resources, including PPAs with third parties and Demand Side Options ("DSO"), and accounts for certain resources on an equivalent capacity basis.

Q. WHAT EVALUATION HAS STAFF PERFORMED OF THE COMPANY'S LOAD FORECAST?

[8] In Table 2, positive values for the line – "Capacity Required to Meet GPC Target" means the Company has a capacity need.
[9] Based on STF-JKA-2-2 Supplemental Attachment B.xlsx without proposed resources.

A. Daymark evaluated Georgia Power's load forecast, and derived Staff's load forecasts which were used by this panel to develop Staff's recommendations regarding acquiring additional capacity. The two forecasts this panel relied on are referred to as the "Uniform w/ Delays P95" forecast and the "Uniform w/ Delays P80" forecast. Many utilities provide a range of forecasts that are independent of fuel and carbon assumptions. Consistent with this notion, Staff's Uniform w/ Delay's P95 case is Staff's "base" case forecast, and Staff's Uniform w Delay's P80 is Staff's "low" forecast, while the Company's P95 scenario reflects a "high" sensitivity case.

Staff's adoption of the "Uniform w/Delays P95" load forecast is described by the Daymark panel, and is supported by the Company's broad definition of "won" loads. The great majority of the "won" loads / customers have not signed anything more than a "Request For Service" agreement, which obligates the customers to take service from Georgia Power if they decide to construct and operate the new facility. Very few of the "won" load customers have signed more formal Contract for Electric Service, Customer Baseline Load Agreement and Meter Totalization Term and Condition agreements with Georgia Power. This absence of signed formal and binding agreements between "won"

load customers and Georgia Power supports Daymark's forecast of slower growth in load.[10]

Q. DOES STAFF AGREE THAT THE COMPANY HAS A NEED FOR NEW CAPACITY RESOURCES BY THE WINTER OF 2025/2026?[11]

A. No. The Company's assertion is that based on its load forecast, it will have a need for additional capacity resources to meet the winter of 2025/2026 peak demand forecast, which is three years earlier than the need date the Company identified in the 2022 IRP. Staff agrees that the Company will have an earlier need date for additional capacity resources than what was identified in the 2022 IRP; however, Staff has found that based on its revised load forecast, the Company's need date may advance by two years, not three. Based on this analysis, Staff has found that only some of the resources the Company has identified will be required, specifically the MPC and Santa Rosa PPAs. The remainder of the resources the Company has identified can be postponed, and if they are found to be economic in a competitive solicitation process, they could be acquired later.

Q. HAS STAFF DEVELOPED ALTERNATIVE LOAD AND RESOURCE TABLES?

A. Yes, Exhibit NHW-4 provides an alternative view of the Company's Load and Resource

[10] See STF-JKA-4-7 and STF-DEA-4-7.
[11] Note, while Georgia Power has a need for resources in Jan 2026 to meet its TRM requirement, the System is actually long on resources 2026, and the first year the System has a need for resources is 2027.

tables, and Staff's Proposed Plan reflects the load forecast and other alternative assumptions Staff has identified, including a revised TRM, alternative assumptions for existing resources, and Staff's recommendation for resources that the Company could acquire to satisfy its resource needs.

In addition to these differences in loads and resources, Staff Witness Kaduk also evaluated the Company's request for additional demand side tariffs (DCL, DCO, CL). Staff's forecast in Exhibit NHW-4 has assumed that the new and amended demand response programs, and the two new customer-sited distributed energy resource ("DER") programs, will provide only a minimal amount of capacity. Nevertheless, Staff believes demand response and DER programs could play a greater role in meeting the Company's resource needs. It is conceivable that the Residential TempCheck program capacity could double and that the Clean and Renewable Energy Subscription ("CARES") RFP could identify hundreds of MW of capacity in the form of 2-hour BESS collocated with solar.[12]

Q. EXHIBIT NHW-4 CONTAINS THREE DIFFERENT TABLES, PLEASE DESCRIBE THE DIFFERENCES BETWEEN THEM.

A. Table A contains Staff's view of the Company's load and resource balance table without new resources based on Staff's assumptions for load, TRM, and other changes, which shows that the Company has a small need for resources of 143 MW in 2027. Table B

[12] See STF-PIA 9-14

contains Staff's Proposed Plan, which accounts for future capacity in the pipeline (RFP renewable and BESS capacity and the possibility to extend Scherer and Gaston) as well as Staff's recommendation for approval of only the MPC and Santa Rosa PPAs. According to Staff's Proposed Plan, after acquiring MPC and Santa Rosa, the Company's next need for capacity moves to 2029 (winter 2028/2029), which will allow time for RFPs to be conducted and resources identified based on competitive procurement processes. This also assumes the Company's 2022 IRP procurements (2029 – 2031 All-Source, ESS and Renewable RFPs) would be issued and identify the Company's future capacity resources.

Table C contains an illustrative case (not part of Staff's Proposed Plan) that Staff performed assuming a P80 load forecast and selection of the MPC PPA resource only, which will be described in further detail in the Staff Ranking Analysis section below (Section V).

Reserve Margin

Q. IN THE 2022 IRP, STAFF TOOK ISSUE WITH THE COMPANY'S TRM. PLEASE SUMMARIZE STAFF'S FINDINGS AND RECOMMENDATIONS

FROM THAT IRP.[13]

A. Staff summarized its findings in testimony it filed in the 2022 IRP as follows:

- The Company recommended dual Southern Company System Planning Target Reserve Margins ("TRM") of 16.25% for the summer and 26% for the winter. Even though the Southern Company system is summer peaking, the higher winter TRM provided more than sufficient reliability to meet a 16.25% Summer TRM.

- The Staff's analysis of the Company's Reserve Margin Study found the Company's study overstated the optimal winter TRM. Staff determined that a Long-Term winter TRM of 24.5% would provide capacity sufficient to meet the Company's proposed reliability standard[14] thereby providing the same level of reliability as proposed by the Company. The Staff did not object to continuation of a 16.25% summer Long-Term TRM, as proposed by the Company.

- The Staff also accepted the Company's recommendation to reduce Short-Term winter and summer TRMs by 0.5% as compared to the Long-Term TRMs. This results in a Short-Term winter TRM of 24% and a summer TRM of 15.75%.

Q. DID THE COMMISSION APPROVE STAFF OR THE COMPANY'S TRM RECOMMENDATION IN THE 2022 IRP PROCEEDING?

A. The Commission did not reach a conclusion regarding either of the TRMs in the 2022 IRP. The Stipulation in Docket No. 44160 left this issue up to the Commission to decide at a later time, as explained in the following discussion from the Commission Order:

> There is no requirement for the Commission to act upon the winter TRM request at this time. The Company may propose resource additions in the

[13] Georgia Power discussed its reserve margin study in the 2022 IRP in the report entitled, "An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System," Docket No. 44160, January 2022.

[14] A Value at Risk level ("VaR") of 80%

> next IRP, if needed, to meet winter TRM, and the Commission can determine at that time the appropriate winter TRM and whether such additional capacity is needed. Use of the 26% winter TRM for planning purposes is not an endorsement by the Stipulating Parties of that TRM, and no Stipulating Party is foreclosed from proposing an alternative winter TRM in a future case.[15]

Q. PLEASE EXPLAIN WHY STAFF AND THE COMPANY DISAGREED ON WHICH TRM TO USE.

A. As mentioned above, in the 2022 IRP, Staff contended the Company's 26% winter TRM was overstated and should have only been 24.5%. Staff determined that the overstatement was attributed to the Company's unreasonable derivation of a load forecast error ("LFE") distribution table that was used in the Strategic Energy and Risk Valuation Model ("SERVM") reliability analysis that the Company performed. The LFE distribution table was derived from 18 years of system energy forecasts that were compared to actual weather normalized energy requirement results in the fourth year of the forecast. Because the actual load forecast errors over the past 18 years showed the Company had consistently over-forecast load, the Company elected not to use the actual data to develop its SERVM LFE distribution table. Instead, the Company made an ad-hoc adjustment, in which it subtracted the median percentage forecast error from the actual forecast error each year. Staff found this to be inconsistent with any statistical modeling practice.

[15] Commission Order in Georgia Power's 2022 IRP, Docket No. 44160, July 29, 2022, par. 16, p. 17.

Q. WHAT CORRECTION DID STAFF MAKE TO THE COMPANY'S TRM ANALYSIS?

A. Staff did not have access to the Company's SERVM Model, but was able to make an adjustment that approximated the analysis that could have been performed with SERVM. Since there were no over-forecasted errors, just under-forecasted errors in the past 18 years, Staff applied a "0" probability to the over-forecast scenarios associated with the SERVM results and was able to derive recalculated SERVM results.

Q. HOW DID THE COMPANY RESPOND TO STAFF'S ADJUSTMENT RECOMMENDATION?

A. Georgia Power responded in Rebuttal Testimony that the Company had only over-forecasted peak demand in recent years, which does not mean it would over-forecast its load in future years.[16] The Company also asserted that it would be inappropriate and unwise to only consider over-forecast situations for future load. There are a few problems with the Company's Rebuttal Testimony. The Company did not address the criticism and flaws Staff found with its modeling approach. It is indisputable that the Company made an ad-hoc adjustment, and it had no basis for subtracting the median percentage forecast error from the actual forecast error each year. That was a manufactured calculation to

[16] Direct Testimony of Jeffrey Grubb, A. Wilson Mallard, Michael Robinson, and Jeffrey Weathers, Docket No. 44160, May 6, 2022, p. 6, l. 23.

achieve the LFE distribution the Company desired without basing the results on any historical evidence. Furthermore, the Company's statement that it had only over-forecasted peak demand in recent years was inaccurate as the Company has over-forecasted its weather normalized load every year for the past 18 years. It is appropriate to require the Company to derive the TRM based on a reasonable analysis that considers facts and historical evidence, not based on a made up calculation that the Company cannot support.

Q. WHAT IS STAFF'S RESERVE MARGIN RECOMMENDATION?

A. Staff continues to recommend that the Company use the corrected value of 24.50% as the System long-term winter TRM. This is particularly important, given the Company's election to use the P95 LRM forecast for the large customer loads, which implies there is just a small chance it has under-forecast its load (5%).

Additionally, Staff recommends that in the 2025 IRP, when the Company updates its TRM study, it should incorporate an additional risk variable in its SERVM modeling to address the uncertainty associated with materialization of new large customer loads, which would be in addition to the other uncertainty variables the Company is already modeling, including weather, load forecasting error, and outages.

Q. HOW DOES GEORGIA POWER USE THE TRM RESULTS IN ADDRESSING ITS CAPACITY NEEDS?

A. Southern Company Services, on behalf of Georgia Power, performs long-term resource planning studies for the Southern Company System to identify the optimal mix of resources that satisfy the System's TRM. However, resources have to be allocated to each operating company, and that is done by considering each operating companies' needs, which requires the derivation of operating company TRMs. Operating Company TRMs differ from the System TRM based on the difference that exists between the hour when the Company's peak load occurs, and when the System's peak load occurs. This is reflected as diversity factor in calculating TRMs.

Q. BASED ON STAFF'S RECOMMENDED 24.50% SYSTEM TRM, WHAT DOES STAFF RECOMMEND BE USED FOR GEORGIA POWER'S TRM?

A. For purposes of this updated IRP, Staff used the same approach Georgia Power used to translate the System TRM into Georgia Power's TRM. This approach considers historic peak load data to derive diversity factors between the System peak load and each operating company's peak load. Based on Staff's System TRM of 24.50%, Staff determined Georgia Power TRM should be 23.52%. The following table compares the Company's derivation of its System and Georgia Power TRMs to the values Staff derived after correcting the Company's SERVM modeling error.

Table 3: 2022 IRP Target Reserve Margin

	GPC Assumptions (%)	Staff Assumptions (%)
Southern System TRM	26.00	24.50
Georgia Power TRM	25.00	23.52

Staff points out that the Company normally derives peak load diversity factors using historical load data.[17] However, on a forward looking basis, historical trends may no longer continue, given that the Company's new load growth projection may outpace the load growth other Operating Companies experience, and may result in peak load diversity being reduced between Georgia Power and the System. This dynamic should be evaluated further by the Company in the 2025 IRP.

Q. HAS STAFF IDENTIFIED ANY OTHER ADJUSTMENTS IT RECOMMENDS BE USED IN THIS IRP TO THE COMPANY'S STARTING POSITION?

A. Yes. Table A of Exhibit STF-NHW-4 contains Staff's load and resource balance table before any additional new resources are added, and Staff includes two additional items that were not included in the Company's load and resource balance table. Staff's table accounts for capacity uprates associated with the in-progress Hydro Modernization

[17] See STF-JKA-6-1 and STF-JKA-7-4

projects (31 MW starting in 2027),[18] and includes the Mossy Branch battery energy storage resource beginning in the second quarter of 2024, when it comes online (62 MW in 2025-2026).[19] As Mossy Branch was proposed as a demonstration project, the Company did not consider Mossy Branch to be a firm resource in its load and resource balance table on its In-Service date, and instead assumed it would become a firm resource beginning the winter of 2027/2028. Staff disagrees and believes the Company should allow it to provide "real-world operating experience,"[20] and use it to serve load during peak load conditions once it is online this summer, and therefore Staff included it in its load and resource balance table beginning in the second quarter of 2024.

Q. IN DERIVING STAFF'S PROPOSED PLAN, DID STAFF CONSIDER THE INCLUSION OF ANY OTHER RESOURCES THAN THOSE THAT THE COMPANY CONSIDERED IN THIS PROCEEDING?

A. Yes. In addition to the resources the Company evaluated, Staff also considered the possibility of extending the Gaston and Scherer 3 units, which the Company is currently planning to retire by the end of 2028.[21] Staff also accounted for the Company's approved RFPs for renewable and energy storage resources. Additionally, though no capacity value

[18] See STF-PIA Set 6 responses. The Hydro Modernization project investments were approved in both the 2019 and 2022 IRPs.
[19] Company response to JKA 5-5.
[20] Direct Testimony of Jeffrey Grubb, Narin Smith, Michael Bush, and Jeffrey Weathers, Docket No. 42310, March 14, 2019, p. 52, l. 23.
[21] STF-JKA 2-8

has been assigned, Staff's case also provides a placeholder for additional demand response capacity that could help serve some of the additional load, as plans for those resources are evolving. Staff developed its Proposed Plan based on these resource considerations, which appears in Table B of Exhibit NHW-4.

Q. DOES THE USE OF STAFF'S ASSUMPTIONS NEGATE GEORGIA POWER'S NEED FOR NEW CAPACITY RESOURCES?

A. No. Table 4 compares the 2026-2029 capacity shortfall based on the Staff and Company load forecasts at assumed TRM levels. The table also shows the impact on the additional capacity need, assuming Staff's load forecast and TRM, with the addition of the MPC and Santa Rosa PPA's. With Staff's load forecast and TRM assumption, and the inclusion of MPC and Santa Rosa, Georgia Power's next need for capacity is pushed out to 2029. Additional load and resource balance details for the period of 2024 – 2035 are provided in Exhibit NHW-4. It is important to realize, even using the Company's TRM, not Staff's TRM, but still using Staff's load forecast and proposal to acquire MPC and Santa Rosa, the Company's next need for capacity remains pushed out to 2029.

Table 4: Georgia Power Additional Capacity Resource Need (MW)

Cases	2026	2027	2028	2029
Georgia Power - P95 Load Forecast, 26% TRM (GPC assumptions)	175	1,875	2,601	4,807
Staff - P95 Load Forecast + Uniform with Delays, 24.5% TRM (Staff assumptions)		143	793	2,911
Staff Proposed Plan: P95 Load Forecast + Uniform with Delays, 24.5% TRM, addition of MPC and Santa Rosa PPAs [22]				1,173

Request for Proposals (RFP)

Q. DOES STAFF AGREE THAT THE COMPANY NEEDS TO DEVELOP NEW RESOURCES BY THE WINTER OF 2026/2027?

A. Staff agrees the Company will experience significant load growth but disagrees on how quickly all of the resources will be needed. With the addition of the MPC and Santa Rosa PPAs, the Company will not need additional capacity until 2029. This should provide the Company with enough time to conduct an RFP process to obtain resources at prices competitive with the market.

Q. DOES THE COMPANY HAVE TIME TO COMPLETE AN RFP?

A. Yes, the Company could accelerate the RFPs that were approved in the 2022 IRP and allow bidders to offer earlier commencement dates that could satisfy near-term needs.

[22] Staff's Plan, discussed below, also includes Solar and BESS RFP acquisitions, and extends Scherer and Gaston beginning in 2029, which reduces, but does not eliminate, the Company's 2029 capacity need.

This includes the Company's 2029-2031 All-Source RFP and the 500 MW ESS RFP. Staff is disappointed that the Company has not yet issued these RFPs, despite having had ample opportunity and time already to do so. Staff believes the Company could accelerate these RFPs now such that resources could be acquired to meet the Company's needs for new additional resources.

Q. HOW QUICKLY DOES STAFF BELIEVE THE COMPANY COULD CONDUCT AN RFP?

A. Table 5 compares the dates of recent RFPs other utilities have or are conducting (lines 1-6) to proposed schedules from Georgia Power and Staff. (lines 7-10). The other utilities include Santee Cooper,[23] 1803,[24] Kentucky Power Company,[25] AES Indiana,[26] and Entergy Louisiana.[27]

[23] Santee Cooper https://rfpmarketplace.teainc.org/projects/bidder-rfp-view/173,
[24] 1803 https://www.acespower.com/1803ltrfp2019/ and https://www.acespower.com/1803ltrfp2023/
[25] Kentucky Power https://www.kentuckypower.com/business/b2b/energy-rfps/2023-all-source-rfp
[26] AES https://www.aesindiana.com/project-schedule,
[27] Entergy https://spofossil.entergy.com/ENTRFP/SEND/2022ELLRenewablesRFP/Documents/Main%20Body%20-%20Final%20RFP.pdf

Table 5: Comparison of RFP Schedules

	Company	Proposals Due	Delivery Period	Bid Type	Months
1	**Santee Cooper RFP**	3/26/2023	1/1/2024	Market	10
2	**1803 Electric Cooperative**	11/9/2023	1/1/2025	Market	14
3	**Kentucky Power 2023 All-Source RFP**	11/8/2023	5/1/2026	Thermal	30
4			1/1/2027	Storage	38
5	**AES Indiana All-Source RFP**	6/30/2023	6/1/2025	Market	24
6	**2022 ELL Renewables RFP**	8/12/2022	9/30/2025	Market	38
7	**GPC Proposed All Source (6/27/2023)**	[redacted]	[redacted]	[redacted]	[redacted]
8	**Staff Proposed (8/22/2023)**	[redacted]	[redacted]	[redacted]	[redacted]
9	**GPC Proposed All Source (9/12/2023)**	[redacted]	[redacted]	[redacted]	[redacted]
10	**GPC Proposed All Source (Posted)**[28]	6/14/2024	1/1/2029	Market	55

Based on this table, Staff believes the earliest date resources could commence is between 20 and 36 months after bids are due back and evaluation of bids begins. Georgia Power currently has published a schedule for the 2029-2031 All-Source RFP (line 10 above), which indicates that bids are due back on June 14, 2024. Staff believes resources could commence delivery as early as 20 to 36 months later, which would lead to additional resources being available anywhere from the end of January 2026 to the end of May 2027, which is well ahead of a 2029 capacity need.

Another RFP that should be accelerated is the 500 MW RFP for BESS resources, which was approved in the Commission's 2022 IRP Order. The Company has likewise

[28] https://gpc2029-2031all-sourcerfp.accionpower.com/_gpc_2301/calendar.asp

failed to issue that RFP to date, but Staff expects that it will be issued in 2024. Staff witness Kaduk discusses the status of Company's 2023 CARES RFP in his testimony.

IV. GEORGIA POWER'S ECONOMIC STUDIES

Company Studies

Q. WHAT STUDIES DID THE COMPANY PERFORM IN THE 2023 IRP UPDATE?

A. As discussed above, the Company performed the Economic Analysis Study to support its proposed near-term resource acquisitions, and the Resource Mix study to develop an optimal long-term resource plan, considering different uncertainties, including fuel and CO_2.

Q. WHAT OTHER FILINGS IN THIS DOCKET HAS THE COMPANY MADE SINCE THE INITIAL 2023 IRP UPDATE FILING WAS MADE ON OCTOBER 27, 2023?

A. The Company has made a number of supplemental filings since October 27, 2023 to provide additional information supporting its requests, which has challenged Staff's ability to meet a filing deadline of February 15, 2024, including the following:

- 10/27/23 - Initial Filing, Resource Mix Study consisted of the MG0 case only.
- 12/04/23 – Supplemental Filing – Additional Resource Mix Study fuel scenarios provided, and RFI Information shared.
- 12/07/23 – Errata Filing to correct errors in the allocation of new System resources to Georgia Power.
- 01/11/24 – Demand Response Tariffs provided (DCL-1, DCO-1, and CL-1).

- 01/12/24 – Yates CT updated economic analysis reflecting increased costs and additional deliverability information.
- 01/19/24 – Transmission Supplemental Filing to confirm the Santa Rosa and Mississippi Power PPA require no transmission projects and Yates will remain limited to 600 MW until $59.9 million in transmission improvements can be completed.[29]
- 01/31/24 – Certification request for expedited consideration of 1,300 MW of new CT resources to be added at Plant Yates.

Given the 30-day turn-around requirement for discovery, Staff's review of the latest information that the Company has filed has been limited. The timing of the late filed information suggests caution is in order. Staff's proposal provides additional time for these projects to be evaluated. The fact that the Staff has only had two weeks to review the Engineering, Procurement, and Construction ("EPC") contract, with no opportunity to conduct discovery, is further evidence the Yates Certification should be denied.

Economic Analysis Study

Q. WHAT ANALYSIS WAS USED TO ASSESS THE RESOURCES THAT THE COMPANY PROPOSED?

A. The Company's Economic Analysis Study was performed to evaluate the following resources that the Company determined could be acquired quickly to meet the Company's assumed 2026 and 2027 need dates for resources.

[29] Previously Georgia Power assumed the Yates transmission investment would be $79.2 million. The reduction in cost was not accounted for in the Company's updated Yates economic analysis that was filed 1/12/24.

Table 6: Proposed Supply-Side Resources

Resource	Commercial Operation Date ("COD")	Term or Life	Nameplate MW	Winter Equivalence MW
Robins BESS	11/1/2026	20	128	115
Moody BESS	11/1/2026	20	49.5	44.5
MPC PPA	1/1/2024	5	750	750
Santa Rosa PPA	1/1/2024	5	230	230
Yates 8-10 CTs	12/1/2026 [30]	45	1,300	1,070
Co-located BESS + Solar	11/1/2026	20	200	200 [31]

Q. PLEASE DISCUSS GEORGIA POWER'S ECONOMIC ANALYSIS STUDY THAT WAS FILED IN SUPPORT OF THESE RESOURCES.

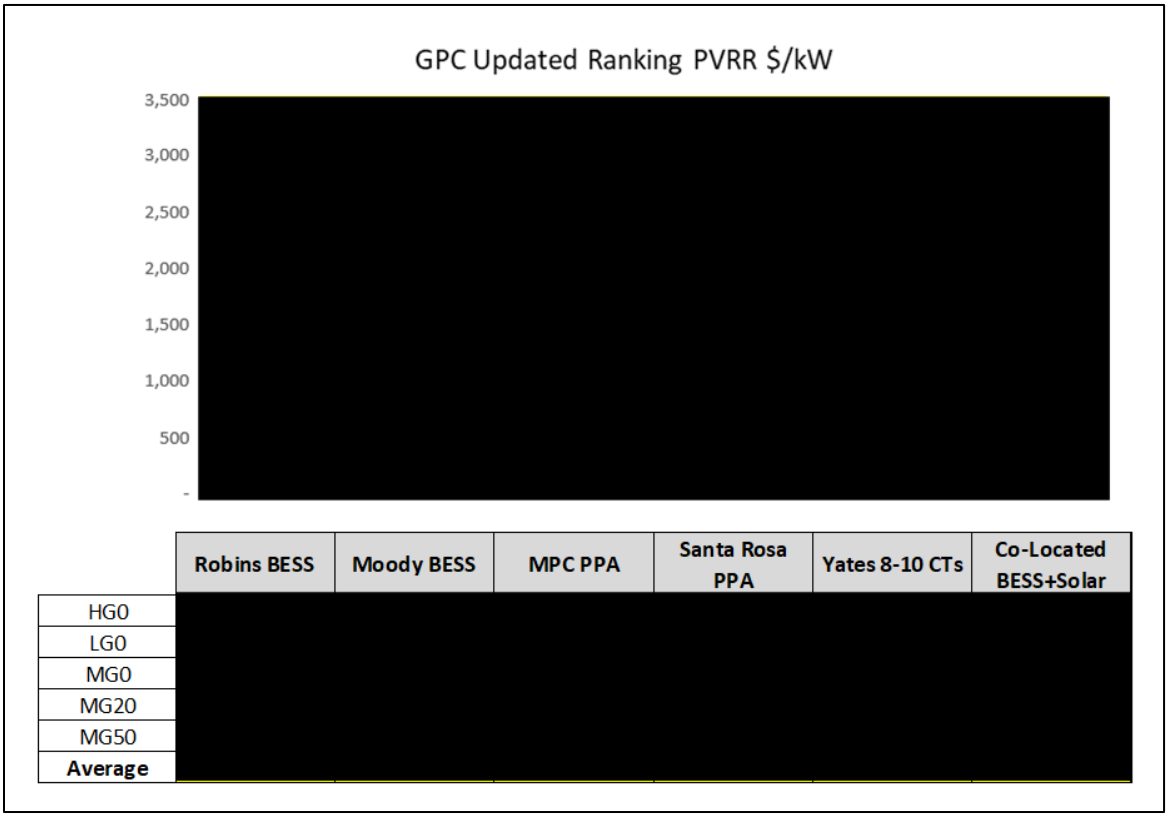
A. Georgia Power's analysis is an Incremental Revenue Requirements ("IRR") analysis. This study compares the annual revenue requirements for the period 2024-2072 for each of the resources under consideration, including the fixed and variable costs net of energy and any other benefits the project may produce. Energy benefits are based on an Aurora run with the evaluation unit operating through the study period. The present value of revenue requirements ("PVRR"), stated on a $/kW basis for each resource, was computed in the analysis. This metric is useful for normalizing the results to compare and rank

[30] Yates 8 providing 357 MW available 12/1/2026 and Yates 9, 10 providing 714 MW in-service 5/1 2027 and 8/1/2027 respectively ahead of the January 2028 Peak. See file: "TS SAM ('23) - 7.0.1 Yates CT 012324 Certification.xlsm," provided in Supplemental Filing January 31, 2024. There is also a limitation of 600 MW at Yates 8-10 until transmission upgrades completed (Summer of 2028).

[31] The Company has assumed a 100% ELCC credit for the co-located projects Solar + BESS projects, which appears inconsistent with the 90% attributed to the new BESS (including Moody and Robins) and 0% attributed to new solar in the mix study.

resources of different sizes and technology choices. Results were provided for each fuel and CO_2 case that the Company modeled. The graph below shows the results of the Company's study based on the Company's fuel and CO_2 cases.[32]

Figure 1: Summary of Georgia Power's Economic Analysis Study Results



[32] The Graph is consistent with the Company's supplemental transmission filing results from January 19, 2024 and certification filing January 31st. The Company failed to supply an analysis using the updated transmission (January 19th) or updated capital costs (Certification Filing on January 31st) and as such the results here reflects staff's adjustment.

In the table above, the five natural gas and CO_2 combinations (LG0, MG0, HG0, MG20, MG50) are included, as well as the average value.

Q. DOES STAFF ENDORSE THE COMPANY'S ECONOMIC ANALYSIS STUDY?

A. No. The study design has shortcomings which limit its usefulness and there are several problems in the execution of the study. At best the study could be useful for choosing between the candidate resources if the Commission determines some of the capacity is not needed. However, the universe of capacity options is limited to these six resources and there is no determination of whether lower cost options exist or even the best mix of the proposed resources.

Q. ARE THERE OTHER CONCERNS REGARDING THE COMPANY'S MODELING APPROACH?

A. Yes. Staff has four other concerns, which relate to dispatch methodology, term equalization, the fact the Company's methodology does not address capacity need issues, and the natural gas and CO_2 emission price forecasts the Company used. Based on these concerns, Staff performed its own economic analysis of the proposed resources, which will be discussed further below in this testimony.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE DISPATCH METHODOLOGY USED IN THE ECONOMIC ANALYSIS STUDY.

A. Staff is concerned the Company studied the proposed resources in the Economic Analysis Study using a simplified avoided cost curve dispatch approach instead of using a

production cost load dispatch approach. The Company's approach did use a production cost dispatch (Aurora), initially, for the purpose of deriving a fixed $/MWh market price curve. However, the market price curve was then fixed and used to dispatch each individual proposed resource the Company is considering to acquire. Since the price curve was fixed before the target resources were considered, and no dynamic impacts were evaluated,[33] the Company's dispatch approach ignored factors such as operating constraints, possible resource curtailments, and the value of resources as resource availability changes. The Company also relied on outdated natural gas and CO_2 price forecasts in its study.

Staff is concerned that the avoided cost methodology is a less accurate way of representing dispatch dynamics and recommends that the conventional load based dispatch approach be used instead. Staff used this alternative approach in its independent analysis discussed below.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE TERM EQUALIZATION ASSUMPTIONS USED IN THE ECONOMIC ANALYSIS STUDY.

[33] Once an avoided cost curve is derived, it is considered fixed because the avoided cost curve does not update as resources are added or removed from the evaluation. In comparison, these dynamic impacts are accounted for when a production cost approach is performed, because resources are dispatched against load and adjust as other resources are added or removed from the evaluation.

A. The Company uses a "Term Equalization" adjustment to address the problem of evaluating resources having different lives, which otherwise would not be considered in the $/kW metric evaluation. The candidate resources are all assumed to be replaced at the end of their contract term or useful life with combustion turbines that have the same capital and operating costs as the Yates Units 8, 9 and 10 Units.

Q. IS THIS THE MOST ACCURATE APPROACH TO EVALUATE RESOURCES THAT HAVE DIFFERENT LIVES?

A. No, a better approach, if this method were to be used, would be to assume the mix of resources should remain constant replacing retiring resources with like capacity (thermal with thermal, storage for storage, solar for solar, combined cycle with combined cycle, etc.), rather than assuming all replacement capacity would be combustion turbine units. However, Staff proposes a different methodology entirely, which relies on an optimization approach, in which resources are optimally selected when resources retire.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE STUDY'S CONSIDERATION OF NEED DATE IN THE ECONOMIC ANALYSIS STUDY.

A. The Company's Economic Analysis Study fails to realistically consider resource capacity need issues. The problem is the Company's evaluation only compares a Net Present Value ("NPV") $/kW metric for each resource and does not consider the impact of the Company having excess capacity. For example, a completely unnecessary, but otherwise low-cost resource, could have a low NPV $/kW value leading to the conclusion that the

resource should be acquired irrespective of whether it is needed. An optimal resource expansion planning model, such as Aurora, considers both cost issues and capacity need issues in identifying the most economic combination of resources.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE STUDY'S USE OF OUTDATED COMMODITY PRICE ASSUMPTIONS IN THE ECONOMIC ANALYSIS STUDY?

A. The Company has prepared its Economic Analysis Study using outdated fuel and carbon tax forecasts. The Company stated:

> *For its long-term fuel price forecasts (natural gas, coal and oil), the Company uses projections provided by the United States Energy Information Administration in its Annual Energy Outlook ("AEO"). For the economic analysis supporting the 2023 IRP Update, the Company used fuel price forecasts from AEO 2022 and for the Resource Mix Study supporting the 2023 IRP Update, the Company used fuel price forecasts from AEO 2023.*[34]

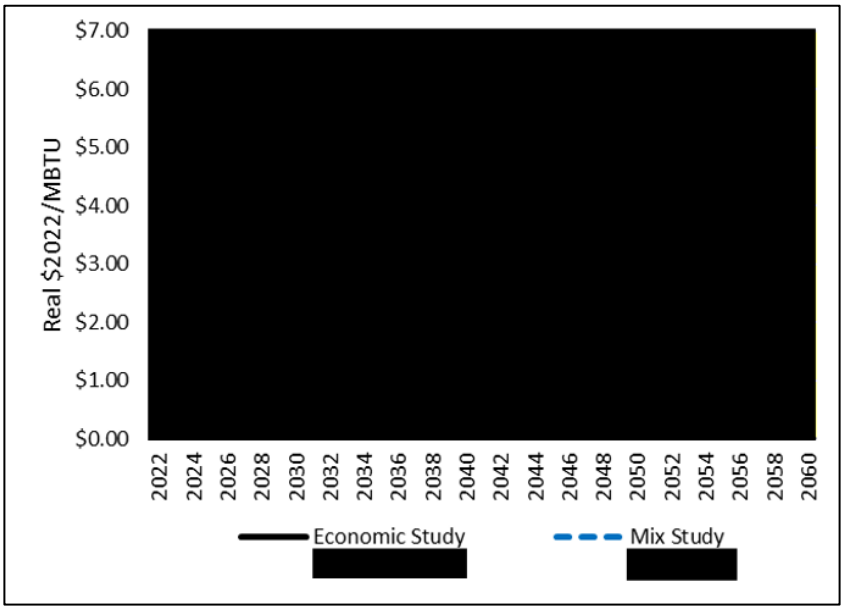
Q. IS THERE A DIFFERENCE BETWEEN THE 2022 AND 2023 AEO FUEL FORECASTS?

A. Yes, the largest differences occur in the early years of the forecasts (2026-2034). The 2022 AEO forecast, used in the Economic Analysis Study, reflects the sudden spike in Natural Gas prices and general inflation that occurred concurrent with preparation of the AEO 2022 report. The 2023 forecast, used in the Resource Mix Study, was prepared

[34] STF-JKA-2-12

more recently and reflects the much lower prices currently prevailing. By 2027 the forecasts are essentially the same, though eventually the 2023 forecast predicts lower gas prices. The figure below illustrates that the natural gas price forecast used in the Economic Analysis Study considered gas resources to be much more expensive to run compared to what they cost to run in the forecast used in the Resource Mix study for the period 2028 to 2038. Further out in time, the two forecasts essentially converge.

Figure 2: Natural Gas Price Forecast Comparison
(Mix Study vs. Economic Analysis)



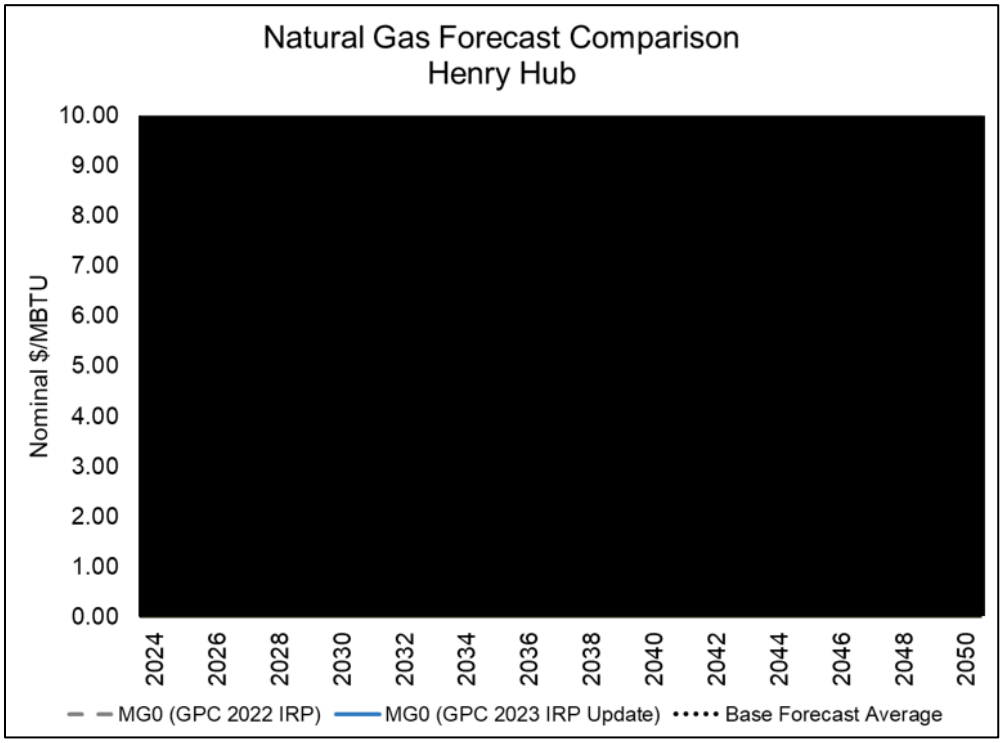
Q. HOW DO THE COMPANY'S GAS PRICE FORECASTS COMPARE TO OTHER PUBLICLY AVAILABLE FORECASTS?

A. The following figure compares the Company's forecasts to a range of other publicly available forecasts, as noted in gray shading,[35] and indicates the Company's forecast is reasonable and within the band consisting of the other publicly available forecasts. In the 2022 Georgia Power IRP natural gas forecast, the Company "adopted and adapted paths produced by the U.S. Energy Information Administration ("EIA") for its 2021 Annual Energy Outlook ("AEO")."[36] The Company also used AEO forecasts for the 2023 IRP Update. In the 2023 IRP Update, for the Economic Analysis, the Company used fuel price forecasts from AEO 2022, and for the Resource Mix Study, the Company used fuel price forecasts from AEO 2023.

[35] Dominion Energy South Carolina 2023 IRP - https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integratedresource-plan.pdf, pg. 49.
GPC 2022 IRP - https://psc.ga.gov/search/facts-document/?documentId=188519, Main Document, pg. 7-38.
EIA AEO2023 - https://www.eia.gov/outlooks/aeo/
Entergy Louisiana 2023 IRP - https://cdn.entergy-louisiana.com/userfiles/content/irp/2023/Combined-Final-Report-05-22-23.pdf, p. 76.
PacifiCorp 2023 - www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integratedresource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_Feb-23-2023, pdf, p. 22.
Santee Cooper 2023 IRP, https://www.santeecooper.com/About/Integrated-Resource-Plan/Reports-and-Materials/Santee-Cooper-2023-Integrated-Resource-Plan_Final-Rev_01.pdf, p. 92.
Duke Energy Carolinas 2023 IRP www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-c-quantitative-analysis.pdf, Appendix C, p. 44.

[36] 2022 IRP Main Document, p. 7-35.

Figure 3: Natural Gas Price Comparison
(2022 IRP vs. 2023 IRP Update)



Q. DO THE CARBON TAX FORECASTS THE COMPANY USED DIFFER BETWEEN THE ECONOMIC ANALYSIS AND THE RESOURCE MIX STUDIES?

A. Yes. In both studies two carbon tax forecasts are modeled, a $20/Ton and a $50/Ton forecast, and they escalate at approximately the same rate.[37] However, the Economic

[37] STF-JKA-2-12 PD

Analysis Study assumes carbon taxes will be in effect beginning in 2025, while the Resource Mix Study assumes carbon taxes will be in effect in 2030, a delay of five years.[38] It is unreasonable to assume in the Economic Analysis Study that carbon taxes would go into effect next year, given there is no pending legislation, and little expectation that legislation will be enacted soon. Even if legislation were enacted soon, typically, this type of legislation would not require an immediate start of the legislation's requirements. It could allow five or more years before the law would begin. Therefore, Staff finds that the Company's Resource Mix Study relied on a more reasonable start date assumption than the CO_2 start date assumption used in the Economic Analysis Study.

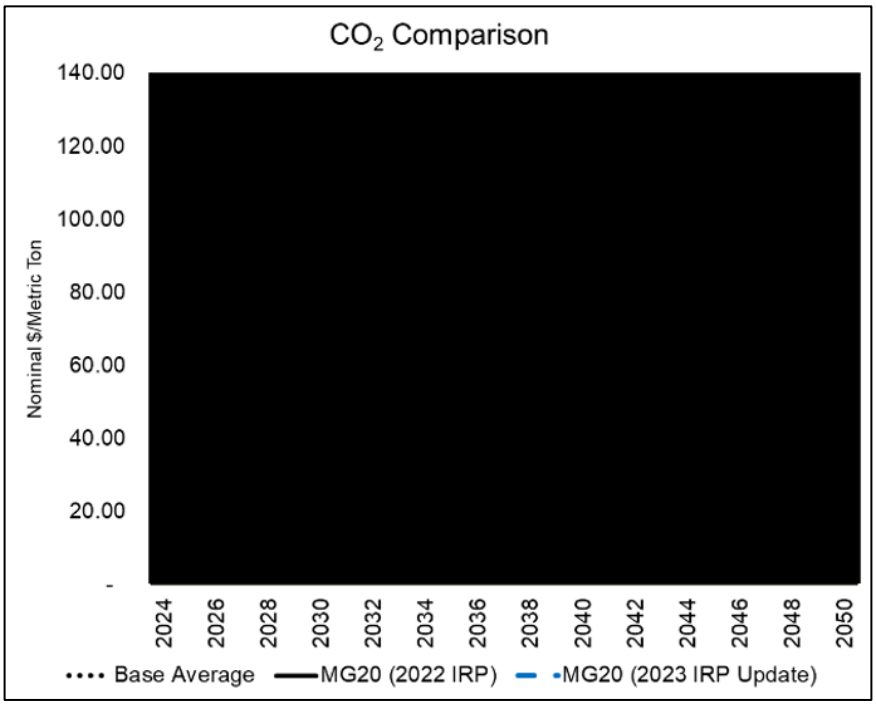
Q. HOW DO THE COMPANY'S CO_2 FORECASTS COMPARE TO OTHER PUBLICLY AVAILABLE CO2 FORECASTS?

A. The following figure compares the Company's Resource Mix Study CO_2 forecast from the 2022 IRP to the Company's Resource Mix Study CO_2 forecast from this IRP, and to a range of other publicly available CO_2 forecasts (in gray shading). The Company's prior forecast appears to be out of date when compared to other publicly available forecasts,

[38] *id* Attachment H, public disclosure.

but the forecast the Company used in the 2023 IRP Update Resource Mix Study appears to be reasonable when compared to other publicly available forecasts.[39]

Figure 4: CO_2 Emissions Price Forecast Comparison (2022 IRP vs. 2023 IRP Update)



[39] Dominion Energy South Carolina 2023 IRP - https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integratedresource-plan.pdf, p. 49.
GPC 2022 IRP - https://psc.ga.gov/search/facts-document/?documentId=188519, Main Document, pp. 7-38.
AVISTA 2023 IRP https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2023-avista-wa-electric-irp-progress-report.pdf pg. 154
Entergy Louisiana 2023 IRP - https://cdn.entergy-louisiana.com/userfiles/content/irp/2023/Combined-Final-Report-05-22-23.pdf, p. 76.
PacifiCorp 2023 IRP - https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integratedresource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_Feb-23-2023, pdf, p.22
Santee Cooper 2023 IRP, https://www.santeecooper.com/About/Integrated-Resource-Plan/Reports-and-Materials/Santee-Cooper-2023-Integrated-Resource-Plan_Final-Rev_01.pdf, p. 92.

Q. WHAT IS STAFF'S POSITION CONCERNING THESE FORECASTS?

A. Staff believes the most up to date fuel and CO_2 forecasts should be used for analyses that utilities conduct. In the case of the CO_2 forecast, it is unreasonable to use a forecast that assumes carbon taxes will go into effect in one year's time. Staff believes the Resource Mix Study assumptions are more realistic to rely on for both natural gas and CO_2 price forecasts.

Request for Information (RFI)

Q. DID THE COMPANY CONSIDER ALL POTENTIAL RESOURCE OPTIONS BEFORE DEVELOPING ITS PLAN TO MEET SHORT-TERM NEEDS?

A. No. The Company had already begun developing projects months ahead of issuing its RFI that was intended to determine if other potential resources could be acquired, and the Company could have issued its RFI well before it did. Ultimately, the Company did not include any potential projects that were identified in its Request for Information ("RFI") process in its economic analysis. The RFI process was initiated in September 2023,[40] and the results were filed in the docket on December 4, 2023, in a Supplemental filing to this IRP, referred to as the "RFI for Capacity Resources – Summary of Results." The Company assumed that these projects would not be available in time to meet the 2027/2028 winter peak, noting:

[40] RFI Summary, December 4, 2023, p. 1.

> As demonstrated by the Company's RFI Summary Report included in Georgia Power's Supplemental Filing made December 4, 2023, there is no indication from the market that there are additional existing resources that can meet the Company's capacity needs in the winter 2025/2026 to winter 2027/2028 timeframe. The RFI results support the Company's resource plan identified in the 2023 IRP Update.

It appears that the Company relied on the RFI to conclude that there were no other resources that it needed to consider; however, the RFI is an incomplete picture of what could be available from the market. Without conducting an RFP, the Company would not be able to know, through the RFI, what other projects, at the same level of development, were or are available.

It also appears the Company only used the RFI to justify its self-build resource options. In fact, the RFI survey was initiated *only after* the Company began negotiations or analysis concerning its proposed capacity resources, which the Company began on the following schedule:[41]

- Co-located Solar/BESS – April 2023
- MPC – July 2023
- Santa Rosa – July 2023
- Moody and Robins – July 2023
- Yates – July 2023.

[41] STF-JKA-2-19 h.

Furthermore, the Company has provided details of other potential projects where a party has a solar PPA with the Company already and at which the Company could potentially co-locate Company-owned BESS resources at the site. The Company states that it may bring these projects to the Commission for approval in 2024 if negotiations with the developers are successful.[42] Given that there is sufficient time to address the Company's resource needs based on Staff's Plan, the Company's projects should be bid into an RFP to be evaluated against other market opportunities.

Q. DID THE COMPANY RECEIVE INDICATIVE PRICING INFORMATION FROM THE RFI RESPONSES?

A. Yes. Even though the Company indicated "the majority of the respondents didn't provide pricing," there was still some useful pricing information available.[43] The Table below shows a summary of the indicative pricing for a selection of projects with expected near-term in-service dates of ESS type resources.

[42] Response to STF-PIA 9-1 identifies additional BESS co-location opportunities [redacted]

[43] Day 1 transcript page 0215 lines 8-13 "I would not totally agree with that assessment. Plus, I would correct that the RFI was not just for the time period in this 2023 IRP update. It was also for the '29 through '31. And the majority of our prices didn't even get -- the majority of the respondents didn't provide pricing."

Table 7: Selected RFI Response Summary

XML ID #	Type	PPA Term	Resource Type	Capacity MW	Proposed Availability	Project Price (BTA/APA)

Q. COULD ANY OF THE RFI PROJECTS COMMENCE OPERATION BY THE COMPANY'S RESOURCE NEED DATE OF 2029?

A. Yes. Based on the Staff load forecast and recommendations (approval of MPC, Santa Rosa, and an accelerated RFP process) the listed projects could be available to meet the 2028/2029 winter peak.

Q. WERE ANY OF THE RFI RESPONSES MORE ECONOMIC THAN THE COMPANY'S PROPOSED PROJECTS?

A. Yes. The table above indicates there may be more economic BESS projects that could be supplied by developers in the market. Staff acknowledges that the RFI responses would

still require additional investigation, contractually obligated bids, and possible transmission costs, but there were RFI responses that appear to be more economic than the Company's proposed resource acquisitions.[44] For example, the RFI indicates developers may be able to develop larger projects, such as 200 MW installations of 4 hour BESS projects for approximately [redacted][45] This can be compared to the Company's proposed Moody (49.5 MW), Robins (128 MW), and Co-located [redacted] (200 MW) BESS projects that are approximately [redacted] respectively, which translate to approximately [redacted] on a $/kW basis.

Furthermore, the Company's Resource Mix Study provides a view of "generic candidate unit" project costs which can be considered a proxy for market-based resources. The source of the generic candidate unit cost information is the detailed Technology Application Standards ("TAS") reference document that Southern Company maintains and updates on behalf of all operating companies, and contains generation technology input assumptions for all resource types that Southern Company monitors in the market. Southern Company updates the information based on its interaction with

[44] In response to STF-JKA-6-6, the Company states it did not evaluate the RFI pricing provided, "the Request for Information ("RFI") conducted was not a Request for Proposals and therefore the submissions were not bids, pricing was not required or provided by all respondents, and no economic or transmission evaluation was performed for the responses provided in the RFI."

[45] [redacted] as provided in the December 4, 2023 Supplemental filing TS Workpapers associated with the Request for Information.

market players and uses this information in studies it performs. Essentially, the costs in the TAS represent the best estimate of what Southern Company believes resources can be constructed for based on market information. The TAS indicates that Southern Company has determined that BESS resources could be constructed for a cost of [redacted], which is again less than the costs of the Company's proposed projects on a $/kW basis.[46]

Finally, in this proceeding, the Company has primarily focused on co-locating BESS resources at solar sites, and while there may be benefits of doing this, there may be other potential sites that batteries could be located that could provide even greater benefits to customers and should be considered.[47]

Revenue Considerations ("Downward Pressure on Rates")

Q. GEORGIA POWER HAS ASSERTED SERVING NEW LARGE CUSTOMER LOADS WOULD PUT "DOWNWARD PRESSURE" ON RATES.[48] IS THAT AN ACCURATE STATEMENT?

A. It may not be accurate for all customers or customer classes. The Company provided a calculation to support its assertion that indicates the revenues from new large customer loads exceed the costs incurred to serve these customers, which would put downward

[46] "TS SAM ('23) - 7.0.1 - BESS 4hr.xlsm" $[redacted] for 300 MW of winter capacity equivalence credit in-service in 2029.
[47] Co-located solar is limited in its summer peak dispatch contribution and there may be additional ITC value captured in other projects.
[48] Testimony of Georgia Power Company, Docket No. 55378, p. 10 and Day 1 Hearing Transcript pp. 0116, 0118, 0122, 0124, 0135-136, 160 and others.

pressure on rates.[49] This calculation is performed at a Company level as though there was only a single customer or customer class and then assumed to apply to residential customers, which may be misleading. However, rates are not set at the Company level but are developed specifically for individual customer classes, and this must be considered when calculating the impact of new large customer loads on the bills and rates of all individual customer classes.

Q. IS THE COMPANY'S CALCULATION THAT SHOWS DOWNWARD PRESSURE ON RATES COMPLETE AND COMPREHENSIVE?

A. No. The analysis only covers three years and should be extended to ten years. There are additional costs such as transmission investment and O&M expenses necessary to serve new large customer loads that should be taken into account in the analysis. Also, the Company's calculation fails to account for increased fuel costs, which may be a significant cost. The calculation also appears to implicitly assume some of the revenue collected from new large customer loads is diverted to the residential customer class. That is not consistent with how rates are developed in a Cost of Service Study.

Q. HOW ARE RATES DEVELOPED FOR INDIVIDUAL CUSTOMER CLASSES?

A. Through a Cost of Service Study that is generally filed by the Company in base rate cases. In a Cost of Service Study, Georgia Power's costs (revenue requirement) are

[49] STF-DEA-3-6 Supplemental Attachment A

allocated across all customer classes and then rates for each customer class are set to collect enough revenue to cover those costs.

Q. COULD SOME CUSTOMER CLASSES HAVE DOWNWARD PRESSURE ON RATES WHILE OTHER CUSTOMER CLASSES HAVE UPWARD PRESSURE ON RATES AS A RESULT OF SERVING NEW LARGE CUSTOMER LOADS?

A. Yes. This depends on how the Company's costs are allocated to individual customer classes in a Cost of Service Study. In the Company's Cost of Service Studies, Company-wide costs are spread to all customer classes. If this same allocation methodology were applied including the new large customer loads and associated costs, then the potential exists that the other customer classes such as residential and small business classes would incur higher costs and upward pressure on rates.

Q. COULD BETTER INFORMATION BE PRODUCED TO ANSWER THE QUESTION CONCERNING "DOWNWARD PRESSURE ON RATES," WHICH COULD BE USED TO MITIGATE THE IMPACT OF SERVING NEW LARGE CUSTOMER LOADS ON RESIDENTIAL AND SMALL BUSINESS CUSTOMERS?

A. Yes, an analysis that addresses the flaws mentioned above could be performed in order to determine whether or not downward pressure on rates will occur for all customer classes. Ultimately the Commission could use this information in the 2025 base rate case to adjust

the Company's Cost of Service Study to mitigate the impact of serving new large customer loads on other customer classes.

Q. WHAT IS STAFF'S RECOMMENDATION TO ADDRESS THIS ISSUE IN THIS IRP?

A. First, given the level of interest in this proceeding in knowing whether serving the new large customer loads will put "downward pressure on rates," the Company should file in rebuttal testimony, a Cost of Service Study that allocates the new costs associated with the Company's proposed resources and the new loads to customer classes based on allocation methodologies consistent with the Company's most recent Cost-of Service Study. By the Company performing this study with the corrections Staff outlined above, the Commission will be able to see impacts with and without the new large customer loads, and will be able to determine clearly how the new large customer loads will impact the individual customer classes.

Second, Staff recommends that when the Company files its next IRP in January 2025, the Company should be required to file an updated Cost of Service Study as outlined above, which should also be consistent with the latest data known at the time of that filing. Filing this information in the 2025 IRP would give Staff time to do a thorough review of the Company's Cost of Service Study and develop its own Cost of Service Study, if necessary, ahead of the next rate case.

Q. WHAT IS STAFF'S CONCLUSION?

A. Staff does not believe the Company has conducted an adequate study to address the question of whether or not the new load will provide upward or downward pressure on rates for all customers. That question has been of paramount interest in this proceeding, and Staff recommends that GPC provide a revised Cost of Service Study in rebuttal testimony and in the next IRP that considers all appropriate costs associated with the new large customer load to determine impacts on each individual customer class.

In addition, because Staff is concerned that individual customer class rates could be impacted as a result of adding significant new customer loads, it is even more critical that the Company be required to identify the least-cost resources to serve that load. Staff continues to recommend that this be ensured by the Company selecting resources through RFP processes.

V. STAFF ANALYSES

Q. HOW DID STAFF ADDRESS ITS CONCERNS WITH THE COMPANY'S ECONOMIC ANALYSIS STUDY?

A. Given the problems inherent in the Company's Economic Analysis Study, Staff decided to perform two analyses using Aurora and modeling data from the Company's Resource Mix Study. The first study was Staff's version of a Resource Mix Study that Staff used to identify which, if any, of the proposed resources should be selected to satisfy short-term needs, and which generic candidate resources should be selected to satisfy long-term needs. The second was a Ranking Analysis that Staff developed to order the Company's

proposed resources from best to worst in the event the Commission prefers that more resources be acquired beyond what Staff recommends. Both of these analyses address the modeling flaws discussed above.

Staff's Resource Mix Study

Q. WHY DID STAFF PERFORM A RESOURCE MIX STUDY?

A. Staff performed its own Resource Mix Study to use Staff's preferred modeling assumptions (primarily load forecast and TRM), to optimally select both short-term and long-term resources, and to address the flaws that Staff identified in the Company's Economic Analysis modeling approach that were discussed above.

Q. PLEASE PROVIDE AN OVERVIEW OF STAFF'S MODELING APPROACH.

A. Staff evaluated the proposed resources, and considered whether all of the proposed resources had to be acquired or whether just some of the proposed resources could be acquired as a bridge, while procurement processes could be performed to acquire other resources more competitively, and potentially save customers money. Staff's analysis traded off the need to add the new proposed resources quickly, against generic candidate units that could be acquired by the 2027/2028 time frame. Staff used the Company's Resource Mix model (Aurora) and data assumptions, such as the generic candidate

resource assumptions.[50] Georgia Power's Resource Mix Study included generic CTs, CCs, BESS and Solar resources.

Staff performed its modeling under base MG0 and sensitivity MG20 scenarios. Staff's study period was 2024 to 2040, which allowed Staff to focus on the near-term impacts of the increased load, and the near-term cost/benefits of the resource selections in 2027, as well as to identify resources for a longer-term period, and to do so with reasonable run times. For purposes of modeling capital costs for the proposed resources in Aurora, Staff computed economic carrying charge ("ECC") cost profiles based on the revenue requirement data that the Company modeled in its Economic Analysis Study.

Q. WHAT ASSUMPTIONS DID STAFF RELY ON FOR NEW RESOURCE OPTIONS?

A. Staff relied on the Company's assumptions for new build resource options as shown below.

[50] The Southern Company developed the generic candidate resource assumptions in the TAS for use in modeling studies such as the Resource Mix Study.

Table 8: Summary of Company Modeled Generic Resources [51]

Resource Name	Short Name	Capacity Equivalence (%)	Build Time (Yr)	Asset Life (Yr) [52]	MG0 Date Available
Combined Cycle	CC	100%	[redacted]	[redacted]	2030
Combined Cycle with Carbon Capture & Sequestration	CCwCCS	100%	[redacted]	[redacted]	2034
Dual Fuel Combustion Turbine with Future Emission Controls	CTwSCR	100%	[redacted]	[redacted]	2027
Reciprocating Internal Combustion Engines	RICE	100%	[redacted]	[redacted]	2029
Solar PV	Solar	0%	[redacted]	[redacted]	2027
Onshore Wind Power	Wind	35% [53]	[redacted]	[redacted]	2032
Battery Energy Storage System (4 hour)	BESS	Declining Tranches	[redacted]	[redacted]	2027
Medium Duration Energy Storage System (12 hour)	MDESS	100%	[redacted]	[redacted]	2034
Nuclear	Nuclear	100%	[redacted]	[redacted]	2035

Staff compared the Company's generic resource cost and operating characteristic assumptions to publicly available data to assess the reasonableness of the Company's assumptions as shown in Exhibit NHW-5. The sources for the publicly available data included the National Renewable Energy Laboratory ("NREL"), Lazard, and information

[51] 2023 IRP Update, Resource Mix Study Report, Table 2: Candidate Technology Assumptions, pg. 14. See also the technology screening analysis information the Company provided in response to STF-JKA-2-16.
[52] CC and CT asset lives have increased from [redacted] assumed in the 2022 IRP.
[53] The ELCC value of Onshore Wind Power resources decreased from 41% assumed in the 2022 IRP.

from a selection of other utilities. Staff also included a comparison to Georgia Power's 2022 IRP assumptions and notes that the Company's assumed build costs have increased, which is consistent with market trends. The Company's latest generic candidate resource cost estimates appear reasonable, though generally they are lower in cost compared to the benchmark datapoints.[54]

Staff also included the Company's proposed BESS, BESS plus Solar resources, Yates, and the proposed Santa Rosa PPA as additional selectable options in the optimization model. Finally, Staff included the possible extension of the Gaston and Scherer units from a planned retirement at the end of 2028 to the end of 2035 as an additional selectable option that Aurora could make.

Q. PLEASE SUMMARIZE THE ASSUMPTIONS STAFF REVISED IN ITS ANALYSIS?

A. The following table compares the input assumptions that Staff used in its analysis compared to what the Company used in its Resource Mix Study:

[54] [redacted]

Table 9: Staff Aurora Study Assumption Summary

Data Assumption	Company Resource Mix Study	Staff Analysis
Study Length	2024-2057	2024-2040
System TRM	26%	24.5%
Load Forecast	Company P95 Forecast	Revised Uniform w/ Delays P95 Forecast
Proposed Resources	Omitted, with exception of MPC PPA in 2027/2028	Selectable in 2026/2027, with presumed acceptance of MPC PPA.[55]
Gaston and Scherer Extensions	Not selectable	Selectable[56]

As discussed above, Staff allowed Aurora to determine whether it would be economic to extend the lives of the Scherer 3 and Gaston 1-4 Units from 2028 to 2035. Staff does not recommend a decision on extending the lives of Scherer 3 and Gaston 1-4 be made in this proceeding, but instead be considered in the 2025 IRP, in the context of a

[55] Staff's proposed resource assumptions included updated B2024 proxy fuel costs for Yates and Santa Rosa (STF-JKA 3-9 and STF-JKA 3-10) as well as the Max ICE Factor to be greater of MG0 and MG20 for utilization in both studies. Staff relied on the MG0 resource availability assumptions with the exception of the CC availability ending in 2034 in Staff's MG20 case as PTC and BESS differences due to the IRA past 2045 are not required for Staff's study that ended in 2040.

[56] Fixed Costs were obtained from STF-JKA 5-1 and STF-JKA 5-2

comprehensive unit retirement study. However, if a decision were ultimately made to extend the lives of these units, the need for additional new capacity resources beginning in 2029 would not be as great as the Company has indicated and could reduce ratepayer cost by delaying the need for additional new capacity.

Finally, in the 2022 IRP, Staff included modeling adjustments for BESS and Solar Effective Load Carrying Capability ("ELCC") values and solar integration costs, and in the modeling it performed in this IRP, the Company appears to have generally adopted Staff's recommendations.[57]

Q. HOW DID STAFF CONDUCT ITS RESOURCE EVALUATION?

A. Staff performed a series of Aurora optimization runs based on the Company's Resource Mix Study (Aurora Study) and database, in which the entirety of the Southern Company System was modeled. Staff evaluated both the MG0 (medium natural gas forecast and zero CO_2 cost) case and the MG20 (medium natural gas forecast and 20 $/ton CO_2 cost) case over Staff's study period. The purpose of Staff's analysis was to allow the proposed resource options (Moody, Robins, Battery plus Storage, Yates) to be modeled as selectable resources. However, in all of the cases Staff ran, the MPC resource was treated

[57] The Company used different ELCC values for BESS resources in its studies. For example, 100% is used for first tranche of new BESS resources, 90% for Robins and Moody at existing solar locations, and 95% for the 500 MW ESS RFP projections. These assumptions may need to be refined in future IRPs for consistency. Also, the Company continues to model a 0% ELCC for Solar in the 2023 IRP modeling. Staff notes that if Solar were given a small capacity contribution value, which may be reasonable, additional solar resources could further defer the near-term need date of capacity. See ELCC study results provided in STF-JKA-2-11.

as having been selected first, based on cost and reliability considerations, and the fact that MPC resources are already operating as a part of the Southern Company System resources.

Q. WHAT WERE THE RESULTS OF STAFF'S EVALUATION?

A. Staff's results showed that only Santa Rosa (and MPC as discussed above) was selected, but none of the other proposed resources (Robins, Moody, BESS plus Solar, Yates) were selected when the proposed resources were modeled as selectable resource options. This occurred in both a case that was based on the Company's load forecast and TRM assumptions, and in a case that was based on Staff's lower load forecast and TRM assumptions.

The following table compares three sets of results that led to the conclusions above, associated with the MG0 case for the period of 2024 to 2030. The load, TRM, and resource options that were assumed in each case are summarized in the first few rows of the table. The label "Resource Options: STF" is intended to indicate that the proposed resources were selectable in that case, and to mean that the extension of Scherer and Gaston was decided by Aurora. The MW values are shown in cases in which the resources were selected by the optimization run for the Southern Company System, and N/A implies that the resources were not considered selectable in the specified run. The amount of MWs shown is assumed to be the cumulative nameplate capacity installed between 2024 and 2030.

Table 10: GPC Resource Mix Study vs. Staff Resource Mix Study
MG0, Case
Southern Company System MWs Selected by 2030

LOAD (MG0)	GPC	GPC	STF
TRM	26%	26%	24.5%
RESOURCE OPTIONS:	GPC	STF	STF
Generic Resource Options (MW*)			
CC	[redacted]		
CT w SCR			
Solar			
BESS (Tranche 1)			
BESS (Tranche 2)			
Proposed Resources			
MPC PPA**	750	750	750
Santa Rosa PPA**	N/A	230	230
Robins BESS	N/A	-	-
Moody BESS	N/A	-	-
200 MW Co-Located Solar	N/A	-	-
Yates 8-10	N/A	-	-
Extension Options			
Scherer	N/A	645	645
Gaston	N/A	1,037	1,020

*Nameplate MW
**MPC and Santa Rosa end in 2028

N/A indicates resource was not included in Aurora as a selectable resource

The leftmost case was run the same way the Company set up the case in its Resource Mix Study, but for Staff's study period of 2024 to 2040. In that case, the Company's load forecast and TRM assumptions were modeled, and the proposed resources were not treated as selectable resources. In that case, MPC was modeled as having been selected, and the results show that a set of generic candidate resources were selected to satisfy Southern Company's load requirements.

In the middle case, Staff reran the Company's Resource Mix Study, but allowed the proposed resources to be selectable. Staff also allowed Aurora to decide if the Scherer and Gaston units should be permitted to continue to operate beyond 2028. The results of the middle case show that MPC and Santa Rosa were selected, along with a selection of generic candidate resources. In that case, the other proposed resources (Yates, Robins, Moody, and the BESS plus Solar options) were found to be more expensive and were not selected in the run. Also, Aurora found that it would be economic to continue to operate the Scherer and Gaston units beyond 2028.

The rightmost case used Staff's load forecast and TRM assumptions, and the results show, again, that only MPC and Santa Rosa were selected, along with a set of candidate generic resources. Fewer candidate generic resources were selected because Staff's case used a lower load forecast and TRM assumption. Once again, Aurora found that it would be economic to continue to operate the Scherer and Gaston units beyond 2028.

The conclusion from these analyses is that MPC and Santa Rosa should be acquired, but beyond that other resources should be determined in an RFP process. In addition, allowing Scherer and Gaston to operate past 2028 could result in the Company needing to add fewer resources in the 2029 to 2035 time period. While this implies it may be lower in cost for Georgia Power to extend the operation of those units, Staff

recommends that this decision be evaluated further in the 2025 IRP based on the Company performing a detailed unit retirement study.

Q. SINCE THE RESOURCE MIX STUDY IDENTIFIES RESOURCES BASED ON THE SOUTHERN COMPANY LOAD REQUIREMENT, HOW ARE RESOURCES ALLOCATED TO GEORGIA POWER?

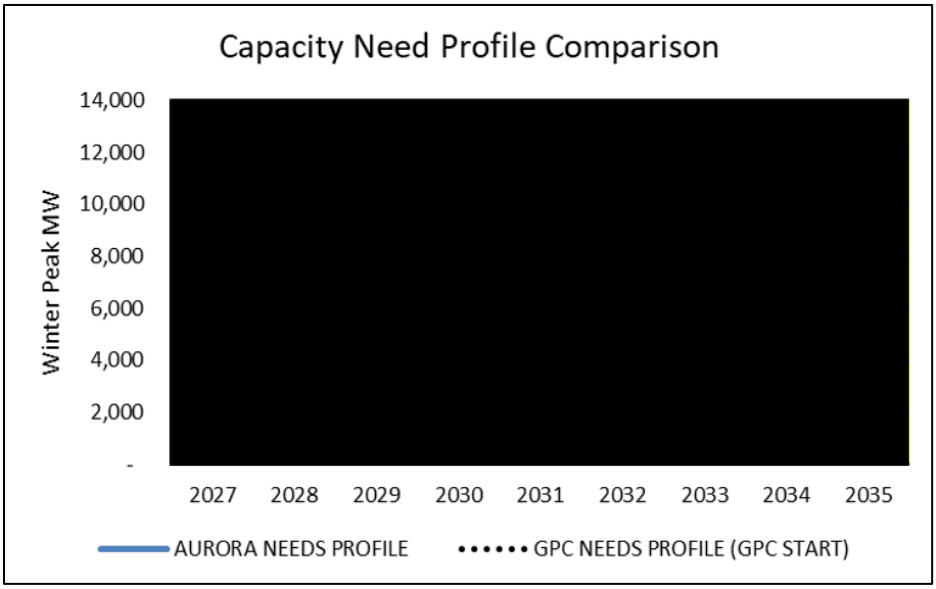
A. After the Resource Mix Study was performed and an expansion plan was derived to satisfy the Southern Company load requirement, a spreadsheet analysis was performed to allocate the resources selected by Aurora to Georgia Power. The spreadsheet determined how much of each resource type should be allocated to Georgia Power to meet its needs on a peak demand and energy basis compared to the other operating companies' needs. The operating companies with the greatest needs were assigned resources first.[58] Based on the Company's allocation process, Georgia Power was assigned a majority of the CT, CC, and BESS Tranche 1 capacity resources before 2030 ([redacted]%, [redacted]%, and [redacted]% respectively).

The following graph indicates the amount of incremental capacity that will be needed to satisfy the System's load requirements, and the amount that was allocated to Georgia Power using the spreadsheet model. It appears that due to Georgia Power's

[58] See the Company's December 7, 2023 Supplemental Errata filing and spreadsheet, "TS Capacity Expansion Plans Supplemental - Errata.xlsx"

significant new large customer load, most of the Southern Company's resource needs will be driven by Georgia Power's needs, and most of the incremental new capacity resources will have to be assigned to Georgia Power.

Figure 5: Incremental System Needs vs. Incremental GPC Needs (MG0)



Q. DID STAFF CONSIDER THE POSSIBILITY OF HOW RESULTS WOULD CHANGE UNDER A HIGHER CARBON COST CASE?

A. Yes, Staff ran a sensitivity case using MG20 assumptions to evaluate if the proposed projects would fair differently under a carbon sensitivity case. For this analysis, the same three cases are presented (Company, Company with Selectable Options, and Staff Case with Selectable Options).

Table 11: GPC Resource Mix Study vs. Staff Resource Mix Study
MG20, Case
Southern Company System MWs Selected by 2030

LOAD (MG20)	GPC	GPC	STF
TRM	26%	26%	24.5%
RESOURCE OPTIONS:	GPC	STF	STF
Generic Resource Options (MW*)			
CC	[redacted]		
CT w SCR			
Solar			
BESS (Tranche 1)			
BESS (Tranche 2)			
Proposed Resources			
MPC PPA**	750	750	750
Santa Rosa PPA**	N/A	230	-
Robins BESS	N/A	128	-
Moody BESS	N/A	50	50
200 MW Co-Located Solar	N/A	-	-
Yates 8-10	N/A	-	-
Extension Options			
Scherer	N/A	645	645
Gaston	N/A	1,037	1,020

*Nameplate MW
**MPC and Santa Rosa end in 2028

N/A indicates resource was not included in Aurora as a selectable resource

The results of the MG20 case were consistent with the results of the MG0 case, in that when a lower load forecast was used, the model selected less CC and BESS resources. Also, once again, the model determined that it would be economic to extend the operation

of the Scherer and Gaston resources.[59] Another result of this CO_2 case is that the additional carbon pressure also led to the Robins and Moody BESS projects being selected. In other words, Robins and Moody was selected in the Company's load forecast case (middle column), and just Moody was selected in Staff's load forecast case shown in the rightmost column. Ultimately, a combination of MPC, Santa Rosa, Robins, and Moody, was selected economically to best fit the load projection in the carbon sensitivity scenarios.

MPC and Santa Rosa PPAs

Q. PLEASE DESCRIBE STAFF'S RECOMMENDATION REGARDING THE MPC PPA RESOURCE.

A. Staff proposes certification of the MPC PPA on a risk mitigation and economic basis. Staff finds there is a capacity need beginning in 2027, and since the MPC PPA consists of resources already in operation, acquisition of that PPA eliminates risks associated with attempting to construct resources in that short of a time period. Staff Witness Larkin addresses the Company's request for an additional sum and Staff's recommendation that all benefits from the resale of the PPAs should flow to Georgia Power customers.

Q. PLEASE EXPLAIN STAFF'S RECOMMENDATION REGARDING THE SANTA ROSA PPA.

[59] Staff examined the capacity factors of Scherer and Gaston for this case and found the units had capacity factors below 10% in the years reviewed.

A. The same considerations discussed above for the MPC PPA applies to the Santa Rosa PPA. Staff recommends certification of the Santa Rosa PPA along with the remarketing of the associated capacity when needed.

Additionally, the Company should provide an update in rebuttal testimony regarding the deliverability of the capacity following the January 12th Supplemental Filing it made, in which the Company stated:

> Furthermore, the Company updated the Santa Rosa PPA firm capacity based on the results of a Southern Company Native Load Reservation interface study report for the Santa Rosa PPA resource. While annual firm transmission cannot be confirmed for 2024 through May 2026, Georgia Power is pursuing and may obtain short-term firm transmission for the resource during this period. Consistent with the transmission screening analyses in the 2023 IRP Update, no transmission project costs are attributable to the Santa Rosa PPA.[60]

The Company should address the reasonableness of customers paying capacity payments for a resource that cannot secure annual firm transmission rights.

Yates 8-10 CT Resources

Q. WHAT INFORMATION HAS THE COMPANY PROVIDED TO SUPPORT ITS REQUEST FOR THE THREE NEW CT UNITS AT PLANT YATES?

A. The Company has provided a number of estimates for the costs and in-service dates for the Yates CT projects as shown in the table below. In the Company's initial 2023 IRP

[60] STF JKA 2-2 Supplemental

Update filing, noted "IRP Filing" in the table below, the Company provided a summary statement, a 3-page Technical Information Appendix document, and an economic analysis study with a financial model. The Company then filed a supplemental financial and economic analysis on January 12, 2024 that updated the Yates costs, which is noted as "Supplemental" in the table. Finally, the Company provided a certification filing on January 31, 2024, which is noted as "Certification" in the table. The table provides total in-service costs, which includes capital costs and financing costs for various capital cost components (generators, transmission, gas lateral).

Table 12: Yates CT Cost Summary

$ Billions	IRP Filing	Supplemental	Certification
U8, U9, U10 Only			
Spend Curve $	[redacted]		
In-Service $			
Tie Line and Gas Lateral			
Spend Curve $	[redacted]		
Inservice $			
Total			
Spend Curve $	[redacted]		
In-Service			
U8 COD	12/1/2026	12/1/2026	12/1/2026
U9 COD	12/1/2026	5/1/2027	5/1/2027
U10 COD	4/1/2027	8/1/2027	8/1/2027

Q. PLEASE EXPLAIN STAFF'S FINDINGS AND RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO SELF BUILD THREE CTS AT YATES.

A. Staff recommends that the Company's request for additional CT capacity at Yates be denied given that no additional resources are needed before 2029, and the project is not an economic resource. The Company's latest assumption is that a portion of the Yates project (Yates Unit 8) will be available to serve load by the winter of 2026/2027 and all of the capacity would be completed by August 2027 (including Yates 9 and 10). However, Staff has demonstrated that the entire Yates project and the proposed BESS projects are not needed until 2029, and there is no reason that Yates should be selected based on an exception outside of the standard Commission required RFP process.

In addition, if Georgia Power were to contend that the 1,300 MW Yates project is needed before 2029, the Commission should be aware that due to transmission limits, only 600 MW of the project will be fully deliverable prior to 2029. That is because transmission upgrades will have to be constructed to ensure full deliverability of the Yates capacity, which will not occur until 2029, and possibly not until later if the transmission upgrades are delayed. Staff does not believe there would be any advantage in approving the Yates project now, as the project will not provide the full capacity any earlier than it would if it were required to go through an RFP selection process.

Finally, there is no proof that the Yates project is more economical than other peaking capacity that might be available from a market resource obtained via an RFP as indicated by Staff's Resource Mix Study results. Neither the Yates CT capacity, nor even generic CT capacity were selected prior to 2030 in Staff's Resource Mix cases. Staff does not recommend certification of the Yates project until it is determined to be a least-cost resource in a RFP process.

BESS (and Solar) Requests

Q. WHAT BESS PROJECTS HAS THE COMPANY CONTEMPLATED ACQUIRING IN THIS IRP UPDATE?

A. The Company has requested "[a]uthority to develop, own, and operate up to 1,000 MW of BESS at various sites…,"[61] and the Company states that these units could be brought "online by the end of 2027, inclusive of 378 MW for the proposed Robins, Moody, and BESS plus solar project."[62] The Company has requested flexibility to be able to add the remainder of the 1,000 MW, or 622 MW as needed to meet load requirements.

Q. WHAT BESS PROJECTS DOES THE COMPANY CURRENTLY HAVE AUTHORIZATION FOR?

[61] Georgia Power's 2023 IRP, Main Document, Request 4, p. 4.
[62] Georgia Power's 2023 IRP, Direct Testimony of Jeffrey Grubb, Francisco Valle, Lee Evans, and Michael Bush, p. 27, l. 2.

A. From the 2019 IRP, the Company has the authority to own and operate the Mossy Branch BESS project (65 MW), a 13 MW project at Ft. Stewart, and a 2 MW project at a distribution facility within the Company's service territory. From the 2022 IRP, the Company has the authority to own and operate the McGrau Ford (265 MW) BESS project and to conduct an RFP for an additional 500 MW of ESS projects.

With regard to the 500 MW ESS RFP, the Company has been inconsistent in its presentation of plans for that procurement. In the initial filing, the Company provided a load and resource balance table that indicated the Company would acquire the 500 MW 2022 IRP ESS RFP resources by the winter of 2029. The Company did not include the proposed new BESS resources (Robins, Moody and BESS plus Solar project) in that table. In response to Staff discovery STF-JKA-2-2f, the Company provided another load and resource balance table that included the proposed resources, but did not include the 500 MW 2022 IRP ESS RFP resources. The Company also included a line, "Other BESS," that appears to be the remainder of the 1,000 MW that the Company is seeking authorization in this proceeding to be able to add.[63] Staff understands the Company does intend to issue the 500 MW 2022 IRP ESS RFP, sometime in 2024.[64]

[63] The Company filed both an original Load and Resource balance workpaper in STF-JKA-2-2 and a supplemental workpaper, and both show the elimination of the 500 MW 2022 IRP ESS RFP resource, and the inclusion of the 560 MW "Other BESS" capacity.
[64] STF-JKA-5-3a.

Q. IF THE COMPANY'S 1,000 MW REQUEST IS APPROVED, HOW MUCH BESS CAPACITY FROM THIS AND PRIOR PROCEEDINGS WILL HAVE BEEN COMPETITIVELY PROCURED?

A. The following table shows all of the Company's BESS procurements, based on this IRP and approvals from prior proceedings.

Table 13: GPC Energy Storage Procurement Plan Summary (MW)

	Request
Mossy Branch (Owned)	65
Ft. Stewart 4-hr BESS (Owned)	13
Distribution Storage (Owned)	2
McGrau Ford (Owned)	265
2022 IRP Approved ESS (RFP)	500
2023 IRP Update Request (Owned)	1,000
Total	**1,845**

If the Company's request is approved in this proceeding, only 27% (500/1,830) of these BESS resources will have been acquired through a competitive procurement process. Furthermore, the Company has not even begun the 500 MW procurement process from the 2022 IRP, despite having been authorized to do so for more than a year and a half (since July 2022).

Q. ARE THE COMPANY'S PROPOSED OWNED RESOURCES COST COMPETITIVE COMPARED TO RESOURCES THAT COULD BE PROCURED IN THE MARKET?

A. No. The following table compares the Company's proposed BESS projects to the generic candidate BESS resource the Company modeled in the Company's Resource Mix Study, which is a proxy for what the Company believes that BESS resources could be acquired for in the market.

Table 14: BESS Cost Comparison (Rev. Req)

PVRR Comparison	GENERIC BESS (2027)	ROBINS BESS	MOODY BESS	CO-LOCATED BESS
Winter Credit	**300**	**115**	**44.5**	**200**
PVRR $/Winter kW				
Build Capital	[redacted]	[redacted]	[redacted]	[redacted]
Maintenance Capital				
FOM				
PVRR $/kW Total				

The table indicates that the least expensive Company-owned proposed project (Robins) is [redacted]% ([redacted]) more expensive than the generic candidate BESS resource. Furthermore, it is possible that BESS prices may fall a significant amount further in 2024, according to a recent report[65] by Clean Energy Associates.[66] Also, as noted above, the

[65] "BESS Prices in US Market to Fall a Further 18% in 2024, says CEA", Energy Storage News, February 7, 2024, https://www.energy-storage.news/bess-prices-in-us-market-to-fall-a-further-18-in-2024-says-cea/

[66] According to its website, Clean Energy Associates is a clean energy advisory company founded in 2008 with offices in Denver and Shanghai, with more than 200 professionals employed. https://www.cea3.com/about

RFI supports the notion that there may be more economic BESS projects available in the market.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED SELF-BUILD BESS PROJECTS?

A. Staff does not recommend certification of the Robins, Moody, or co-located solar and BESS projects until they are determined to be a least cost resource option from an RFP process. If the Company wants to acquire these projects, they should be included in the 500 MW ESS RFP process.

Staff's Ranking Analysis

Q. WHY DID STAFF PERFORM A RANKING ANALYSIS?

A. If the Commission were to decide a higher load forecast and / or an earlier capacity need date are appropriate, then a ranking analysis such as the one Staff performed could be used to assist in deciding which of the proposed resources to select. The purpose of Staff's Ranking Analysis was to determine the economic ordering of the proposed resources.

For example, if the Commission were to decide that one or more resources beyond MPC and Santa Rosa are needed, Staff's ranking analysis could be used to identify the next resource(s) that should be selected. Or if the Commission were to decide that a lower load forecast was appropriate and fewer resources were needed, Staff's

ranking analysis would again be helpful in deciding which resource to eliminate. In fact, for illustration purposes, Staff presents one additional lower load forecast case, based on a "P80" load forecast. The load and resource plan associated with this load forecast is presented as Table C in Exhibit NHW-4, which shows that even the Santa Rosa PPA would not be needed in the short-term period based on this case.

Q. PLEASE EXPLAIN THE MOTIVATION FOR USING THE P80 LOAD FORECAST IN STAFF'S ILLUSTRATIVE CASE.

A. The decision to use the P80 load forecast for Staff's illustrative case is that in the 2022 IRP Reserve Margin Study, the Company used an 80% confidence interval for the Value at Risk metric in its derivation of the Target Reserve Margin. In that study, the Company settled on a 26% Target Reserve Margin based on the determination that an 80% confidence interval would offer a reasonable balance between cost and reliability. In this IRP, the Company has proposed to use a 95% confidence level for the probabilistic LRM analysis associated with new large customer load. To be consistent in balancing cost and risk, Staff believes it would be reasonable to use an 80% confidence level, as was used in the Reserve Margin Study, for developing a lower load forecast sensitivity case. Consequently, Daymark produced a P80 LRM scenario with the Uniform success probability rates and wider delay assumptions that this panel used for the illustrative case.

Q. HOW DID STAFF CONDUCT ITS RANKING ANALYSIS STUDY?

A. Staff used the Company's Resource Mix Study database that contains a model of the Southern Company System, and then Staff added all of the proposed resources that the Company identified in the model and set them all to operate at the same time. Staff then performed Aurora runs, in which each proposed resource was removed one at a time, and Staff measured the $NPV/kW change (benefit) associated with the removal of each resource. A series of Aurora runs were performed on an iterative basis to compare results to determine which proposed resource was considered to be the least beneficial to the System. In the first round of the analysis, the least beneficial resource was identified, and it was removed from modeling. Another series of runs were made, and the next resource considered to have the least benefit out of the remaining units was identified and removed. The process continued each time by removing one unit, and ultimately Staff was able to determine the ranking order for the resources based on the benefits they could provide.

By performing this study using Aurora, an optimal ranking of the proposed resources could be identified. Staff preferred this approach as it remedied Staff's concerns with the term equalization issue, and satisfied Staff's goal of performing the analysis using a load-based dispatch approach. By using the Company's Resource Mix database, Staff was also able to use its preferred natural gas and CO_2 price forecasts.

Q. WHAT WERE THE RESULTS OF STAFF'S RANKING ANALYSIS?

A. The following table provides Staff's Ranking Analysis results, in which a "1" is considered the highest ranked resource and "6" is considered the lowest ranked resource. A supplemental filing was made on January 19, 2024, in which the Company updated Yates transmission costs, and another supplemental filing was made on January 31, 2024, in which the Company updated the Yates capital cost assumptions to support its Certification request. Staff's Ranking Analysis utilizes the latest Yates assumptions available. The results of Staff's study that was performed dynamically using the Aurora model are shown below. [67]

Table 15: Staff Ranking Analysis Summary

MG0	Staff Ranking
1	MPC PPA[68]
2	Robins BESS
3	Santa Rosa PPA
4	Moody BESS
5	Co-located BESS + Solar
6	Yates 8-10 CTs

Details of this analysis, including results by each round of the analysis are provided in Exhibit NHW-6.

[67] Staff's analysis also used Staff's load forecast and TRM assumptions but given the structure of the analysis – these assumptions did not fundamentally impact the ranking analysis function.

[68] Because MPC is composed of resources already part of the Southern Company System, it was not evaluated iteratively similar to the other proposed resources However, based on a preliminary analysis considering MPC's capacity cost, Staff determined MPC should be selected, and it was placed in the first ranking position in Staff's Ranking column.

VI. OTHER ISSUES

Flex Capacity Framework

Q. HAS STAFF REVIEWED THE FLEX CAPACITY FRAMEWORK?

A. Yes. The Company summarized the request:

> The Flex Capacity framework would authorize Georgia Power to undertake and recover the cost for preliminary development activities in connection with the development, operation, and ownership of new capacity resources. Additionally, the Company would be authorized to continue to explore PPA or acquisition options that could be presented for Commission approval and certification prior to the filing of the Company's 2025 IRP and recover any incremental cost incurred for this effort.[69]

Staff recommends that the Commission deny the Company's request. This framework has not been required in the past and does not afford customers any additional protections. The Company would file its 2025 IRP in January 2025, and therefore the request for interim relief is not required, as the Company could make new requests and present information to the Commission in that proceeding. Staff witness Ralph Smith provides additional discussion regarding the ratemaking implications of the Company's request.

Commission Rule 515-3-4-.04(3)(f)(7)

Q. HAS STAFF REVIEWED THE COMPANY'S NOTICE REGARDING THE COMMISSION RULE THAT WOULD REQUIRE GEORGIA POWER TO

[69] Geogia Power 2023 IRP Testimony, p. 50, l. 24.

MAINTAIN A PERCENTAGE OF THEIR CAPACITY AS "SELF-OWNED" RATEBASE ASSETS?

A. Yes. Staff has reviewed Commission Rule 515-3-4-.04(3)(f)(7), which states that the Company shall maintain a minimum percentage of all of its resources as "self-owned rate-based assets".[70] The rule does not state what the minimum percentage must be, but instead states the percentage should be set by Commission Order, and it states that the minimum percentage "may be changed from time to time." The Commission established the 70% minimum percentage amount when it issued its Final 2001 IRP Order in Docket No. 13305.[71]

Q. BESIDES INDICATING THE RULE MAY BE CHANGED FROM TIME TO TIME, DOES THE RULE PROVIDE THE COMMISSION FLEXIBILITY TO SUSPEND OR ADJUST THE MINIMUM PERCENTAGE REQUIREMENT?

A. Yes. An important part of the rule is that when a Company finds it is approaching the point of falling below the minimum percentage level, it is required to inform the Commission, so that the Commission, "in its discretion, may suspend these rules and provide guidance to the soliciting utility as to how it should proceed." The Company has provided notice to the Commission in this proceeding that it is approaching the point of

[70] https://rules.sos.state.ga.us/gac/515-3-4
[71] STF-JKA-2-17, Order issued July 17, 2001, at p. 21.

falling below the minimum percentage level, which it states will occur as early as the winter of 2026/2027.[72] However, by the plain language of the rule, it states the Commission has the discretion to suspend the rule, and to provide guidance to the utility as to how the utility should proceed.

Q. WHAT IS STAFF'S RECOMMENDATION?

A. Staff recommends that the Commission suspend the rule and not impose a minimum percentage requirement at this time. The Commission should wait to determine this after capacity RFPs are underway and the cost of third-party generation is known, which should occur prior to the 2025 IRP. At that time it can be determined whether third-party generation is more economical and just as reliable compared to Company owned generation. If such a determination is made, then the Commission could decide to reduce the minimum percentage requirement below 70%. At that time, the Commission will have the necessary information to make an informed decision.

In addition, the Company is now having to deal with extraordinary circumstances, and it should be permitted as much flexibility as possible to find solutions that are both reliable and economic. Finally, the Company has not provided any evidence of other utilities having a minimum percentage requirement of 70%, nor has the Company presented any evidence that since the 70% requirement went into place in 2001 that it has

[72] 2023 IRP Main Document, p. 18.

resulted in a more reliable low-cost system, or that any of its existing PPA's have underperformed. The Company should present evidence of this type to the Commission prior to the Commission reinstating use of the 70% minimum percentage requirement. Alternatively, a lower minimum percentage requirement should be established.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 55378**
2023 INTEGRATED RESOURCE	**)**	
PLAN UPDATE	**)**	

EXHIBITS

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

FEBRUARY 15, 2023

EXHIBIT

STF-NHW-1

Exhibit STF-NHW-1
Tom Newsome Qualifications

Summary of Educational and Professional Experience of Tom J. Newsome

Mr. Newsome received a Bachelor of Chemical Engineering with certificates in Pulp & Paper and Polymers from the Georgia Institute of Technology in June 1986. In 1994, Mr. Newsome passed both required examinations and received a professional engineering license (PE) from the State of North Carolina. Mr. Newsome received a Master of Science in Business Economics and a Master of Science in Finance from Georgia State University in August 1996 and June 1997, respectively. Mr. Newsome is the recipient of the George J. Malanos Graduate Award for Academic Excellence for completing the finance program with a 4.0 grade-point average. In 2003, Mr. Newsome received Chartered Financial Analyst (CFA) designation from the CFA Institute after successfully completing three six-hour examinations on security analysis and portfolio management.

After graduation from Georgia Tech, Mr. Newsome worked as plant/process engineer for Shaw Industries, a carpet manufacturer. In April 1988, Mr. Newsome joined Weatherly, Inc., engineering and construction firm specializing in fertilizer plants, as a process engineer. Mr. Newsome's primary responsibilities were process design and plant start-ups, including start-ups in Korea and India. Mr. Newsome joined Midrex Direction Reduction Corp., an applied research, engineering and construction firm with proprietary iron ore processing plant technology in March 1993 as a process engineer. Mr. Newsome duties were similar to those at Weatherly, including assisting in the start-up of the world's largest Direct Reduction Iron plant in India.

Following graduation from graduate school at Georgia State, Mr. Newsome joined Georgia Gulf Corporation in 1997 as a corporate development analyst. While at Georgia Gulf, Mr. Newsome performed financial analysis and modeling for natural gas purchasing/hedging program, developed a "make-or-buy" model for methanol business, performed financial modeling for an acquisition, and calculated and summarized the financial performance of prior capital investments. In 1999, Mr. Newsome joined FMV Opinions, Inc. as a business valuation analyst and valued private companies for gift and estate tax, transactional and management planning purposes.

Mr. Newsome joined the Georgia Public Service Commission ("Commission") in January 2005 as a Financial Analyst/Economist. Mr. Newsome was promoted to Director of Utility Finance in 2008.

Mr. Newsome has testified in twenty-three Georgia Power Company ("Company" or "Georgia Power") proceedings before the Commission.

Mr. Newsome's most recent testimony was in Docket 29849 in 28th Vogtle Construction Monitoring ("VCM"). Prior to that, Mr. Newsome testified in Docket 44902 Fuel Cost Recovery (FCR-26). Prior to that Mr. Newsome's testified in Docket 29849 26th and 27th VCMs. Prior to that Mr. Newsome testified in Docket 44160 Integrated Resources Planning on supply side

resources. Prior to that Mr. Newsome testified in Docket 29849 23rd Vogtle Construction Monitoring ("VCM"), 24th VCM and 25th VCM on Vogtle economics. Prior to that was testimony in 22nd VCM and in Docket 43011 Fuel Cost Recovery (FCR-25) on the Company's hedging program and certain other issues. Prior to that Mr. Newsome's testified in Docket 29849 20th / 21st Vogtle Construction Monitoring ("VCM") on Vogtle economics. Prior to that Mr. Newsome's testified in Docket 42310 Georgia Power Company's 2019 Integrated Resource Plan on supply side and certain other issues. Prior to that testimony Mr. Newsome testified in Docket 29849 19th Vogtle Construction Monitoring ("VCM"), 18th VCM and 17th VCM on the economics of continuing Vogtle 3 and 4 construction and provided the Commission policy recommendations to protect ratepayers. Prior to testifying in the 17th VCM Mr. Newsome testified in the 2016 Integrated Resource Plan on the Company's requested to capitalize cost for investigation of new nuclear units. Mr. Newsome's testified in Docket No. 39638 Fuel Cost Recovery (FCR-24) on the Company's natural gas hedging program. In Docket No. 22403, Mr. Newsome addressed Georgia Power Company's natural gas hedging program and in Docket No. 24506 Mr. Newsome testified on the application of AFUDC accounting for calculating financing cost of capital projects. In Docket No. 27800, Certification of Plant Vogtle Expansion, Mr. Newsome addressed the sources, impact and mitigation of financial risk from the construction and operation of new nuclear units at Plant Vogtle. Mr. Newsome testified in Docket No. 29849 concerning Georgia Power's First Semi-annual Construction Monitoring Report on Plant Vogtle expansion. Mr. Newsome evaluated the economic analysis performed by Georgia Power and developed Staff's own independent economic and risk analysis of the Project. In the Second Vogtle Semi-annual hearing, Mr. Newsome testified on the Company's proposal to change how escalation on certain project cost was calculated (Amendment 3). In the Third Vogtle Semiannual hearing and in separate proceeding, Adoption of a Risk Sharing Mechanism, Mr. Newsome testified on Staff's revised risk sharing mechanism for Vogtle 3 & 4. In Docket No. 28945 Fuel Cost Recovery FCR–21, Mr. Newsome testified on seasonal rates. Mr. Newsome also presented cost of equity testimony in Atmos Energy Corporation's Rate Case in Docket No. 30442 and Generic Proceeding to Implement House Bill 168 (small telephone companies) in Docket No. 32235 in 2011 and 2018. Mr. Newsome provided testimony before the Commission in Georgia Power's 2013 Base Rate Case in Docket No. 36989 on the Company's projected cost of debt for 2014 – 2016. Mr. Newsome's primarily responsibility, prior to presenting testimony in these dockets, has been performing analyses of the parties' cost of equity capital positions in Docket Nos. 18638 (Atlanta Gas Light Company 2004/2005 Rate Case), 19758 (Savannah Electric and Power Company 2004 Rate Case), 20298 (Atmos Energy Corporation - Georgia Division 2005 Rate Case), 25060 (Georgia Power Co. 2007 Rate Case) and 27163 (Atmos Energy Corporation - Georgia Division 2008 Rate Case) and developing the Advisory PIA Staff's cost of equity recommendation to the Commission.

EXHIBIT

STF-NHW-2

EDUCATION/CERTIFICATION

M.S., Electrical Engineering, Georgia Institute of Technology, 1980
B.S., Electrical Engineering, Purdue University, 1979
Cooperative Education Certificate, Purdue University, 1979

PROFESSIONAL AFFILIATIONS

National Society of Professional Engineers
Georgia Society of Professional Engineers
Institute of Electrical and Electronic Engineers

EXPERIENCE

Since completing his Master's program, Mr. Hayet worked for fifteen years at Energy Management Associates, now Ventyx, providing consulting services and client service support to electric utility companies for the widely used planning models, PROMOD IV and STRATEGIST. Mr. Hayet had an instrumental role in designing some of the modeling features of those tools including the competitive market modeling logic in STRATEGIST.

In 1995, Mr. Hayet formed the utility consulting firm, Hayet Power Systems Consulting ("HPSC"), and worked for customers in the United States, and internationally in Australia, Japan, Singapore, Malaysia, the United Kingdom, and Vietnam. Mr. Hayet provided consulting services to Public Utility Commissions, Regional Power Pools, State Energy Offices, Consumer Advocate Offices, Electric Utilities, Global Power Developers, and Industrial Companies. Mr. Hayet's expertise covers a number of areas including utility system planning and operations, RTO analysis, market price forecasting, Integrated Resource Planning, renewable resource evaluation, transmission planning, demand-side analysis, and economic analysis.

In 2000, Mr. Hayet also joined the consulting firm of J. Kennedy & Associates, Inc. ("Kennedy and Associates") and assisted on projects that required utility resource planning, analysis, and software modeling expertise. Mr. Hayet merged his firm and became a Vice-President and Principal of Kennedy and Associates in 2015.

Mr. Hayet has conducted numerous consulting studies in the areas of RTO Cost/Benefit Analysis, Renewable Resource Evaluation, Renewable Portfolio Standards Evaluation, Electric Market Price Forecasting, Generating Unit Cost/Benefit Analysis, Integrated Resource Planning, Demand-Side Management, Load Forecasting, Rate Case Analysis and Regulatory Support.

2000 to Present: **J. Kennedy and Associates, Inc.**
Vice President and Principal

- Initially began as Director of Consulting, became Vice President and Principal in 2015
- Managed electric related consulting projects.
- Responsible for business development.
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.

1996 to Present: Hayet Power Systems Consulting
President and Principal

- Managed electric utility related consulting projects
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.

1991 to 1996: EDS Utilities Division, Atlanta, GA (Now Ventyx)
Lead Consultant, PROSCREEN (Now STRATEGIST) Department

- Managed a client services software team that supported approximately 75 users of the STRATEGIST electric utility strategic planning software.
- Participated in the development of STRATEGIST's competitive market modeling features and the Network Economy Interchange Module
- Provided client management direction and support, and developed new consulting business opportunities.
- Performed system planning consulting studies including integrated resource planning, DSM analysis, marketing profitability studies, optimal reserve margin analyses, etc.
- Based on experience with PROMOD IV, converted numerous PROMOD IV databases to STRATEGIST, and performed benchmark analyses of the two models.

1988 to 1991: Energy Management Associates (EMA), Atlanta, GA
Manager, Production Analysis Department

- Served as Project Manager of a database modeling effort to create an integrated utility operations and generation planning database. Database items were automatically fed into PROMOD IV.
- Supervised and directed a staff of five software developers working with a 4GL database programming language.

- Interfaced with clients to determine system software specifications, and provide ongoing client training and support

1980 to 1988: **Energy Management Associates (EMA), Atlanta, GA**
Senior Consultant, PROMOD IV Department

- Provided client service support to EMA's base of over 70 electric utility customers using the PROMOD IV probabilistic production cost simulation software.
- Provided consulting services in a number of areas including generation resource planning, regulatory support, and benchmarking.

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
09/98	97-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah jurisdictional Net Power Costs, PacifiCorp Rate Case Proceeding
07/01	01-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah Jurisdictional Net Power costs in General Rate Case
2001	ER00-2854-000	FERC	Louisiana Public Service Commission	Entergy	Proposed System Agreement Modifications
07/02	02-035-002	UT	Utah Committee for Consumer Services	PacifiCorp	Special contract for industrial consumer
2002/ 2003	U-25888	LA	Louisiana Public Service Commission	Entergy	Investigation of retail issues related to the System Agreement
2003	U-27136 Subdocket A	LA	Louisiana Public Service Commission Staff	Entergy	Aging gas steam-fired retirement study
07/03	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy	Rough production cost equalization proceeding
05/04	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Development of a large QF avoided cost methodology
06/04	18687-U 18688-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	2004 Integrated Resource Planning Studies
08/04	ER03-583-000	FERC	Louisiana Public Service Commission	Entergy	Affiliate power purchase agreements
11/04	03-035-19	UT	Utah Committee for Consumer Services	PacifiCorp	Industrial customer's request for a special economic development tariff
11/04	03-035-38	UT	Utah Committee for Consumer Services	PacifiCorp	Large QF proceeding.
03/05	03-035-14	UT	Utah Committee	PacifiCorp	Concerning PacifiCorp's Schedule 38

Date	Case	Jurisdict	Party	Utility	Subject
			for Consumer Services		avoided cost tariff and remaining unsubscribed capacity
07/05	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Concerning PacifiCorp's Schedule 38 avoided cost proceeding
12/05	04-035-42	UT	Utah Committee for Consumer Services	PacifiCorp	Net power costs in General Rate Case
04/06	05-035-54	UT	Utah Committee for Consumer Services	PacifiCorp	Certification request to expand Blundell Geothermal Power Station. Related to Mid-American Energy Holding's Acquisition of PacifiCorp
05/06	22403-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	March 2006 fuel cost recovery filing
2006	06-35-01	UT	Utah Committee for Consumer Services	PacifiCorp	2006 rate case, net power costs
08/06	U-21453	LA	Louisiana Public Service Commission Staff	Entergy Gulf States	Jurisdictional separation.
11/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Fuel adjustment clause filings
01/07	23540-U	GA	Georgia Public Service Commission Staff	Georgia Power	November 2005 fuel cost recovery filing
04/07	07-035-93	UT	Utah Committee for Consumer Services	PacifiCorp	General Rate Case
06/07	24505-U	GA	Georgia Public Service Commission Staff	Georgia Power	2007 Integrated Resource Planning
10/07	U-30334	LA	Louisiana Public Service Commission Staff	Cleco Power	2008 Short-Term RFP
04/08	26794-U (FCR-20)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing

Date	Case	Jurisdict	Party	Utility	Subject
2008	6630-CE-299	WI	Wisconsin Industrial Energy Group, Inc.	WEPCO	Certification Proceeding for environmental upgrades at Oak Creek power plant
07/08	ER07-956	FERC	Louisiana Public Service Commission	Entergy	2006 rough production cost equalization compliance filing in the System Agreement case
09/08	6680-CE-180	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light	Certification proceeding concerning Nelson-Dewey coal-fired generating unit
11/08	08-1511-E-GI	WV	West Virginia Energy Users Group	Allegheny Power	Fuel cost recovery filing
12/08	27800-U	GA	Georgia Public Service Commission Staff	Georgia Power	Vogtle 3 and 4 nuclear unit certification proceeding
2008	08-035-35	UT	Utah Committee for Consumer Services	PacifiCorp	Chehalis Combine Cycle Power Plant based on a waiver of the RFP solicitation process certification proceeding
07/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy	2007 rough production cost equalization compliance filing in the System Agreement case
07/09	U-30975	LA	Louisiana Public Service Commission Staff	SWEPCO and Cleco	Application to acquire the Oxbow Mine to supply Dolet Hills Power Station certification proceeding
09/09	E015/PA-09-526	MN	Large Power Intervenors	Minnesota Power	Request for approval to purchase Square Butte's 500 kV DC transmission line, restructure a coal based power purchase agreement
09/09	09-035-23 Direct	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
10/09	09A-415E	CO	Public Utilities Commission of Colorado	Black Hills/Colorado	CPCN application to construct two LMS 100 natural gas combustion turbine units
10/09	09-035-23 Surrebuttal	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
12/09	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	First Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
12/09	ER08-1224	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
2009	09-2035-01	UT	Utah Office of Consumer Services	PacifiCorp	2008 IRP
01/10	28945-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
2010	EL09-61	FERC	Louisiana Public Service Commission	Entergy	System Agreement, individual operating company sales
06/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Second Semi-Annual Vogtle Construction Monitoring Report
12/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Third Semi-Annual Vogtle Construction Monitoring Report
01/11	ER09-1350 Direct	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
02/11	ER09-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
04/11	33302-U (FCR-22)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
06/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fourth Semi-Annual Vogtle Construction Monitoring Report
09/11	U-31892	LA	Louisiana Public Service Commission Staff	Cleco Power	Settlement agreement, CPCN to upgrade Madison 3 coal unit to accommodate biomass fuel
11/11	26550-U	GA	Georgia Public Service Commission Staff	Georgia Power	Reacquisition of wholesale block capacity
11/11	34218-U	GA	Georgia Public Service Commission Staff	Georgia Power	Decertification of two aging coal units, acquire PPA resources, approve IRP update

Date	Case	Jurisdict	Party	Utility	Subject
12/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifth Semi-Annual Vogtle Construction Monitoring Report
03/12	U-32148	LA	Louisiana Public Service Commission Staff	Entergy	Change of Control Proceeding to move to Midwest ISO
2012	20000-EA-400-11	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power	Certification of environmental upgrades at Naughton 3
05/12	35277-U (FCR-23)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
05/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixth Semi-Annual Vogtle Construction Monitoring Report
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Environmental upgrades in compliance with MATS and CSAPR
09/12	U-32275	LA	Louisiana Public Service Commission Staff	Dixie Electric Member Cooperative	Ten year power supply acquisition certification proceeding
12/12	EL09-61-002 Direct	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement
12/12	U-32557	LA	Louisiana Public Service Commission Staff	Entergy	Certification of 28 MW PPA for renewable energy capacity (RAIN waste heat) in accordance with LPSC's Renewable Energy Pilot
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy	Retail proceeding regarding termination of cross-PPAs
12/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Seventh Semi-Annual Vogtle Construction Monitoring Report
03/13	EL09-61-002 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Mitchell Certificate of Public Convenience and Necessity

Date	Case	Jurisdict	Party	Utility	Subject
05/13	36498-U	GA	Georgia Public Service Commission Staff	Georgia Power	2013 IRP and request to decertify over 2,000 MW of coal-fired capacity
07/13	U-32785	LA	Louisiana Public Service Commission Staff	Entergy	8.5 MW PPA for renewable energy capacity (Agrilectric rice hull) in accordance with LPSC's Renewable Energy Pilot
08/13	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighth Semi-Annual Vogtle Construction Monitoring Report
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Base rate case
05/14	13-035-184	UT	Utah Office of Consumer Services	PacifiCorp	2014 General Rate Case, net power cost
06/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Ninth/Tenth Semi-Annual Vogtle Construction Monitoring Report
07/14	20000-446-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 General Rate Case, net power cost
08/14	2000-447-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 Energy Cost Adjustment Mechanism application
08/14	14-035-31	UT	Utah Office of Consumer Services	PacifiCorp	2014 Energy Balancing Adjustment application
09/14	ER13-432	FERC	Louisiana Public Service Commission	Entergy	Allocation of Union Pacific Settlement Agreement benefits
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power	Kentucky Power Company's Fuel Adjustment Clause
12/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eleventh Semi-Annual Vogtle Construction Monitoring Report
05/15	14-035-140	UT	Utah Office of Consumer Services	PacifiCorp	Solar and wind capacity contribution avoided cost proceeding.
06/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twelfth Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
08/15	15-035-03	UT	Utah Office of Consumer Services	PacifiCorp	2015 Energy Balancing Adjustment application
09/15	14-035-114	UT	Utah Office of Consumer Services	PacifiCorp	Cost and Benefits of PacifiCorp's Net Metering Program
11/15	39638-U	GA	Georgia Public Service Commission Staff	Georgia Power	FCR-24 Fuel Cost Recovery Proceeding
11/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Thirteenth Semi-Annual Vogtle Construction Monitoring Report
5/16	40161	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power Company's 2016 IRP and Application for Decertification of Plant Mitchell Units 3, 4A, and 4B, Kraft Unit 1 CT, and Intercession City CT
6/16	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Fourteenth Semi-Annual Vogtle Construction Monitoring Report
8/16	16-035-27	UT	Utah Office of Consumer Services	PacifiCorp	Renewable Energy Services Contract between Rocky Mountain Power and Facebook, Inc
8/16	16-035-01	UT	Utah Office of Consumer Services	PacifiCorp	2016 Energy Balancing Adjustment application
9/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Direct Testimony
11/16	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifteenth Semi-Annual Vogtle Construction Monitoring Report
11/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Rebuttal Testimony
11/16	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Direct
3/17	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Rebuttal
6/17	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixteenth Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
9/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Direct
11/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Surrebuttal
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Response
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Rebuttal to Response
12/17	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Direct
1/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Rebuttal
4/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Second Rebuttal
6/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighteenth Semi-Annual Vogtle Construction Monitoring Report
8/18	Cause 45052	IN	Indiana Coal Council	Vectren Energy Delivery of Indiana	Request for Approval of an 850 MW CCGT Plant
9/18	U-34836	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Authorization to Participate in a 50 MW Solar PPA
11/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Nineteenth Semi-Annual Vogtle Construction Monitoring Report
1/19	U-35019	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Authorization to Make Available Experimental Renewable Option and Rate Schedule RTO
4/19	42310-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2019 IRP Proceeding
11/19	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty/Twenty-First Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
5/20	43011-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power Fuel Cost Recovery Application (FCR-25)
6/20	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Second Semi-Annual Vogtle Construction Monitoring Report
7/20	17-035-61	UT	Utah Office of Consumer Services	Rocky Mountain Power	Approval of an Export Credit Rate for Customer Generators (Primarily Rooftop Solar)
9/20	20-035-04	UT	Utah Office of Consumer Services	Rocky Mountain Power	Utah Rate Case
10/20	2019-226-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina	Review of DESC's 2020 IRP
10/20	2019-227-E	SC	South Carolina Office of Regulatory Services	Lockhart Power Company	Review of Lockhart Power Company's 2020 IRP
11/20	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Third Semi-Annual Vogtle Construction Monitoring Report
12/20	20-035-01	UT	Utah Office of Consumer Services	Rocky Mountain Power	Application for Approval of the 2020 Energy Balancing Account
2/21	2019-224 and 225-E	SC	South Carolina Office of Regulatory Services	Duke Energy Carolinas and Duke Energy Progress	Review of Duke Energy's 2020 IRP
6/21	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Fourth Semi-Annual Vogtle Construction Monitoring Report
9/21	U-35927	LA	Louisiana Public Service Commission	1803 Electric Cooperative	Compliance with MBM Order in Conducting RFP and Acquiring Resources
12/21	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Fifth Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
5/22	44160-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2022 IRP Proceeding
6/22	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Sixth Semi-Annual Vogtle Construction Monitoring Report
12/22	22-035-01	UT	Utah Office of Consumer Services	Rocky Mountain Power	Application for Approval of the 2022 Energy Balancing Account
12/22	2022-259-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina, Inc.	Mid-Period Adjustment to Increase Base Rates for the Recovery of Electric Fuel Costs
1/23	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Seventh Semi-Annual Vogtle Construction Monitoring Report
06/23	2023-9-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina, Inc.	Review of DESC's 2023 IRP
7/23	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Eighth Semi-Annual Vogtle Construction Monitoring Report
09/23	2023-154-E	SC	South Carolina Office of Regulatory Services	South Carolina Public Service Authority	Review of Santee Cooper's 2023 IRP
11/23	23-0735-E	WV	West Virginia Energy Users Group	Mon Power and Potomac Edison	Expanded Net Energy Cost proceeding.
12/23	U-36974	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Application for Certification of a Capacity Purchase Agreement.

ADDITIONAL JUDICIAL PROCEEDINGS AND OTHER PROJECT INFORMATION

- 1995 – 2000 - Modeled the Singapore Power Electricity System and analyzed the benefits of dispatching a new oil-fired unit within the system, BHP Power

- 1995 – 2000 - Modeled the Australian National Energy Market to develop market based energy price forecasts on behalf of an Independent Power Producer in Australia, BHP Power
- 1995 – 2000 - Analyzed the benefit of purchasing existing gas-fired steam turbine units within the Australian market, BHP Power
- 1995 – 2000 Developed market price forecasts for South Australia as part of the evaluation of a new gas fired combined cycle unit, BHP Power
- 1995 – 2000 - Modeled the Vietnam Electricity System as part of a project to develop Least Cost Expansion plans for Vietnam, EVN State Utility
- 1995 – 2000 - Assisted in the evaluation of Phu My CCGT power plant in Vietnam, BHP Power
- 1995 – 2000 - Assisted in the development of Market Price Forecasts in several regions of the US. These forecasts were used as the basis for stranded cost estimates, which were filed in testimony in a number of jurisdictions across the country.
- 1995 – 2000 - Conducted research regarding ISO Tariffs and Operations for the PJM Power Pool, the California ISO, and the Midwest ISO on behalf of a Japanese Research.
- 1995 – 2000 - Performed research on numerous electric utility issues for 3 Japanese research organizations. This was primarily related to deregulation issues in the US in anticipation of deregulation being introduced in Japan.
- 1995 – 2000 - Critiqued the IRP filings of 5 utilities in South Carolina on behalf of the South Carolina State Energy Office
- 1999 - Helped to analyze the rate structure and develop an electricity price forecast for the Metropolitan Atlanta Rapid Transit Authority (MARTA) in Atlanta, Georgia
- August 2002 – Expert Report, Civil Action No. 1:00-cv-1262 in the United Stated District Court for the Middle District of North Carolina, United States v. Duke Energy Corporation, Department of Justice
- 2002 - Worked on behalf of the Utah Committee of Consumer Services to provide guidance and assist in the analysis of PacifiCorp's 2002 Integrated Resource Plan.
- July 2003 - Worked on behalf of the Oregon Public Utility Commission to Audit PacifiCorp's Net Power Costs per a Settlement Agreement accepted by the Public Utility Commission of Oregon in its Order No. 01-787. Audit report in Docket No. UE-116 filed July 2003.
- 2003 - Regulatory support to the Utah Committee of Consumer Services regarding PacifiCorp's 2003 Utah General Rate Case Docket # 03-2035-02.

- 2004 – Assistance to the Utah Committee of Consumer Services to analyze a series of power purchase agreements and special contracts between PacifiCorp and several of its industrial customers.
- 2005 - Worked on behalf of the Utah Committee of Consumer Services to help analyze PacifiCorp's restructuring proposals.
- 2005 - Assisted the Utah Committee of Consumer Services by evaluating PacifiCorp's 2005 IRP and assisted in writing comments that were filed with the Commission.
- 2007 - Assisted the Utah Committee of Consumer Services to evaluate PacifiCorp's 2007 IRP.
- 2007 - Conducted an investigation of the Southern Company interchange accounting and fuel accounting practices on behalf of the Georgia Public Service Commission Staff (Docket 21162-U).
- 2008 - Assisted the Louisiana Public Service Commission Staff with the review and evaluation of Cleco Power's 2008 Short Term RFP and its 2010 Long-Term RFP.
- 2008 - Assisted the Utah Committee of Consumer Services by participating in a collaborative process to develop an avoided cost tariff for large QFs.
- 2008 - Assisted the Louisiana Public Service Commission Staff with a rulemaking for the opportunity to implement a Renewable Portfolio Standard in Louisiana. (Docket No. R-28271 Sub-Docket B)
- April 2011 – Initial Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States v.Detroit Edison
- June 2011 – Rebuttal Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States Detroit Edison
- 2011 - Assisted the Georgia Public Service Commission Staff to investigate the acquisition of additional coal and combustion turbine capacity currently wholesale capacity (Docket 26550).
- 2012 - Assisted the Louisiana Public Service Commission Staff with a rulemaking to design Integrated Resource Planning ("IRP") rules. (Docket No. R-30021)
- December 2013 – Expert Report, Civil action no. 4:11-cv-00077-RWS, on behalf of the Department of Justice in US District Court, United States v. Ameren Missouri.

PUBLICATIONS AND PRESENTATIONS

Co-authored "Review of EPA's Section 111 May 23, 2023 Proposed Rule for the State of South Carolina", on behalf of South Carolina Office of Regulatory Staff, August 2023.

Co-authored "Review of EPA's Section 111(d) CO_2 Emission Rate Goals for the State of Montana, on behalf of the Montana Large Customer Group, October 2014.

Authored "Singapore's Developing Power Market", which appeared in the July/August 1999 edition of Power Value Magazine

Co-authored "The New Energy Services Industry – Part 1", which appeared in the January/February 1999 edition of Power Value Magazine.

Co-authored and Presented "Evaluation of a Large Number of Demand-Side Measures in the IRP Process: Florida Power Corporation's Experience", Presented at the 3rd International Energy and DSM Conference, Vancouver British Columbia, November 1994

Co-authored "Impact of DSM Program on Delmarva's Integrated Resource Plan", Published in the 4th International Energy and DSM Conference Proceedings, held in Berlin, Germany, 1995

Presentation – Law Seminars International, Electric Utility Rate Cases, Case Study of the Louisiana Public Service Commission's Quick Start Energy Efficiency Program, March 2015.

EXHIBIT

STF-NHW-3

EDUCATION

M.S. Operations Research, Georgia Institute of Technology, 2017
B.S. Mathematics, Georgia Southern University, 2012

PROFESSIONAL AFFILIATIONS

Women's Energy Network, Greater Atlanta Chapter – Board Member (2019 – 2023)
Women's Energy Network, Greater Atlanta Chapter – Member (2016 – Present)

EXPERIENCE

Ms. Wellborn has been working in regulated energy markets since early 2013. She has an undergraduate degree in mathematics and graduate degree in operations research. She started her career working at J. Kennedy and Associates, Inc., and sub-contracting to Hayet Power Systems Consulting. For these companies, she provided critical support in the areas of production cost modeling and data analysis through 2018. Ms. Wellborn then spent nearly 3 years at Accenture, supporting its global regulated energy team within the procurement practice, helping large commercial and industrial clients manage their energy spend and energy related initiatives, as they related to regulated utility tariffs, economic dispatch, planning, and market risk (energy efficiency, green tariffs, PPA/VPPA, etc.). Ms. Wellborn rejoined J. Kennedy and Associates in late 2021, and currently provides analytical support to clients in the areas of utility resource planning and market modeling.

2021 to Present: **J. Kennedy and Associate, Inc.**
Manager, Consulting

Performs analysis and prepares expert witness testimony on utility planning studies and economic evaluations in review of electric utility regulatory filings. Clients included State Public Service Commissions, Industrial Users Groups, and Consumer Advocacy Groups.

2019 to 2021: **Accenture, LLP**
Associate Manager, Global Lead - Regulated Energy Procurement

As a part of Accenture Operations' Energy Management and Procurement practice, the Regulated Energy team helps clients identify opportunities for electricity and natural gas cost savings through data analysis and deep industry experience. Clients include large industrial and commercial end-use customers with locations spread across multiple geographies and utility service territories.

• Conducts tariff optimization analysis and ad hoc economic decision analysis for clients with operations and energy spend in areas served by regulated electricity and natural gas distribution utilities.

• Leads cross functional international delivery team of 10, providing career counseling and project oversight. Supports international energy procurement functions as they relate to regulated utilities/energy markets of Australia, Southeast Asia, and Latin America.
• Manages project assessments and economic studies as they relate to resource planning or capacity/energy market risk and dispatch pricing (renewables, time-of-use tariffs, real-time-pricing/avoided cost, PPA, VPPA, etc.)
• Collaborates with all energy management work streams - including utility bill management, renewable energy procurement, deregulated markets competitive sourcing, market intelligence, and project management/technology development initiatives to manage customer spend end to end.

2013 to 2019: **J. Kennedy and Associate, Inc.**
Senior Consultant

Responsible for conducting research, performing data analysis, developing production-cost model input assumptions and running production-cost studies, analyzing model output, and conducting related economic studies.

CERTIFICATIONS

Energy Exemplar – Aurora Core Certification Course (March 2022)
Energy Exemplar – PLEXOS Power Core Certification Course (June 2023)

CLIENTS SERVED

Georgia Public Service Commission Staff
Louisiana Public Service Commission Staff
Kentucky Industrial Utility Customers, Inc.
Utah Office of Consumer Services
South Carolina Office of Regulatory Staff
Wisconsin Industrial Energy Group

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
06/18	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Eighteenth Semi-Annual Vogtle Construction Monitoring Report
11/18	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Nineteenth Semi-Annual Vogtle Construction Monitoring Report
5/22	44160	GA	Georgia Public Service Commission Staff	Georgia Power	2022 Integrated Resource Plan (Supply Side Resource Plan, Aurora)
10/22	44280	GA	Georgia Public Service Commission Staff	Georgia Power	2022 Rate Case (Revenue Forecast)
8/23	2023-9-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	2023 Integrated Resource Plan
12/23	2023-154-E	SC	South Carolina Office of Regulatory Staff	South Carolina Public Service Authority (Santee Cooper)	2023 Integrated Resource Plan
12/23	36974	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Application for Certification of a Capacity Purchase Agreement.

REPORTS AND INDUSTRY PUBLICATIONS

Date	Title	Author(s)
8/23	Review of EPA's Section 111 May 23, 2023 Proposed Rule for the State of South Carolina	J. Kennedy and Associates, Inc. (On behalf of the South Carolina Office of Regulatory Staff)

EXHIBIT

STF-NHW-4

Company Load and Resource Balance without Planned Resources (based on Staff's load forecast and TRM)

Table A	Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
line	**Owned Generating Capacity (MW))**	**14,770**	**15,403**	**15,405**	**15,737**	**15,737**	**14,732**	**14,734**	**14,734**	**14,734**	**14,734**	**14,734**	**14,044**
1	As modeled by GPC	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013
2	Hydro Modernization Adjustment	0	0	0	31	31	31	31	31	31	31	31	31
3	Mossy Branch Availability (2025-2026)	0	62	62	0	0	0	0	0	0	0	0	0
4	Staff assumed extensions Scherer and Gaston	0	0	0	0	0	0	0	0	0	0	0	0
line	**Proposed Resource Capacity (MW)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	GPC Proposed MPC PPA less Sale	0	0	0	0	0	0	0	0	0	0	0	0
6	GPC Proposed Santa Rosa PPA	0	0	0	0	0	0	0	0	0	0	0	0
7	GPC Proposed Robins BESS	0	0	0	0	0	0	0	0	0	0	0	0
8	GPC Proposed Moody BESS	0	0	0	0	0	0	0	0	0	0	0	0
9	GPC Proposed Co-located Solar + BESS	0	0	0	0	0	0	0	0	0	0	0	0
10	GPC Proposed Yates 8-10	0	0	0	0	0	0	0	0	0	0	0	0
11	GPC Proposed Remaining 1000 MW BESS	0	0	0	0	0	0	0	0	0	0	0	0
12	**Purchased Generating Capacity (MW)**	**4,535**	**5,149**	**5,222**	**5,222**	**5,478**	**5,178**	**5,178**	**3,124**	**3,124**	**3,069**	**3,066**	**1,749**
13	Existing Contracts	4,535	5,149	5,222	5,222	5,478	5,178	5,178	3,124	3,124	3,069	3,066	1,749
14	2022 IRP Planned Renewable	0	0	0	0	0	0	0	0	0	0	0	0
15	2022 IRP Planned ESS	0	0	0	0	0	0	0	0	0	0	0	0
16	**Dispatchable DSOs (MW)**	**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**
17	Existing Programs (CVR, DPEC, RTP, TempCheck)	675	675	669	669	657	602	604	602	601	601	601	601
18	DER Customer Program (2022 IRP)	0	21	47	89	148	148	148	148	148	148	148	148
19	Staff Assumed Additional Demand Response												
20	**Total Capacity (MW)**	**19,980**	**21,248**	**21,343**	**21,718**	**22,020**	**20,661**	**20,663**	**18,608**	**18,607**	**18,552**	**18,548**	**16,542**
21	**Winter Peak Demand Forecasts**												
22	Uniform w/Delays P95	15,202	15,513	16,041	17,699	18,470	19,084	19,768	20,375	20,666	20,888	21,040	21,145
23	**Winter Target Reserve Margin (Staff)**	22.94%	22.94%	22.94%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%
24	**Capacity Required to Meet Target (MW)**												
25	Uniform w/Delays P95	(1,291)	(2,176)	(1,622)	**143**	**793**	**2,911**	**3,753**	**6,559**	**6,919**	**7,248**	**7,440**	**9,576**

Staff Plan (based on Staff's load forecast and TRM)

Table B	Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
line	**Owned Generating Capacity (MW))**	**14,770**	**15,403**	**15,405**	**15,737**	**15,737**	**15,743**	**15,744**	**15,744**	**15,744**	**15,744**	**15,744**	**15,055**
1	As modeled by GPC	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013
2	Hydro Modernization Adjustment	0	0	0	31	31	31	31	31	31	31	31	31
3	Mossy Branch Availability (2025-2026)	0	62	62	0	0	0	0	0	0	0	0	0
4	Staff assumed extensions Scherer and Gaston	0	0	0	0	0	1,011	1,011	1,011	1,011	1,011	1,011	1,011
line	**Proposed Resource Capacity (MW)**	**239**	**239**	**750**	**980**	**980**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	GPC Proposed MPC PPA less Sale	239	239	750	750	750	0	0	0	0	0	0	0
6	GPC Proposed Santa Rosa PPA	0	0	0	230	230	0	0	0	0	0	0	0
7	GPC Proposed Robins BESS	0	0	0	0	0	0	0	0	0	0	0	0
8	GPC Proposed Moody BESS	0	0	0	0	0	0	0	0	0	0	0	0
9	GPC Proposed Co-located Solar + BESS	0	0	0	0	0	0	0	0	0	0	0	0
10	GPC Proposed Yates 8-10	0	0	0	0	0	0	0	0	0	0	0	0
11	GPC Proposed Remaining 1000 MW BESS	0	0	0	0	0	0	0	0	0	0	0	0
12	**Purchased Generating Capacity (MW)**	**4,535**	**5,159**	**5,237**	**5,321**	**5,576**	**5,905**	**5,905**	**3,886**	**3,924**	**3,906**	**3,940**	**2,661**
13	Existing Contracts	4,535	5,149	5,222	5,222	5,478	5,178	5,178	3,124	3,124	3,069	3,066	1,749
14	2022 IRP Planned Renewable	0	10	15	98	98	252	252	287	325	362	400	437
15	2022 IRP Planned ESS	0	0	0	0	0	475	475	475	475	475	475	475
16	**Dispatchable DSOs (MW)**	**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**
17	Existing Programs (CVR, DPEC, RTP, TempCheck)	675	675	669	669	657	602	604	602	601	601	601	601
18	DER Customer Program	0	21	47	89	148	148	148	148	148	148	148	148
19	Staff Assumed Additional Demand Response												
20	**Total Capacity (MW)**	**20,219**	**21,497**	**22,108**	**22,796**	**23,098**	**22,398**	**22,401**	**20,381**	**20,417**	**20,400**	**20,433**	**18,465**
21	**Winter Peak Demand Forecasts**												
22	Uniform w/Delays P95	15,202	15,513	16,041	17,699	18,470	19,084	19,768	20,375	20,666	20,888	21,040	21,145
23	**Winter Target Reserve Margin (Staff)**	22.94%	22.94%	22.94%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%
24	**Capacity Required to Meet Target (MW)**												
25	Uniform w/Delays P95	(1,530)	(2,425)	(2,387)	(935)	(285)	**1,173**	**2,015**	**4,786**	**5,109**	**5,400**	**5,555**	**7,653**

Staff Illustrative (Uniform with Delays P80)

Table C	Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
line	**Owned Generating Capacity (MW))**	**14,770**	**15,403**	**15,405**	**15,737**	**15,737**	**15,743**	**15,744**	**15,744**	**15,744**	**15,744**	**15,744**	**15,055**
1	As modeled by GPC	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013
2	Hydro Modernization Adjustment	0	0	0	31	31	31	31	31	31	31	31	31
3	Mossy Branch Availability (2025-2026)	0	62	62	0	0	0	0	0	0	0	0	0
4	Staff assumed extensions Scherer and Gaston	0	0	0	0	0	1,011	1,011	1,011	1,011	1,011	1,011	1,011
line	**Proposed Resource Capacity (MW)**	**239**	**239**	**750**	**750**	**750**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	GPC Proposed MPC PPA less Sale	239	239	750	750	750	0	0	0	0	0	0	0
6	GPC Proposed Santa Rosa PPA	0	0	0	0	0	0	0	0	0	0	0	0
7	GPC Proposed Robins BESS	0	0	0	0	0	0	0	0	0	0	0	0
8	GPC Proposed Moody BESS	0	0	0	0	0	0	0	0	0	0	0	0
9	GPC Proposed Co-located Solar + BESS	0	0	0	0	0	0	0	0	0	0	0	0
10	GPC Proposed Yates 8-10	0	0	0	0	0	0	0	0	0	0	0	0
11	GPC Proposed Remaining 1000 MW BESS	0	0	0	0	0	0	0	0	0	0	0	0
12	**Purchased Generating Capacity (MW)**	**4,535**	**5,159**	**5,237**	**5,321**	**5,576**	**5,905**	**5,905**	**3,886**	**3,924**	**3,906**	**3,940**	**2,661**
13	Existing Contracts	4,535	5,149	5,222	5,222	5,478	5,178	5,178	3,124	3,124	3,069	3,066	1,749
14	2022 IRP Planned Renewable	0	10	15	98	98	252	252	287	325	362	400	437
15	2022 IRP Planned ESS	0	0	0	0	0	475	475	475	475	475	475	475
16	**Dispatchable DSOs (MW)**	**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**
17	Existing Programs (CVR, DPEC, RTP, TempCheck)	675	675	669	669	657	602	604	602	601	601	601	601
18	DER Customer Program	0	21	47	89	148	148	148	148	148	148	148	148
19	Staff Assumed Additional Demand Response												
20	**Total Capacity (MW)**	**20,219**	**21,497**	**22,108**	**22,566**	**22,868**	**22,398**	**22,401**	**20,381**	**20,417**	**20,400**	**20,433**	**18,465**
21	**Winter Peak Demand Forecasts**												
22	Uniform w/Delays P80	15,167	15,420	15,792	17,315	17,990	18,504	19,095	19,627	19,897	20,109	20,257	20,359
23	**Winter Target Reserve Margin (Staff)**	22.94%	22.94%	22.94%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%
24	**Capacity Required to Meet Target (MW)**												
25	Uniform w/Delays P80	(1,573)	(2,539)	(2,693)	(1,180)	(648)	**456**	**1,184**	**3,862**	**4,158**	**4,438**	**4,587**	**6,681**

EXHIBIT

STF-NHW-5

Combustion Turbine Frame											
	GPC 2023 IRP Update	GPC 2022 IRP	Duke 2023 IRP	Santee Cooper 2023 IRP		DESC 2023 IRP		1803 2023 IRP Frame	EIA AEO 2023 Frame	NREL ATB 2023 Mod F-Frame	Entergy 2023 IRP CT (M501JAC)
				(H-Class)	(F-Class)	Frame 1x	Frame 2x				
Dollars			2023	2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			425	402	230	262	523	237	237	233	365
Capital Cost ($/kW)			750-900	699	744	1,402	1,154	782	867	1,069	925
Fixed O&M ($/kW-yr.)				4.8	7.7			7.92	7.88	25.59	6.66
Variable O&M ($/MWh)				11.42	8.53			5.09	5.06	6.92	14.74
Average Heat Rate (MBTU/MWh)			9,270	9,160	10,021			9,905	9,905	9,717	9,165

Combined Cycle 1x1										
	GPC 2023 IRP Update	GPC 2022 IRP	Santee Cooper 2023 IRP		DESC 2023 IRP (1x1)	1803 2023 IRP 1x1	EIA AEO 2023 (Single-Shaft 1x1x1)	Lazard 2023 LCOE (Low) (New Build)	Lazard 2023 LCOE (High) (New Build)	Entergy 2023 IRP Data Filing (1x1)
			1x1 7HA.03 w/ACC	1x1 7FA.05 w/ACC						
Dollars			2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			630	357	650	418	418	550	550	525
Capital Cost ($/kW)			1,103	1,702	1,452	1,204	1,330	650	1,300	1,156
Fixed O&M ($/kW-yr.)			7.31	11.05		15.94	15.87	10.00	17.00	18.43
Variable O&M ($/MWh)			2.68	3.11		2.88	2.87	2.75	5.00	3.47
Average Heat Rate (MBTU/MWh)			6,136	6,668		6,431	6,431	6,150	6,900	6,375

Onshore Wind											
	GPC 2023 IRP Update	GPC 2022 IRP	Duke 2023 IRP	Santee Cooper 2023 IRP	DESC 2023 IRP	EIA AEO 2023	NREL ATB 2023 (Mod)	Entergy 2023 IRP Data Filing	1803 2023 IRP	Lazard 2023 LCOE (Low)	Lazard 2023 LCOE (High)
Dollars	[redacted]		2023	2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			800	100	100	400	1,000	600	50	1,000	1,000
Capital Cost ($/kW)			4,150-4,850	3,952	4,323	6,672	2,572	3,620	2,618	3,000	5,000
Fixed O&M ($/kW-yr.)				118.73		123.81	112.09	76.95	117.68	60.00	80.00

Solar											
	GPC 2023 IRP Update	GPC 2022 IRP	Duke 2023 IRP	Santee Cooper 2023 IRP	DESC 2023 IRP	EIA AEO 2023	NREL ATB 2023 (Mod)	Entergy 2023 IRP Data Filing	1803 2023 IRP	Lazard 2023 LCOE (Low)	Lazard 2023 LCOE (High)
Dollars	[redacted]		2023	2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			75	100	75	150	100	100	50	150	150
Capital Cost ($/kW)			1,850	1,402	1,240	1,448	1,381	1,063	1,256	700	1,400
Fixed O&M ($/kW-yr.)				22.24		17.16	23.11	10.52	22.76	7.00	14.00

Battery Storage									
	GPC 2023 IRP Update (4 Hour)	GPC 2022 IRP	Duke 2023 IRP (4 Hour)	Santee Cooper 2023 IRP (4 Hour)	DESC 2023 IRP (4 Hour)	EIA AEO2023 (4 Hour)	NREL ATB 2023 (Mod) (4 Hour)	Entergy 2023 IRP (4 Hour)	1803 2023 IRP
Dollars			2023	2022	2022	2022	2022	2022	2022
Capacity (MW)			100	100	100	50	60	50/200	50
Capital Cost ($/kW)			2,250	1,757	1,459	1,270	1,844	1,171	1,593
Fixed O&M ($/kW-yr.)				43.92		45.75	46.10	13.39	39.85

Nuclear (Small Modular Reactor)									
	GPC 2023 IRP Update	Duke 2023 IRP	Santee Cooper 2023 IRP 12x60 MW	DESC 2023 IRP	EIA AEO2023	NREL ATB 2023 (Mod)	1803 2023 IRP	Lazard 2023 LCOE (Low) (New Build)	Lazard 2023 LCOE (High) (New Build)
Dollars		2023	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)		300	683	274	600		600	2,200	2,200
Capital Cost ($/kW)		6,450	5,986	12,354	7,590	7,493	7,892	8,475	13,925
Fixed O&M ($/kW-yr)			95.50		106.92	163.53	107.43	131.50	152.75
Variable O&M ($/MWh)			11.65		3.38	2.66	3.39	4.25	5.00
Average Heat Rate (MBTU/MWh)		10,551	10,900		10,447	10,447	10,443	10,450	10,450

Medium Duration Energy Storage System	
	GPC 2023 IRP Update
Dollars	[redacted]
Capacity (MW)	
Capital Cost ($/kW)	
Fixed O&M ($/kW-yr)	
Variable O&M ($/MWh)	

EXHIBIT

STF-NHW-6

Staff Ranking Analysis						
		NPV ($000)	Cost (Savings)	Winter MW	NPV $/kW	Drop
Round 1	**ALL ON (BASE)**	[redacted]	[redacted]		[redacted]	
	REMOVE COLOCATED SOLAR+BESS			200		
	REMOVE MOODY			45		
	REMOVE ROBINS			115		
	REMOVE SANTA ROSA			230		
	REMOVE YATES			1,070		x
Round 2	**REMOVE YATES (BASE)**					
	REMOVE COLOCATED SOLAR+BESS			200		x
	REMOVE MOODY			45		
	REMOVE ROBINS			115		
	REMOVE SANTA ROSA			230		
Round 3	**REMOVE COLOCATED SOLAR+BESS (BASE)**					
	REMOVE MOODY			45		x
	REMOVE ROBINS			115		
	REMOVE SANTA ROSA			230		
Round 4	**REMOVE MOODY (BASE)**					
	REMOVE ROBINS			115		x
	REMOVE SANTA ROSA			230		

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S 2023	**)**	**DOCKET NO. 55378**
INTEGRATED RESOURCE PLAN UPDATE	**)**	

DIRECT TESTIMONY
OF
JOHN L. KADUK

On Behalf of the

Georgia Public Service Commission

Public Interest Advocacy Staff

February 15, 2024

DIRECT TESTIMONY OF
JOHN L. KADUK

IN THE MATTER OF GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE

DOCKET NO. 55378

I. INTRODUCTION

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

A. I am a Senior Public Utilities Engineer in the Energy Efficiency and Renewable Energy Unit with the Georgia Public Service Commission ("Commission"). My business address is 244 Washington Street SW, Atlanta, GA 30334.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My educational background and work experience are provided in my resume, which is attached as Staff Exhibit_JLK-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified in Docket No. 31081, Georgia Power Company's 2010 Integrated Resource Plan; Docket No. 36498, Georgia Power Company's 2013 Integrated Resource Plan; Docket No. 38877, Georgia Power Company's Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements; Docket No. 40161, Georgia Power Company's 2016 Integrated Resource Plan; Docket No. 41596,

Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements; Docket No. 41734, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements for the Commercial and Industrial Program; Docket No. 42310, Georgia Power Company's 2019 Integrated Resource Plan; Docket No. 42625, Georgia Power Company's Application for the Certification of the 2020/2021 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements; Docket Nos. 4822, 16573 and 19279, Georgia Power Company's Avoided Cost Dockets; and Docket No. 43814, Georgia Power Company's Application for the Certification of the 2022/2023 Utility Scale Renewable Power Purchase Agreements.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am testifying on behalf of the Commission Public Interest Advocacy Staff ("Staff").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address Georgia Power Company's ("Georgia Power" or "Company") request for new customer-sited programs, customer demand response program, the Company's request to amend its Certificate of Public Convenience and Necessity ("Certificate") for the Thermostat Demand Response ("TSTAT DR" or "Temp Check") Demand Side Management ("DSM") Program, and the reasonable capacity equivalence of a current renewable plus battery storage procurement used by Georgia Power in its 2023 Integrated Resource Plan Update ("2023 IRP Update") proceeding.

II. PROGRAMS AND TARIFFS

Q. IN ITS 2023 IRP UPDATE, DID THE COMPANY PROPOSE ANY NEW CUSTOMER PROGRAMS?

A. Yes. Georgia Power is proposing several new programs to leverage customer-sited resiliency resources that can also provide system reliability for the benefit of all customers. The proposed programs are the distributed energy resource ("DER") Colocation Program, the DER Customer Owned Program, and the Curtailable Load Program.

Q. IN ITS IRP UPDATE, DID THE COMPANY PROPOSE MODIFICATIONS TO ANY OF ITS EXISITNG DSM PROGRAMS?

A. Yes. Georgia Power is proposing to expand its currently certified Residential Thermostat DR Program.

Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED DER PROGRAMS.

A. The proposed DER programs are designed to add capacity to the system, although the Company has not provided an estimate of such capacity in its resource ledger. When asked during cross examination, if these programs have a defined capacity contribution on the resource ledger, Company witnesses responded with "No, not yet." (Transcript ("Tr.") at 329). Company witnesses stated that it would be difficult to estimate how to reflect the capacity contribution of the proposed DER programs due to uncertainty around the timeline for construction of the resources, and if it is a new facility, when that facility would come online (Tr. at 330). The proposed DER Colocation Program ("DCL-1 tariff") is designed for qualifying commercial and industrial customers, whereby Georgia Power will own,

operate, maintain, and control dispatchable DER at customer premises, and economically dispatch the resources to provide energy and capacity benefits to all customers. The proposed DER Customer Owned Program ("DCO-1 tariff") is designed for qualifying commercial and industrial customers whereby Georgia Power will operate and control customer-owned, new dispatchable DER located at customer premises and economically dispatch the resources to provide energy and capacity benefits to all customers.

Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED CURTAILABLE LOAD PROGRAM.

A. The Curtailable Load Program ("CL-1 tariff") is proposed to enable demand response of commercial and industrial customer loads during extreme supply and demand conditions thereby providing system capacity and reliability benefits to all customers. As proposed, the CL-1 tariff will be available to qualifying commercial and industrial customers for long-term commitments to reduce their load.

Q. DID THE COMPANY PROVIDE TARIFFS FOR ITS PROPOSED DER PROGRAMS?

A. Yes. Although the Company did not provide tariffs in its original IRP Update, proposed tariffs were filed on January 11, 2024.

Q. HAS THE COMPANY PROVIDED TARIFFS FOR PROPOSED DER PROGRAMS IN PREVIOUS IRPS?

A. No. The Company usually files new and modified tariffs as part of its Rate Case proceedings. In the 2022 IRP proceeding, the Company proposed a DER Customer

Program to be implemented through a Demand Response Credit Tariff ("DRC-1") and the Resilience Asset Service Tariff ("RAS-1") on a pilot basis with an overall cap of 250 megawatts ("MW"). The tariffs and associated contract terms and conditions were not provided during the IRP proceedings; however, the Company was ordered by the Commission to design the tariffs in a manner that will eliminate, to the extent reasonably possible, any potential that non-participating customers will be harmed. Within four months following the issuance of the Commission's 2022 IRP Order Adopting Stipulation, the Company was to collaborate with the Commercial Group and Staff on the development of the elements in the DER pilot program tariffs. Following this collaboration, the Company filed the DRC-1 and RAS-1 tariffs for Commission approval.

Q. DID GEORGIA POWER DESIGN OR MODEL ITS PROPOSED DER PROGRAMS AFTER ANY OTHER UTILITY PROGRAMS?

A. No. During the Direct Hearing, the Company's witnesses stated that the proposed DER programs were not modeled after any other utility (Tr. at 248). Staff is aware that similar programs exist such as Power Through for Entergy Arkansas.

Q. DOES STAFF HAVE ANY CONCERNS REGARDING THE DER COLOCATION PROGRAM?

A. Yes. Staff is concerned that costs for participating customers may be paid for by non-participating customers. As proposed, the program is designed for participants to be able to lower their resiliency costs and at the same time provide capacity at a lower capacity cost for all customers. The Company's witnesses in the Direct Hearing were asked about whether the Company anticipates any situation in which nonparticipating customers would

be responsible for paying for the cost of this program, where a customer fails to make a payment. Company witnesses responded that they do not foresee such costs being at risk to non-participating customers. Specifically, "unlike our current DER programs, those aren't going to be paid for over a period of time over the contract. Those are going to be paid for up front." (Tr. at 250). However, Staff would like assurances from the Company that the DCL-1 tariff will not assign any participating customer program costs to non-participating customers. The current proposed limitations on the size of DERs to be deployed for the DCL-1 tariff is set at a minimum nameplate capacity of 10 MW, which is different from the similarly designed DCO-1 tariff. There are also no proposed maximum or corresponding customer load requirements in the tariff.

Q. WHAT IS STAFF'S RECOMMENDATION FOR THE DER COLOCATION PROGRAM?

A. Staff recommends approval of the DER Colocation Program and associated tariff with a few modifications. Since this program is similar to the Company's proposed DER Customer Owned Program, Staff recommends that the two programs have similar structure regarding the size of the DER. Georgia Power's proposed DCO-1 tariff DER size limits are proposed to be no less than 1 MW, but no greater than 10 MW. Staff recommends mirroring this limitation in the DCL-1 tariff. The DCL-1 tariff is similar to Georgia Power's RAS-1 tariff which was approved in the Company's 2022 IRP docket. The RAS-1 tariff put a limit on the size of the Company-installed DER at the participating customer's annual peak load at the premises served under the schedule. Staff recommends setting the limit on the installed DER to match the customer's annual peak load at the premises, up to, but not exceeding the program maximum DER size limit.

Q. DOES STAFF HAVE ANY CONCERNS REGARDING THE DER CUSTOMER OWNED PROGRAM?

A. Yes. As proposed, the program is similar to the DER Colocation Program in that it is designed for participants to be able to lower their resiliency costs and at the same time provide capacity at a lower capacity cost for all customers. Georgia Power's witnesses stated during cross examination, "Unlike the current program where those payments are done over a contract period, for the -- for the co-location, not the customer-owned, because the customer-owned, there is no -- there is no payment from the customer; right? They are buying their own asset and participating in our program." (Tr. at 249). However, Staff would like assurances from the Company that the DCO-1 tariff will not assign any participating customer program costs to non-participating customers. There are also no proposed maximum or corresponding customer load requirements in the tariff.

Q. WHAT IS STAFF'S RECOMMENDATION FOR THE DER CUSTOMER OWNED PROGRAM?

A. Staff recommends approval of the DER Customer Owned Program and associated tariff with one modification. Staff recommends that the size of the DER be capped at the participating customer's annual peak load at the premises served as opposed to the Company's proposed uncapped amount.

Q. WHAT IS STAFF'S RECOMMENDATION FOR THE CURTAILABLE LOAD PROGRAM?

A. Staff recommends approval of the CL-1 tariff with one modification. Building upon the Company's Demand Plus Energy Credit ("DPEC") Program's design, the CL-1 tariff

lengthens a participating customer's commitment to the program. Both programs credit customers that provide demand reduction of at least 200 kilowatts ("kW"), upon request by Georgia Power during extreme supply and demand conditions. The DPEC-4 tariff currently has a 1-year term. The CL-1 establishes a rolling term of 6 years that is automatically renewed each year unless it is declined by either party. Staff recommends that the CL-1 tariff be modified to change all instances of the word "Customer" to "customer", where appropriate, for consistency of defined terms.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISIONS TO THE TSTAT DR PROGRAM.

A. The Company requested to amend its Certificate for the Residential TSTAT DR Program pursuant to O.C.G.A. § 46-3A-6 and Commission Rule 515-3-4-.10. The Commission certified the program in the 2022 DSM Plan in Docket No. 44161. The Company requested to expand the current program enrollment from 25,000 participants to 50,000 participants. Additionally, the Company stated that the program now reflects a positive Total Resource Cost value and therefore no longer requires a waiver of Commission Rule 515-3-4-.04(4)(a)(3) as was approved in the 2022 IRP Order Adopting Stipulation.

Q. PLEASE DESCRIBE THE CURRENT TSTAT DR PROGRAM PERFORMANCE AND SAVINGS.

A. The TSTAT DR Program was originally certified in the 2019 IRP to serve residential customers of both single-family and multi-family buildings with central heating, ventilation, and air conditioning ("HVAC") systems. This program allows the Company to make event calls that adjust participating customers' thermostat behavior during a

limited period. The Company pays participating customers an incentive for this ability. Participants can either bring their own thermostat ("BYOT") or purchase a new thermostat through the Georgia Power Marketplace. The program was certified in the 2022 IRP with 25,000 participants with a projected demand savings of up to 18,000 kW. The program provides a one-time $50 incentive for new BYOT participants, and all other existing enrolled customers receive up to an annual $25 incentive to continue participation. The TSTAT DR Program has been called by the Company between four and eight times per year since 2020. The demand savings for 2023 in the summer months averaged 21,186 kW per event, while the winter demand savings averaged 18,302 kW per event. Program participation in 2023 for summer months averaged 21,988 customers and in winter months participation averaged 15,048 customers.

Q. WHAT ARE THE EXPECTED ANNUAL DEMAND SAVINGS IF THE COMPANY'S REQUEST TO DOUBLE CUSTOMER PARTICAPTION IS APPROVED?

A. The Company's request to double participants to 50,000 would increase the projected annual demand reduction for this program to 37,000 kW.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE PROPOSED CHANGE TO THE THERMOSTAT DEMAND RESPONSE PROGRAM?

A. Staff recommends approval of the Company's request to amend the Certificate for the Residential TSTAT DR Program. Staff anticipates robust participation in the program and that the increase in projected demand reduction for this program will be realized. As the Company stated in its Direct Testimony on Page 49, lines 3-7, further residential load

flexibility exists. Staff agrees that further expansion of this program is very likely. Staff further recommends that the Company continue to evaluate the potential of this program for the upcoming IRP to identify the optimal participation level for the program to cost effectively meet future demand reductions.

Q. DOES STAFF HAVE ANY RECOMMENDATIONS REGARDING OTHER DER PROGRAMS THAT COULD BE OFFERED TO GEORGIA POWER'S CUSTOMERS IN A FUTURE IRP?

A. Yes. Staff recommends that the Company research a residential and small commercial battery program to be considered by the Commission in the 2025 IRP. A pilot for residential and small commercial customers could help increase the number of customers eligible for the Company's DER program offerings while providing grid reliability and capacity benefits. The Company should research opportunities for a new pilot that can help provide reliability benefits to customers through the use of new dispatchable DER located on customers' premises while also providing capacity and energy benefits to all customers. Utilities in other jurisdictions have begun implementing such programs. Examples include Green Mountain Power's Tesla Powerwall and Bring Your Own Device programs, Duke Energy's PowerPair program, and Xcel Energy's Renewable Battery Connect program.

II. CAPACITY EQUIVALENCE OF PROJECTS WITH BATTERY STORAGE

Q. HOW DOES THE COMPANY VALUE CAPACITY IN MEETING ITS TARGET RESERVE MARGINS?

A. The Company's current target reserve margin is based on meeting its summer system peaking needs. The Company also has a planning reserve margin to meet its winter peaking needs. The timing of the resources Georgia Power is proposing to add in this IRP Update are primarily driven by capacity needs of its forecasted winter peaks. Georgia Power's planning resource ledger contains a capacity equivalence for all of its Company-Owned and contracted supply-side and demand-side resources. The Commission's 2022 IRP Order Adopting Stipulation directed Georgia Power to begin valuing intermittent supply-side resources, such as solar and wind technologies, using an effective load carrying capability ("ELCC") method when determining capacity value for procurement activities.

Q. HAS THE COMPANY USED THE ELCC METHOD FOR CALCULATING THE CAPACITY VALUE OF RENEWABLE RESOURCES AND/OR BATTERIES IN ITS 2023 IRP UPDATE FILING?

A. Yes. The Company used results from its ELCC study to value projects with solar, wind, or battery energy storage systems ("BESS").

Q. DID THE COMPANY ACCOUNT FOR RENEWABLE RESOURCES TO BE PROCURED IN FUTURE REQUEST FOR PROPOSALS ("RFP") IN ITS RESOURCE LEDGER?

A. Yes. The Company included ELCC capacity equivalence values for the projects that will be procured in the Company's 2023 Clean and Renewable Energy Subscription ("CARES") RFP and the Company's BESS RFP.

Q. PLEASE DESCRIBE THE CARES AND BESS RFPS.

A. The goal of the CARES RFP is to procure 3,350 MW of renewable resources with or without 2-hour minimum duration energy storage systems, including up to 650 MW of Carbon Free Energy-Around the Clock Resources. The first phase of the CARES RFP is for the procurement of up to 2,875 MW of resources with in-service dates in the 2026-2028 timeframe. The remaining MW not procured during the first phase will be targeted during the second phase of the CARES RFP. The Company's upcoming BESS RFP will seek to procure up to 500 MW of 2-hour minimum duration standalone energy storage systems with in-service dates to meet the Company's 2029 winter need but will also have an early commencement option.

Q. WHAT CAPACITY EQUIVALENCE DID THE COMPANY INCLUDE IN ITS RESOURCE LEDGER FOR THE TARGETED RESOURCES FOR BOTH RFPS?

A. The Company's capacity equivalence estimate for the first phase of the CARES RFP assumes that standalone solar projects will be awarded half of the 3,350 MW CARES target procurement amount. Standalone solar projects are given a 5% capacity equivalence in GPC's ELCC study from the 2022 IRP which equates to only 83.75 MW for the first phase of CARES. The Company's capacity equivalence estimate for the BESS RFP for standalone batteries is 95% which equates to 475 MW for the BESS RFP.

Q. HAVE PREVIOUS GEORGIA POWER RFPS PROCURED SOLAR PLUS BESS PROJECTS?

A. Yes. Previous utility scale RFPs have procured solar plus storage bids. The Company's 2020/2021 Renewable Energy Development Initiative RFP certified 408.5 MW of solar plus storage projects, out of a total procurement of 558.5 MW. The Company's 2022/2023

Utility Scale Renewable RFP certified 830 MW of solar plus storage projects, out of a total procurement of 970 MW. However, the certified 2022/2023 Utility Scale Renewable RFP projects that included storage were ultimately amended to allow the counterparties to perform in accordance with the performance metrics included in the certified power purchase agreements ("PPA") without installing a physical energy storage device on the project site. This was approved by the Commission due to the effects of Covid-19 and supply chain issues and to help preserve the low-priced PPA's for Georgia Power's customers. Prior RFPs have included different storage usage cases (e.g. smoothing, firming, shifting, scheduling) with a relatively small ratio of batteries to solar panels. The 2023 CARES RFP only allows a full Company controlled usage case of scheduling, with a higher ratio of batteries to solar panels (50% of the nameplate capacity of the solar resource).

Q. DOES STAFF RECOMMEND A CHANGE TO THE COMPANY'S CAPACITY EQUIVALENCE ASSUMPTIONS FOR EITHER RFP?

A. Yes. Staff estimates that 500 MW of solar paired with storage could be selected for procurement as part of the 2023 CARES RFP. These projects are required to be 2-hour minimum duration battery with solar projects, which are given a 100% capacity equivalence by the Company. In response to STF-PIA-9-14, the Company stated that if any bids with BESS are selected in the 2023 CARES RFP, with "batteries sized exactly at the minimum requirement of 50% of the nominal output of the attached solar, the site capacity equivalence will be 0.5 MW per 1 MW of solar."

At a 50% ratio, 500 MW of BESS would be paired with 1,000 MW of solar, for the first phase procurement target of 2,875 MW. Staff notes that the higher cost of including

storage as part of its bid may not be worth the additional evaluation credit provided to bidders. However, a conservative amount of solar plus storage projects is a reasonable expectation based on previous utility scale renewable RFP results and improving storage market conditions. The Staff Panel of Newsome/Hayet/Wellborn describe how the Company's modified load forecast and approval of only a subset of the Company's requested capacity additions is sufficient to meet its short-term capacity needs. Any additional MW recognized in the Company's resource ledger for the 2023 CARES RFP will reduce future capacity needs and/or move such needs to future years. The Company's resource ledger should reasonably account for 500 MW of winter capacity equivalence resulting from the first phase of the CARES RFP. The requested in-service date for the winning projects from the first phase is no later than 2028 but could be as early as 2026. This additional capacity could reduce the need for future capacity procurements. If such resources are not ultimately certified in the 2023 CARES RFP, the second phase of CARES should provide additional information to developers regarding the value of solar paired with storage to encourage bids for projects that provide a higher capacity equivalence value.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Errata to Pre-filed Testimony of Newsome, Hayet, and Wellborn

Page and Line Number	Change
Page 74, line 10	Insert at start of line before the word "Details" the following: "Staff assumed that the PTC for the Co-located BESS + Solar resource would be spread out over the life of the unit in its ECC revenue requirement modeling. Had Staff captured the full value of the PTC within the first ten years of operation, Co-located BESS + Solar would have ranked fourth and Moody BESS fifth."

Errata to Pre-filed Testimony of Thomas Newsome, Philip Hayet, and Leah Wellborn

Page and Line Number	Change
Page 19, line 5	Strike "no over-forecast errors, just under-forecasted errors" and replace with "no under-forecast errors, just over-forecasted errors."
Page 74, Table 15, Row 2	Strike "Robins BESS" and replace with "Santa Rosa PPA."
Page 74, Table 15, Row 3	Strike "Santa Rosa PPA" and replace with "Robins BESS."

MS. DAVIS: Thank you. And, Mr. Chairman, with your permission, I would like to ask that the panel be allowed to give a summary of their prefiled testimony, followed by a summary by Mr. Kaduk.

CHAIRMAN SHAW: Yes, go ahead.

A (Witness Newsome) Good afternoon, Commissioners. Our testimony addresses supply side and certain other requests that Georgia Power is seeking to be approved in the 2023 IRP update filing.

The company presented a plan to acquire or build approximately 3300 megawatts of new capacity before 2028 outside the competitive bid -- outside a competitive procurement process. Staff disagrees with the company's plan and has developed an alternative resource plan based on staff's load forecast and a revised target reserve margin assumption.

Staff's plan only requires the acquisition of approximately 1000 megawatts outside a competitive procurement process. Beyond that, staff recommends all additional capacity be acquired through a competitive solicitation process or request for proposal.

Our panel's recommendations and findings include the following: Staff recommends approval of the Mississippi Power 750-megawatt capacity PPA and the Santa Rosa 230-megawatt purchase power agreement.

This new capacity would push out the company's need date for additional capacity to 2029. This will provide enough time to conduct a capacity RFP so the most cost-effective capacity can be procured.

Staff recommends the company expedite its currently ongoing request for proposals for the 2029-2031 All-Source RFP and the 500-megawatt energy storage system, or battery RFP, to competitively procure additional resources for 2029 but expand the start date to the resource selection to begin as early as 2027.

Staff recommends that the company deny the company's request for certification of the Yates CTs and the company's request for 1000 megawatts of company-developed battery projects, including the proposed Robins, Moody, and co-located battery solar resources.

Staff recommends that those resources be assessed in a competitive procurement process, such as the 2029-2031 All-Source capacity RFP or the 500-megawatt storage RFP as approved in the 2022 IRP.

Staff recommends the company deny the company's -- excuse me. Staff recommends the Commission deny the company's request for approval of the FLEX Capacity framework which would authorize the company to develop even more capacity without going through a

competitive solicitation process.

Staff recommends the company perform a new target reserve margin study in the 2025 IRP that incorporates the load realization model impacts as an evaluated variable, along with other variables already modeled by the company, including weather, load forecast error, and outages.

In staff's analysis, staff relied on a 24.5 percent target reserve margin consistent with staff's position in the 2022 IRP.

Staff recommends the company's notice of a 70 percent rule for owned capacity not be considered as a part of the rational for acquiring company-owned resources in this proceeding. The 70 percent rule should be evaluated separately outside the context of this extraordinary load-growth-dominated IRP proceeding to consider the impacts on ratepayers.

The company provided an Economic Analysis of Capacity Resource Study to support approval of its proposed contracts and resource additions and a resource mixed study to evaluate resource types for acquisition over a longer time horizon.

Staff finds the company's economic analysis was deficient and relied on outdated assumptions and methodologies. Staff provides an alternative analysis

which supports staff's recommendations.

In the event the Commission decides more capacity is needed in the '27-'28 time frame period, beyond the Mississippi Power and Santa Rosa PPAs, staff developed and provides a ranking of projects in Table 15 in our testimony, which indicates that Robins project is the next project in order that should be acquired.

However, staff believes that competitive procurement process is the best process to identify and acquire the most cost-effective capacity for customers.

Given the company's assertions that the 2023 IRP update load growth and proposed resources will have downward pressure on rates, staff recommends the company file in rebuttal testimony a cost of service study that allocates the new cost associated with the company's proposed resources and new loads to customer classes based on the allocation methodologies, consistent with the company's most recent cost of service study.

By the company performing this study, with correction staff had outlined in its testimony, the Commission will be able to see the impacts before and after the new large customer load impacts and will be able to determine clearly how the new large customer loads will impact individual customer classes.

Finally, when the company files its next IRP in

January of 2025, staff recommends the company be required to file a revised cost -- a revised cost of service study using the latest data known at the time of the filing. Filing this information with the 2025 IRP would give staff time to do a thorough review of the company's cost of service study and develop its own study, if necessary, ahead of the next rate case. This concludes our summary.

A (Witness Kaduk) Commissioners, the purpose of my testimony is to address Georgia Power Company's request for new customer-sited programs, a customer demand response program, the company's request to amend its certificate from the thermostat demand response DSM program, and the reasonable capacity equivalents of the current renewable plus battery storage procurement used by Georgia Power Company in its 2023 IRP plan update.

Georgia Power is proposing several new programs to leverage customer-sited resiliency resources that can also provide system reliability for the benefit of all customers. The proposed programs are the Distributed Energy Resource, or DER co-location program; the DER customer-owned program, and the Curtailable Load Program.

The proposed DER programs are designed to add capacity to the system, although the company has not provided an estimated of such capacity in its resource ledger. The proposed DER co-location program is designed

for qualifying commercial and industrial customers whereby Georgia Power will own, operate, maintain, and control dispatchable DER at customer premises and economically dispatch the resources to provide energy and capacity benefits to all customers.

The proposed DER customer-owned program is designed for -- sorry. That's -- and staff recommends approval of the DER co-location and customer-owned programs and associated tariffs with a few modifications.

Since both programs are similar -- since both programs are similar, staff recommends that the two programs have similar structure regarding the size of the DER. Georgia Power's proposed DER customer-owned tariffs, DER size limits, are proposed to be no less than 1 megawatt but no greater than 10 megawatts.

The staff recommends mirroring this limitation in the DER co-location tariff. The DER co-location tariff is similar to Georgia Power's current RAS tariff, R-A-S, which was approved by the company in its -- it was approved by the Commission in the company's 2022 IRP docket.

The RAS-1 tariff put a limit on the size of the company-installed DER at the customer's premises at the customer's annual peak load. The staff recommends setting this DER limit similarly to match the customer's

annual peak load at the premises up to, but not exceeding, the program maximum DER size limit.

The Curtailable Load Program is proposed to enable demand response of commercial industrial customer's loads during extreme supply and demand conditions, thereby providing system capacity and reliability benefits to all customers. The Curtailable Load tariff is similar to the company's current Demand Plus Energy Credit Program, DPEC. However, it lengthens a participating customer's commitment to the program for one year and DPEC to a six-year rolling term. Staff recommends approval of this Curtailable Load tariff.

Staff recommends that the company research a residential and small commercial battery program to be considered in the Commission's upcoming -- Commission in the company's 2025 IRP.

A pilot for residential and small commercial customers could help increase the numbers of customers eligible for the customer's DER program offerings while providing grid reliability and capacity benefits. The company should research opportunities for a new pilot that can help provide reliability benefits through the use of new dispatchable DER located on customers' premises while also providing capacity and energy benefits to all customers. Utilities in other

jurisdictions have begun implementing such programs.

Georgia Power is proposing to expand its currently certified residential thermostat demand response program by amending its certificate. Commission certified this program in the 2022 DSM plan in Docket Number 44161. The company is requesting to expand the current program enrollment from 25,000 participants to 50,000 participants.

Additionally, the company stated that the program now reflects a positive TRC value and, therefore, no longer requires a waiver of the Commission Rule 515-3-4-.04483. That was approved in the 2022 IRP order.

The staff recommends approval of the company's request to amend this certificate for residential TSTAT DR program. Staff further recommends that the company continue to evaluate the potential of this program for the upcoming IRP to identify the optimal participation level for the program to cost effectively meet future demand reductions.

The company's current target reserve margin is based on meeting its summer system peaking needs. The company also has a planning reserve margin to meet its winter peaking needs. The timing of the resources Georgia Power is proposing to add in this IRP update are primarily driven by capacity needs of its forecasted

winter peaks.

Georgia Power's planning reserve ledger contains the capacity equivalents for all of its company-owned and contracted supply side and demand side resources. The Commission's 2022 IRP order directed Georgia Power to begin valuing intermittent supply-side resources such as solar and wind technologies using an effective load carrying capability, or ELCC method, when determining capacity value for procurement activities.

In its resource letter, the company included ELCC values for the projects that will be procured in the company's 2023 Clean and Renewable Energy Subscription Program, the CARES RFP, and the company's battery energy storage system, the BESS RFP.

The goal of the CARES RFP is to procure 3,350 megawatts of renewable resources with or without two-hour minimum duration energy storage systems, including up to 650 megawatts of carbon-free energy around-the-clock resources.

The first phase of the CARES RFPs for the procurement of up to 2875 megawatts with in-service dates in the 2026-2028 time frame.

The remaining megawatts from the 3,350 megawatt total, not procured during the first phase, we targeted during the second phase of the CARES RFP. The company's

upcoming BESS RFP will seek to procure up to 500 megawatts of two-hour minimum durations download and energy storage systems with in-service dates to meet the company's 2029 winter need, but will also have an early commencement option.

The company's capacity equivalent estimate as found in their resource ledger for the first phase of the CARES RFP assumes that only standalone solar projects will be awarded in the first phase. The standalone solar projects are only given 5 percent capacity equivalents in GPC's ELCC study from the 2022 IRP, which only equates to about 84 megawatts for the first phase of CARES. The company's capacity equivalents estimate for the BESS RFP for standalone batteries is 95 percent, which equals 475 megawatts for the BESS RFP.

Previous utility scale RFPs have procured solar-plus storage bids. The company's 2020/2021 REDI RFPs certify 409 megawatts of solar-plus storage out of a total of 559 megawatts. The company's 2022/2023 utility scale renewable RFP certify 830 megawatts of solar-plus storage out of a total procurement of 970. However, some of these -- the certified 2022/2023 utility scale RFP projects that includes storage were ultimately amended to allow the counterparties to perform in accordance with the performance metrics without having to install the

storage to help reserve the low-price PPAs for Georgia Power's customers.

The 2023 CARES RFP only allows a full company-controlled use case of batteries with a higher ratio of batteries to solar panels. In response to a data request, the company stated that if any bids with BESS are selected in the 2023 CARES RFP, with battery size exactly at the minimum requirement 50 percent of the nominal output of the attached solar, the site capacity equivalence will be .5 megawatts per 1 megawatt of solar.

At this 50 percent ratio, staff estimates that 500 megawatts of BESS paired with 1000 megawatts of solar could be selected for procurement as part of the 2023 CARES RFP, which would only account for about a third of the first phase procurement.

Staff notes that the higher cost of including storage as part of its bid may not be worth an additional evaluation credit provided to bidders. However, conservative amounts of solar-plus storage projects is a reasonable expectation based off of previous utility scale renewable RFP results and improving storage market conditions.

Any additional megawatts recognized in the company's resource ledger for the 2023 CARES RFP will further reduce capacity needs and/or move such needs to

future years.

The company's resource ledger should reasonably account for 500 megawatts of winter capacity equivalence resulting from the first phase of the CARES RFP. If such resources are not ultimately certified in the first phase, the second phase of CARES should provide additional information to the developers regarding the value of solar paired with storage to encourage bids for projects that provide a higher-capacity equivalence value. This concludes my summary.

MS. DAVIS: Mr. Chairman, the witnesses are now available for questions from Commissioners as well as cross-examination.

CHAIRMAN SHAW: Commissioners?

VICE CHAIRMAN ECHOLS: Yes.

CHAIRMAN SHAW: Go ahead.

VICE CHAIRMAN ECHOLS: John, would you -- you said that you were recommending a higher ratio just at the end of BESS to solar. Was that two to one? Can you explain that to me?

MR. KADUK: Sure.

VICE CHAIRMAN ECHOLS: You were talking very fast.

MR. KADUK: Sorry about that. I was trying to get done quicker.

So the current requirement, if you are bidding in CARES, if you are bidding in a solar-plus storage facility, whatever megawatts that you bid in for solar, you have to match that 50 percent with BESS, with batteries. That's all. So it is a 50 percent ratio, minimum, that you have to bid into the RFP.

And if you meet that, Georgia Power's ELCC says that project, its capacity equivalence will be basically set to whatever that battery size is.

So Georgia Power, in their resource ledger, is only assuming all solar will be built. Solar only gets a 5 percent credit towards capacity equivalence. We are saying if any batteries get built, they get 100 percent capacity equivalence. And we say it's -- it's a reasonable assumption that assumes some of the projects that will win the CARES RFP will have batteries associated with it. Therefore, we think higher-capacity equivalence should be included in the company's resource ledger.

VICE CHAIRMAN ECHOLS: So that kinds of chips away at what we need if you change the formula?

MR. KADUK: It does.

VICE CHAIRMAN ECHOLS: Yeah.

COMMISSIONER PRIDEMORE: Can I ask a follow-up to that? It chips away the formula, but does the

CARES RFP have a two-hour battery storage requirement or a four hour?

MR. KADUK: It has a two.

COMMISSIONER PRIDEMORE: It has a two. So walk me through -- that's in winter. What does that do for us?

MR. KADUK: It provides two hours of guaranteed output any time of day that you charge it up the day before. And then when solar -- when daylight comes around, it's -- you are right, it is ramping up and providing power the rest of the day. But Georgia Power's ELCC study, that measured the capacity equivalence, is 100 percent, it -- capacity equivalent for all the batteries.

COMMISSIONER PRIDEMORE: But the capacity equivalent for all the batteries, does it --

MR. KADUK: Sure.

COMMISSIONER PRIDEMORE: I have a battery engineering question, if anybody can answer. If it is a two-hour -- and these are, like, lithium ion batteries; right?

MR. KADUK: Correct.

COMMISSIONER PRIDEMORE: If it is a two-hour lithium battery, then I am only getting two hours out of it. When the sun goes down at five o'clock

and the sun doesn't come up -- this is winter we are talking. We will be generous. The sun goes down at six, the sun comes back up at seven, how do I manage that balance in between within my load?

MR. KADUK: Well, it depends. You know, Georgia Power can discharge the battery. I mean, it doesn't all have to be at the same time. They can spread it out to make it a longer duration, but Georgia Power's own studies say it is equivalent to having a -- like a CT on for two hours. And your peaks usually aren't stretching for much hours at a time anyway. It's a couple hours in the morning that this could be fully charged the night before or the day before.

COMMISSIONER PRIDEMORE: Okay. I will talk to them. That's okay. Thank you.

VICE CHAIRMAN ECHOLS: Okay. John, if the thermostat program, the check TEMP Program yields -- so we have 25,000 people on it right now.

MR. KADUK: Yes. That's the current limit, and, yes, it is around there. Yes.

VICE CHAIRMAN ECHOLS: High customer satisfaction, I am told. So it is yielding -- when we call those, it is yielding about 32 megawatts of power; is that right?

MR. KADUK: No. I think it is -- oh, it's --

VICE CHAIRMAN ECHOLS: What does it yield?

MR. KADUK: Sure.

VICE CHAIRMAN ECHOLS: I mean, I know not -- some people might opt out, but when we have an event, what are we gaining?

MR. KADUK: Sure. So where are we? Yeah, it is averaging about -- they are getting about -- during the winter demand, a savings of about 18 megawatts per event.

VICE CHAIRMAN ECHOLS: 18 per event. Okay. So why wouldn't we -- why would we, in this great time of need, why would we just double it? I mean, we have got millions of customers. We have just a pittance on the program. Why wouldn't we greatly accelerate it? If it is high customer satisfaction, if it is -- if the finances are working on it, why wouldn't we roll it out with a vengeance here?

MR. KADUK: We can see the value of that. Georgia Power's request was to double it. We definitely are agreeing with that, and we are suggesting that Georgia Power continue looking at the value of expanding it, and like this next upcoming IRP, proposing to increase that cap even more.

VICE CHAIRMAN ECHOLS: But wouldn't it be wise to go ahead now and accelerate it so that we have got the data to see that if it carries through to the next -- let's say we bumped it from 25,000 to 250,000. Let's say we did tenfold now. Wouldn't it be great to have that data to tell us that, yeah, this is holding, this is holding; we are picking up 18 megawatts every time we do this? I mean, do you see any downside to that?

MR. KADUK: I know the Commission prefers a measured approach, and doubling of the current program, I mean, it is -- I don't know if it is still classified a pilot program, but it is -- yes, we can see there would be additional value for additional participants, yes.

VICE CHAIRMAN ECHOLS: Yeah, I love measured. I love measured. We do things incrementally. We go slow. But we are being told that we have got an emergency here; right? So, I mean, we are about to run some units on oil over there because we are in such an emergency; right? So it seems like it would make sense to do something aggressive, that the utility really doesn't -- it is not going to cost anything for us to do it.

MR. KADUK: We see the value in that, but our

testimony is just to double it for now. Yes.

VICE CHAIRMAN ECHOLS: So on the residential battery pilot that you mentioned, I don't know if you were in when I asked the previous panel about -- about ramping it up while the IRA money is sitting here as an asset; right? So, yeah, I love going slow, but if we -- if we wait and this money -- if for some reason, Congress, you know, changes this and we lose this, it is -- it is repealed or who knows what could happen next year. That it seems like if we make this decision now and this fall our customers are able to go ahead and take advantage of that, it seems like that we are putting money back into the pockets of our ratepayers by doing that with these tax credits plus another 10 percent if they are in an energy community.

I mean, would you have any problem with, you know, aggressively doing this now as a -- as a pilot --

MR. KADUK: No.

VICE CHAIRMAN ECHOLS: -- with more than just a 100 people or 500 people?

MR. KADUK: No, I don't think staff would. Our recommendation was, once again, to take this up in the '25 IRP, give the company time to come up and

propose a program on it. As of right now, this is just, yeah, just a proposal to start up a new program for residential and small commercial.

VICE CHAIRMAN ECHOLS: But the company has tried this -- I mean, the Pulte project out here in West Atlanta, the Birmingham project, they have tinkered with batteries in homes for a while. They have been buying Tesla batteries for six years. Well, I mean, they have -- they own PowerSecure for goodness' sakes. They know batteries well; right? I mean, they are building microgrids with batteries, their sister company is. So --

Okay. Tom, did you say that staff was not recommending that we do the H Units or that they be acquired with an RFP? You said -- you used a pronoun that I didn't quite understand.

MR. NEWSOME: Okay. The company is saying, approve their Yates CTs right now. We are saying deny that; however, we are saying do an RFP, and they can enter -- put the Yates in the competitive RFP and go that route. So our issue is financial, not necessarily the technology.

VICE CHAIRMAN ECHOLS: Okay. Tom, regarding the data centers, I mean, we have got these construction articles here, but how long does it

take to build a data center? Is it a quick thing?

MR. NEWSOME: I would think it would take two or three years.

VICE CHAIRMAN ECHOLS: Yes. So you think the chip -- the chip shortage, you know, and the other supply chain issues are likely to continue to affect the building of projects like this?

MR. NEWSOME: I mean, they could, yes.

VICE CHAIRMAN ECHOLS: Yeah.

MR. NEWSOME: I mean, the other issue is, does it push up the cost, too. Now, if it's Google or Microsoft or Amazon, they may not care about the cost. But, yes, that could be a part of it, too.

VICE CHAIRMAN ECHOLS: And Georgia Power, I am told some of their transformers are a year, a year waiting list. I mean, not waiting list, but a year out to be able to get them, certain sizes.

MR. NEWSOME: We have gotten similar information from them.

VICE CHAIRMAN ECHOLS: So is it likely that all of this data center load is going to get here as quick as they think it will?

MR. NEWSOME: That's our point. We are not -- we know it is coming, the load is coming, but how fast it gets here is a separate issue. And if you

are a little bit -- if it arrives slower, we have got time to do an RFP. Remember, they are asking for 3300 capacity. No competitive bid. They self-build.

Historically, they -- when they have had to go through a competitive bid, they have been more expensive than third parties. They haven't gotten chosen. So, again, that's why we are saying put it through a competitive bid, all the stuff they want to propose to do, the batteries and Yates. Run it through a competitive bid. And if it is economic, it will get selected, and they can put it in the rate base, and we keep moving.

VICE CHAIRMAN ECHOLS: You may have heard me ask them in the first set of hearings, if they were so confident as they were under oath, would they forego a rate case in 2025; and they were unable, of course, to speak for the company. I totally get that. But, I mean, I would feel a whole lot better about all of this acquisition if they would assure me there would be no rate case, because then there would be nothing to fall on the backs of our ratepayers.

MR. NEWSOME: Well, not necessarily. They are asking for deferrals. They will get their money

later. And we have got a panel coming up to handle that. So you can have no rate case, but if you have a bunch of deferrals, they will just collect it later.

VICE CHAIRMAN ECHOLS: That's a good point. Thank you.

COMMISSIONER PRIDEMORE: Mr. Chairman, I have got some questions.

CHAIRMAN SHAW: Go ahead.

COMMISSIONER PRIDEMORE: I will go back to you, Mr. Kaduk. So just now talking about the thermostat program, is the thermostat program a voluntary program?

MR. KADUK: It is.

COMMISSIONER PRIDEMORE: So it's completely -- it's depending upon take rate; right?

MR. KADUK: Yes. For signing up for it, yes.

COMMISSIONER PRIDEMORE: Yeah, for signing up. So you have got 25,000 customers, estimate that there is 1800 megawatts. They want to double it to 50,000 leading to 32 megawatts.

If you were to increase that ten-fold, then you would be at 180 megawatts. But it still says -- it's still dependent upon the take rate?

MR. KADUK: It is.

COMMISSIONER PRIDEMORE: Yes. So we don't know if we have got a quarter of a million customers that want to do it. So it depends -- so you think about the capacity equivalent of that and trying to hold onto that, I think that that gets tricky. That's a lot.

I wanted to ask you about the DERs. So in staff's recommendation on the DERs, that there could be no less than 1 megawatt but no more than 10 megawatts; right?

MR. KADUK: Yes.

COMMISSIONER PRIDEMORE: Okay. Staff has held a position previously that they want those DERs to be externally owned. Has staff changed their position, or are they coming around to the idea of having them be owned by the company?

MR. KADUK: Currently, yes, we are proposing both programs be approved, yes.

COMMISSIONER PRIDEMORE: Okay.

MR. KADUK: Company-owned and customer-owned.

COMMISSIONER PRIDEMORE: Okay. I have probably got some more questions about the CARES extension and then the BESS RFP, but I will wait and let some other folks go.

Mr. Newsome.

MR. NEWSOME: Yes, ma'am.

COMMISSIONER PRIDEMORE: So walk me through, you said that the staff ranking analysis for alternative means of capacity is in Table 15 of your testimony; right?

MR. NEWSOME: Correct.

COMMISSIONER PRIDEMORE: Okay. Table 15, for all those following along, is on page 74. You mentioned that staff's position is that 1000 megawatts should be in sourced, and they should be the Mississippi Power PPA, 750 megawatts, and the Santa Rosa PPA at 230 megawatts, for a total of 980 megawatts. There is 20 megawatts missing. Where are they coming from?

MR. NEWSOME: It is a rounding error.

COMMISSIONER PRIDEMORE: Okay. So if that's -- if those are the two, the ranking, though, is the Mississippi Power PPA, then Robins, then Santa Rosa PPA?

MR. EVANS: We filed errata on that.

CHAIRWOMAN PRIDEMORE: You did? Okay.

MR. EVANS: So it's switched up. Just switch --

COMMISSIONER PRIDEMORE: You switched two and three?

MR. NEWSOME: Yes.

COMMISSIONER PRIDEMORE: All right. I will go read your errata then.

MR. NEWSOME: Well, no, we should have had that to begin with.

COMMISSIONER PRIDEMORE: That's okay.

And then talk me through staff's philosophy on the 70 percent rule of the capacity ownership and why it shouldn't apply to this case.

MR. NEWSOME: We believe the 70 percent rule should be taken in context of what the cost is going to take to adhere to that rule. You could have a more expensive portfolio. If you adhere to the 70 percent, it could be more expensive capacity, as opposed to the lower. So what we are saying is, do the RFPs, you will get your -- you will get your generation resources. You will get capacities, you know, one through ten, or whatever it is. And then you can have one that's just whatever the cheapest one is. It may be -- force you below the 70 percent threshold.

COMMISSIONER PRIDEMORE: Right.

MR. NEWSOME: That's one thing.

Then you will look at one where you add back some up, some self-build to keep you at 70. You

will have two different portfolios, one that makes the 70 percent threshold, the least expensive one that doesn't, or it may, it does it, and then you will have -- know what the difference is in cost is to adhere to that 70 percent threshold. That's what we are driving at on this.

COMMISSIONER PRIDEMORE: Is staff's recommendation to change the 70 percent threshold from this point forward because the amount of renewables in the system?

MR. NEWSOME: No. We are saying have the RFP, let's see what the two different portfolios look like, see what the difference in cost is, and then you can make a rational decision on whether to move from it or not.

COMMISSIONER PRIDEMORE: Okay. Probably come back on that one. But that's good. Thank you.

MR. NEWSOME: That's fine.

CHAIRMAN SHAW: Is that it?

VICE CHAIRMAN ECHOLS: Just one more thing, Commissioner. When you go to the Georgia Power website, on the smart thermostat check TEMP Program, it says it is fully subscribed. We need to get them to immediately add a waiting list and start the waiting list on this thing. It turns people away,

and we need to start -- start collecting these names. So your comment reminded me --

COMMISSIONER PRIDEMORE: I nominate Commissioner Echols to operate the waiting list off of his website.

VICE CHAIRMAN ECHOLS: This is a great program. It is a great program.

COMMISSIONER PRIDEMORE: I am not discounting the program. I just think you should own the waiting list. I think you would like it.

CHAIRMAN SHAW: Speaking of waiting, John, you mentioned -- you know, your recommendation is to get this residential program in the '25 IRP; correct?

MR. KADUK: Yes. The battery one, yes.

CHAIRMAN SHAW: Yes.

MR. KADUK: Thank you.

CHAIRMAN SHAW: So that would be the -- that could be something like Duke is doing --

MR. KADUK: Correct.

CHAIRMAN SHAW: -- or virtual power plants, stuff like that?

MR. KADUK: Yes.

CHAIRMAN SHAW: Talk me through your rationale on -- again, on why you are recommending that we wait until the '25 IRP to look at that.

MR. KADUK: Well, and there is no program before us currently for residential and small commercial. It's just, we think there should be one.

CHAIRMAN SHAW: But I guess I am asking why do it in '25 instead of the '23 update?

MR. KADUK: There is other intervenors here that talk about -- you are right -- that would want to move forward sooner than the '25 IRP and, you know -- yeah.

CHAIRMAN SHAW: What would be your thoughts on, like, maybe waiting until '25 but going ahead and doing a working group to go ahead and get the ball rolling?

MR. KADUK: I am sure staff -- yeah, staff would be great to -- would be glad to be involved with that. Yes.

CHAIRMAN SHAW: All right. Thank you.

Any other questions?

(No response.)

CHAIRMAN SHAW: All right. We will start going down the list. Start with Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association. Mr. Dunbar?

MR. DUNBAR: Thank you, Mr. Chairman. I do have a few questions.

CROSS-EXAMINATION

BY MR. DUNBAR:

Q Good afternoon, Panel.

A (Witness Kaduk) Good afternoon.

Q I have a few questions about staff's modeling with respect to the Mississippi Power PPA. Could you please turn to page 55 of your testimony, and I am talking about the Newsome/Hayet/Wellborn testimony.

So in Table 9 on that page, in the row labeled "Proposed Resources" in the column that's labeled "Staff Analysis" it says, "Selectable in 2026/2027, with presumed acceptance of MPC PPA." Just to clarify, MPC PPA in this context refers to the Mississippi Power PPA; correct?

A (Witness Hayet) Correct.

Q And would you also please turn to page 56. And on the bottom of that page and going onto the next page, you are discussing the series of Aurora optimization runs that staff ran; and your testimony states, quote, "However, in all of the cases staff ran, the MPC resource was treated as having been selected first, based on cost and reliability considerations, and the fact that MPC resources are already operating as a part of the Southern

Company system resources," end quote.

Do you see that?

A (Witness Hayet) Yes.

Q So can you just clarify whether the selection of the Mississippi Power PPA was the result of staff's modeling or whether the Mississippi Power PPA was an assumption that you built into your modeling runs?

A (Witness Wellborn) Yes, we can clarify. So the Aurora model is a Southern Company system model. So it already includes Mississippi Power resources as well as the Georgia Power resources, and so there wasn't a double counting of that selection. The fact that those resources are there and we have assessed the cost and the reliability, we are presuming the acceptance of the PPA because we are keeping those resources in the mix.

A (Witness Hayet) Another way to look at it is we did some analysis upfront and decided that, on the basis of reliability, that all those resources exist. The need -- the extreme need for capacity that we agree exists, that we looked at the way that the Mississippi Power's modeled, and we reached a conclusion that that should be selected. So that's the presumption that we made. We did select it. It is part of our portfolio.

Q Okay. So it is -- it is an assumption, not a result of the modeling?

A (Witness Hayet) It is not a -- it is not an output of the modeling, but it is an analysis we conducted that determined the economics, and, therefore, it was selected.

A (Witness Newsome) I mean, we looked at the capacity prices on the thing, and it was -- and compared that to the other ones. And it looked like the best deal. So it wasn't just we just assumed it.

And the other issue, the cost was -- I mean, it is still an expensive PPA. It is double what we paid for in those six PPAs previously, so it is not inexpensive. But versus what the company was proposing with the batteries and CTs, it was -- it came out ahead. And then from their standpoint, they are having to run all these models and stuff. And by locking that down, we are going to have to take -- we knew we were going to have to take something. We did enough analysis, load, with the --

Our load forecast guys came back, said they need more -- they need more -- you know, they are going to need more -- have more load. Said we have got to have more capacity.

So the Mississippi Power, we said it is going to get selected. So in terms of trying to cut down all the modeling and stuff -- because these runs take hours. And we just -- we just fixed that, and then we looked at

everything else. So it is not -- you know, we didn't just accept it. We looked at the capacity payments, looked at the other ones, and then we locked it down.

A (Witness Wellborn) And I would add the company's analysis did allow for an economic selection of it, so that first column in our results table is the result of an economic test within Aurora. So we kind of have that data point, as well, in addition to just the reliability considerations Mr. Newsome has discussed.

Q Okay. All of that background is very helpful.

Did staff run any -- did you perform any modeling runs in which the model was allowed to not select the Mississippi Power PPA?

A (Witness Wellborn) Again, mechanically, because those resources exist, whether or not the PPA is approved, right, we couldn't take them out of the model in order to kind of come up with the alternative scenario.

So to answer your question, no, I guess there wasn't an alternative considered.

A (Witness Hayet) But it is our opinion that it would be considered if there were a means of constructing it and taking it out. Therefore, we locked it down.

Q Okay. So we heard at the last hearing, Georgia Power's witnesses talk about the possibility that

Mississippi Power could have signed a PPA with another utility if Georgia Power hadn't acted quickly. So just hypothetically, if Mississippi Power had signed a PPA for that capacity with the utility outside the Southern Company system, you could run a model showing that resource as unavailable; right? Hypothetically?

A (Witness Wellborn) Yes. Hypothetically that could have been modeled.

A (Witness Hayet) Or you can model the load that they have to serve, so that you have the resources and the load that they are going to serve, and you can run the model that way.

A (Witness Wellborn) Model a sale, basically.

A (Witness Newsome) But I believe the bottom line would be we didn't have full Mississippi Power to pulling one of --

Q I am sorry, I couldn't hear you.

A (Witness Newsome) We didn't -- if we had not taken the Mississippi Power PPA or recommend the Commission take the Mississippi Power PPA, we are down to pulling one of the more expensive batteries, that Yates CT, so...

Q Okay. Thank you for all that.

Would you please -- I am going to jump around a little bit. Would you please turn to page 35 of your

testimony. So starting on line 16 and going onto the next page, you discussed the difference between the 2022 and 2023 AEO fuel forecast. Do you see that?

A (Witness Hayet) Yes.

Q And "AEO" in this context refers to the Annual Energy Outlook prepared by the U.S. Energy Information Administration; correct?

A (Witness Hayet) Yes.

Q Did staff run any sensitivity analyses with the Aurora model to determine whether the model would select different resources under higher gas price assumptions than these two, the 2022 and the 2023 AEO forecast?

A (Witness Wellborn) Aurora was only reflecting the more recent, so just the '23, and we only used the mod gas scenarios.

Q Okay.

A (Witness Newsome) But we double checked. We look at other forecasts. So I guess --

Q Right.

A (Witness Newsome) Using their -- they used the AEO forecast. We didn't accept that blindly. We looked at other forecasts. They have got access to other forecasts for other utilities, and we used that as a check to see if it was rational or not.

A (Witness Wellborn) Right. Figure 3 shows sort

of our check to validate that we were comfortable using the gas forecast that was presumed as the medium gas.

Q Right. And that makes sense. I was just wondering as a sensitivity analysis to just see how things change if gas prices were higher than anyone expects. And it sounds like that -- that was not done. You stuck with the 2023 AEO forecast; correct?

A (Witness Wellborn) That's correct.

Q Okay. Thank you. And last -- last jump, would you please turn to page 62 of your testimony. Table 11. Now, this table shows the results of a sensitivity model you ran in which you assumed that there is some cost to carbon; is that correct?

A (Witness Hayet) Yes.

Q And you point out elsewhere in your testimony -- I am not going to make you turn to it again, but you point out that there is currently no pending legislation that would impose a cost on carbon; correct?

A (Witness Hayet) Correct.

Q Would you agree that in the -- even in the absence of an actual price on carbon, assigning a cost to carbon and resource modeling, such as what you did in this case, can serve as a proxy for other constraints on carbon?

A (Witness Wellborn) Sure. Yes. I mean, carbon

price could be a proxy for carbon pressure. But, you know, that's why we provide the sensitivity, because no one knows what sort of future impacts there might be.

Q Right.

A (Witness Newsome) But if you want to be accurate in your modeling, it is either carbon price -- I mean, I have been here for 20 years and have never seen one. So it is either carbon price or you are going to do the CCS, carbon sequestration/capture thing. Well, rather than using a modeling price, you would say, what is the construction cost to build one of those things? You know, the capture, store, and all of that.

So, I mean, you are right to use a proxy; but if you are getting down to spend real money, you need to actually model what the -- what the solution is. So if they are doing abatement, a lot of capital costs there, a lot of O&M there, a lot of energy there. So I think if you are actually going to model stuff, you need to model it accurately.

Q Thank you.

So in Table 11, in this carbon constrained sensitivity model the staff ran, the model did not select the Santa Rosa PPA; correct?

A (Witness Hayet) Correct.

A (Witness Wellborn) That's correct.

Q And presumably, a major driver -- excuse me. A major driver for the model not selecting the Santa Rosa PPA in this carbon constrained sensitivity is the fact that the Santa Rosa Energy Center is a natural gas combined cycle facility; correct?

A (Witness Hayet) Presumably, yes.

Q And just to lay it out there, the reason for that is that in the carbon constrained sensitivity model, gas becomes more expensive when carbon is expensive; right?

A (Witness Hayet) Yes.

Q Would you agree that --

A (Witness Hayet) I am sorry. Would you repeat that question? I want to make sure I gave you the accurate, instead of just responding back.

Q I will take your yes, actually. No, I am kidding.

So you agreed with me that a major driver of the model not selecting the Santa Rosa PPA in the carbon constrained sensitivity is that the Santa Rosa Energy Center is a natural gas facility. I believe you agreed with that. And so I am just unpacking that a little bit, that the reason for that is that in the carbon constrained sensitivity model, gas is more expensive when carbon is expensive; right?

A (Witness Wellborn) I would say in -- generally, you know, gas resources, not gas price necessarily, but gas resources would be more expensive with their emissions rate.

There is also a fit piece of this, in terms of there is a slightly different load forecast. And so we are presuming that there is some sort of carbon pressure that may be impacting Santa Rosa, but the company's assumption on carbon doesn't actually start until 2030 when this PPA would be transitioned.

So it is -- there is a number of drivers that could be impacting that selection or nonselection.

Q Understood, yes. I understand there is lots of levers involved.

But would you agree based on -- based on that and subject to the caveats you just laid out, for similar reasons, if you had run a sensitivity model that assumed higher gas prices, higher than the 2023 AEO forecast, it is possible, depending on how high the gas prices were, of course, it is possible that the model would not have selected or, excuse me, would not select the Santa Rosa PPA in that context?

A (Witness Hayet) You know, I would say it is possible; but also, keep in mind that Santa Rosa isn't around for the life of the study. It exists only for a

short period of time. And if you are assuming higher gas prices, higher gas prices typically trend up. So over the period that you have Santa Rosa in operation, it might not have as big of an impact as you are trying to imply.

A (Witness Newsome) And just to reinforce what they said previously, both Mississippi Power and Santa Rosa are five-year deals. December of '28, that's it, they go away. So the whole thing about the carbon and -- I mean, the gas price is probably a little more -- gas prices moving around is more of an issue; but as far as the carbon CO2 tax, I don't -- I think that's a minimal risk on these.

Q Right. Right. And I am not going to quibble with you about that, of course. I -- just trying to -- well, what we think, and I am wondering if you agree, is that if the model shows that under a high carbon constrained scenario Santa Rosa is not selected, that if gas prices spike in the next year unexpectedly, similarly, if you assume much higher gas prices than the 2023 AEO, the model might not select Santa Rosa in that case, as well. Would you agree?

A (Witness Hayet) Yes. I could agree if you had much higher gas prices at the time that Santa Rosa is operating, which you have to evaluate and wonder if

that's possible with the gas prices we have today. But, yes, I would agree.

Q Great, thank you.

And do you know whether the model -- going back at the carbon -- excuse me. Looking at the carbon constrained sensitivity run, do you know if the model would have selected the Mississippi Power PPA in that carbon constrained sensitivity if you had not built that in as an assumption?

A (Witness Hayet) It would have. You need capacity. You can't do anything else. So, again, one of the reasons we selected Mississippi Power in the way we did is because of timing. You have got to be able to have capacity as early as possible, and Mississippi Power is capacity that's available. So, yes.

MR. DUNBAR: Okay. Thank you, Panel.

Thank you, Chairman. Commissioners.

CHAIRMAN SHAW: Thank you. Heelstone?

MR. GALLOWAY: No questions, Mr. Chairman.

CHAIRMAN SHAW: Georgia Association of Manufacturers?

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions?

(No response.)

CHAIRMAN SHAW: Georgia Center for Energy Solutions?

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments?

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power and Light?

CROSS-EXAMINATION

BY MS. WHITFIELD:

Q Good afternoon again, Commissioners. Thank you, Panel. I am Jennifer Whitfield on behalf of Georgia Interfaith Power and Light. I want to start by asking you about the timeline on page 8 and 9 of the Newsome/Hayet/Wellborn testimony concerning the discussions between staff and Georgia Power.

My understanding from the timeline is that -- and I would like you to tell me if this is a correct interpretation, is that as of March of 2023, staff has been encouraging Georgia Power to get started with the All-Source RFP approved in that prior year.

A (Witness Newsome) That's correct.

Q Okay. At the -- and then in August of 2023, it appears that staff proposed an RFP schedule, and my reading of this is that the RFP schedule that staff

proposed would seek bids for capacity resources that staff believed could be available as early as December 1st, 2025. Is that correct?

A (Witness Newsome) That's correct.

Q Okay. At the time of this conversation, this August 2023 conversation with Georgia Power, to the extent that you recall, Georgia Power was already in negotiations for most of the assets they are asking for in this IRP, which you list on page 42 of your testimony.

My question, and if you want a second to look at that, I will just pause for a minute.

A (Witness Newsome) Okay. Yeah.

Q So my question is whether staff was aware, during this conversation in August of 2023, that Georgia Power was already in negotiations for most of the assets that it's asking for, including the Yates CTs?

A (Witness Newsome) We don't know one way or the other.

Q Okay.

A (Witness Newsome) I don't think we were aware of it, but...

Q But you don't recall?

A (Witness Newsome) Yeah.

Q Okay. I want to move to your cost-of-service study recommendation. The panel makes a recommendation

that -- their recommendation comes in various places but including on page 49, lines 5 through 13. The panel recommends that Georgia Power file a cost-of-service study to better understand how costs might be allocated among the different customer classes. And the recommendation's that they file a study "consistent with the company's most recent cost-of-service study." And that's a quote.

So my question is, traditionally, the company has performed an embedded cost-of-service study; correct?

A (Witness Newsome) Yes.

Q Is that fair?

A (Witness Newsome) Fair.

Q If that's not fair, let me know.

A (Witness Hayet) Yeah, that's fair.

Q Okay.

A (Witness Wellborn) Embedded to mean the costs that are already on their system?

Q Yes. Embedded as opposed to a marginal cost-of-service study.

A (Witness Newsome) Yes.

Q And I am wondering if --

A (Witness Newsome) Go ahead.

Q Yeah. So I am wondering if staff considered asking that ask that they provide a traditional cost

of service -- Georgia Power traditional cost-of-service study as well as a marginal cost-of-service study? Which I understand is designed to look specifically at the incremental cost of serving additional load and additional customers.

A (Witness Hayet) I will go ahead and answer that. No. What we are interested in knowing may also be considered a cost-benefit analysis. We are interested in looking at costs over the next ten years and looking at, ultimately, the costs that are going to be incurred as a result of the incremental -- incremental projects being added. But then we are interested in understanding the impacts by rate class. And we thought that taking the traditional cost-of-service study could be essentially that kind of a cost-benefit analysis that could be done.

We also have another panel here who is probably going to be able to answer more questions than we are on the conduct of a cost of service study which is the financial panel that we have.

Q Okay. Thank you.

MS. WHITFIELD: That's all I have. Thank you.

CHAIRMAN SHAW: Georgia Solar Energy Association?

(No response.)

CHAIRMAN SHAW: Georgia WAND?

CROSS-EXAMINATION

BY MS. SCOTT:

Q Thank you, Panel, for being here todays's.

Mr. Newsome, you were reported in the Augusta Chronicle on December 17, 2021, regarding the Georgia Public Service Commission '25 Vogtle Construction Monitoring Report Hearing, saying that, "There is no scenario that looked at where the expansion of Vogtle is cheaper overall than constructing an equivalent natural gas generation plant."

MS. DAVIS: Objection. This is outside of the scope of this hearing.

MS. SCOTT: Well, it is dealing with this hearing in regards to the natural gas generation plant. He was making a comment about the price.

CHAIRMAN SHAW: I'm going to --

A (Witness Newsome) I need to see the article.

BY MS. SCOTT:

Q Okay. I have a copy of it.

CHAIRMAN SHAW: Hold on.

A (Witness Newsome) Let them look at it first.

MS. SCOTT: Okay.

CHAIRMAN SHAW: So how are you saying this is relevant?

MS. SCOTT: Well, because we are talking about

a natural gas generation plant. He was making the comment about Vogtle and how even with the expansion of Vogtle, it's cheaper, overall, than constructing an equivalent natural gas generation plant. And Georgia Power is asking --

MR. NEWSOME: I need to see the article...

MS. SCOTT: Okay.

MS. DAVIS: Do you have a copy of it?

MS. SCOTT: Yes, I have one copy of it.

CHAIRMAN SHAW: I will tell you what --

MS. SCOTT: While they look at that --

CHAIRMAN SHAW: -- just move forward to your next question and then if --

MS. SCOTT: Okay. We can come back.

CHAIRMAN SHAW: I will go back to their objection after they have had a chance to look at that.

MS. SCOTT: Yes, sir.

BY MS. SCOTT:

Q On page 3 of your report, Mr. Newsome, you said, "The company provided an Economic Analysis of Capacity Resource studies. It is an economic analysis study to support approval of its proposed contracts and resource additions."

You stated that, "The staff finds the company's

study was deficient due to the company's overstated load forecast, failure to consider PPA options, use of outdated fuel and carbon tax forecasts, and other problems."

So the question is, is what do you consider to be downward pressure on rates? And I asked the other panel that, but they told me that it would be more appropriate to ask you.

A (Witness Newsome) We need a page number and some line numbers first.

Q Excuse me, sir?

A (Witness Newsome) We need page numbers, line numbers.

Q Okay. If you will allow me to get my laptop, I can pull it right up. Thank you.

It is in your recommendations dealing with the economic analysis study.

A (Witness Newsome) We need a page number and line number.

Q All right. So, correction, page 5; and it is the line items 1 through 6, and specifically where you are talking about your economic analysis study. Actually, it is page 7 and item 12.

A (Witness Hayet) Okay. Would you mind repeating your question now?

Q So the question is, is what do you consider to be downward pressure on rates?

A (Witness Hayet) We did not conduct an analysis of whether there is downward pressure on rates or upward. It is the company who brought to the -- brought that issue out. And all we have done is suggest that there are some flaws that need to be addressed and we think another study performed.

A (Witness Wellborn) And I might clarify. I think these are two separate issues. The quote you are giving us with our twelfth recommendation is around the economic analysis performed to support the resource acquisitions, and the downward pressure on rates discussion is separate.

Q Okay. So page 7, number 14, again, in that staff recommendation, you said that the utility would file or needed to file a cost-of-service study or update. So the reason why we are asking about, or I am asking about, downward pressure on rates, because it suggests that you agree that there is some type of potential cost implications with their request.

A (Witness Newsome) There absolutely is a cost implication. We are trying to figure out who bears the cost. That's why we want the cost-of-service study done.

Q Okay. And in your staff recommendation, you

also said that, "Given the significant impact new large customer's loads could have on other thirteen customer classes, staff recommends the company file a cost-of-service study," and basically consistent with the 2023 IRP amendment.

I heard some -- another intervenor ask if that could also be done for 2025 ahead of the 2025 IRP. So do you agree that that is something that could be done prior to?

A (Witness Newsome) I mean, that's our recommendation.

Q Okay. Well, I didn't see that recommendation. I saw that you used --

A (Witness Newsome) Well --

Q You stated that you wanted to -- you wanted the company to do a 2025 IRP filing.

A (Witness Newsome) Okay. Lines 15 through 18, page 7. "Furthermore, the company should be required to file a cost-of-service study with its 2025 IRP filing to demonstrate potential rate impacts considering all costs on all customer classes consistent with the company's proposed 2025 IRP plan."

Q So what we asked -- what I just asked is, can it be done ahead of the 2025 IRP?

A (Witness Wellborn) Right. I think 14 is two

recommendations. So the first half of 14 is for this case, we would like to see it as soon as possible. We would like to see it in rebuttal. And then the second part of the recommendation is to see an update consistent with the '25 IRP, because we don't know what those asks are going to be.

Q And the reason why I am asking is because we approved -- this PSC approved the 2023 IRP, and then you came back because you said you had inconsistent modeling and forecasting that wasn't consistent, and now there is an amendment because you need more capacity.

So if you have a new modeling structure and new forecasting, is there any way that we could have an IRP that looked at the updated forecasting ahead of the 2025 IRP?

A (Witness Hayet) We are -- there is two -- as my colleague mentioned, there is two recommendations. Within the 2023 IRP update, the case that we are in, we are asking that the company would file a cost-of-service study to account for the cost to learn what the impacts are on the different customer classes.

The Commission is ultimately going to make a decision in this case. When it does, and consistent with other -- other things that will change that affect the company, prior to the '25 IRP, we are asking that another

cost-of-service study be performed. That -- that will be useful to staff, especially as it moves towards the 2025 rate case. Those are our two recommendations. So I think we are asking for what you are asking for.

Q Okay. Also -- I am trying to get my page numbers right. Okay. In regards to the battery energy storage, again, there was a mention of 1000 megawatts of power that the battery energy storage systems would be able to generate. But yet, I believe it is on page 69, and go back. You mentioned that you would not approve the BESS systems or the BESS project?

A (Witness Newsome) Not this -- not this --

Q Not in this?

A (Witness Newsome) Not this proceeding here. We are saying to go ahead and take that 1000 megawatts that Georgia Power is proposing and put it through the competitive RFP process, so we determine whether there is actually competitively pricing or not.

Q Okay.

A (Witness Newsome) We are not saying, no, don't do the 1000 megawatts. We are saying don't approve it in this proceeding, and run it through an RFP.

Q Okay. So a young man mentioned earlier, I don't know if you had a chance to hear it, that on February 25th, just this past week, ER CO2 -- ERCOT,

which is Electric Reliability Council in Texas, their grid reached 82.8 percent carbon-free power with 71.2 percent provided by renewables.

And then they talked about the prices were zero for about six hours. And so the question is, is that, you know, knowing these records, you said on page 25 you agree that we need alternative resources in winter 2026/2027. So why -- why wouldn't the staff recommend, you know, that Georgia Power meet future energy demand in ways that accelerate carbon-free emissions instead of coal and oil and gas that Georgia Power is asking for?

A (Witness Newsome) We are not opposed to the battery. We are saying you need to run it through a competitive RFP. We are not opposed to the battery.

Q So what about the rooftop and -- rooftop residential and commercial?

A (Witness Newsome) That wasn't part of our remit on this. We had to deal with what the company proposed, and one was the large-scale batteries. We have said, not now, RFP.

Q Okay. Do you know what percentage of gas surcharges are part of residential bills right now? For Georgia Power customers?

A (Witness Newsome) I am not aware of a gas surcharge.

Q It is 25 percent. Did you know that these surcharges are hidden on the bill and that people paying Georgia Power bills cannot see a label --

MS. DAVIS: Objection to testifying. The witnesses are here to testify and not people asking questions.

CHAIRMAN SHAW: All right. Sustained.

MS. DAVIS: Thank you.

BY MS. SCOTT:

Q All right. The last question that I have is that, do you think it is appropriate for this utility, Georgia Power, to continue to use coal, gas, oil, what we consider to be dirty energy, to supply electricity?

A (Witness Newsome) We are not concerned how they develop -- how they generate power. We are concerned about three things: Safety, reliability, cost.

Q Right.

A (Witness Newsome) And so we let it compete and look at those three criteria, is how we are going to make selections. If there is a carbon tax, that becomes part of our analysis. But there isn't one now. So we have to deal with the world we are in, not the one we wish we were in. And we have -- I mean, again, it's safety, reliability, cost.

Q So the last question is, is that you -- you say

you have to rely on the analysis. But I heard you say earlier that you haven't run modeling. Is that correct?

A (Witness Newsome) No.

A (Witness Hayet) Yeah. Actually, we do have a case that has a carbon tax price.

MS. SCOTT: All right. That's it. Thank you.

CHAIRMAN SHAW: Thank you, Ms. Scott.

Georgia Watch?

MS. COYLE: No questions.

CHAIRMAN SHAW: MARTA?

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft Corporation?

(No response.)

CHAIRMAN SHAW: Resource Supply Management?

CROSS-EXAMINATION

BY MR. BAKER:

Q Good afternoon, Panel. My questions are going to be -- and Mr. Kaduk. Unfortunately, Mr. Kaduk, I have nothing for you. I am sure you are heartbroken.

But let me go directly to the panel. Does the staff have a specific recommendation for allocating peaking capacity in a cost-of-service study?

A (Witness Newsome) No. Definitely want the study done.

Q Okay. Isn't peaking capacity normally utilized

primarily by residential and small commercial customers?

A (Witness Newsome) I don't know one way or the other.

Q You don't know.

A (Witness Hayet) We suggest you pass your question onto the financial panel.

Q And who would that be?

A (Witness Hayet) Mr. Smith.

Q Got it.

CHAIRMAN SHAW: The next panel.

MR. BAKER: Got it.

BY MR. BAKER:

Q All right. Could you tell me what is driving the increase in the winter peak forecast reflected in Table 1 on page 11?

A (Witness Hayet) Economic develop- -- the large customer site development that's going on.

Q For winter peak?

A (Witness Hayet) Yes.

Q Isn't large -- aren't large load customers, don't they have a consistent load profile throughout the year and don't have any type of --

A (Witness Hayet) 100 percent capacity factor means during the winter you will have a growth in the peak.

A (Witness Newsome) At 7:00 a.m. they are contributing to that peak.

COMMISSIONER PRIDEMORE: But, Mr. Hayet, that winter reserve margin was established at the time because of the amount of renewables put into the system. You wouldn't have had -- you'd have the same level of industrials. You wouldn't have had to have a winter reserve margin if you had the same load of industrials because you were operating off more coal. Correct?

MR. HAYET: Commissioner, I -- I am sorry. I am trying to understand your question, and I am trying to understand his question. His question is, as he said it, was what is driving the increase in the load that we are seeing in the Table Number 1 on page 11.

A (Witness Hayet) And the answer is, that's what the case is about. The increase in the load is this new economic development load. That's what has caused this load to go up dramatically.

MR. HAYET: Now I am trying to understand your question, which was about target reserve margin and renewable.

COMMISSIONER PRIDEMORE: His question was about the winter reserve margin, Mr. Hayet.

MR. NEWSOME: That's not what --

MR. HAYET: I heard "the load."

COMMISSIONER PRIDEMORE: Maybe repeat your question, Mr. Baker.

MR. BAKER: Actually, my question was about the peak, the winter peak, not the reserve.

COMMISSIONER PRIDEMORE: Well, okay. But the winter peak exists, though.

MR. BAKER: Yes.

COMMISSIONER PRIDEMORE: Because -- or the necessity to even examine a winter peak. We used to be a summer-peaking state with a summer-peaking utility.

MR. HAYET: That's correct, Commissioner.

COMMISSIONER PRIDEMORE: Yes.

MR. HAYET: And I -- I agree with that.

COMMISSIONER PRIDEMORE: Okay.

BY MR. BAKER:

Q All right. Turning to page 15, if you want to refer. "Staff believes demand response could play a larger role in meeting the company's resource needs," with staff support allowing more existing load to shift to marginal cost, as has been done in the past five rate cases.

A (Witness Newsome) We are not prepared to answer

that one.

Let me clarify. The reason we pulled up the cost-of-service study was Georgia Power is here coming in and saying, Well, hey, it is going to put downward pressure on rates. They looked at it, but the problem was they were looking at company wide, not how it hit individual rate classes. That's why we said, Well, how do rates get set? They get set in a cost-of-service study, and then we allocate it across the rate classes.

So that's why we were saying you need to do a revised cost-of-service study. The details on that are way beyond this panel, the nitty-gritty on it. We are just trying to say, do the cost-of-service study, so we can figure out where all these costs they're proposing to add to the system get allocated.

Q But staff does support demand response playing a larger role in meeting the company's resource needs?

A (Witness Kaduk) Yes, we do.

Q I'm sorry?

A (Witness Kaduk) Demand response, yes. So we actually approve a couple in here. Well, expanding the thermostat demand and the -- the Curtailable Load is a demand response program.

Q Thank you, Mr. Kaduk.

How does the company's reserve margin compare

to other utilities?

A (Witness Hayet) It is higher.

Q Significantly higher? Slightly higher?

A (Witness Hayet) You know, as we understand it, Duke is at 22 percent, so...

Q Is that the next-highest level reserve margin?

A (Witness Hayet) I --

A (Witness Wellborn) I don't know if we have an updated comparison; but in the '22 IRP, I believe there was evidence that it was on the higher side -- that Georgia Power's was on the higher side.

Q All right. But is Duke's reserve margin the second highest, that you are aware of?

A (Witness Hayet) From what -- sitting here and not having reviewed other ones, that right now is the second highest compared to Georgia Power.

Q Okay. Thank you.

Because the company has over-forecasted its weather normalized load every year for the past 18 years, isn't that a clear indication the target, the company's target reserve margin is excessively high?

A (Witness Hayet) It is an indication that if you do an analysis differently, as we did, to correct that situation that you are referring to, that it is higher. We still came out with a reserve margin target of

24-and-a-half percent. And that's what we used in the analysis we performed.

Q Do you think your recommended reserve margin is adequate to meet all reasonable anticipated demand?

A (Witness Hayet) Yes, we do. Because we are using the same methodology as the company, and we are addressing the issue that we saw with the calculation. So, yes, we do believe it is adequate. It is even higher than the industry standard one day and ten-year criteria, which would lead you to 20 percent. So, yes, we think it is -- we think 24-and-a-half is reasonable.

VICE CHAIRMAN ECHOLS: Let me hop in and follow that. But the reserve margin does allow us the opportunity to bring new businesses in. It is why people are coming here. Wouldn't you say it's having an impact on people knocking on our door now because we had it?

MR. HAYET: Yes, I do believe that they -- I would answer the question this way: I do believe that they would rely on the company to be able to serve their load and 24-and-a-half percent, yes, that would be sufficient, in our view, to be able to serve the load, even in a growing situation.

We do also recommend that in the '25 IRP, that that be updated, but that always is updated. So in

the coming IRP they should take into consideration changed conditions. For example, our -- is the cost of capacity higher now? And how does -- because the company actually does an economic optimal reserve margin analysis; and as the capital cost of your combustion turbines go up, that affects whether or not you want to -- you need to have as high of a reserve margin.

So they do trade off a little bit of unreliability in the sense of what is the cost of not being able to serve your load against the capital cost of having to add capacity, and as the capacity goes up -- cost goes up, they actually could see a reduced target reserve margin.

But from what we are comfortable with for this -- at this point in time, and knowing the additional load that comes -- that's coming to the system, we do think 24-and-a-half is adequate and reasonable.

VICE CHAIRMAN ECHOLS: Thank you.

BY MR. BAKER:

Q Would extending the operation of Gaston Units 1 through 4 and Scherer Unit 3 reduce or eliminate the need for some or all the proposed Yates CTs?

A (Witness Wellborn) That -- those extensions

would be for the period of '29 to '35 in our modeling. So to the extent that the Yates CTs are expected to provide capacity between '27 and '29, yes, it could defer some of those. I don't know if it is a one-for-one swap. But staff's plan, as we proposed with the PPAs carrying us through '28, and then those potential extensions, could provide a path to more valuation in the capacity RFP.

So the long of it to say if the Yates is competing in the capacity RFP, we would know more then, whether Scherer and Gaston were a suitable replacement.

Q But -- Mr. Hayet, you want to say something?

A (Witness Hayet) No.

Q Aren't these -- aren't Gaston and Scherer units existing units, they don't have to be built. They don't have to be permitted. They are ready. I mean, they are there?

A (Witness Newsome) I mean, that's one reason they are modeling. We showed them running through 2035 for that reason, as existing assets, so we included them in the modeling through 2035.

Q Will the extension of those units be considered for the 2025 IRP?

A (Witness Wellborn) The company has indicated they are going to do a study for those in the '25 IRP.

A (Witness Newsome) I mean, we did in this IRP update, so I am sure we would in the 2025 IRP.

Q Did the company consider all potential resource options before developing its plan to meet short-term needs?

A (Witness Wellborn) I think our testimony, and I probably could point you to a specific page, but we do think that there may be other options. That's why we are advocating for an RFP to consider all of the potential options.

Q Does the staff support setting rates following the cost-of-service study?

A (Witness Newsome) Yeah. I mean, it depends on how, I guess, you do the cost-of-service study, but, yes. I mean, there is a lot of discretion in those things.

A (Witness Wellborn) The cost-of-service studies we are requesting here are not in rate cases. They would be in the IRP, so they are more educational. They are more to provide context for the requests. I don't --

A (Witness Hayet) But the idea, I think, to follow onto what my colleague is saying is that it's to provide the information, especially to answer a lot of the questions that came up about the downward pressure on rates. We think that's important information. It was obviously important, as we saw in the last hearing.

However, we think that especially in the '25 IRP, when that information is provided, it is going to factor into the rate case that's going to immediately follow.

Q I realize you are saying the cost of service -- a cost-of-service study would be educational, but would it be educational in the sense that it would show or indicate where the cost would fall if the Yates Units were built, the battery energy storage units were built? Wouldn't it show where those costs would ultimately fall or likely fall?

A (Witness Hayet) It could, but -- and other parties can make adjustments to it to look, if they don't see the exact setup that they want. So, yeah, it could be used to study different situations such as what you are suggesting.

Q Well, let me refer just to the Yates Units. The Yates Units, I believe the company has stated that they need those to deal with shoulder peaking, and especially in the morning; is that accurate? Is that your understanding?

A (Witness Wellborn) I think most of the capacity offered in here is to serve that winter reserve margin requirement, which is that winter peak in the morning.

Q Winter peak in the morning. Now, wouldn't -- just on the Yates Unit, wouldn't that be -- wouldn't that

winter peak be driven more by the smaller customers, such as residential and small commercial customers? A data center is not going to be ramping up in the morning.

A (Witness Newsome) No, the ramp up is not the issue. The issue is how many or who on that -- say seven o'clock is the peak. Okay. Who is taking load at seven o'clock? It's industrial, commercial, residentials. It's everybody. Everybody is contributing to the problem at seven o'clock. Now, how much they are contributing, yeah, that's different. But everybody contributes.

Q Okay. So would the cost-of-service study show how much each class is contributing to that peak increase?

A (Witness Newsome) Presumably, it would.

A (Witness Hayet) Yes.

A (Witness Newsome) But it depends how you do it and how the cost gets shifted around, too. I mean, there is a lot of discretion on how those things are done.

Q Hypothetically, if this new influx of potential large load customers had not materialized, would there be a need for any of the new proposed supply-side resources requested by the company?

A (Witness Newsome) We wouldn't be having this hearing now. When we get to 2025, that's a different story. But, yes, we wouldn't be here.

Q In the past, haven't rates been set by equal percentage increases across all rate classes?

A (Witness Newsome) It has. That's a Commission decision.

Q But wouldn't -- if a cost-of-service study were done, would the cost-of-service study then show where those costs should fall?

A (Witness Hayet) Again, you are way outside of the bounds of what our testimony is about. All our testimony on the cost-of-service study is to say that we don't have the information -- the downward pressure on rates argument, we don't really have a good study to look at that or anybody be able to analyze that. But we didn't do any work on cost of service, and we presented within our testimony. So you are asking a lot of questions that require speculation on our part.

Q The staff does not recommend certification of the Yates project until it is determined to be a least-cost resource in an RFP process. When would that occur? In the 2025 rate case or the 2025 IRP?

A (Witness Newsome) It would be -- well, you'd make the determination through doing the RFP, and I don't know when that would be completed. We are going back and forth with them on schedule. But you would probably get bids late spring, and then they have got to analyze them.

So you wouldn't probably have an answer until sometime in '25, probably second quarter.

A (Witness Wellborn) Though I think the posted schedule now is still subject to Commission review, but, yeah, bids, I think, are due June of this year. And so if the pool of bids, if Yates was included in that process, the pool of bids, potentially, would be known in June. So it is not -- it may not be that significant of a wait time. Though the company has indicated it could take time for studies. But if there is not a lot of resources, it might not take as long.

Q But that would be considered, then, either the IRP or the rate case in 2025?

A (Witness Wellborn) I mean, if they know in June, I -- it could be.

A (Witness Hayet) You mean the certification would be decided? Is that what you are asking?

Q No.

A (Witness Wellborn) Oh, right.

A (Witness Hayet) What are you asking?

Q Well, let me move on here.

A (Witness Hayet) Okay.

Q Are any of the BESS projects included in Table 13 complete and operational?

A (Witness Newsome) Have you got a page number on

that one?

Q Page 69, line 6.

A (Witness Newsome) None of them are except for the -- yeah. Just -- I know maybe a distributed storage and --

A (Witness Wellborn) What was the question?

A (Witness Newsome) Which in Table 13, which one are in operation. I think the distributed storage is, and Mossy Branch is supposed to show up second quarter this year.

Q So only the distributed -- 2 megawatts distributed storage is operational?

A (Witness Newsome) That's my understanding.

Q Okay.

A (Witness Newsome) Subject to check.

Q Now, wasn't Mossy Branch authorized in the 2019 IRP?

A (Witness Newsome) Yes.

Q And wasn't another 500 megawatts of BESS authorized in the 2022 IRP?

A (Witness Newsome) Correct, yes.

Q So at this time, with all of this potential, the only realized BESS that's in service is 2 megawatts. Is that --

A (Witness Newsome) That's our understanding.

Q And maybe --

A (Witness Newsome) Maybe at Fort Stewart. Maybe there is something going on with that.

A (Witness Kaduk) No. I am agreeing, yes. Mossy Branch and McGrau Ford are not in service yet, to our understanding.

A (Witness Newsome) And Fort Stewart?

A (Witness Hayet) Fort Stewart?

A (Witness Kaduk) Fort Stewart?

A (Witness Hayet) Does that ring a bell?

A (Witness Kaduk) No. I think that's -- no, I am not aware of that one.

A (Witness Newsome) Okay.

Q So on average, it would take about seven years to fully develop a project; is that what I am hearing you say?

A (Witness Hayet) That's your interpretation.

A (Witness Newsome) Based on Mossy Branch, I don't know. It has taken them a while to get -- I don't think it takes seven years, but it has taken them a while at Mossy Branch.

Q Or five years, I should say five years.

A (Witness Hayet) It is not expected to take that long, but it is taking time on these.

A (Witness Newsome) I mean, there is two

different -- the question is how -- you know, there is -- once you get approved to build it, then there is time to build it and start it up. Then a lot of this are RFPs they have got to go through, too. So there is time on the front end to do -- conduct the RFP. That's also slowing it up, too.

Q Is there a need to authorize 1000 megawatts of additional battery energy storage when they still have an unused 500 megawatts that hasn't been fully -- hasn't been touched?

A (Witness Newsome) I mean, that's a fair point, but that's why we wanted to go through an RFP.

Q Why are all the Georgia Power battery energy storage projects more expensive than generic battery energy storage resources?

A (Witness Newsome) I think maybe efficiency of construction. They have got a higher cost of capital, though. I mean, they have got 56 percent equity in capital structure and 10-and-a-half ROE. So I think it's just they are getting beaten up on capital cost.

A (Witness Hayet) Even if you look at the company's assumption, escalation of costs of the battery storage project, they show that it is a falling cost -- cost curve over time. And because of that, we think that part of the answer to your question is that in -- in

time, projects are dropping in price, and some of the generic projects are assumed to be a little bit further out in time than the projects that they have. And because of that, we think that their generic costs are somewhat lower than the existing projects. But we don't have a complete answer on why their costs are higher.

A (Witness Wellborn) I will say there is also a slight difference in the proposed projects getting the full 40 percent ITC, whereas, the generics modeling that the company is proposing does assume that it could be up to 40 percent. So there is -- there is that slight difference, too, in terms of how much capital cost gets fully realized.

Q All right. And could you tell me, do any other utilities use the FLEX Capacity framework, to your knowledge?

A (Witness Newsome) I am not aware of it. But they work with a lot more jurisdictions than I, so they would probably know better than me.

A (Witness Hayet) Yeah. No, I can't say I can think of a single company that also has that authority.

Q So this would be a unique situation?

A (Witness Hayet) From sitting here right now, I can't think of another company.

Q Okay. And let me see. Should the company's

23-year-old 70 percent rule be updated in favor of more competitive sourcing of new capacity assets?

A (Witness Newsome) Yes. But, again, we -- like I told Commissioner Pridemore, we need to figure out what the cost -- there is probably some savings by having a lower threshold, so we need to measure those savings against the reliability.

Q And finally, I understand the legislature may be considering customer -- let me just ask: Would the staff support legislation if, I understand it may be considered, allowing customer generation for peak use in lieu of additional company capacity?

A (Witness Newsome) From a financial aspect, that's what you want. Keep it out of rate base.

A (Witness Wellborn) Yeah. I think Mr. Kaduk might have more on customer-sided resources.

A (Witness Kaduk) Please ask the question again. Sorry.

Q All right. I understand that there may be some legislation pending, but would staff support legislation allowing customer generation for peak use in lieu of additional company capacity?

A (Witness Kaduk) Yes. I mean, one of the programs that we are asking the company to look into is that -- it is a residential and small commercial battery

possibly paired with residential solar or small commercial solar. And, yes, that would be -- help to either meet their peak or it depends on how the battery or, yes, is dispatched.

MR. BAKER: Thank you, Panel.

Thank you, Commissioners.

CHAIRMAN SHAW: Thank you. Sierra Club?

While Zach is coming up, I just want to give a little housekeeping. Our plan is to break around 5:30 for probably about 45 or 50 minutes, at least. The snack bar is going to stay open until 6:00. But if you wanted to order some food or something, just -- that's the plan, and then we will come back. And like I said earlier today, we might have to go until about 9:00 to try to make sure we get out of here at a decent time tomorrow. Thank you.

MR. FABISH: Thank you. I will do my best to move things along.

CROSS-EXAMINATION

BY MR. FABISH:

Q Thank you, Panel. Just a few questions following up a little bit on some of the earlier questions you had about carbon price in your analysis. So if I recall correctly -- and I think it was you, Mr. Newsome, but if I get that wrong, please don't be

offended. Someone said that you could model either a carbon price or you could model the specific compliance costs associated with a regulation; is that right?

A (Witness Newsome) Right.

Q Yeah. Are y'all familiar with EPA's proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants?

A (Witness Newsome) To some extent, yes.

Q To some extent? Okay. And that was published in the Federal Register on May 23, 2023. Is that --

A (Witness Hayet) Yes.

COMMISSIONER PRIDEMORE: To be specific, you are talking about EPA 111?

MR. FABISH: Yes, I am. Yes.

COMMISSIONER PRIDEMORE: Thank you.

MR. FABISH: Yeah. I just used the full title from the Fed Reg, but 111 rules, yes.

BY MR. FABISH:

Q So you are aware that the proposal, if finalized as proposed, could mean that existing coal units could have to co-fire gas, significant levels, by 2032 -- or by 2030?

A (Witness Hayet) Yes. If it is approved as proposed, but, of course, you have -- you are aware that there is possibility that there are going to be changes

to it, so...

Q Oh, yes, yes, absolutely. I am just saying, if finalized substantially as proposed.

And that, you know, if existing coal units retired by 2032, they wouldn't necessarily have to do that co-firing to comply with the rule, if it is finalized as proposed?

A (Witness Hayet) If finalized as proposed.

Q Okay. And if finalized as proposed, the 111 rule could mean that new gas units could have to reduce capacity factors or co-fire with hydrogen or achieve very high, 90 percent, levels of carbon capture sequestration; is that right?

A (Witness Newsome) That's the rule.

A (Witness Hayet) If finalized as proposed; but, once again, there is a good chance that it is not going to be finalized as proposed.

Q Now, in the resource evaluation other analysis that I think you discussed earlier, you looked at a carbon price; is that correct?

A (Witness Hayet) Yes.

Q But that carbon price isn't a perfect proxy, by any means, for the 111 rules, if finalized as proposed?

A (Witness Hayet) Right. And realize that, also, to a large extent, the fact that there has been ITC and

PTC has led to the introduction of significant amounts of renewables and significant amounts of economic coal retirements.

Q Is there a risk that if the rule is finalized, the 111 rule is finalized as proposed, or substantially as proposed, the sort of carbon price base resource evaluation that y'all did might not predict -- might not accurately predict the compliance costs and risks associated with investments in coal and gas-fired generation?

A (Witness Newsome) I would say yes.

Q Okay.

A (Witness Newsome) I mean, what you are talking about, you are firing the hydrogen, restoring the carbon. I mean, that's massive -- especially carbon storage. I mean, it is massive capital cost. Massive O&M. I mean, it's a political process. I think you are going to get a little pushback on that. Maybe a lot.

COMMISSIONER PRIDEMORE: Mr. Newsome, you follow this space. Is that being done anywhere right now in the world, that you are aware of?

MR. NEWSOME: I mean, there have been pilot projects here in the States, but I am not aware of -- I mean, it's a big world, so maybe, what have you. I think what you have found with the pilot

project in the past, they can run it for a year or two, and then it is just -- it's too much money.

BY MR. FABISH:

Q Last couple of questions: Is it your understanding that EPA intends to finalize this rule and so we will get to see whether or not it is substantially similar to the proposal within the next couple of months?

A (Witness Newsome) That rings a bell with me, but --

A (Witness Hayet) Yeah. I mean, that's something that we have heard, but it is not a guarantee.

Q Okay. Particularly if it is finalized before the next IRP, do you think it would be a good idea to -- for someone, not necessarily y'all -- but, like, for someone to analyze the compliance costs of the rule in the context of the next IRP?

A (Witness Hayet) Yes. That's typically what is done. They would conduct analysis prior to the IRP, and it would be used within the IRP.

MR. FABISH: Okay. That's all the questions I have. Thank you so much.

CHAIRMAN SHAW: Thank you.

Southern Alliance for Clean Energy.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy

Association.

MR. COX: No questions.

CHAIRMAN SHAW: United States Department of Defense.

MR. MCNUTT: No questions, Mr. Chairman.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: All right. Georgia Power.

MR. HEWITSON: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Panel, how are you this afternoon?

A (Witness Newsome) Good.

A (Witness Hayet) Good. Thank you.

A (Witness Kaduk) Good.

Q Steve Hewitson on behalf of Georgia Power. Good to see y'all again.

Let's start on pages 5 to 7 where you provide your recommendations to the Commission. And is it fair to say that your recommendations regarding the company's proposed resource additions are based on the load forecast performed by Daymark and presented by Mr. Trokey's panel?

A (Witness Newsome) Correct.

Q And that load forecast agrees with Georgia

Power that the load is growing significantly, but it included adjustments that resulted in the load materializing later and at lower levels than Georgia Power projected. Is that fair to say?

A (Witness Newsome) Correct.

A (Witness Hayet) Still had significant amount of load growth, so I don't think that anybody should suggest that we are not accounting for dramatic increase in load. We are.

Q And based on staff's load forecast, as you have discussed with a few of the other -- or a few of the intervenors, you recommend approval of the two PPAs, Mississippi Power and Santa Rosa, but deny all other requests because staff's load forecast shows the year of need in 2029 if the PPAs are approved; right?

A (Witness Newsome) That's true, but there is also the issue of the cost of these, of what you are proposing. And it is quite expensive. And it needs to be run through -- we think it needs to be run through an RFP to make sure it is actually cost effective against the market.

Q Let's turn to the target reserve margin. You spent several pages in your testimony discussing the target reserve margin and reminding us of the disagreement between staff and the company in the 2022

IRP.

To be clear, while the company's 26 percent value is not approved, both the 2019 and the 2022 IRPs approved Georgia Power to plan to 26 percent, and that is what the company has done; right?

A (Witness Hayet) Yes. With one exception, that the Commission didn't foreclose the possibility of any other party being able to recommend a different target reserve margin. And we have.

Q Okay. And that's fair, Mr. Hayet. And the staff has advocated for a 24.5 percent target reserve margin; right?

A (Witness Hayet) Yes.

Q And the premise of staff's adjustment, at least in the 2022 IRP, was that the company had always over forecasted load, not under forecasted load, and I think you said it a little bit earlier today in response to some questions; right?

A (Witness Hayet) I think somebody else talked about that, but the --

Q Sorry that I confused you with somebody else.

A (Witness Hayet) The analysis that was conducted, that we conducted, had to do with the fact that there had been over forecasting, but, more importantly, it was the adjustment that the company made.

And we referred to that as an ad hoc adjustment.

Q But you would agree that the company is now dealing with a significant under forecast situation?

A (Witness Hayet) We agree that the company is dealing with a situation, as you said, that's unprecedented. It has nothing to do with whether, you know, you have under forecasted. Because the -- this is -- the data center load, the new explosive load, is outside of any forecasting that you have done.

I am not going to deny -- there has never been an attempt to forecast this, so I can't say that you have under forecast, because an attempt wasn't even ever made.

Q Okay. And I think you took out some of the questions, so everyone is going to be really happy about that, Mr. Hayet. But just to confirm, the 1.5 percent differential between the company's current planning target reserve margin and staff's recommendation does not materially change any of the recommendations in this proceeding that you have; right?

A (Witness Hayet) What are you referring to as 1.5 percent?

Q Between 24 percent and 26 percent, between the company and the staff's recommendation.

A (Witness Hayet) Right. We would still have the same recommendations, but we think that -- we think that

there is a number of factors that are not accounted for, that, when added together, do provide you some additional ability.

And all we are saying is we think that there is going to be a delay potentially. We think that you are getting 1000 megawatts of CASI. We are getting to the point where that allows an RFP to be conducted.

Q Well, let's talk about staff's alternative resource plan. Is it fair to say that the main disagreement between the company and the staff in this update proceeding is when the increased load will arrive?

A (Witness Newsome) That's part of it, yes.

Q If staff's load forecast is correct, then the company's need year is 2027, but that need is smaller than what the company believes it to be. Is that fair statement?

A (Witness Newsome) Yes.

Q And staff's alternative resource plan which approves the two PPAs addresses that smaller capacity need so that the company does not require additional capacity resources until 2029; right?

A (Witness Newsome) Correct.

Q Would you agree with me, though, that if the load shows up when Georgia Power is expecting it, staff's alternative resource plan would not adequately cover the

capacity needs identified by the company?

A (Witness Wellborn) It wouldn't at the 26 percent reserve margin or the 24 percent reserve margin. But those are economically optimal value at risk reserve margins. If we -- Mr. Hayet discussed, if we consider the reliability standard at 20 percent, just as a temporary oops kind of situation, staff's plan would still get you through to 2028. And hopefully enough time to still evaluate resources in an RFP.

Q But it would be to reduce the reserve margin to 20 percent, which necessarily impacts reliability concerns; right?

A (Witness Wellborn) Economic reliability concerns. I think reliability concerns to the one day and ten years standard would be met by 20 percent.

Q And if there were -- do you know what would have happened on the system if the company was at a 20 percent target reserve margin during Winter Storm Elliott?

A (Witness Hayet) Yes. And also, since Winter Storm Elliott, there has been lessons learned. There has been a NERC effort to implement standards on it. So, yes, because of what happened then, there has been a nationwide effort to improve reliability of resources.

A (Witness Newsome) And presumably, Georgia Power

has also improved their resources.

Q But what do you think would have happened if we were at a 20 percent target reserve margin during Winter Storm Elliott?

A (Witness Hayet) During -- a different situation than what might happen in the future, but....

Q But what do you think would have happened?

A (Witness Hayet) I think that what would have happened is there could have been a potential reliability issue.

Q And we all know that experts can disagree, and we also know that projections are subject to change as time unfolds. But I want to walk through with you what happens if these resource plans are adopted and the load materializes or doesn't. If Georgia Power's resource plan is adopted but the load does not arrive, then Georgia Power has been approved to build or buy more to serve load than is needed; right?

A (Witness Newsome) Correct.

Q And that's a cost issue, as I think Mr. Newsome, you have said a couple times, that nobody really wants to deal with; right?

A (Witness Newsome) Well, the ratepayer is going -- if you build it, the ratepayer is going to be dealing with it.

Q Well, the Commission has authority to and ability to address the cost issues; right?

A (Witness Newsome) Well, sure. But, I mean, you start building the stuff, you are going to get a return, you are going to get your cost recovery, so, I mean, there is going to be a material impact.

Q And even if the capacity is not needed now, we do all agree that the load is going to show up; right?

A (Witness Newsome) We don't know when. I think that's debate. And I mean -- go ahead.

Q Well, if Georgia Power has approval for more capacity than it needs, there are tools in place to slow the acquisition of that capacity or the building of that capacity; right?

A (Witness Newsome) Well, what -- you want to tell me what those tools are? I mean, you are asking for stuff to be approved now. You can wait.

Q You could sell generation on the wholesale market; right? That's one option.

A (Witness Newsome) Right, but that hasn't recovered all of your cost on those PPAs.

Q You could also reduce RFPs or what you were going to get in future RFPs; right?

A (Witness Newsome) But that doesn't help you on the money for the ratepayer now. I mean, once it is in,

it is in.

A (Witness Wellborn) I think there is -- I think there is a concern that, if you are going to, in your scenario, overbuild, wouldn't you rather overbuild the most economic capacity? I mean, I think the primary recommendation we are trying to get is a competitive evaluation. And so if we do decide that that's the capacity we need, let's do it competitively.

Q Okay. Then let's look at the other side of that. If staff's resource plan is adopted but the load materializes earlier than staff believes that it will show in its forecast, Georgia Power will not have adequate capacity to serve that load; right?

A (Witness Hayet) We disagree. We disagree, because we think that on a standard of one day and ten year, industry standard, the company will be able to meet that. We also think that the company's schedule for doing RFPs can be accelerated. We also think that there is other capacity that the company is not accounting for. And we think that, also, there is demand response that the company can account for.

So there are other levers that the company is not attempting to rely on because the company really wants to, you know, build these resources, which would then put them into the rate base and customers,

ultimately, would be on the hook for paying.

Q And staff's reaction to that is to say that you would have adequate capacity if we lower reliability?

A (Witness Newsome) If you have a lower reserve. You are using -- they are using 20 percent for the --

Q Target reserve margin?

A (Witness Newsome) -- the reserve margin.

Q Right. Said would have an economic reliability issue.

A (Witness Hayet) Remember, we used 24-and-a-half percent, but we are just saying that you can go as low as 20 percent for a very short period of time. And that would be industry standard reliability.

So we are not sitting here suggesting to the Commission that they should set it at 20 percent for the long term, but we are saying that an industry standard is 20 percent.

Q Yes. But that's -- the industry standard is not what Georgia Power has historically planned to; is it?

A (Witness Hayet) That's correct.

Q And it is not what this Commission has approved in prior RFPs; is it?

A (Witness Hayet) That's correct.

Q Okay. So what you are saying is your plan can

work as long as you plan to a lower reliability standard, at least in a short term?

A (Witness Hayet) Let's also be clear that the Commission has approved, not necessarily 26 percent, they have -- they have approved a lower value in the short term. So you don't actually plan the 26 percent or the system planning to 26 percent in the short term. It is a longer-term target reserve margin.

That doesn't get talked about very often. But that is actually the case, that there is a shorter, three-year period or so. So all we are saying is, for a short-term period of time, if -- if -- if the load materialized greater, and we don't think it will, we think that there is a -- that it is better to be able to use the -- find the economic resources. And that's our recommendation.

Q All right. Now, one of the things that you said is to -- one of the options is to alter the approved target reserve margin. The other thing that I think you said was to accelerate RFPs?

A (Witness Hayet) Yes.

Q Okay. And in what way? Are you saying the All-Source RFP?

A (Witness Hayet) We are -- yes.

Q All of them?

A (Witness Newsome) All of them. Let me go just through this. Y'all knew in '21 you were getting load growth. It started accelerating in '22. You knew in the end of '22 that things were bubbling. Excuse me. Not you. I am sorry. Your client.

Q But you are pointing the finger at me, Mr. Newsome.

A (Witness Newsome) Well, I am going to get my point across. They knew in '22 that things were -- that load was building. At that time, that was the time to start to initiate the RFP process.

Q Would staff have supported an initiation of an RFP process or acquiring new capacity prior to the need year changing?

A (Witness Newsome) You knew the need year was -- my point is you knew --

Q Well, hold on.

A (Witness Newsome) All right, go ahead.

Q The need year changed in June of 2023; right?

A (Witness Newsome) Well, that's when you told us the year -- the need year changed.

Q Well --

A (Witness Newsome) But it was growing all through '21, '22.

Q Right. But there was excess capacity on the

system, wasn't there, at that time, Mr. Newsome?

A (Witness Newsome) There is still excess capacity on the system now. We are worried about the future. And if it was growing in '21, '22, it seemed like to me that you are going to need more capacity sooner and you do need to do an RFP. I know you are standing behind that 70 percent thing to shield you from that.

Q I haven't mentioned that at all, have I?

A (Witness Newsome) Well, you are going to come to it, I am sure. But you had opportunity -- what I am saying, it was growing, the RFP could have been moved up, and then we wouldn't be having this debate now.

Q But that -- but would staff -- do you believe that staff would have supported the company starting the RFP in January of 2023 when the need year hadn't even moved? You heard the Georgia Power witnesses say, we recognize the need year moved in June of 2023; right?

A (Witness Newsome) Well, if your loads that you are showing are growing up, we would have supported the RFP to get the information, to not to be in this situation we are in now, where it is like we have got to take -- we are going to have a shortfall, so we have got to take all this capacity.

A (Witness Kaduk) And one minor point. The

current 4822 filing still says it is 2029, so -- I know the company did tell staff earlier that we are expecting more load and the need year will be sooner, but still, the -- whatever is on file right now, it is still 2029.

Q For what, Mr. Kaduk?

A (Witness Kaduk) The need -- the year of capacity, first year of capacity.

Q For the All-Source RFP?

A (Witness Kaduk) Sorry. Just for Georgia Power, in general, the 4822, winter capacity need is still 2029, according to what is on file, the most recent filing from Georgia Power.

Q But not what has been filed with this IRP update?

A (Witness Kaduk) No, I agree.

Q Okay. And didn't -- when the company met with staff in June of 2023, didn't the company suggest that we bifurcate the All-Source RFP to be able to run it sooner?

A (Witness Newsome) My memory -- I believe that was something like that. Our issue with you on that was -- I am sorry. The company; not you -- was that you guys wanted to start bifurcating RFPs. And we were saying, just load them all up there and do All-Source, then we have only got to deal with one of them, not multiple ones.

In terms of the timing and stuff, we still wanted it done sooner rather than later.

Q And staff also rejected the issue of having an earlier RFP based on changed load forecast without first having the opportunity to vet those load forecasts and have a hearing; right?

A (Witness Newsome) I don't agree -- I don't agree with that.

Q You don't agree with that?

A (Witness Newsome) Nope.

Q Okay.

A (Witness Newsome) When you came to us, we were in favor of getting the RFPs moving as fast as you could.

Q But not bifurcating?

A (Witness Newsome) Correct.

Q You wanted to move it fast, but you didn't want to allow us to bifurcate; correct?

A (Witness Hayet) There was a 2029 IRP approved, and there were discussions about that. There were a lot of RFPs that were put on the table that staff was concerned about the number of. Staff -- staff thought about different ways that the 2029 IRP -- RFP could be used. It could be accelerated. It could be expanded. There were a lot of discussions about that.

So I think what you are getting at is somewhat

unfair. That's all I am going to say about that. Because I think we are talking about conversations that were -- that we had back, and it's subject to the memory of people that were on the call.

Q Well, that's a fair statement, Mr. Hayet, but I am not the one that put the timeline of events in my testimony. You put the timeline of events in your testimony, and you seem to have left out proposals by the company to bifurcate the All-Source RFP.

A (Witness Newsome) But the issue on the RFP is the timing. We told you back then. In fact, Mr. Trokey had to come track y'all down in March and ask you what is going on. Then y'all show up in June -- in June and say, Hang on, load's blowed up. We have got to have -- you know, and now we have got to have all this capacity.

So the issue is the timing. We never moved away from that. No. No, we didn't want to bifurcate because we didn't want to have to manage several different RFPs. But the timing, we were set on that from the beginning. Move sooner, not later.

Q On page 52 of your testimony at lines 3 and 4, you note that the staff's resource mixed study period was 2024 to 2040 rather than the company's mixed study that went to 2058; is that right?

A (Witness Hayet) Yes.

Q Did you observe any impacts on the mixed study results because of that shorter study period?

A (Witness Wellborn) We have got -- when we re-ran the company's mixed study on just our shorter period, the general short-term indications through 2030 were consistent.

Q Okay. And on page 67, lines 3 to 4, you note that, "Neither the Yates CT capacity, nor even generic CT capacity were selected prior to 2030 in staff's resource mix cases"; right?

A (Witness Wellborn) Yes.

Q Okay. Would it surprise you to learn that extending the study period to 2058 does result in generic CTs being selected prior to 2030?

A (Witness Hayet) Generic what?

Q CTs.

A (Witness Wellborn) Generic CTs.

A (Witness Newsome) But this is Yates he is talking about. We're talking about Yates here.

Q No, I am talking about generic CTs.

A (Witness Newsome) Go ahead. Go on.

A (Witness Wellborn) I guess it would surprise me, but it is not -- wouldn't be out of the realm of possibility.

Q Okay. And let's talk about Yates specifically.

On page 65, Table 12, you note that in the company's certification application, Unit 8 is expected to be on-line in 2026, and Units 9 and 10 have COD dates in 2027; correct?

A (Witness Wellborn) Can you point me to that one more time?

Q Yes. Table 12 on page 65.

A (Witness Wellborn) 65. Yes.

Q See COD dates down there?

A (Witness Hayet) Repeat your question.

Q Sure. I believe that you had Unit 8 being expected to be on-line in 2026 and Units 9 and 10 to have COD dates in '27; right?

A (Witness Wellborn) Right. So the 2026 date is ahead of the 2027 peak, and then the 2027 dates are ahead of the '28 peak. That's -- that's right.

Q In your modeling, is it true that you allowed Yates 8 and 9 to only be selected in 2026 and Unit 10 to only be selected in 2027?

A (Witness Wellborn) I don't believe that's what I have modeled, but that would have been consistent with the IRP filing, so -- the original date. So if that was the case, it would have been, you know, a timeliness error, given the late-filed updates we got from the company.

Q Well, can I make a hearing request for staff to let me know whether in their modeling they only allowed Yates 8 and 9 to be selected in '26 and Unit 10 to only be selected in 2027?

A (Witness Wellborn) If you give me a second, I can probably do it right now.

A (Witness Newsome) Well, let's -- we'll do --

A (Witness Wellborn) Oh, we will do a hearing request.

Q I am fine with a hearing request.

A (Witness Wellborn) Okay.

Q In the interests of time.

Let me ask you this then: Would it surprise you to learn that by allowing the Yates Units flexibility to be selected in more years than just '26 and '27, as we believe staff used, the Yates Units are, in fact, selected by the model in 2028?

A (Witness Wellborn) That may be the case, and I think that argues for the time that we need for an RFP. The Yates decision isn't necessarily something we have to make today with that sort of timeline and that flexibility you are discussing.

Q On page -- I am going to move on to your economic analysis study now. On page 45, lines 10 to 12, you discuss the "generic candidate unit" costs and

suggest that there may be BESS resources that could be built for less than the specific BESS projects identified by the company in the update filing; right?

A (Witness Hayet) Yes.

Q Do you agree with me, though, that generic projects do not consider location, timing, interconnection, or transmission service costs?

A (Witness Hayet) That is correct.

Q And those are all factors which may impact cost; right?

A (Witness Hayet) And we mentioned that there are costs that are potentially not included. Yes. The magnitude of the cost difference is considerable, but we did acknowledge that.

A (Witness Wellborn) And I would add that I think this discussion on page 45 is also around these co-located projects, which wouldn't have those same types of costs, because the transmissions were used, and so -- in terms of apples to apples, if we are talking just pure construction, it may be a more reasonable comparison.

Q Okay. Well, but there would still be an issue of interconnecting if you were going to change that project? Still be a transmission study that would need to be done even if it is a co-located project; right?

A (Witness Hayet) Yes.

Q Okay. And it is similar with the RFI responses you discuss on pages 44 and 45. Just because indicative pricing was provided does not mean that the projects would be bid into the RFP in -- at those prices; right?

A (Witness Newsome) Right.

A (Witness Hayet) That's correct. But an RFP at least would give you the opportunity to do a comparison that would have the, you know, complete information.

Q Okay. Thank you.

Mr. Kaduk. Your testimony recommends that the company should revise its resource ledger to include 500 megawatts of winter capacity equivalence from the 2023 CARES utility scale RFP; right?

A (Witness Kaduk) Yes.

Q And that RFP is still in progress; right?

A (Witness Kaduk) It is.

Q Do you agree that the company developed its resource ledger based on installed, planned, and committed resources?

A (Witness Kaduk) Planned and committed, yes.

Q Okay. Because the CARES RFP is still ongoing and bids haven't even been received yet, there is no guarantee that 500 megawatts of solar-plus storage would be bid into the RFP; right?

A (Witness Kaduk) Bids have been received as of

last month.

Q Well, there is no indication -- there is no guarantee that they will be selected; right?

A (Witness Kaduk) No, there is not.

Q You note that the CARES RFP seeks resources with in-service dates between 2026 and 2028; right?

A (Witness Kaduk) Correct.

Q The RFP does not require resources to be on-line in 2026 or 2027. They just have to be on-line by the end of 2028; is that right?

A (Witness Kaduk) Anywhere in the three years.

Q For planning purposes, though, there could be a significant difference between resources coming on-line in '26 versus '27 versus '28; right?

A (Witness Kaduk) Sure.

Q And in your testimony, you did not propose a year in which the company should assume the 500 megawatts from the CARES RFP is on-line; right?

A (Witness Kaduk) No. But the company already assumed that it would come on-line at the winter of '27, so we are just saying, replace that number with the staff's proposed number.

Q Okay. You -- that -- I am sorry. I may have missed that in your testimony.

A (Witness Kaduk) Sure.

Q That's in your testimony?

A (Witness Kaduk) Not the exact year, no. But that's what I would recommend today, that it is currently -- you are right, it is not in my testimony. It is currently in there in your resource ledger. We are suggesting you replace what is in your current resource ledger with our proposed 500-megawatt value.

Q I will accept that.

And you have overseen and been involved with several Georgia Power renewable RFPs; right, Mr. Kaduk?

A (Witness Kaduk) I have been involved with them, yes.

Q Do you agree that it would be unprecedented for the entire portfolio of winning bids in a renewable RFP to come on-line when they say they will?

A (Witness Kaduk) It is not likely. Not the entire portfolio, no. But A majority still could.

Q But you recommend that the company rely on these projects coming on-line at least by 2028; right?

A (Witness Kaduk) I think the majority always do come on-line by the end of the period that they are supposed to come on-line.

Q Okay. But don't you --

A (Witness Kaduk) More often than not.

Q I am sorry. And I did not mean to cut you off.

A (Witness Kaduk) No, I am sorry.

Q Don't you think that, to be included in the company's resource ledger, there should be some certainty that solar-plus storage projects are, A, bid into the RFP; B, win; and C, come on-line when they say they will?

A (Witness Kaduk) The company already made an assumption. I mean, the company has an assumption in there for the BESS RFP, 500 megawatts of storage. They are, you know, putting in the capacity equivalence of the entire portfolio in that year.

Q But you are recommending the company do something different here than what it is currently doing with that resource ledger; right?

A (Witness Kaduk) The resource you are -- that you are assuming will win. That's all. We are assuming, based off of past renewable RFPs, the majority of those winning projects have included storage. It is likely to happen again in this one. And also, in addition to -- so not only will you get a capacity credit from these batteries that are co-located with solar project, it also is requesting up to 650 megawatts of carbon-free around-the-clock energy, which is a little bit of solar with a ton of batteries. So that could even be another 650 megawatts right there, but we are only assuming 500.

Q All right. But as you just said, it is based

on the last several renewable RFPs; right?

A (Witness Kaduk) Just for the solar and storage. But we are also looking for a novel concept of that carbon-free around-the-clock energy.

Q But let's talk about the last few RFPs that you say you are basing it on. Because the most recent renewable RFP procured zero resources; right?

A (Witness Kaduk) That's correct.

Q Okay. And most of the winning solar-plus storage projects from the 2022/2023 utility scale renewable RFP did not actually install a storage device because of supply chain issues during COVID; right?

A (Witness Kaduk) That's correct. So when the company requested that to happen, staff agreed and the Commission agreed; and that's ultimately what was approved.

Q Right. But you are now basing your testimony saying that we should assume solar-plus storage comes on based on the last three RFPs. And we know that two of the three last RFPs ended up with no solar-plus storage; right?

A (Witness Kaduk) Winning bids, no. There were.

Q I was --

A (Witness Kaduk) And I am not saying the last three. Those two RFPs I picked, you are right. The most

recent one, because of COVID issues, supply chain issues, no.

Q But for the company to plan on capacity actually being there, it has to be there; right?

A (Witness Kaduk) I would say the company is planning that there will be solar even. Just based off of that, from -- why would the company put in 5 percent of some solar if they expected no solar would be picked based off the most recent RFP?

Q But the difference here is capacity based on the solar-plus storage; and what I am asking you is, does recent history support that that solar-plus storage actually gets on-line?

A (Witness Kaduk) Based off of those two previous RFPs, I would say yes. The company is still including solar, even though the last RFP didn't include any solar. So we are assuming, based off of what the company has already assumed, you are assuming, yes, there will be winning projects. We are assuming, not only will it just be solar, it will be solar-plus storage. Plus this carbon-free around-the-clock energy. All that considered, 500 megawatts is an appropriate number.

Q Based on the last RFP that procured zero, and the other RFP -- one of the other three most recent RFPs, that none got built?

A (Witness Kaduk) Another thing that's different now is the IRA tax credits. So hopefully -- that will hopefully encourage these projects to be able to bid in competitively and win the...

Q But, Mr. Kaduk, you are asking the company to rely on resources and build its resource plan around an assumption that it will be there. Is that a correct statement?

A (Witness Kaduk) Yes.

A (Witness Wellborn) And I would like to add, as Mr. Kaduk's testimony overlaps with our panel, the staff plan that was provided in NHW-4 had a placeholder for the types of additional resources that would be coming out of these new programs in the CARES RFP. So to the extent that staff's plan is relying on those, I think what we are trying to do is point out that it could help chip away at that need without overly relying on it.

So to the extent that we clarify that consistency, I think -- that's the upside, that we could potentially have that. And it could avoid additional investments in the proposed resources.

Q Yeah. And I guess what I just wanted to make sure that we clarified was that, if you are basing this assumption on recent history, recent history shows that it hasn't happened; is that correct?

A (Witness Kaduk) What has not happened?

Q Solar-plus storage has not actually come onto the system coming out of these renewable RFPs?

A (Witness Kaduk) One of the three last RFPs it did.

Q Okay. And one of the most recent renewable RFPs received no -- or procured no resources; right?

A (Witness Kaduk) That's correct.

MR. HEWITSON: Thank you, Panel. That's all I have for you.

CHAIRMAN SHAW: Redirect?

REDIRECT EXAMINATION

BY MS. DAVIS:

Q Just one question. Is staff's insistence on using an RFP to ensure that economic resources are selected and to protect the ratepayer?

A (Witness Newsome) Yes.

Q Thank you.

MS. DAVIS: That's all I have right now.

We would ask that staff's exhibits be entered into the record and that our witnesses may be excused.

CHAIRMAN SHAW: So marked.

(Staff's Exhibits 1 through 11 were admitted into evidence.)

MS. DAVIS: Thank you.

CHAIRMAN SHAW: Panel, thank y'all. You are all excused.

MS. WELLBORN: Thank you.

MR. KADUK: Thank you.

CHAIRMAN SHAW: And while the next panel is getting prepared, just saying, it might be a good chance if anybody needs a quick break. But we are going to keep rolling.

(A recess was taken.)

CHAIRMAN SHAW: All right. We will go ahead and get started back. Ginny, Georgia Public Service Commission, you can go ahead and call up your next panel and swear them in.

MS. DAVIS: Thank you, Mr. Chairman. At this time, I call the panel of Ralph Smith and Benjamin Deitchman to the stand.

Thereupon,

RALPH C. SMITH,
BENJAMIN H. DEITCHMAN,
having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. DAVIS:

Q Could you both please state your full names, by whom you are employed, and your responsibilities for the record?

A (Witness Smith) My name is Ralph C. Smith. I am a senior regulatory consultant with Larkin & Associates, and we were consultants to the staff on certain issues in this 2023 integrated resource plan update.

Q Thank you.

A (Witness Deitchman) I am Benjamin Deitchman. I work for the Georgia Public Service Commission as the utilities analyst in the electric unit, and I am here on behalf of the public interest advocacy staff.

Q Thank you. Mr. Smith, on February 15th of this year, did you file or cause to be prefiled 140 pages of testimony in question-and-answer format along with six exhibits marked as Exhibits RCS-1, BHD-1, RS/BD-2, RS/BD-3, RS/BD-4, and RS/BD-5?

A (Witness Smith) We did file on February 15th with those exhibits. How many pages did you say?

Q 140 total. So that would include, like, the cover page and Certificate of Service.

A (Witness Smith) Okay. We filed 46 pages of testimony, and I don't know how many pages are in the exhibits?

Q Plus -- so that's plus the exhibits.

A (Witness Smith) Yes, we did file all that.

Q Okay. I will ask you, Mr. Deitchman, are you

aware if that's the entirety of your filing?

A (Witness Deitchman) Correct.

Q Thank you. And did you also file or cause to be prefiled errata on February 22nd of this year?

A (Witness Smith) Yes, we did.

Q If I were to ask you the same questions today under oath, would your answers be the same as set forth in your prefiled direct testimony as corrected by your errata?

A (Witness Smith) Yes, they would.

MS. DAVIS: Mr. Chairman, the court reporter has been provided with a copy of the prefiled direct testimony and the errata. I would ask that the direct testimony, as corrected by the errata, be copied into the record as if given here today.

And with your permission, I would ask that the panel be allowed to give a summary of their prefiled testimony. I am sorry I cut you off.

CHAIRMAN SHAW: So marked.

MS. DAVIS: Thank you.

CHAIRMAN SHAW: Gentlemen, go ahead.

(The documents referred to were marked for identification as Staff Exhibit 12 through 17.)

(Prefiled direct testimonies of Mr. Deitchman and Ralph Smith follows, including Erratas:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S 2023	**)**	**DOCKET NO. 55378**
INTEGRATED RESOURCE PLAN UPDATE	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

RALPH C. SMITH

AND

BENJAMIN H. DEITCHMAN

On Behalf of the

Georgia Public Service Commission
Public Interest Advocacy Staff

Public Disclosure Version

February 15, 2024

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III. REQUEST FOR NEW REGULATORY DEFERRALS.....20

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Exhibit	Description
RCS-1	Ralph C. Smith Background and Qualifications
BHD-1	Benjamin H. Deitchman Background and Qualifications
RS/BD-2	Georgia Power's responses to STF-LA-1-5, STF-LA-1-6, STF-LA-1-8, STF-LA-1-9 (Trade Secret), STF-LA-1-23, Supplemental STF-DEA-3-6 (Trade Secret) and Supplemental STF-JKA-2-19 (Trade Secret) concerning Georgia Power's proposal that new regulatory deferrals be granted in this proceeding
RS/BD-3	Georgia Power's responses to STF-LA-2-20, STF-LA-3-4, STF-LA-3-5, and STF-LA-3-8 from Georgia Power's 2022 IRP, which relate to the Additional Sum on new Capacity and Energy Purchased Power Agreements ("PPAs")
RS/BD-4	Georgia Power's responses to STF-LA-1-4, STF-PIA-10-2, STF-PIA-10-3 (Trade Secret), STF-JKA-2-14 (Trade Secret), STF-JKA-2-20 (Trade Secret), STF-JKA-4-19 (Trade Secret), and STF-JKA-6-5 (Trade Secret) which relate to Georgia Power's requested approval of two new PPAs, one for a 230 MW capacity purchase from Santa Rosa and another for a 750 MW capacity purchase from Georgia Power's regulated affiliate, Mississippi Power Company ("MPCo")
RS/BD-5	Georgia Power's responses to STF-LA-1-20, STF-PIA-4-9 (Trade Secret), STF-PIA-4-10 and STF-PIA-4-11, concerning benefits associated with the Inflation Reduction Act ("IRA") and how they have been considered by the Company in the 2023 IRP Update

I. INTRODUCTION

Q. MR. SMITH, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit RCS-1. This exhibit summarizes my regulatory experience and qualifications.

Q. DR. DEITCHMAN, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Benjamin H. Deitchman, 244 Washington St. SW, Atlanta, Georgia 30334.

Q. WHAT IS YOUR OCCUPATION?

A. I am a Utilities Analyst in the Electric Unit at the Georgia Public Service Commission ("Commission").

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit BHD-1. This exhibit summarizes my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. We are testifying on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("Staff").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to address certain accounting/ratemaking issues proposed by Georgia Power Company ("Georgia Power" or "Company") in the Company's 2023 Integrated Resource Plan Update ("2023 IRP Update") proceeding.

We address the statements by the Company in this 2023 IRP Update regarding their assertion that if implemented, would put "downward pressure on customer rates" as well as the requests of Georgia Power for approval of new regulatory cost deferrals, Additional Sums and other items that could defeat the objective of putting downward pressure on customer rates.

In Section II of our testimony, we discuss the statements made by the Company that its projected additions of large amounts of new commercial and industrial load are expected to put downward pressure on rates. We discuss ratemaking concerns associated with risks that the Company's forecasts of new large customer load additions do not materialize as projected by the Company. The Kelly-Pol-Trokey panel is addressing the Company's load projections in additional detail. Our testimony focuses on addressing concerns to alleviate upward pressure on existing customer rates.

In Section III of our testimony, we address the new and additional cost deferrals that the Company has requested. In this 2023 IRP Update proceeding, the Company is requesting approval for several new cost deferrals, but not yet for the recovery of such costs. Staff

believes that an IRP proceeding is not the appropriate forum for addressing ratemaking issues. Ratemaking issues should be addressed in a rate case that considers all the Company's revenues, expenses, earnings, and risk. Requesting deferrals in this proceeding is single issue ratemaking where only expenses that are increasing would be considered and expense decreases or revenue increases occurring during the same period are not taken into account. Moreover, the Company's earnings for 2023, 2024 and 2025 are subject to sharing if they exceed the top end of a return on equity earnings band range, from 9.5% to 11.9%, and are the Company's responsibility within that earnings band. If new or additional regulatory deferrals were to be authorized, that would shift costs incurred in 2023, 2024 and 2025 into the Company's next rate case, putting upward pressure on existing customers' bills starting in 2026.

Also, the Company has stated repeatedly that it expects that adding the new large customer loads projected in its 2023 IRP Update will "put downward pressure on rates." The expectation that adding several new large customers, including customers within and outside of the Company's service territory would put downward pressure on rates is apparently based on the Company having a high degree of confidence in its load projections and in the Company's expectation that the revenues received from the new customers will exceed the additional costs and revenue requirements that would be incurred to serve those new large customers. Staff is concerned that the new regulatory deferrals requested by the Company that would put upward pressure rates for existing residential and small business customers by deferring costs from 2023, 2024 and 2025 into subsequent years. Accordingly, Staff recommends that the Commission not approve the new regulatory deferrals that have been requested by the Company in this proceeding.

Moreover, if any of those new regulatory deferrals were to be allowed at all, which Staff does not recommend, Staff recommends that the Commission require that recovery of any new regulatory deferrals in the Company's next rate case should be only from the customer classes into which the new large load customers that caused the Company to file its 2023 IRP Update have been added.

In Section IV, we discuss the Additional Sum for new and energy capacity Power Purchase Agreements (PPAs) that have been requested by the Company. The Company has requested approval of Additional Sum amounts for two new PPAs, one for a 230 MW capacity purchase from Santa Rosa and another for a 750 MW capacity purchase from Mississippi Power Company ("MPCo"), which is a regulated utility affiliate of Georgia Power. The Newsome-Hayet-Wellborn panel is addressing the cost-benefit analysis of those new capacity PPAs. We present Staff's recommendation concerning the related new Additional Sums. Staff recommends that no new Additional Sums be allowed for the years 2024 and 2025 for those new PPAs. Additionally, Staff recommends that no authorization for Additional Sums on those new capacity PPAs beyond 2025 be authorized in the current 2023 IRP update proceeding; but rather, whether or not to allow Additional Sums beyond 2025 for new capacity PPAs, should be addressed in the Company's next IRP and in the Company's next rate case, both of which are scheduled to be filed with the Commission in 2025.

Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. In addition to our qualifications, which are in Exhibit RCS-1 and BHD-1, respectively, Staff has attached Exhibits RS/BD-2 through RS/BD-5 which contain Company responses to discovery and other materials referenced in our testimony.

Q. WHAT IS SHOWN IN EXHIBIT RS/BD-2?

A. Exhibit RS/BD-2 contains responses to STF-LA-1-5, STF-LA-1-6, STF-LA-1-8, STF-LA-1-9 (Trade Secret), STF-LA-1-23, Supplemental STF-DEA-3-6 (Trade Secret) and Supplemental STF-JKA-2-19 (Trade Secret) concerning Georgia Power's proposal that new regulatory deferrals be granted in this proceeding.

Q. WHAT IS SHOWN IN EXHIBIT RS/BD-3?

A. Exhibit RS/BD-3 contains responses to STF-LA-2-20, STF-LA-3-4, STF-LA-3-5, and STF-LA-3-8 from Georgia Power's 2022 IRP, which relate to the Additional Sum on Capacity and Energy Purchased Power Agreements ("PPAs").

Q. WHAT IS SHOWN IN EXHIBIT RS/BD-4?

A. Exhibit RS/BD-4 contains responses to STF-LA-1-4, STF-PIA-10-2, STF-PIA-10-3 (Trade Secret), STF-JKA-2-14 (Trade Secret), STF-JKA-2-20 (Trade Secret), STF-JKA-4-19 (Trade Secret) and STF-JKA-6-5 (Trade Secret), which relate to Georgia Power's requested approval of two new PPAs, one for a 230 MW capacity purchase from Santa Rosa and another for a 750 MW capacity purchase from Georgia Power's regulated affiliate, Mississippi Power Company ("MPCo").

Q. WHAT IS SHOWN IN EXHIBIT RS/BD-5?

A. Exhibit RS/BD-5 contains the response to STF-LA-1-20, STF-PIA-4-9 (Trade Secret), STF-PIA-4-10 and STF-PIA-4-11, concerning the Company incorporating any benefits associated with the IRA in the 2023 IRP Update.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS ON THESE ISSUES?

A. Staff's conclusions and recommendations are as follows:

1. Downward Pressure on Rates

The Company has stated that it is their expectation that the addition of several new large load customers would put "downward pressure on rates." For various reasons, the Company's statements that it expects that there would be "downward pressure on rates" does not provide assurance that rates for all customer classes, such as for residential and small business customers, would not be subject to increased rates if the Company's requests in this IRP Update proceeding were to be granted. As described below, several of the Company's requests, such as but not limited to, the Company's requests for new regulatory accounting deferrals and for new Additional Sums proposed in the Company's 2023 IRP Update would put upward pressure, not downward pressure, on rates in the Company's next rate case. Staff recommends that new cost deferral and new Additional Sums requests being made by the Company that would contribute to upward pressure on rates be denied.

2. New Regulatory Accounting Deferrals

The new regulatory accounting deferrals proposed in the Company's 2023 IRP Update would put upward pressure, not downward pressure, on rates in the Company's next rate case. Staff recommends that no approval for new regulatory deferrals be granted in the current proceeding. Staff notes that the Company has ample bandwidth within the return on equity ("ROE") range of 9.5 percent to 11.9 percent that was established in the Company's most recent (2022) rate case, Docket 44280 to absorb the expenses the

Company is requesting to defer.[1] To the extent that cost fluctuations fall within that earnings band, there is not a need to defer such costs into the Company's next (2025) rate case, where such new cost deferrals would only put upward pressure on the rates being established in that case.

As discussed in the Newsome Hayet Wellborn testimony, because the requests being made by the Company in this 2023 IRP Update proceeding are all being driven by the addition of several new large load customers, all incremental costs being incurred due to that large customer growth should be absorbed by those customers. Consequently, one possible alternative to not approving the Company's requests for new deferrals of cost would be to require that the impact of all incremental deferrals must be absorbed by the rate classes into which such large load customers are being added when such new regulatory assets would commence amortization starting in 2026. That could potentially be another way of avoiding upward pressure on the rates of existing smaller customers from the new regulatory deferrals that the Company has requested.

3. Additional Sums for New Purchased Power Agreements

Staff recommends that the Company's request for Additional Sum amounts for two new Capacity and Energy Purchased Power Agreements ("PPAs") be rejected for 2024 and 2025 for the new capacity PPAs. Additional Sum amounts can be allowable pursuant to the guidance provided in O.C.G.A. § 46-3A-8. The Additional Sum amounts, once approved by the Commission, effectively function as additional revenue to the Company which produces pre-tax profits to shareholders. Additional Sum amounts for PPAs

[1] Staff estimates the impact of expensing the deferrals in 2024 and 2025 would be an approximate ROE reduction of 0.25 percent to 0.40 percent in isolation. Of course, there are many factors that could occur in 2024 and 2025 which could increase ROE.

approved in the Company's 2022 IRP were set at $3.00/kW-year for new PPAs that were not put to an RFP and competitive bidding process. The revenues related to those Additional Sums have been excluded from consideration in the reviews of the Company's earnings and earnings sharing that occur in conjunction with the reviews by Staff of the Company's Annual Surveillance Reports. Staff finds that additional capacity provided for in the new PPAs with Santa Rosa and with an affiliate, Mississippi Power Company ("MPCo") is not needed in 2024 or 2025. Moreover, those two new PPAs were not obtained through an RFP and competitive bidding process. Therefore, existing ratepayers should not be saddled with additional costs related to new Additional Sums for those two new capacity PPAs. Staff recommends that the Company's proposals for Additional Sums on the Santa Rosa and MPCo capacity PPAs for 2024 and 2025 in the current IRP Update proceeding be rejected. Alternatively, if the Commission were to determine that Additional Sums are required for those PPAs, Staff recommends that only di minimis amounts be provided, such as once cent per kW-year.

4. Federal Income Tax Incentives

Our testimony briefly discusses some of the new federal income tax incentives provided by the Inflation Reduction Act ("IRA") and how those incentives could affect resource selection. While the Company was aware of and considered many of the tax incentives that have been made available by the IRA, it appears that impacts of new incentives for additional behind-the-meter resources and energy efficiency were not specifically considered. Therefore, there may be an opportunity for further development of energy efficiency measures and distributed energy resources that could provide resources beyond what the Company has presented in its 2023 IRP Update to help address growth in load and peak demand that the Company is projecting related to adding several new large customers within and outside of its service territory.

II. COMPANY STATEMENTS CONCERNING "DOWNWARD PRESSURE ON CUSTOMER RATES"

Q. HAS THE COMPANY MADE STATEMENTS ABOUT EXPECTING TO HAVE "DOWNWARD PRESSURE ON CUSTOMER RATES" IN ITS DIRECT TESTIMONY, APPLICATION AND DURING THE HEARINGS?

A. Yes. As examples, in the Company's Direct Testimony at page 10, it states that:

> *All else being equal, we expect* that the projected revenues associated with incremental load from these new customer projects will offset the costs of the resources requested in this filing, and put downward pressure on our *overall* retail rates as we continue to provide clean, safe, reliable, and affordable power for *all* of Georgia Power's customers in the coming years.

A similar statement is made on page 56 of the Company's Direct Testimony.

Q. WERE ADDITIONAL STATEMENTS ABOUT "DOWNWARD PRESSURE ON RATES" MADE DURING THE HEARING?

A. Yes. During the hearing on Georgia Power Company's direct testimony, a number of statements were made by the Company about having "downward pressure on rates" including the following:

> "…the IRP update identifies the effect of recent economic growth on the company's load forecast and capacity needs and proposes a well-balanced portfolio and resource plan that is expected to put downward pressure on rates for all customers and enable Georgia Power to continue to provide clean, safe, reliable and affordable energy for Georgia as it continues to grow and thrive." (Tr. 0116.)

> "To be clear, the economic growth we are seeing benefits our state. As I'll discuss, it also benefits all Georgia Power customers by putting downward pressure on rates." (Tr. 0118.)

> "Although there are costs associated with implementing the proposed resource plan, Georgia Power is not requesting a rate adjustment in this IRP update. In fact, all else being equal, the company does not expect customer rates to increase as a result of the company's requests in this case. In addition to proposing a cost-effective means of addressing the energy needs of our customers in this period of extraordinary economic

growth, the company's plan in this IRP update is expected to provide economic benefits for all customers by placing downward pressure on rates." (Tr. 0122.)

Q. HAS THE COMPANY MADE ANY FIRM COMMITMENT THAT ITS RATES FOR ELECTRIC SERVICE WOULD NOT BE INCREASING IN ITS NEXT RATE CASE, SCHEDULED TO BE FILED IN 2025, AS A RESULT OF THE REQUESTS BEING MADE IN ITS 2023 IRP UPDATE?

A. No. The Company has avoided making a firm commitment that rates for electric service would not be increasing as a result of its 2023 IRP Update requests. While the Company has stated that, as noted above, with "all else being equal" it does not expect that rates would increase and that it expects "downward pressure on rates," when these Company statements are examined, there is no firm commitment from the Company that its rates, such as for residential and small business customers, will not be increasing as a result of the Company's requests that are being made in this 2023 IRP Update. As examples, the Company's Direct Testimony panel was asked about this by the Chairman and responded as follows:

> "CHAIRMAN SHAW: So I heard you say that the IRP update won't change rates, but could it cause revenue requirements to go up and higher rates being necessary in the -- in the 2025 rate case?
>
> "MR. GRUBB: So from the -- the request in this filing, we do not expect upward pressure on rates. We expect downward pressure on rates. And we say that based on the analysis that we did and then provided in the data request where we looked at exactly what you're asking. So we looked at the revenue requirements for all the resources that we've requested in this IRP update compared to the revenues from the incremental load that's driving the need for those resources. And that shows a -- a higher level of revenues than it does revenue requirements for these resources; thereby, putting downward pressure on all rates." (Tr. 0135-0136.)

Commissioner Pridemore also expressed concern that the Company's 2023 IRP Update requests could in fact cause upward pressure on rates:

> "COMMISSIONER PRIDEMORE: … I'm very concerned about customer rates related to this docket especially because what's being requested is a -- is a lot of increased infrastructure.
>
> "Mr. Grubb, you said that -- that rates are not likely to increase because of the result of this docket. Determine to me what "likely" means and how can we move your "likely" to a "will not increase"?
>
> "MR. GRUBB: So I would say based on this filing, they will not put upward pressure on rates. Mr. Evans can speak to the costing side on how we're doing. We mentioned the rate impact measure test, but what we've done is what we've looked at and provided in the DR was the revenue requirements for '26, '27, and '28 for these resources that are coming online to serve customers and the revenues. And we actually did the revenues at a lower load level than the resource plan. So we -- we have some -- a little bit of headroom in there.
>
> "So it's a -- a few hundred million dollars of downward pressure on rates from that analysis. And that's why we say we're -- from this filing, we -- we expect downward pressure for rates."
>
> '''
>
> "MR. EVANS: Yes. And I agree with everything Mr. Grubb said. I would also add that the declining revenue requirement nature of the infrastructure invested, those revenue requirements will go down over time. But that revenue will at least stay there or increase over time. So all things being equal, the downward pressure on rates will increase from what we filed." (Tr. 0159-0160.)

Notably, the Company's responses explained to some extent what "likely" meant but fell short of saying that rates "will not increase" or to committing that rates would not increase due to the additional costs of serving the unprecedented levels of new load being added to the system from the new large load customers, or from other aspects of the Company's requests, such as for new cost deferrals and for new Additional Sums. Also, it appears from Mr. Evans' statement that the Company has assumed that there would be a declining revenue requirement for serving the new large load customers, i.e., that the Company's cost to serve them would go down over time. If that does not occur, i.e., if the revenue requirement for the added customers remains stable or increases, the "downward pressure on rates" that the Company has indicated it expects might not pan out as expected, which

presents risks to existing customers of having higher rates due to the Company's 2023 IRP Update requests.

Q. HAS THE COMPANY PROVIDED SOME INFORMATION CONCERNING ESTIMATED IMPACTS IN 2026, 2027 AND 2028 ON OVERALL CUSTOMER REVENUE REQUIREMENTS?

A. Yes. The Company's supplemental response to STF-DEA-3-6 stated in part that:

> All else being equal, the Company expects that the projected revenues associated with incremental load from known new customer projects, which necessitate the additional capacity requested in the 2023 IRP Update, will fully offset the costs of those resources requested in the 2023 IRP Update and put downward pressure on overall retail rates. Please note, the projected revenues provided are preliminary estimates at this point in time and may differ from future revenues. See TS STF-DEA-3-6 Attachments A-I for additional information.

One of the attachments to the Company's supplemental response to STF-DEA-3-6, Attachment A, which is reproduced in the following Table 1, provides the following information concerning the Company's preliminary estimates on projected revenue requirement impacts for each year, 2026, 2027 and 2028:[2]

[2] The supplemental response to STF-DEA-3-6, Attachment A shows the Company's preliminary estimates on projected revenue requirement impacts as public information. The Company had originally designated such information as Trade Secret, but in a supplemental response received on February 9, 2024, the Company removed the Trade Secret designation from some of that information.

Table 1 – Estimated Net Impacts to Customers

Cumulative View

	2026	2027	2028
Estimated Incremental Revenue Requirement due to Load Growth*	$190	$580	$620
Estimated Incremental Revenue due to Load Growth**	$340	$680	$860
Net Estimated Cumulative Impact to Customers	-$150	-$100	-$240

Incremental View

	2026	2027	2028
Total Revenues	$10,970	$10,660	$10,760
Estimated Incremental Revenue Requirement due to Load Growth*	$190	$390	$40
Estimated Incremental Revenue due to Load Growth**	$340	$340	$190
Net Estimated Incremental Impact to Customers	-$150	$50	-$150
Estimated Rate Impact (%)	-1.4%	0.5%	-1.4%
Cumulative (compounded) %	-1.4%	-0.9%	-2.3%
Estimated Typical Residential $/month Impact	-$2.58	$0.86	-$2.58
Cumulative Typical Residential $/month Impact	-$2.58	-$1.72	-$4.30

**Reflects projected transmission capital associated with Plant Yates 8-10. Does not include revenue requirements for transmission projects that may be identified and placed in service in 2026-2028 due to load growth.*

Q. WHAT COSTS ARE INCLUDED IN THE COMPANY'S ESTIMATE OF THE INCREMENTAL REVENUE REQUIREMENT DUE TO LOAD GROWTH?

A. The Company's supplemental Trade Secret response to STF-DEA-3-6, Attachment A, provided the following information concerning the Company's estimates of costs that would be included in an incremental revenue requirement related to load growth preliminary estimates on projected revenue requirement impacts for each year, 2026, 2027 and 2028:

Table 2 – Estimated Incremental Revenue Requirements

[BEGIN CONFIDENTIAL]

Proposed Resource	2026	2027	2028
Mississippi Power PPA	[redacted]		
Santa Rosa PPA			
Moody BESS			
Robins BESS			
Co-located BESS			
Co-located Solar			
Other BESS			
Plant Yates Units 8-10			
Transmission Capex*			
Amortization of Reg Asset			
Total Estimated Incremental Revenue Requirement	$190	$581	$618

**Reflects projected transmission capital associated with Plant Yates 8-10. Does not include revenue requirements for transmission projects that may be identified and placed in service in 2026-2028 due to load growth.*

[END CONFIDENTIAL]

Q. ARE OTHER STAFF PANELS ADDRESSING THE COMPANY'S LOAD FORECAST AND THE COSTS OF SOME OF THE ADDITIONAL RESOURCES THAT THE COMPANY PROJECTS WILL BE NEEDED?

A. Yes. The Daymark Energy Advisors ("DEA") panel is addressing the Company's load forecast. The Kennedy Associates panel and a DEA panel are addressing the costs of some of the projected additional resources.

Q. WHAT ARE SOME OF THE COMPANY'S ASSUMPTIONS THAT COULD BE INCORRECT AND CAUSE CUSTOMER RATES TO INCREASE?

A. A number of assumptions could turn out to vary from the Company's projections. The costs

of serving the additional load could come in higher than projected. The anticipated revenues from adding the new large customers could come in lower or later than the Company has projected. Additionally, there could be additional costs incurred that have not yet been considered in the Company's preliminary estimates. The Company's calculation above only covers 2026 – 2028 and not future years so the long-term financial impact of serving new large load customers is not known at this time and could turn out to vary significantly from the Company's current expectations.

Q. HOW CAN THE COMMISSION MOVE WHAT THE COMPANY HAS PRESENTED CLOSER TO AN ASSURANCE THAT RATES "WILL NOT INCREASE" AS A RESULT OF DECISIONS MADE IN THIS 2023 IRP UPDATE PROCEEDING?

A. One thing that the Commission can do to help assure that rates to currently existing customers, such as residential and small business customers, would not increase in the Company's 2025 rate case as a result of decisions made in this 2023 IRP Update proceeding is to reject the Company requests that, other things being equal, would contribute to the Company's increased revenue requirements in 2026. As we will discuss in additional detail in the following sections of our testimony, creating additional cost deferrals, which would push cost recognition from 2023-2025 and into 2026, and subsequent years, is one aspect of the Company's requests that, in itself, would put upward pressure on rates for the 2025 rate case. The Company has also requested new Additional Sum amounts on the Santa Rosa and Mississippi Power Company purchase power agreements. Those Additional Sum amounts, if allowed would represent an additional revenue requirement to ratepayers that would put upward pressure on rates in the Company's next rate case.

Q. IS THERE A CONCERN THAT THE REQUESTS BEING MADE IN THE COMPANY'S 2023 IRP UPDATE COULD CONTRIBUTE TO HIGHER RATES FOR RESIDENTIAL CUSTOMERS AND SMALL GENERAL SERVICE CUSTOMERS IN THE COMPANY'S NEXT BASE RATE CASE THAT IS SCHEDULED TO BE FILED IN 2025?

A. Yes. Georgia Power is proposing to add several new large customers, including data centers and other customers. The Company has provided a Ratepayer Impact Measure ("RIM" test) which purports to show that there would be overall downward pressure on rates over the life of the respective resources that would need to be added to serve the large amount of additional load.[3] While some of the information provided by the Company as a preliminary estimate shows the Company's calculations of a potential decrease for the typical residential customer in 2026 and 2028,[4] Staff has not seen analysis from the Company that projects out impacts in Class Cost of Service Study ("COSS") detail, such as showing expected impacts on residential customers, from the cost of additional resources that would be added by the Company to serve the additional amounts of new large commercial and industrial customer load over the long term.

Q. WHY ARE THERE CONCERNS WITH HOW THE SUBSTANTIALLY INCREASED COSTS THAT WOULD BE INCURRED BY THE COMPANY TO SERVE NUMEROUS NEW LARGE LOAD CUSTOMERS COULD AFFECT RATES FOR OTHER CUSTOMERS?

A. One problem with Georgia Power's analysis is that it is looking at the impact on customers

[3] The RIM test calculates whether an individual customer will generate enough revenue to cover their cost to serve. A RIM test does not measure the specific impact on other customers.

[4] See, Trade Secret Attachment A to the Company's supplemental response to STF-DEA-3-6, which is reproduced in Table 1 above.

as a whole, rather than showing impacts on existing individual customer classes, such as on residential and small business customers. Moreover, there are several assumptions being made by the Company that could vary significantly from what actually happens over the life of new assets. When the Company's new base rates are set in a rate case, rates are set for each customer class. With reference to the prior COSS from the 2022 base rate case, the projected substantial increase in kWh sales from the new data centers and other large load customers and the related amounts of increased revenue would presumably be accruing only to the large customer rate classes in an updated COSS that would be filed with the Company's next rate case. The analysis presented by the in the 2023 IRP Update appears to assume that an overall increase in the number of large customers and the substantial increases in revenues projected to result from adding those large customers would produce in downward pressure on all customer base rates. But the increased revenues from those new large load customers would presumably be credited only to the rate classes under which those new customers are taking service in an updated COSS and not to other customer classes. In a COSS, the assignment of cost is done using a variety of factors, not just kWh sales to each customer class. Based on the Company's most recent cost of service study from the Company's 2022 rate case, Staff estimates the majority of new large load customer cost would be assigned to customers a large commercial customer class. The large commercial customer class with the data center customers would presumably see a large increase in revenues and kilowatt-hours and could see a decrease in rates, if, as the Company projects, the additional revenues from serving those new large load customers exceed the allocated cost to serve those customers.

Q. HOW COULD THE ALLOCATION OF NEW LARGE LOAD CUSTOMER COST LEAD TO UPWARD PRESSURE ON RATES FOR CUSTOMER CLASSES THAT ARE NOT RESPONSIBLE FOR THE DEMAND GROWTH?

A. Some of the increased costs that are being incurred by the Company to serve the new large load customers could be allocated to residential and small business customers which would put upward pressure on their rates. Looking at the projected net revenue requirement impacts on an overall basis, rather than considering how an updated COSS would allocate the increased costs to individual customer classes, such as to residential customers, could produce downward pressure on rates to certain classes, such as the large commercial and industrial class, while producing upward pressure on rates to other classes, such as to residential and small business customers. The problem for other rate classes, such as the residential class, is that in an update of the Company's 2022 COSS in the Company's next rate case (currently scheduled to be filed in 2025), is that they could be assigned much of the new significantly increased costs, but do not have the corresponding additional (kilowatt) sales or revenue to offset the increased allocated costs and, consequently, their rates could increase. Staff thus has concerns that the Company's 2023 IRP Update proposals could result in upward pressure on residential and other customer rates in the 2025 rate case.

Q. ARE THERE ALSO CONCERNS ABOUT POTENTIAL DELAYS IN THE COMPANY'S RECEIPT OF REVENUES FROM ADDING THE NEW LARGE LOAD CUSTOMERS?

A. Yes. Staff has concerns that the increased revenues from the new large load customers may materialize at lower levels or at a slower pace or both than has been projected by the Company. Once costs to add additional generating and transmission resources to serve the projected new large load customers are incurred, those costs, if allowed, would become part of the Company's overall revenue requirement. If revenues from the new large load customers materialize at lower levels or at a slower pace than has been projected by the Company, Staff is concerned that would put upward pressure on the rates of existing

Georgia Power ratepayers[5].

Q. IS IT GUARANTEED THAT ADDING THE LARGE AMOUNTS OF NEW COMMERCIAL AND INDUSTRIAL CUSTOMER LOAD WOULD IN FACT PUT DOWNWARD PRESSURE ON CUSTOMER RATES?

A. No. While the Company projects that the additional revenues it expects from the large amounts of new load would cover additional costs of serving that additional load, there is no assurance that adding the large amounts of new commercial and industrial customer load would result in the Company's filing in its next rate case, currently scheduled to be filed in 2025, would contain rate reductions or would otherwise reflect downward pressure on rates. Nor is there assurance that costs incurred relating to adding such large amounts of new load and serving the new customers that are forecast by the Company would not result in increased costs of providing electric utility service to current customers, thus resulting in rate increases to the Company's current customers in the Company's next rate case.

Q. ARE THERE A NUMBER OF ELEMENTS IN THE COMPANY'S REQUESTS THAT WOULD INCREASE COSTS AND/OR DEFER COSTS INTO 2026?

A. Yes. There are a number of Company requests being made in the current proceeding that, if approved, would have the opposite impact of putting downward pressure on customer rates. Items such as Company requests for new additional regulatory cost deferrals and for Additional Sums, if allowed, would put upward pressure on rates for the Company's next rate case.

[5] If all of the cost to serve large load customer is assigned to their customer class then the upward pressure on rates would only impact those large load customer rate classes and not other customer classes such as residential and small business.

Q. WHAT ELSE COULD CAUSE UPWARD PRESSURE ON RATES?

A. The cost to serve the additional load could exceed the additional revenue that the new load is projected by the Company to produce.

III. REQUEST FOR NEW REGULATORY DEFERRALS

Q. WHAT IS A REGULATORY COST DEFERRAL?

A. A regulatory cost deferral basically involves deferring the recognition of costs from the period in which such costs are incurred into a future period so the costs can be addressed in a future rate case. Otherwise, costs must be recognized in the period incurred and this would lower Company profits all else equal. Deferring cost to a future time period would provide the Company the opportunity to increase rates to recover the cost from ratepayers in a subsequent rate case.

Q. UNDER THE COMMISSION'S ORDER IN GEORGIA POWER COMPANY'S 2022 RATE CASE, DOCKET NO. 44280, HOW ARE THE COMPANY'S EARNINGS IN THE YEARS 2023, 2024 AND 2025 BEING REVIEWED?

A. The Company's earnings in each year 2023, 2024 and 2025 are being reviewed in an Annual Surveillance Report ("ASR") process that calculates the earned return on equity ("ROE") and compares that to an ROE band of 9.5 percent to 11.9 percent that was established in the Commission's order. The Company's current three-year rate plan also provides that if the Company's earnings in a year exceeds the top end of the ROE band, there are established provisions for the sharing of the excess earnings. If the Company projects that its earnings would fall below the low end of the ROE band, it can petition for rate relief. If earnings are within the established ROE band, i.e., within the "dead band," there is no sharing between Company investors and ratepayers. One of the expectations of

having the Company on a three-year rate case filing cycle, is that fluctuations of revenue and expenses resulting in changes to net income to shareholders that is within the earnings band would typically not require base rate modifications or entail the creation of new regulatory assets. One goal of utility regulation is to simulate a competitive market environment for the utility. In competitive markets businesses have the responsibility to manage changes in revenues and costs resulting from changing market conditions. The earnings band also provides the Company incentives to control costs and to maximize profits.

Q. WHAT IS THE EARNINGS BAND FROM THE COMPANY'S 2022 RATE CASE?

A. The Company has earnings bandwidth within the ROE range of 9.5 percent to 11.9 percent that was established in the Company's most recent (2022) rate case, Docket 44280. On a retail jurisdictional rate base of approximately $26.9 billion for 2024, and with a common equity proportion of capital of 56 percent, a 9.5 percent ROE equates to equity earnings of approximately $1.429 billion. An 11.90 percent ROE equates to equity earnings of approximately $1.790 billion. The difference between those two amounts for that earnings band range is the equivalent of approximately $361 million in net income to shareholders. The $361 million in earnings bandwidth is approximately $484 million in revenue requirement equivalent.[6] A revenue requirement equivalent band of approximately $484 million should be more than sufficient to cover the additional costs that the Company wants to defer. Moreover, even at a 9.5 percent ROE, as noted above, that is approximately $1.429 billion of annual earnings. Thus, new deferrals of costs from 2023, 2024 and 2025, for recovery in the Company's next rate case are not necessary.

[6] After multiplication by a Gross Revenue Conversion Factor of 1.34056.

Q. WHAT HAPPENS TO EARNINGS THAT ARE WITHIN THE BAND?

A. To the extent that earnings are within the band, there is no sharing between investors and ratepayers. Consequently, to the extent that there are revenue or cost fluctuations that occur in each year, 2023, 2024 or 2025, that result in earnings that are within that earnings band, there is not a need to defer such costs into the Company's next (2025) rate case, where such new cost deferrals would only put upward pressure on the rates being established in that case for the 2026-2028 period.

Q. HAS THE COMPANY PROVIDED PRELIMINARY ESTIMATES OF THE REVENUE REQUIREMENT IMPACTS IT EXPECTS FOR 2026-2028?

A. Yes. As noted above, TS Attachment A to the Company's supplemental response to STF-DEA-3-6 projects the following incremental impacts: a $150 million overall revenue requirement reduction in 2026, a $50 million revenue increase in 2027 and a $150 million revenue requirement reduction in 2028.[7]

Q. WHAT NEW REGULATORY DEFERRALS HAS THE COMPANY REQUESTED?

A. As stated on pages 54-56 of the Company's Direct Testimony, Georgia Power has requested authorization the following new regulatory cost deferrals:

- Regulatory asset to defer capacity and non-fuel energy payments under the Mississippi Power PPA (page 54, lines 24-29)
- Regulatory asset to defer capacity and non-fuel energy payments under the Santa Rosa Power PPA (page 55, lines 4-8)

[7] The supplemental response to STF-DEA-3-6, Attachment A shows the incremental revenue requirement impacts as public information.

- Regulatory asset for development costs not useful or transferrable for 1000 MW of BESS (page 55, lines 11-13)
- Regulatory asset for development costs not useful or transferrable for 1400 MW from three CTs (page 55, lines 17-19)
- Regulatory asset for development costs for Flex Capacity (page 55, lines 28-30)

Q. DID THE COMPANY CONFIRM THAT THE ABOVE LIST CONSTITUTES THE ENTIRETY OF THE NEW REGULATORY ASSETS FOR WHICH IT IS REQUESTING APPROVAL IN THIS 2023 IRP UPDATE PROCEEDING?

A. Yes. The Company's response to STF-LA-1-23(f) confirmed that "there are no other regulatory assets or cost deferrals that would result from the Company's proposals contained in the 2023 IRP Update."

Q. WAS THE COMPANY ASKED TO QUANTIFY THE AMOUNTS OF DEFERRALS THAT COULD OCCUR UNDER EACH OF ITS NEW REGULATORY ASSET APPROVAL REQUESTS?

A. Yes. STF-LA-1-23(a) through (e) requested that the Company "identify, quantify and explain the amounts of regulatory asset build-up in each year, 2024 and 2025, that the Company projects for each of the following requested regulatory asset permission items" followed by a listing of the Company's requested new regulatory assets.

Q. DID THE COMPANY PROVIDE A CLEAR IDENTIFICATION OF THE DEFERRAL AMOUNTS, I.E., THE RATEPAYER EXPOSURE, FOR EACH NEW COMPANY-REQUESTED REGULATORY ASSET?

A. No. Thus, neither the Staff, nor the Commission has a clear indication of the total dollar amounts of ratepayer exposure to these Company requests for new regulatory assets. Moreover, without reliable estimates of the likely and maximum potential amounts of cost

deferral build-up that could occur for each of these regulatory assets, the magnitude of such potential cost deferrals cannot be determined.

Q. IF THE COMMISSION DOES NOT APPROVE THE MPCO AND SANTA ROSA CAPACITY PPAS, DOES IT LOOK LIKE GEORGIA POWER COMPANY WOULD NEVERTHELESS PROCEED WITH THOSE PPAS?

A. Yes. It appears from those capacity PPA agreements that GPC would proceed with the purchases even if the Commission do not approve those PPAs. If that happened, it appears that the Company would use the energy/capacity to serve wholesale customers.

Q. HOW MUCH COST DOES THE COMPANY PROJECT COULD BE DEFERRED INTO FUTURE PERIODS RELATED TO ITS PROPOSED NEW REGULATORY ASSETS FOR THE MPCO AND SANTA ROSA CAPACITY PPAS?

A. The Company's response to STF-LA-1-5(d) refers to a "Deferral Calculation" that was presented in the Company's supplemental Trade Secret response to TS STF-DEA-3-6 and states that: "The maximum expected regulatory asset amounts for 2024 and 2025 are the net difference of the capacity expenses on rows 7 and 9 and the wholesale revenues on row 8."

Based on those responses, the Company's maximum expected regulatory asset amounts for 2024 and 2025 for both the MPCo PPA and the Santa Rosa PPA are summarized in the following table:

Table 3 – Georgia Power's Maximum Expected Regulatory Assets for New PPAs

[BEGIN CONFIDENTIAL]

	2024	2025	2026	2027	2028
Mississippi Power PPA					
Regional Sale PPA					
Net Mississippi Power PPA					
Santa Rosa PPA					
Total Amount Deferred					
Reg Asset Beginning Balance					
Amortization					
Reg Asset Ending Balance					
Deferred Tax Liability					
Average					
Pre-Tax Weighted Average Cost of Capital					
Financing Cost on Reg Asset					

[END CONFIDENTIAL]

As shown in the above table, for 2024 and 2025, the Company's expected regulatory asset for the MPCo and Santa Rosa PPAs are approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. HOW MUCH COST DOES THE COMPANY PROJECT COULD BE DEFERRED INTO FUTURE PERIODS RELATED TO ITS PROPOSED NEW REGULATORY ASSET FOR THE SANTA ROSA CAPACITY PPA?

A. The Company's response to STF-LA-1-23(b), which had asked for that information, refers to the Company's response to STF-LA-1-6(b), which in turn contains the following statement: "Please refer to the Santa Rosa SAM file provided to Commission Staff on October 27, 2023. Also, please note that the Santa Rosa PPA is not in effect in years 2029-2031."

Q. DOES THE "SANTA ROSA SAM FILE" THAT THE COMPANY'S RESPONSE REFERENCES IDENTIFY THE SPECIFIC DOLLAR AMOUNTS THAT COULD BE INCURRED?

A. The "Santa Rosa SAM File" that was referred to in the Company's response to STF-LA-1-6(b) identified specific dollar amounts that the Company expects to incur in the years 2024 through 2028 which are summarized in the table below:

Table 4 – Georgia Power's Estimated Costs for the Santa Rosa PPA

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

The amounts for 2024 and 2025 are close to the Santa Rosa regulatory asset amounts that were identified in Trade Secret Attachment A to the Company's supplemental response to STF-DEA-3-6, which was discussed above.

Q. HOW MUCH COST DOES THE COMPANY PROJECT COULD BE DEFERRED INTO FUTURE PERIODS RELATED TO ITS PROPOSED COST DEFERRAL FOR THE 100MW OF BESS?

A. The Company's response to STF-LA-1-23(c), which had asked for that information, refers to the Company's response to STF-LA-1-8(a) and (b) and states that:

> In the event that the Commission denies approval of the project, the development costs for 2023 and any costs to be spent through March 2024 identified in that response are

the costs requested to be deferred in the regulatory asset.

Q. CAN YOU TELL FROM THOSE RESPONSES THE LIKELY OR MAXIMUM DOLLAR AMOUNTS OF COSTS THAT THE COMPANY EXPECTS TO OCCUR FOR BESS DEVELOPMENT AND/OR WHICH COULD BE DEFERRED BY THE COMPANY INTO PERIODS BEYOND 2025?

A. No, not specifically, other than a $4 million amount for costs incurred in 2023 that was identified in the Company's response to STF-LA-1-8(a).[8] As it relates to the likely or maximum dollar amounts of costs that could be deferred into periods beyond 2025 for the BESS regulatory asset, in its response to STF-LA-1-8(b), the Company does not identify specific amounts but states that:

> The specific amounts per year between 2024 and 2031 will depend on the commercial operation date ("COD") for each project and variable lead times of equipment and associated commitments to reserve the equipment, which are not known at this time. Each project is unique, and these costs can include items such as engineering, design, environmental studies, geotechnical, land options, and equipment purchase agreements.

Q. HOW MUCH COST DOES THE COMPANY PROJECT COULD BE DEFERRED INTO FUTURE PERIODS RELATED TO ITS PROPOSED COST DEFERRAL FOR THE 1400 MW FROM THREE NEW COMBUSTION TURBINE GENERATING UNITS AT PLANT YATES?

A. The Company's response to STF-LA-1-23(d), which had asked for that information, refers to the Company's response to STF-LA-1-9(a) and states that:

> In the event that the Commission denies approval of the project, the development costs

[8] The response to STF-LA-1-8(a) states that the BESS development costs incurred in 2023 are estimated at approximately $4 million, and include costs related to engineering, design, geotechnical investigations, environmental studies, project management, land acquisition and interconnection studies.

for 2023 and any costs to be spent through March 2024 identified in that response are the costs requested to be deferred in the regulatory asset.

The Company's response to STF-LA-1-9(a) in turn contains the following statement:

> Please refer to the Company's response to TS STF-JKA-2-19 Attachment A. The costs associated with the reservation fee are required to ensure all needed equipment and services would be available to achieve the "Guaranteed Substantial Completion Dates" in the proposed agreement. There are no reservation fees beyond what was paid in 2023."

The amount of the reservation fee in 2023 per the Company's response to TS STF-JKA-2-19 Attachment A is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Q. THE PASSAGE ABOVE FROM THE RESPONSE TO STF-LA-1-9(A) STATES THAT THERE ARE NO RESERVATION FEES BEYOND WHAT WAS PAID IN 2023. HOW MUCH WAS PAID IN 2023 FOR RESERVATION FEES?

A. As noted in the above passage, the response to STF-LA-1-9(a) references the Company's response to STF-JKA-2-19, Attachment A. This Trade Secret attachment is a contract and is titled "Agreement for Preliminary Engineering and Development Services and Option to Purchase Equipment." This agreement was executed between Southern Company Services, Inc. ("SCS"), Mitsubishi Power Americas, Inc. and Black and Veatch Construction, Inc. and is dated October 2, 2023. In Section 2 – Price and Payment Terms (subsections 2.1 and 2.2) it states the following:

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. CAN YOU TELL FROM THOSE RESPONSES WHAT IS THE LIKELY OR MAXIMUM DOLLAR AMOUNTS OF COST THAT COULD BE DEFERRED IF THE COMPANY'S REQUEST FOR A NEW ACCOUNTING DEFERRAL RELATED TO PLANT YATES WERE TO BE GRANTED?

A. Other than the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] reservation fee from 2023 noted above, the Company had not until recently identified other amounts that could be included in this regulatory asset; however, the Company's supplemental response to STF-LA-1-23, provided on February 13, 2024, states as follows:

> The Company is requesting regulatory asset treatment for development costs not useful or transferable to other projects in the event the Company's request to develop three simple cycle combustion turbines ("CTs") at Plant Yates is denied. Based on the 2023 IRP Update Procedural and Scheduling Order, the Commission will render a decision on the 2023 IRP Update on April 16, 2024. Therefore, the estimated maximum regulatory asset amount, if the project is denied, would equal the total development costs incurred through April 2024, plus cancellation costs to be incurred following the April 16, 2024 decision. This value is estimated to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] which consists of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of projected development costs and a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] cancellation cost.
>
> Should the project not receive approval, the Company will assess whether these costs are transferable or applicable to future projects. Any costs that can be reallocated to other projects will be excluded from the regulatory asset to be recovered from customers in the Company's next base rate case. If the project is denied on April 16, 2024, no development costs will be incurred beyond the date of the Commission decision. Furthermore, the Company is not requesting regulatory asset treatment for

any development costs in the event the project is approved.

Q. HOW MUCH COST DOES THE COMPANY PROJECT COULD BE DEFERRED INTO FUTURE PERIODS RELATED TO ITS PROPOSED COST DEFERRAL FOR THE FLEX CAPACITY?

A. No estimate for that deferral has been provided. The Company's response to STF-LA-1-23(e) states that: "The Company cannot estimate any development costs for Flex Capacity as it has not met the proposed criteria which would trigger development of the Flex Capacity."

Q. IS ANOTHER STAFF PANEL ADDRESSING WHETHER THE COMPANY'S "FLEX CAPACITY" PROPOSAL SHOULD BE APPROVED?

A. Yes. The Newsome-Hayet-Wellborn panel recommends that the Company's "Flex Capacity" proposal should not be approved.

Q. IF THE COMPANY'S "FLEX CAPACITY" PROPOSAL IS NOT APPROVED, WOULD THERE BE ANY NEED FOR APPROVAL OF A NEW OPEN-ENDED REGULATORY ASSET RELATED TO THAT?

A. No.

Q. EVEN IF THE COMPANY'S "FLEX CAPACITY" WERE TO BE APPROVED AS REQUESTED BY THE COMPANY OR IN SOME MODIFIED FORMAT, WOULD THAT CHANGE STAFF'S RECOMMENDATION TO DENY APPROVAL OF A NEW REGULATORY ASSET RELATED TO THE "FLEX CAPACITY"?

A. No. Staff's recommendation is to deny approval of a new regulatory asset related to the Company's Flex Capacity program even if some modified version of that program were to

receive Commission approval.

Q. DOES STAFF HAVE A RECOMMENDATION CONCERNING THE COSS ASSIGNMENT OF ANY "FLEX CAPACITY" DEFERRAL COSTS THAT MIGHT BE AUTHORIZED?

A. Yes. If the Commission were to approve deferral of Flex Capacity costs contrary to Staff's recommendation, then Staff recommends that all of the deferred cost should be allocated to the rate classes under which the new large load customers take electric service.

Q. WOULD APPROVAL OF NEW REGULATORY DEFERRALS OF THE AMOUNTS IDENTIFIED ABOVE, OR OF OTHER AS-YET UNDETERMINED AMOUNTS PUT ADDITIONAL UPWARD PRESSURE ON RATES?

A. Yes. Approval of new regulatory assets of positive or undetermined amounts would put upward pressure on rates. It would not put downward pressure on rates. The approval of new regulatory deferrals, such as the ones requested by the Company, would create additional cost build-ups that would need to be addressed and which would put upward pressure on rates in the Company's next base rate case, which is scheduled to be filed in 2025. The amounts recorded in the new regulatory deferrals, if authorized, would become an additional cost that would presumably be requested for recovery from ratepayers when the Company's rates are being reset in the Company's next rate case.

Q. WHAT IS STAFF'S RECOMMENDATION CONCERNING THE NEW REGULATORY DEFERRALS THAT HAVE BEEN REQUESTED BY THE COMPANY IN THIS 2023 IRP UPDATE PROCEEDING?

A. Given that the creation of new regulatory assets would only put upward pressure on rates to be determined in the Company's next rate case to be filed in 2025, Staff recommends

that these requests for new regulatory asset approvals be rejected, particularly in view of the numerous statements made in the proceeding about the desire to have downward pressure on rates, rather than upward pressure on rates. Accordingly, Staff recommends the Commission not approve the Company's new regulatory deferral requests.

Q. DOES STAFF HAVE A RECOMMENDATION CONCERNING NEW REGULATORY DEFERRALS IF COMMISSION APPROVES THESE DEFERRALS?

A. Yes. If the Commission were to approve the deferrals including Mississippi Power and Santa Rosa PPAs, BESS and Yates CTs development costs contrary to Staff's recommendation, then Staff recommends that all of the deferred cost should be allocated to the rate classes under which the new large load customers take electric service.

Q. DOES STAFF HAVE A COSS ASSIGNMENT RECOMMENDATION THAT WOULD ONLY APPLY IF SOME NEW REGULATORY DEFERRALS WERE AUTHORIZED?

A. Yes. If, contrary to Staff's recommendation, some new regulatory deferrals were to be authorized in this 2023 IRP Update, Staff recommends that such costs should only be recoverable from the rate classes under which the additional large load customers would be taking electric service.

IV. ADDITIONAL SUM AMOUNTS FOR TWO NEW CAPACITY PPAS

Q. WHAT ARE "ADDITIONAL SUM" AMOUNTS?

A. Additional Sum amounts represent incremental revenue to Georgia Power tied to PPA

agreements. There is no capital investment made by the Company or incurred cost so the Additional Sum revenue drops straight to the bottom line. Under traditional ratemaking the Company makes capital investments in utility plant in order to provide reliable electric utility service. The Commission allows the Company to earn a return on capital investment that is included in utility rate base in order to compensate Company investors. In contrast, the Company makes no capital investment when procuring capacity through capacity PPAs but can be allowed by the Commission a profit through the provision of an Additional Sum. The Additional Sum amounts, once approved by the Commission, effectively function as additional revenue to the Company which produces profits to shareholders. The revenues related to those Additional Sums have historically been excluded from consideration in the reviews of the Company's earnings and earnings sharing that have occurred in conjunction with the reviews by Staff of the Company's Annual Surveillance Reports.

Q. WHAT HAS THE COMPANY PROPOSED FOR ADDITIONAL SUM AMOUNTS FOR TWO NEW CAPACITY PPAS?

A. The Company requests Commission authorization for Additional Sum amounts for new capacity PPAs with Santa Rosa and MPCo.

Q. HOW DOES THE GEORGIA CODE PROVIDE FOR AN ADDITIONAL SUM?

A. O.C.G.A. §46-3A-8, states that the Company is entitled to an Additional Sum, *as determined by the Commission*, for purchased power resources based on the consideration of certain factors which shall be considered by the Commission, such as lost revenues, changed risks and equitable sharing of benefits between the Company and ratepayers in determining the appropriate Additional Sum required to encourage long-term power purchases. While the Georgia Code sets forth certain factors that the Commission must consider in setting the Additional Sum, neither the Act nor Commission Orders set forth

any specific methodology or formula to calculate that additional sum.

Q. WHAT FACTORS DOES O.C.G.A. §46-3A-8 INDICATE NEED TO BE CONSIDERED?

A. O.C.G.A. §46-3A-8 states as follows:

> The approved or actual cost, whichever is less, of purchase of any certificated long-term power purchase shall be recovered in rates by the utility, along with an additional sum as determined by the commission to encourage such purchases. The commission shall consider lost revenues, if any, changed risks, and an equitable sharing of benefits between the utility and its retail customers.

Q. IS IT STAFF'S UNDERSTANDING THAT THE COMMISSION MUST GRANT GEORGIA POWER COMPANY AN ADDITIONAL SUM PROFIT AMOUNT ON ALL PPAS?

A. No. An Additional Sum is supposed to "encourage" behavior. It is Staff's position that the Commission should not be encouraging non-competitively bid PPAs with affiliates, especially for years when the Company does not even need the capacity.

Q. IF THE WORD "SHALL" IN O.C.G.A. §46-3A-8 WERE TO BE INTERPRETED TO REQUIRE AN ADDITIONAL SUM, HOW WOULD THAT AFFECT STAFF'S RECOMMENDATION?

A. The Company has argued in the past that §46-3A-8 requires the Commission to include an Additional Sum, noting that O.C.G.A. §46-3A-8 uses the word "shall." As noted above, while Staff disagrees that an additional sum is required on all PPAs, even under the Company's interpretation, the Commission could set a de minimus Additional Sum, such as one cent per kW-year instead of the $3.00 /kW-year that the Company is requesting.

Q. WHAT ADDITIONAL SUM HAS THE COMPANY TYPICALLY RECEIVED

FOR RESOURCES PROCURED IN CAPACITY RFPS?

A. The Company had historically received $2.30/kW-year as an additional sum for capacity resources procured through competitively bid capacity RFPs. In the 2022 IRP, Docket No. 44160, it was agreed in a stipulation that was approved by the Commission that the new capacity PPAs approved in that docket which resulted from an RFP/competitive procurement process, would have an additional sum of $3.00/kW-year. Notably, in Docket No. 44160 each of the new capacity PPAs approved in that case were the result of a competitively bid capacity RFP process.

Q. ARE THE NEW SANTA ROSA OR MISSISSIPPI POWER COMPANY CAPACITY PPAS FOR WHICH GEORGIA POWER IS REQUESTING ADDITIONAL SUM AMOUNTS IN THE CURRENT 2023 IRP UPDATE CASE THE RESULT OF PROCUREMENTS THAT UTILIZED AN RFP PROCESS?

A. No. On September 26, 2023, the Company issued a Request for Information ("RFI") in order to gather information regarding the availability of existing and planned capacity resources and Georgia Power has identified a need for the period 2026 through 2028. In the Company's 2023 Request for Information For Capacity Resources – Summary of Results dated December 4, 2023, at Section 2.3, the Company stated:

> There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027.

Q. HAS THE COMPANY EXPLAINED HOW IT WAS ABLE TO NEGOTIATE THE SANTA ROSA PPA OUTSIDE OF AN RFP?

A. Yes. The Company explained how it was able to negotiate the Santa Rosa PPA outside of an RFP. Specifically, in its Trade Secret response to STF-JKA-6-5(b), the Company stated:

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

The Trade Secret response to STF-JKA-6-5(c) provided an identical explanation as it relates to the MPCo PPA being negotiated without an RFP.

Q. "TO ENCOURAGE SUCH PURCHASES" IS MENTIONED AS A FACTOR FOR CONSIDERATION IN O.C.G.A. §46-3A-8. DID THE COMMISSION HAVE TO "ENCOURAGE" GEORGIA POWER TO UNDERTAKE THE NEW SANTA ROSA OR MPCO CAPACITY PURCHASES?

A. No. It appears that Georgia Power undertook these new capacity PPA purchases on its own, without any encouragement from the Commission and without authorization from the Commission in the Company's 2022 IRP case. As noted above, O.C.G.A. §46-3A-8 specifies that "an additional sum as determined by the commission to encourage such purchases" can be authorized for recovery. Since the new capacity PPAs with Santa Rosa

and Mississippi Power were undertaken by the Company on its own, without Commission encouragement, those do not appear to qualify for an Additional Sum. As mentioned above, these PPAs are also not the result of the Commission's competitive procurement process. From a policy standpoint, Staff also would not recommend that the Commission encourage that by awarding extra profits that go beyond what it approved in the rate case.

Q. DURING THE PERIOD 2020 THROUGH 2023 DID GEORGIA POWER OBTAIN PURCHASED POWER OR PURCHASE ANY CAPACITY FROM MPCO?

A. No. According to the Company's response to STF-LA-1-4, there were no purchased power or capacity transactions between Georgia Power and MPCo. Rather, the response states that Southern Company Services ("SCS") acts as an agent on behalf of the retail operating companies for both energy and capacity transactions in accordance with the Intercompany Interchange Contract ("IIC") whereby all payments are settled between SCS and each operating company.

Q. WHEN DID GEORGIA POWER ENTER INTO THE MPCO PPA?

A. The 2023 IRP Update Main Document at page 17 states that on October 11, 2023, Georgia Power and MPCo executed the PPA for the sale of the 750 MW of capacity and energy.

Q. HAS GEORGIA POWER EXPLAINED WHY THEY ACQUIRED THE 750 MW FROM MPCO THROUGH THE PPA IN OCTOBER 2023 WHEN THAT CAPACITY IS NOT CURRENTLY NEEDED?

A. Yes. In its response to STF-JKA-2-20(a), the Company stated:

> The term of the Mississippi Power Company ("Mississippi Power") power purchase agreement ("PPA") begins January 1, 2024, because Mississippi Power was ordered to retire

approximately 950 MW of capacity by the end of 2027 or show with detailed evidence why continued operation of the resources is in the best interests of its customers. Therefore, Mississippi Power planned to retire some of that capacity by the end of 2023 and was actively remarketing the remaining capacity to be sold outside of the Southern Company system. Had Georgia Power not executed the PPA for the full five years, the proposed resource very likely would not have been available for the last three years when the Company has a capacity need. By purchasing 750 MW from Mississippi Power through the PPA, Georgia Power ensures that this resource not only remains in the Southern Company pool but also provides dedicated, reliable, market-priced capacity and energy to Georgia Power's customers to meet its burgeoning short-term demand.

Q. HAS THE COMPANY DEMONSTRATED THAT IT HAS "LOST REVENUES" IN THE CONTEXT OF O.C.G.A. §46-3A-8?

A. No. The Company has undertaken the Santa Rosa and MPCo PPAs to enable it to serve additional load from large customers. The Company has not lost any revenues based on the Company's own assertions that the large load customers to be added will be paying more than the costs to serve those customers.

Q. WOULD CHARGING RATEPAYERS FOR AN ADDITIONAL SUM FOR THE MPCO AND SANTA ROSA IN 2024 AND 2025 PPAS RESULT IN AN EQUITABLE SHARING OF BENEFITS BETWEEN THE UTILITY AND ITS RETAIL CUSTOMERS?

A. No. Those new PPAs are not needed to serve load in 2024 or 2025, so charging ratepayers for such costs in 2024 and 2025, including Additional Sum amounts in those years would not be equitable. Moreover, the benefits that the Company projects from the capacity PPAs appear to be for periods in 2026 and beyond. Because those capacity PPAs are not needed in 2024 or 2025, there is a lack of benefits, and indeed an anticipated net additional cost in

those years. Thus, those PPAs also appear to fail the "equitable sharing of benefits between the utility and its retail customers" criteria for 2024 and 2025. Therefore no Additional Sum amounts should be authorized for either 2024 or 2025 on those new capacity PPAs.

Q. HOW HAVE ADDITIONAL SUM AMOUNTS THAT HAVE BEEN APPROVED BY THE COMMISSION BEEN TREATED FOR RATEMAKING AND ANNUAL SURVEILLANCE REPORT ("ASR") PURPOSES?

A. For both rate case and ASR purposes, the Additional Sum amounts provide revenue to the Company but there is no related expense recorded in the Company's general ledger.[9] In Staff's view, the Additional Sum amounts essentially provide additional revenue and profit to the Company. Moreover, the Additional Sum amounts are removed in the ASRs so the profits related to that additional pre-tax income has not been subject to sharing or with keeping the Company's earnings above the minimum threshold approved in the 2022 rate case, Docket No. 44280. In the ASRs, the Additional Sum amounts are reflected in a column adjustment and are thus effectively removed from the consideration of whether the Company's earned ROE is within or above the band.

Q. IF NEW ADDITIONAL SUM AMOUNTS WERE TO BE APPROVED FOR THE SANTA ROSA AND MPCO CAPACITY PPAS, WOULD THAT PUT ADDITIONAL UPWARD PRESSURE ON RATES?

A. Yes. The additional sum amounts for those new capacity PPAs would provide additional pre-tax profits to the Company and would become an additional cost to the Company's ratepayers when rates are being reset in the next rate case.

[9] See, e.g., the Company's responses to STF-LA-2-20 and STF-LA-3-4 in the Company's 2022 IRP, which provide the Company's explanation. Both of those responses are included in Exhibit RS/BD-3.

Q. DOES THE COMPANY INCLUDE THE ADDITIONAL SUMS IN ITS ECONOMIC EVALUATION OF THE CAPACITY PPAS?

A. No, as indicated in the response to STF-LA-3-5 in the Company's 2022 IRP. [10]

Q. IN THE 2022 IRP CASE, DID THE COMPANY PROVIDE AN EXPLANATION OF THE $2.30 /KW-YEAR THAT HAD HISTORICALLY BEEN USED FOR THE ADDITIONAL SUMS FOR THEN-EXISTING CAPACITY PPAS?

A. Yes. The Company's response to STF-LA-3-8 in the 2022 IRP provided an explanation.[11]

Q. HAS THE COMPANY INDICATED THAT IT WILL RE-SELL CAPACITY ASSOCIATED WITH THE MPCO PPA?

A. Yes. The Company has indicated that it will re-sell capacity associated with the MPCo PPA. Specifically, on page 17 of the 2023 IRP Update, it states:

> For the benefit of customers, Southern Wholesale Energy ("SWE"), on behalf of Georgia Power, will attempt to remarket capacity for the years prior to the winter of 2025/2026. The Company has already contracted for the sale of 500 MW to a regional electrical service provider for January 1, 2024, through September 30, 2025, thereby recovering costs from a third party in a period before the capacity is needed to serve Georgia Power retail customers.

The Company's response to STF-PIA-10-2 states that the Company anticipates that it will be able to remarket the remaining 250 MW of capacity to a regional electrical service provider at price comparable to that 500 MW. The Company's response to STF-JKA-4-

[10] A copy of that response is included in Exhibit RS/BD-3.

[11] A copy of that response is included in Exhibit RS/BD-3.

19(c) states that the same counterparty to the 500 MW subsequently requested the additional 250 MW of capacity and that negotiations are currently underway.

Q. HAVE THE COMPANY'S RESALES SO FAR OF THAT PPA CAPACITY THAT IS NOT NEEDED FOR 2024 OR 2025 BEEN SUFFICIENT TO FULLY COVER THE INCREASED COST THAT THE COMPANY HAS PROJECTED FOR THOSE YEARS?

A. No. The re-sales to date do not cover the cost that the Company has identified for MPCo and Santa Rosa PPAs in 2024 and 2025.

Q. HAS THE COMPANY INDICATED THAT IT WILL ATTEMPT TO RE-SELL CAPACITY ASSOCIATED WITH THE SANTA ROSA PPA?

A. Yes. The Company has indicated that it will re-sell capacity associated with the Santa Rosa PPA. Specifically, on page 17 of the 2023 IRP Update, it states:

> For the benefit of customers, SWE, on behalf of Georgia Power, will attempt to remarket capacity for years prior to the winter of 2025/2026.

In its Trade Secret response to STF-PIA-10-3, the Company stated that it anticipates that SWE will successfully remarket the Santa Rosa capacity to a regional electrical service provider at a capacity price [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. SHOULD THE COMPANY BE ALLOWED TO CHARGE RATEPAYERS FOR ANY ADDITIONAL SUM AMOUNTS FOR EITHER THE MPCO PPA OR THE SANTA ROSA PPA FOR THE PERIODS IN WHICH THE POWER HAS BEEN REMARKETED, OR IN WHICH GEORGIA POWER IS ATTEMPTING TO

REMARKET THAT POWER?

A. No.

Q. WHAT DOES STAFF RECOMMEND FOR THE ADDITIONAL SUM FOR THE NEW SANTA ROSA AND MPCO CAPACITY PPAS FOR 2024 AND 2025?

A. Staff recommends that the Company's request for Additional Sum amounts on the Santa Rosa and MPCo capacity PPAs be rejected for 2024 and 2025.

Q. WHAT DOES STAFF RECOMMEND FOR THE ADDITIONAL SUM FOR THE NEW SANTA ROSA AND MPCO CAPACITY PPAS FOR YEARS BEYOND 2025?

A. Staff recommends that the Additional Sum amounts for years beyond 2025 for the Santa Rosa and MPCo capacity PPAs not be authorized at this time. Rather than approve or deny Additional Sum amounts for periods beyond 2025 for those new PPAs in the current 2023 IRP Update proceeding, Additional Sum amounts related to those new PPAs for periods beyond 2025 should be reviewed in the Company's next IRP, which is scheduled to be filed in 2025.

V. INFLATION REDUCTION ACT

Q. WHEN WAS THE INFLATION REDUCTION ACT ("IRA") SIGNED INTO LAW?

A. The IRA was signed into law on August 16, 2022. Notably, that was after the Company's 2022 IRP case was completed.

Q. DOES THE IRA INCLUDE TAX INCENTIVES RELATED TO CLEAN ENERGY?

A. Yes. The IRA includes various tax incentives for electric vehicles, energy efficiency, and related to clean energy and sustainable infrastructure.

Q. HAS THE COMPANY INCORPORATED ANY BENEFITS FROM THE IRA WITH ITS RESOURCE REQUESTS (INCLUDING RENEWABLES) IN ITS 2023 IRP UPDATE?

A. Yes. In its response to STF-LA-1-20, the Company stated that it incorporated expected benefits from the IRA with its battery and solar requests in the 2023 IRP Update and that it will continue to assess opportunities to leverage funding from the IRA and from other similar incentives, if any, for the benefit of customers. The response to STF-LA-1-20 also referenced other related data request responses as well as the Trade Secret Economic Analysis of Capacity Resources file in the Technical Appendix to the Company's 2023 IRP Update.

Q. WHAT DOES THE COMPANY'S ECONOMIC ANALYSIS OF CAPACITY RESOURCES FILING STATE WITH REGARD TO THE IRA?

A. On page 3 of the Company's Economic Analysis of Capacity Resources, it states the following with regard to the IRA:

> The Inflation Reduction Act ("IRA") provides opportunities for Investment Tax Credits ("ITC") and Production Tax Credits ("PTC") that directly benefit customers. The Company included the assumed benefits of the ITC for battery storage systems ("BESS") and PTC for solar resources. The impact of the ITC on BESS is reflected in the in-service capital costs. The PTC benefits for solar resources are reflected in the additional benefits.

Q. DID THE COMPANY ELABORATE ON ITS STATEMENT THAT THE IRA PROVIDES OPPORTUNITIES FOR INVESTMENT TAX CREDITS AND PRODUCTION TAX CREDITS AS IT RELATES TO BESS AND SOLAR RESOURCES?

A. Yes. The Company elaborated on its statement that the IRA provides opportunities for ITC's and PTC's as it relates to BESS and solar resources. Specifically, in its Trade Secret

response to STF-PIA-4-9, the Company stated that it included ITC benefits for BESS, PTC benefits for solar and wind, as well as a 10-year clean electricity PTC for nuclear as part of Company's Resource Mix Study.

Q. DID THE COMPANY DESCRIBE HOW THE IRA'S DOMESTIC CONTENT BONUS CREDIT AND ENERGY COMMUNITY BONUS CREDIT WERE CONSIDERED IN THE SELECTION OF RESOURCES?

A. Yes. The Company describes how the IRA's Domestic Content Bonus Credit and Energy Community Bonus Credit were considered in the selection of resources. Specifically, in its Trade Secret response to STF-PIA-4-9, Georgia Power stated that for BESS, the Resource Mix Study assumes a 40 percent ITC assuming BESS will qualify for the base tax credit with bonuses for labor as well as either the Domestic Content Bonus Credit or Energy Community Bonus Credit.

Q. DID THE COMPANY IDENTIFY SPECIFIC PROJECTS THAT INCORPORATE THE BENEFITS OF THE IRA?

A. Yes. In its Trade Secret response to STF-PIA-4-9, the Company identified projects at Robins BESS, Moody BESS and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Solar plus BESS project that incorporates the benefits of the IRA. Specifically, the Company stated:

> The BESS projects all assume utilization of the ITC. The BESS projects also assumed that augmentations performed in later project years will qualify for the domestic content bonus credit. The solar component of the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Solar plus BESS project is assumed to generate PTCs. For the BESS and solar projects, the Company assumes the ability to earn the base credit plus the labor bonus credit. The Company will continue to look for opportunities to also leverage the domestic

content or energy community bonus credits to bring further IRA benefits to customers where sensible.

Q. DID GEORGIA POWER CONSIDER POTENTIAL FUNDING OPPORTUNITIES FROM THE IRA THAT WOULD INCREASE CUSTOMER SPENDING ON ELECTRIC TRANSPORTATION READINESS AND INFRASTRUCTURE IN ITS 2023 IRP UPDATE?

A. Yes. In its response to STF-PIA-4-11, the Company stated:

> The Electric Power Research Institute ("EPRI") produces High, Medium, and Low electric vehicle ("EV") Market share scenarios each year. These scenarios are guided in part by external studies produced by outside researchers. The July 2023 Revision to the EPRI forecast includes at least one external study that considers EV incentives provided by the Inflation Reduction Act ("IRA") as part of the impact of a "supportive policy environment."
>
> Georgia Power's forecast of electric vehicles utilizes EPRI's Medium scenario for the state of Georgia. To the extent the impacts of the IRA are incorporated into EPRI's Medium scenario, then it is implicitly considered in the 2023 IRP Update. However, the Company did not make any explicit adjustments based on the expected impacts of the IRA on electric transportation readiness and infrastructure.

Q. DID GEORGIA POWER CONSIDER POTENTIAL FUNDING OPPORTUNITIES FROM THE IRA THAT WOULD INCREASE CUSTOMER SPENDING ON BEHIND-THE-METER GENERATION ASSETS AND BATTERY STORAGE IN ITS 2023 IRP UPDATE?

A. No. According to the response to STF-PIA-4-10, Georgia Power did not explicitly consider potential funding opportunities from the IRA that would increase customer spending on behind-the-meter generation assets and battery storage in its 2023 IRP update.

Q. COULD ADDITIONAL OPPORTUNITIES FOR CUSTOMER ENERGY EFFICIENCY ("EE") AND INCREASED DEVELOPMENT OF DISTRIBUTED ENERGY RESOURCES ("DER") PROVIDE ADDITIONAL RESOURCES TO ADDRESS LOAD GROWTH AND PEAK DEMAND?

A. Yes. There may be additional opportunities for EE and DER for which the economics have been enhanced by the IRA that deserve further exploration, which apparently have not been considered by the Company in its 2023 IRP Update. As addressed in Staff witness Kaduk's testimony, EE changes must be done through an amended certificate, and the Company is requesting as an amendment to the Thermostat Demand Response ("TSTAT DR" or "Temp Check") Program. The details of how the IRA funding will affect EE has yet to be determined as the Georgia Environmental Finance Authority (GEFA) is working on an implementation plan.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT__(RCS-1)

Exhibit__(RCS-1)
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, Barbados, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company (Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
U-87-47	Anchorage Water and Wastewater Utility (Alaska PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628	Duquesne Light Company, et al, plaintiffs, against Gulf+Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)

6531	Hawaiian Electric Company (Hawaii PUCs)
R-901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona & U-1551-89-103 Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
U-91-091	Anchorage Telephone Utility (Alaska PUC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)

94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed	Citizens Utility Company - Arizona Telephone Operations Staff Investigation (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed	Delaware - Estimate Impact of Universal Services Issues Staff Investigation (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed	Bell Atlantic - Delaware, Inc., Review of New Telecomm. Assistance and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)

T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)

02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-84	ACS of Fairbanks dba Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-82	ACS of Anchorage dba Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-86	ACS of Alaska dba Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
04-0113	Hawaiian Electric Company (Hawaii PUC)
U-14347	Consumers Energy Company (Michigan PSC)
05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
21229-U	Savannah Electric & Power Company (Georgia PSC)
19142-U	Georgia Power Company (Georgia PSC)
03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
19042-U	Savannah Electric & Power Company (Georgia PSC)
2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
03-07-02	Connecticut Light & Power Company (CT DPUC)
EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022,	

U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
U-04-81	Protest by Aurora Gas, LLC against Beluga Pipe Line Company (Regulatory Commission of Alaska)
05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
ER-2006-0315	Empire District Electric Company (Missouri PSC)
ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No. 07-186	Chesapeake Utilities Corporation (Delaware PSC)
UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
09-0319	Illinois-American Water Company (Illinois CC)
09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC &	

09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)

11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)
43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
FC No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
E-04230A-14-0011 & E-01933A-14-0011	Reorganization of UNS Energy Corporation with Fortis, Inc. (Arizona CC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
FC No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)

43114-IGCC-12/13	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
15-03-45	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)
PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
U-15-016	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/ SR-2015-0302	Missouri American Water Company (Missouri PSC)
U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
P-15-014	PTE Pipeline LLC (Regulatory Commission of Alaska)
P-15-020	Swanson River Oil Pipeline, LLC (Regulatory Commission of Alaska)
U-15-127 through U-15-138	Doyon Utilities, LLC (Regulatory Commission of Alaska)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P (Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)
E-01345A-16-0036	Arizona Public Service Company (Arizona CC)
Docket No. 4618	Providence Water Supply Board (Rhode Island PUC)

Docket No. 46238	Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy Inc. (Texas State Office of Administrative Hearings; Texas PUC)
U-16-066	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
2016-00370	Kentucky Utilities Company (Kentucky PSC)
2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)
Case No. 9449	Merger of AltaGas Ltd. and WGL Holdings (Maryland PSC)
FC No. 1142	Merger of AltaGas Ltd. and WGL Holdings (District of Columbia PSC)
2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
2017-AD-112	Mississippi Power Company (Mississippi PSC)
D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)
U-18-021 & U-18-033	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 4800	Suez Water Rhode Island Inc. (Rhode Island PUC)
GO No. 236.1	In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act (West Virginia PSC)
20180047-EI	Duke Energy Florida, LLC. (Florida PSC)
20180046-EI	Florida Power & Light Company (Florida PSC)
20180048-EI	Florida Public Utilities Company – Electric (Florida PSC)
20180052-GU	Florida Public Utilities Company – Indiantown (Florida PSC)
20180054-GU	Florida Division of Chesapeake Utilities Corporation (Florida PSC)
20180051-GU	Florida Public Utilities Company – Gas Division (Florida PSC)
20180053-GU	Florida Public Utilities Company - Fort Meade (Florida PSC)
45032 S4	Indiana American Water Company, Inc. Phase 2 (Indiana Utility Regulatory Commission)
D2018.1.6	Montana-Dakota Utilities Co. (Montana PSC)
D2018.4.24	NorthWestern Energy (Montana PSC)
D2018.4.22	Montana-Dakota Utilities Co. (Montana PSC)
18-0573-W-42T & 18-0576-S-42T	West Virginia-American Water Company (West Virginia PSC)
18-0646-E-42T & 18-0645-E-D	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
18-0049-GA-ALT, 18-0298-GA-AIR, & 18-0299-GA-ALT	Vectren Energy Delivery of Ohio, Inc. (Ohio PUC)
R-2018-3003558, R-2018-3003561	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
Cause No. 45142	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
U-18-043	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)

T-03214-17-0305	Citizens Telecommunications Company of The White Mountains, Inc. d/b/a Frontier Communications of The White Mountains (Arizona CC)
D2018.9.60	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. 4890	Narragansett Bay Commission (Rhode Island PUC)
PUR-2018-00131	Columbia Gas of Virginia (Virginia SCC)
EL18-152-000	Louisiana PSC v. System Energy Resources, Inc. and Entergy Services, Inc. (FERC)
PUR-2018-00175	Virginia-American Water Company (Virginia SCC)
A-2018-3006061, A-2018-3006062 and A-2018-3006063	Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC (Pennsylvania PUC)
D2018.2.12	NorthWestern Energy (Montana PSC)
Docket No. 42310	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
U-18-102	Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
49494	AEP Texas, Inc. (Texas PUC)
Application 18-12-009	Pacific Gas and Electric Company (California PUC)
19-0316-G-42T	Mountaineer Gas Company (West Virginia PSC)
U-19-020	Chugach Electric Association, Inc. and Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
19-0051-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
A-2018-3006061, A-2018-3006062, and A-2018-3006063	Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, and Peoples Gas Company LLC (Pennsylvania PUC)
ER-18-1182-001	System Energy Resources, Inc. (FERC)
E-01933A-19-0028	Tuscon Electric Power Company (Arizona CC)
G-01551A-19-0055	Southwest Gas Corporation (Arizona CC)
2018-UN-205	Entergy Mississippi, LLC (Mississippi PSC)
W-03039A-17-0295, W-03039A-19-0092, and WS-01303A-19-0092	Brooke Water, LLC and EPCOR Water Arizona (Arizona CC)
Docket No. 4975	Block Island Utility District d/b/a Block Island Power Company (Rhode Island PUC)
A-2019-3014248	Pennsylvania-American Water Company and Wastewater System Assets of Kane Borough (Pennsylvania PUC)
Docket No. 4994	Providence Water Supply Board (Rhode Island PUC)
19-0791-GA-ALT	Plant in Service and Capital Spending Prudence Audit of Duke Energy Ohio (Ohio PUC)
U-19-070/U-19-071/ U-19-087/U-19-088	Golden Heart Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)
Docket No. 42516	Georgia Power Company (Georgia PSC)
20200070-EI	Gulf Power Company (Florida PSC)
20200071-EI	Florida Power & Light Company (Florida PSC)
20200092-EI	Florida Power & Light Company and Gulf Power Company (Florida PSC)
20-GREC-01	Fitchburg Gas and Electric Light Company d/b/a Unitil (Massachusetts DPU)

20-GREC-03	Boston Gas Company and Colonial Gas Company d/b/a National Grid (Massachusetts DPU)
20-GREC-04	Liberty Utilities (New England Natural Gas Company) Corp d/b/a Liberty Utilities (Massachusetts DPU)
PUR-2020-00015	Appalachian Power Company (Virginia SCC)
20-0414-G-390P	Hope Gas, Inc. dba Dominion Energy West Virginia (West Virginia PSC)
Cause No. 45032-S16	Hamilton Southeastern Utilities, Inc. (Indiana URC)
2019.1.101	NorthWestern Energy (Montana PSC)
A-2019-3015173	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority (Pennsylvania PUC)
R-2020-3019369 and R-2020-3019371	Pennsylvania American Water Company (Pennsylvania PUC)
2020.06.076	Montana-Dakota Utilities Co. (Montana PSC)
P-20-005	Cook Inlet Pipeline LLC (Regulatory Commission of Alaska)
2020.05.055	Montana-Dakota Utilities Co. (Montana PSC)
2020.05.066	NorthWestern Energy (Montana PSC)
PUR-2020-00169	Virginia Electric and Power Company (Virginia SCC)
20-0746-G-42T	Hope Gas, Inc., d/b/a Dominion Energy West Virginia (West Virginia PSC)
20-553-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Rider of the Dayton Power and Light Company (Ohio PUC)
E-01345A-19-0236	Arizona Public Service Company (Arizona CC)
U-20-012	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
Docket No. 20-01-31	The Southern New England Telephone Company d/b/a Frontier Communications of Connecticut (SNET) (Connecticut PURA)
P-2020-3021191	Peoples Natural Gas Company LLC (Pennsylvania PUC)
A-2021-3026523, A-2021-3026515, and A-2021-3026522	Joint Application of Veolia Environnement S.A., Veolia North America, Inc., SUEZ S.A., SUEZ Water Pennsylvania Inc. and SUEZ Water Bethel Inc. (Pennsylvania PUC)
A-2021-3026794 and A-2021-3026796	Joint Application of Peoples Natural Gas Company LLC and Peoples Gas Company (Pennsylvania PUC)
A-2021-3026774 and A-2021-3026775	Joint Application of Aqua Pennsylvania Inc., and Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC)
A-2021-3024267	Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC)
R-2021-3027385 and R-2021-3027386	Aqua Pennsylvania, Inc, and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
21-0595-WW-AIR	Aqua Ohio, Inc. (Ohio PUC)
21-0596-ST-AIR	Aqua Ohio Wastewater, Inc. (Ohio PUC)
21-0369-W-42T	West Virginia-American Water Company (West Virginia PSC)
U-21-058	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
E-01345A-21-0056	Fuel and Purchased Power Audit of Arizona Public Service Company (Arizona CC)
SW-20445A-20-0214 et al	Global Water Resources, Inc. (Arizona CC)
PUR-2021-00058	Virginia Electric and Power Company (Virginia SCC)
U-21-070/U-21-071	Golden Heart Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)

U-22-001	Railbelt Reliability Council for Certification of an Electric Reliability Organization (Regulatory Commission of Alaska)
Docket No. 44160	Georgia Power Company Integrated Resource Plan (Georgia PSC)
22-620-GA-RDR	Plant in Service and Capital Spending Prudence Audit of Vectren Energy Delivery of Ohio, Inc. d/b/a CenterPoint Energy Ohio (Ohio PUC)
PUR-2021-00255	Virginia-American Water Company (Virginia SCC)
RP19-73-003	El Paso Natural Gas Company, LLC (FERC)
22-0304-E-P	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
R-2022-3031672 and R-2022-3031673	Pennsylvania-American Water Company (Pennsylvania PUC)
22-0294-G-PC	Hope Gas, Inc., dba Dominion Energy West Virginia and Hope Gas Holdings (West Virginia PSC)
G-01551A-21-0368	Southwest Gas Corporation (Arizona CC)
2022.06.064	NorthWestern Energy (Montana PSC)
U-21-088, U-21-089, U-22-006, U-2-007, U-22-008, U-22-009	Sand Point Generating, LLC, North Slope Generating, LLC, TDX Manley Generating, LLC, TDX North Slope Generating, LLC, Sand Point Generating, LLC, TDX ADAK Generating, LLC. (Regulatory Commission of Alaska)
20220067-GU	Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company – Fort Meade, and Florida Public Utilities Company – Indiantown Division (Florida PSC)
PUR-2020-00015	Appalachian Power Company – Remand (Virginia SCC)
U-22-029	Golden Valley Electric Association, Inc. (Regulatory Commission of Alaska)
22-0393-E-ENEC	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
E-01773A-21-0298	Arizona Electric Power Cooperative, Inc. (Arizona CC)
44280	Georgia Power Company (Georgia PSC)
FTC-01/2021-BL&P-RRA-20211004	Barbados Light & Power Company Limited (Barbados Fair Trading Commission)
U-22-002 and U-22-003	Municipality of Anchorage d/b/a Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
A-2019-3015173	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority - Remand (Pennsylvania PUC)
2022.07.078	NorthWestern Energy (Montana PSC)
A.22-05-016	San Diego Gas & Electric Company (California PUC)
2022-UN-86/ 2022-UN-087	Great River Utility Operating Company, LLC (Mississippi PSC)
E-01933A-22-0107	Tucson Electric Power Company (Arizona CC)
A-2022-3035298, A-2022-3035299, A-2022-3035490, A-2022-3035492	Manwalamink Water Company, Manwalamink Sewer Company, NextEra Water Pennsylvania, LLC (Pennsylvania PUC)
PUR-2022-00052	Virginia Natural Gas, Inc. (Virginia SCC)
U-22-078	Alaska Electric Light & Power Company (Regulatory Commission of Alaska)
U-22-081	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
22-47-WW	Narragansett Bay Commission (Rhode Island PUC)
E-01345A-22-0144	Arizona Public Service Company (Arizona CC)

E-04204A-22-0251	UNS Electric, Inc. (Arizona CC)
PUR-2023-00002	Appalachian Power Company (Virginia SCC)
22-1094-WW-AIR	Aqua Ohio, Inc. (Ohio PUC)
22-1096-ST-AIR	Aqua Ohio Wastewater, Inc. (Ohio PUC)
A-2022-3037047, et al.	Pennsylvania-American Water Company, Butler Area Sewer Authority (Pennsylvania PUC)
PUR-2023-00067 and PUR-2023-00112	Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
Docket No. 54634	Southwestern Public Service Company (Texas PUC)
23-0089-EL-RDR	Duke Energy Ohio, Inc. (Ohio PUC)
23-0280-G-42T	Mountaineer Gas Company (West Virginia PSC)
2022-0208	Kauai Island Utility Cooperative (Hawaii PUC)
PUR-2023-00101	Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
23-0383-W-42T and 23-0384-S-42T	West Virginia-American Water Company (West Virginia PSC)
23-0460-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)

Exhibit_(BHD-1)

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Work Experience

Georgia Public Service Commission, Atlanta, GA
Utilities Analyst, Electric Unit (2016-Present)

- Responsibilities across various areas of electricity policy and regulation, with particular attention to utility rates, energy economics, and demand side management programs. Contribute to national initiatives on topics including nuclear waste disposal, electricity transmission, and energy reliability.
- Provided expert Public Interest Advocacy Staff testimony in Georgia Power rate cases (Georgia Public Service Commission Dockets 42516 and 42850) and supported the development of testimony in dockets regulating integrated resource plans, energy efficiency policies, and clean energy valuations.

Rochester Institute of Technology, Rochester, NY
Visiting Assistant Professor of Public Policy in the College of Liberal Arts (2013-2014) and Saunders College of Business (2014-2016)

- Courses Taught: Graduate: Business Ethics & Corporate Social Responsibility and Policy Evaluation & Research Design. Undergraduate: Organizational Behavior, Foundations of Public Policy, and Values & Public Policy.

Georgia Tech School of Public Policy, Atlanta, GA
Evaluation Fellow (2012-2013), Graduate Research Assistant in the Climate and Energy Policy Laboratory (2009-2013)
National Association of State Energy Officials, Alexandria, VA
Regional Program Coordinator (2007-2009)
Select Additional Employment
Cultural Relations Intern (Science) at the British Council USA (2007)
Intern in the US Senate (2005), US House of Representatives Page (2000)
Head of Field Sports and Wilderness Trip Leader at Camp Lincoln (2001-2006)

Education

2009 – 2014
Georgia Institute of Technology, Atlanta, GA
Ph.D. in Public Policy

- Dissertation: "Why U.S. States Became Leaders in Climate and Energy Policy: Innovation Through Competition in Federalism."
- Concentration in Energy and Environmental Policy, Minor in International Affairs.
- Founding President of the Public Policy Graduate Students Association.

2005 – 2007
George Washington University, Washington, DC
Master of Public Administration

- Environmental Policy and Planning Concentration.
- Earned membership into the *Pi Alpha Alpha* Honor Society.

2001 – 2005
Johns Hopkins University, *Baltimore, MD*
B.A. in History

- Minor in Writing Seminar. Study abroad at the University of St. Andrews.
- Graduated *Phi Beta Kappa* with General and Departmental Honors.

Publications

Peer Reviewed Book

- Deitchman, B. (2017). *Climate and Clean Energy Policy: State Institutions and Economic Implications.* New York: Routledge.

Select Peer Reviewed Articles, Chapters, and Proceedings

- Deitchman, B. (2018). Clean Energy and Growth through State and Local Implementation. In *Intergovernmental Relations in Transition: Reflections and Directions.* Stenberg, C.W. & Hamilton, D., eds. New York: Routledge.
- Deitchman, B. (2014). Changing the State of State-Level Energy Programs: Policy Diffusion, Economic Stimulus and New Federalism Paradigms. *Strategic Planning for Energy and the Environment 33(4).*
- Deitchman, R., Pfeckl, C., & Deitchman, B. (2012). Environmental Ethics at Amtrak: From Compliance to Sustainability. *Environmental Practice, 14(3).*
- Deitchman, B., Brown, M., & Baer, P. (2011). Green Jobs from Industrial Energy Efficiency. *Energy Productivity in Industry: Partners and Opportunities,* 2011 American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Industry. Washington, DC: ACEEE.
- Deitchman, B. (2006). A March of Nickels and Dimes for Recycling. *The Current: The Public Policy Journal of the Cornell Institute of Public Affairs, 10*(1).

Columnist Position (2014-Present)

- *The PA Times,* the American Society for Public Administration.

Honors and Awards

- New Professional Scholarship, Association of Energy Services Professionals (2017).
- Selected Participant, American Society for Public Administration International Young Scholars Workshop (2015).
- William H. Read Award for academic excellence and service from the Georgia Tech School of Public Policy (2011).
- TVA Scholarship, American Council for an Energy Efficient Economy Summer Study on Energy Efficiency in Industry (2011).

Current Volunteer Activities

- Trees Atlanta: planting, tree care, and forest restoration.
- American Youth Soccer Organization and Grant Park Baseball: coach.
- Virginia-Highland Elementary School: room parent.

EXHIBIT__(RS/BD-2)

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

STF-LA-1-5

Question:

Mississippi Power Company PPA. As it relates to the 750 MW of capacity purchased from MPC through the PPA, on page 33 of the panel's testimony, the Company states that if it is unable to remarket this capacity during the period January 1, 2024 through September 30, 2025 (and recover all incremental costs), the Company will request regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA (including the additional sum) net of the wholesale capacity and non-fuel revenues from any remarketed capacity sales.

a. For each year, 2024 through 2031, how much capacity does Georgia Power expect to purchase from MPC in each year?

b. For each year, 2024 through 2031, how much capacity that Georgia Power proposes to purchase from MPC is expected to be used by Georgia Power to serve Georgia Power's load?

c. For each year, 2024 through 2031, how much capacity that Georgia Power proposes to purchase from MPC is expected to be remarketed and sold off-system?

d. Please explain fully and in detail the Company's rationale for requesting regulatory asset treatment and identify the anticipated amounts of regulatory asset build-up that the Company expects could occur in each year.

e. Identify, quantify and explain the maximum amounts of regulatory asset build-up that the Company expects could occur in each year if the Company's proposed accounting treatment were to be approved.

f. Explain fully and in detail why the Annual Surveillance Reporting and earnings sharing provisions that were established in Georgia Power Company's most recent general rate case, Docket 44280, are not sufficiently robust to handle changes in utility revenues and costs that Georgia Power Company could incur in 2024, 2025 and 2026?

g. What amounts of "additional sum" does Georgia Power Company expect would occur in each year, 2024 through 2031, related to the capacity purchase from its affiliate, Mississippi Power Company? Show each "additional sum" amount in each year, and show in detail how each of those "additional sum" amounts would be calculated.

Response:

a. Through the Mississippi Power power purchase agreement ("PPA"), Georgia Power will purchase 750 MW of capacity and energy from Mississippi Power from January 1, 2024, through December 31, 2028. The Mississippi Power PPA proposed in this 2023 IRP Update does not include calendar years 2029-2031.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

b. Southern Wholesale Energy ("SWE"), on behalf of Georgia Power, will attempt to remarket the full 750 MW of capacity for years prior to the winter of 2025/2026, when Georgia Power currently has a capacity need. The Company has already sold 500 MW to a regional electrical service provider for January 1, 2024, through September 30, 2025. Therefore, depending on additional remarketing efforts, 250 MW or less from the Mississippi Power PPA are expected to be available to serve Georgia Power load from January 1, 2024, through September 30, 2025, and 750 MW or less from October 1, 2025, through December 31, 2025. The full 750 MW of capacity will be available to serve Georgia Power load from January 1, 2026, through December 31, 2028. The Mississippi Power PPA proposed in this 2023 IRP Update does not include calendar years 2029-2031.

c. See response to subpart (b).

d. Please see the response to subpart (f) below. The net costs that will be deferred to the regulatory asset are the capacity expenses identified in subpart (a) above for 2024 and 2025 net of the wholesale revenues identified in subpart (c) above for 2024 and 2025. Please note, subpart (c) only includes the wholesale revenues currently contracted for sale related to a portion of the PPA capacity. Any additional wholesale revenues from the sale of remaining capacity will further offset the costs in the regulatory asset. There will be no costs deferred to the regulatory asset after 2025. Please see the "Deferral Calculation" tab in TS STF-DEA-3-6 Attachment A in the Company's response to STF-DEA-3-6 for the projected capacity expenses and wholesale revenues. The maximum expected regulatory asset amounts for 2024 and 2025 are the net difference of the capacity expenses on rows 7 and 9 and the wholesale revenues on row 8.

e. Please see the response to subpart (d) above.

f. The 2023 IRP Update is the result of an extraordinary and unprecedented circumstance not contemplated or considered in the 2022 base rate case, similar to the impacts of Tax Cuts and Jobs Act and the COVID pandemic within the prior 3-year Alternate Rate Plan periods, which resulted in regulatory deferral treatment approved by the Commission. The costs projected to be incurred in 2024 and 2025 associated with the incremental capacity requested in the 2023 IRP Update to meet capacity needs starting in Winter 2025/2026 are expected to be significant and necessary to meet the extraordinary future load growth and the Company's obligation of providing reliable electric service to all of its retail customers. Therefore, the regulatory deferral requested in this 2023 IRP Update is appropriate and consistent with past practice. As stated in the Company's filing, the Company has already secured a sale of a majority of this PPA capacity to a third party and will attempt to remarket the remaining capacity to wholesale in 2024 and 2025 to reduce any costs that need to be deferred to the regulatory asset.

g. For the Mississippi Power PPA, the Company requests an additional sum of $3/kW-yr, consistent with the Commission-approved additional sum amounts applied to the six capacity PPAs certified in the 2022 IRP. Please see the "TS Economic Analysis of Capacity Resources.xlsx" file in the "9 TS Economic Analysis" folder of the "TS Technical Appendix,"

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which was previously provided to the Commission Staff on October 27, 2023, in the 2023 IRP Update filing. The formulas associated with additional sum are on the "Cost Inputs" worksheet.

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Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

STF-LA-1-6

Question:

Certification of the Santa Rosa Energy Center PPA. Refer to page 34 (lines 8-12) of the Company's Direct Testimony.

a. Please describe in detail how the Santa Rosa PPA offers several benefits for Georgia Power and its customers.

b. What additional costs does the Company expect to occur in each year, 2024 through 2031, related to the Santa Rosa PPA?

c. What are the existing grandfather rights which result in no additional transmission improvements or transmission service being needed for power to be delivered from the Santa Rosa Energy Center to the Southern Company system? Explain fully.

Response:

a) The Santa Rosa PPA will provide reliable energy and capacity to Georgia Power customers. This resource is already interconnected and online today. Therefore, it does not require new construction and is available to meet near-term capacity and energy needs identified in the 2023 IRP Update. Additionally, the Santa Rosa Energy Center has access to cost-effective firm gas transportation without the need for additional pipeline expansion. For additional information and quantification of many of these factors, please see the Technical Appendix Economic Analysis.

b) Please refer to the Santa Rosa SAM file provided to Commission Staff on October 27, 2023. Also please note the Santa Rosa PPA is not in effect in years 2029-2031.

c) Per Attachment V of the Florida Power & Light Company ("FP&L") Open Access Transmission Tariff ("OATT"), the Santa Rosa Energy Center has grandfathered rights to FP&L transmission service at no cost to deliver output from the facility (minus FP&L transmission losses) to the FP&L / Southern Transmission interface. Santa Rosa Energy Center has no grandfathered rights to transmission service on the Southern Company Transmission system. The Company completed the transmission screening analysis, as described in Technical Appendix Transmission Screening Analyses, which did not identify any required transmission project or improvements necessary to deliver the purchased energy and capacity to load.

Contact: Jeff Grubb

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

STF-LA-1-8

Question:

BESS regulatory asset.

a. What BESS related development costs are being incurred by the Company in 2023?

b. What BESS related development costs are expected to be incurred by the Company in each year, 2024 through 2031?

c. Explain how and why the Company would be incurring BESS development costs that would not be useful.

d. Identify the maximum potential amounts of BESS-related development costs from the response to part b that are at risk of not being useful. Explain in detail how the Company quantified the amounts of projected BESS development costs that could end up not being useful.

e. Explain fully and in detail why Company management and investors (as opposed to ratepayers) should not be held responsible for BESS development costs that end up not being useful.

f. On what Commission authority is the Company relying for proposing to defer any BESS-related development costs that are not useful or transferable to other projects into a regulatory asset? Explain fully and cite by relevant docket number(s) and date(s) of the Commission's Orders.

Response:

a. The battery energy storage system ("BESS") development costs that the Company incurred in 2023 include engineering, design, geotechnical investigations, environmental studies, project management, land acquisition, and interconnection studies. Collectively, for 2023 these costs are estimated at approximately $4 million.

b. The specific amounts per year between 2024 and 2031 will depend on the commercial operation date ("COD") for each project and variable lead times of equipment and associated commitments to reserve the equipment, which are not known at this time. Each project is unique, and these costs can include items such as engineering, design, environmental studies, geotechnical, land options, and equipment purchase agreements.

c. Many project development costs are specific to a project. For example, engineering, design, environmental studies, geotechnical, interconnection upgrades, and land options will not

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Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

be transferable to another project. Additionally, certain equipment may not be transferable to other projects depending on the timing and specific design requirements. Also, this is only applicable if the BESS projects are not approved by the Commission.

d. The maximum potential amount of BESS-related development costs at risk of not being useful is unknown at this time but is expected to be in the range of approximately 15% of the project cost if the resources are not approved by the Commission. By approving a portfolio of 1,000 MW, it is less likely that there will be significant non-transferable BESS-related development costs because there will be more projects to which equipment may be allocated.

e. The Company initiated the development of these assets to meet the reliability needs of its retail electric service customers. As such, the costs of developing these projects should be borne by the customers benefitting from these projects. Had the customer demand not existed, the Company would not have initiated these development activities.

f. In previous Integrated Resource Plans ("IRPs") in Docket Nos. 34218 (2011 IRP Update), 36498 (2013 IRP), 40161 (2016 IRP), 42310 (2019 IRP), and 44160 (2022 IRP), the Commission approved deferral of unusable inventory of decertified plants to a regulatory asset. In addition, pursuant to the Commission's Orders in Docket Nos. 31958 (2010 base rate case) and 36989 (2013 base rate case), certain environmental construction work in progress no longer useful at Plants Branch, Yates, Bowen, and Mitchell were deferred to a regulatory asset as discussed in Docket Nos. 34218 (2011 IRP Update) and 36498 (2013 IRP). As such, the Company requests similar treatment of any not useful or transferable development costs in this case.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-LA-1-9

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-9 ("Response"). In the Response, the Company has provided external consulting and internal labor cost estimates related to the proposed resources in the 2023 IRP Update. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contained herein include competitively sensitive pricing and project development timelines activities, specific to the resources under contract within each power purchase agreement or proposed to be acquired or developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. Lastly, the Company's competitors are not required to reveal or publish similar information and to require the Company to do so would place it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1
PUBLIC DISCLOSURE

STF-LA-1-9

Question:

Combined Turbine ("CT") Resources. Refer to the Company's Direct Testimony that was filed on December 4, 2023. On page 40 (lines 12-17) of the Company's panel testimony, it states: "To support the timely development of these units, the Company has advanced a reservation fee to the consortium to provide for the procurement of long lead time equipment and required services. These steps help ensure the proposed CT units can be developed in the timeframe needed to support the Company's capacity needs identified in the 2023 IRP Update."

a. Please quantify and explain fully and in detail the reservation fee for the procurement of long lead time equipment and required services, including how it was developed. Show detailed calculations for the estimated reservation fees for each year, 2024 through 2031.

b. What amounts of reservation fees does the Company expect would be advanced to the consortium for the procurement of long lead time equipment and required services to help ensure the proposed CT units can be developed in the timeframe needed to support the Company's capacity needs? Explain fully and identify the amounts of reservation fees expected for each year, 2024 through 2031.

c. Through December 31, 2023, has the Company incurred any reservation fees? If so, identify the amounts by account, and explain to whom those amounts were paid.

d. Referring to page 40 (lines 21-24) of the Company's testimony. Explain fully and in detail how CT-related development costs that the Company proposes to incur could become not useful or transferable to other projects?

e. Identify by year, the amounts of CT-related development costs that the Company proposes to incur that the Company believes could become not useful or transferable to other projects.

f. Explain fully and in detail why Company management and investors (as opposed to ratepayers) should not be held responsible for CT-related development costs that end up not being useful.

g. Identify, quantify and explain all projected amounts of regulatory assets that could occur for CT-related development costs that end up not being useful. Show the Company's estimated regulatory asset amounts for each year, 2023 through 2031.

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Response:

a. Please refer to the Company's response in TS STF-JKA-2-19 Attachment A. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

b. Please refer to the Company's response in TS STF-JKA-2-19 Attachment A. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

c. Please refer to the Company's response in TS STF-JKA-2-19 Attachment A.

d. Projected amounts of regulatory assets that could occur for CT-related development costs including those associated with the reservation fee that end up not being useful cannot be determined at this time. The Company will take all reasonable steps to recover expenditures and/or maintain the usefulness of equipment and services received. Please note this is only applicable if the resources are not approved by the Commission.

e. Please see the response to part (d).

f. The Company initiated the development of these assets to meet the reliability needs of its retail electric service customers. As such, the costs of developing these projects should be borne by the customers benefitting from these projects. Had the customer demand not existed, the Company would not have initiated these development activities.

g. Projected amounts of regulatory assets that could occur for CT-related development costs including those associated with the reservation fee that end up not being useful cannot be determined at this time. The reservation fee constitutes only part of the overall plant cost, and the Company continues to negotiate for most favorable terms on behalf of customers. The Company will take all reasonable steps to recover expenditures and/or maintain the usefulness of equipment and services received. Please note this is only applicable if the resources are not approved by the Commission.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Supplemental Data Request No. STF-LA-1-23

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-LA-1-23 ("Response"). In the Response, the Company has provided data supporting the economic analysis of projects proposed in the 2023 IRP Update including an acquisition with sensitive pricing and confidential details (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information includes competitively sensitive details specific to the resources under contract, proposed to be acquired or developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current or future negotiations, as counterparties may use the Information as a bargaining tool in negotiations or fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1
PUBLIC DISCLOSURE

Supplemental STF-LA-1-23

Question:

New regulatory assets requested by the Company. Refer to pages 54-56 of the Company's direct testimony. To the extent not already provided, please identify, quantify and explain the amounts of regulatory asset build-up in each year, 2024 and 2025, that the Company projects for each of the following requested regulatory asset permission items:

a. Regulatory asset to defer capacity and non-fuel energy payments under the Mississippi Power PPA (page 54, lines 24-29)

b. Regulatory asset to defer capacity and non-fuel energy payments under the Santa Rosa Mississippi Power PPA (page 55, lines 4-8)

c. Regulatory asset for development costs not useful or transferrable for 1000 MW of BESS (page 55, lines 11-13)

d. Regulatory asset for development costs not useful or transferrable for 1400 MW from three CTs (page 55, lines 17-19)

e. Regulatory asset for development costs for Flex Capacity (page 55, lines 28-30)

f. Are there any other regulatory assets (besides those listed in parts a through e above,) or cost deferrals that would result from the Company's proposals contained in the 2023 IRP Update? If so, explain fully and provide amounts of expected regulatory asset build-up in each year 2024 and 2025 related to each such additional regulatory asset.

Response:

a. Please see the Company's response to STF-LA-1-5 parts (d) and (e).

b. Please see the Company's response to STF-LA-1-6 part (b). The capacity and non-fuel expenses for 2024 and 2025 identified in that response are the costs requested to be deferred to the regulatory asset.

c. Please see the Company's response to STF-LA-1-8 parts (a) and (b). In the event the Commission denies approval of the project, the development costs for 2023 and any costs to be spent through March 2024 identified in that response are the costs requested to be deferred to the regulatory asset.

d. Please see the Company's response to STF-LA-1-9 part (a). In the event the Commission denies approval of the project, the development costs for 2023 and any costs to be spent

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Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1
PUBLIC DISCLOSURE

through March 2024 identified in that response are the costs requested to be deferred to the regulatory asset.

e. The Company currently cannot estimate any development costs for Flex Capacity as it has not met the proposed criteria which would trigger development of the Flex Capacity.

f. No, there are no other regulatory assets or cost deferrals that would result from the Company's proposals contained in the 2023 IRP Update.

February 14, 2024 Supplemental Filing Update:

d. The Company is requesting regulatory asset treatment for development costs not useful or transferable to other projects in the event the Company's request to develop three simple cycle combustion turbines ("CTs") at Plant Yates is denied. Based on the 2023 IRP Update Procedural and Scheduling Order, the Commission will render a decision on the 2023 IRP Update on April 16, 2024. Therefore, the estimated maximum regulatory asset amount, if the project is denied, would equal the total development costs incurred through April 2024, plus cancellation costs to be incurred following the April 16, 2024 decision. This value is estimated to be **REDACTED**, which consists of **REDACTED** of projected development costs and a **REDACTED** cancellation cost.

Should the project not receive approval, the Company will assess whether these costs are transferable or applicable to future projects. Any costs that can be reallocated to other projects will be excluded from the regulatory asset to be recovered from customers in the Company's next base rate case. If the project is denied on April 16, 2024, no development costs will be incurred beyond the date of the Commission decision. Furthermore, the Company is not requesting regulatory asset treatment for any development costs in the event the project is approved.

Note that the development cost above reflects projected cash flows for the project and is found in cell Y49 in the "Yates Proj Master Estimate" worksheet within the "TS Yates Expansion - Master Estimate - Estimate for Project Scopes.xlsx" workpaper that was provided to Commission Staff on January 31, 2024. The cancellation cost above is calculated by subtracting the EPC payments in the final column of Exhibit L in "TS Attachment A - Plant Yates Units 8-10 EPC Agreement.zip" of the Plant Yates Units 8-10 Certification Application from the cancellation amounts in the final column of Exhibit J in "TS Attachment A - Plant Yates Units 8-10 EPC Agreement.zip" of the Plant Yates Units 8-10 Certification Application, which was filed on January 31, 2024.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-DEA-3-6

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-DEA-3-6 ("Response"). In the Response, the Company has provided forward-looking estimates of revenues, loads, and costs for specific capacity projects. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains detailed data related to the Company's load and revenue forecast in addition to the estimated costs for capacity, financing, capital costs, unit, and operation assumptions. Disclosure of the Information would provide extensive insight into the Company's projected unit operations. If revealed to the public, a generation wholesaler, power marketer, or original equipment manufacturer could use the Information to arbitrarily tailor proposals with the intention of pricing products and services according to the Company's expected costs, which could undermine the Company's ability to procure the best cost products and services for customers. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-DEA Data Request Set Number 3

STF-DEA-3-6

Question:

Provide a forecast of upcoming price increases as a result of the inclusion of Plant Vogtle Units 3 and 4 into rate base as well as the new load acquisitions necessary to serve major new load growth.

Response:

Per Commission approval of the Stipulation in Georgia Power's Application to Adjust Rates to Include Reasonable and Prudent Plant Vogtle Units 3 and 4 Costs in Docket No. 29849, the base rate change will result in an increase of approximately 5% for the average retail customer, which translates to $8.95 per month for a typical residential customer using an average of 1,000 kWh/month. This base rate change will occur the month following the commercial operation date ("COD") of Plant Vogtle Unit 4. Based on the current schedule, rates would change April 1, 2024.

All else being equal, the Company expects that the projected revenues associated with incremental load from known new customer projects, which necessitate the additional capacity requested in the 2023 IRP Update, will fully offset the costs of those resources requested in the 2023 IRP Update and put downward pressure on overall retail rates. Please note, the projected revenues provided are preliminary estimates at this point in time and may differ from future revenues. See TS STF-DEA-3-6 Attachments A-I for additional information.

January 12, 2024 Supplemental Filing Update: In accordance with the Agreement for Engineering, Procurement, and Construction between Georgia Power Company and a consortium of Mitsubishi Power Americas, Inc. and Black & Veatch Construction, Inc., with an effective date of January 12, 2024, and provided as TS STF-JKA-2-19 Supplemental Attachment P, Georgia Power reflects the latest cost and construction schedule for the proposed Plant Yates combustion turbines ("CTs"). Details are provided in TS STF-DEA-3-6 Supplemental Attachment G and are incorporated in row 16 for Plant Yates Units 8-10 on the "Estimated Inc Rev Req" worksheet in TS STF-DEA-3-6 Supplemental Attachment A.

February 9, 2024 Supplemental Filing Update: The Company is providing all values on the "Estimated Net Impact" worksheet for public disclosure in PD STF-DEA-3-6 Supplemental 2-9-24 Attachment A.

Contact: Jeff Grubb

2023 IRP Update - Estimated Net Impacts to Customers

These are preliminary estimates isolated to only the 2023 IRP Update proposed resources and external adjustments for won and potential large load projects.
Values stated in millions of dollars and rounded to nearest ten million. Estimates are subject to change. Fuel costs and revenues not included in estimated incremental revenue requirements and estimated incremental revenue.
**Reflects projected transmission capital associated with Plant Yates Units 8-10. Does not include revenue requirements for transmission projects that may be identified and placed in service in 2026-2028 due to load growth.*
***Estimated revenues based on 2023 IRP Update external adjustments for won and potential large load projects.*

Cumulative View

	2026	2027	2028
Estimated Incremental Revenue Requirement due to Load Growth*	$190	$580	$620
Estimated Incremental Revenue due to Load Growth**	$340	$680	$860
Net Estimated Cumulative Impact to Customers	-$150	-$100	-$240

Incremental View

	2026	2027	2028
Total Revenues	$10,970	$10,660	$10,760
Estimated Incremental Revenue Requirement due to Load Growth*	$190	$390	$40
Estimated Incremental Revenue due to Load Growth**	$340	$340	$190
Net Estimated Incremental Impact to Customers	-$150	$50	-$150
Estimated Rate Impact (%)	-1.4%	0.5%	-1.4%
Cumulative (compounded) %	-1.4%	-0.9%	-2.3%
Estimated Typical Residential $/month Impact	-$2.58	$0.86	-$2.58
Cumulative Typical Residential $/month Impact	-$2.58	-$1.72	-$4.30

2023 IRP Update - Estimated Incremental Revenue Requirements

These are preliminary estimates isolated to only the 2023 IRP Update proposed resources and external adjustments for won and potential large load projects.
Values stated in millions of dollars. Estimates are subject to change. Fuel costs not included in estimated incremental revenue requirements.
**Reflects projected transmission capital associated with Plant Yates Units 8-10. Does not include revenue requirements for transmission projects that may be identified and placed in service in 2026-2028 due to load gro*

Proposed Resource	2026	2027	2028	Source
Mississippi Power PPA	**REDACTED**	**REDACTED**	**REDACTED**	In line - reflects PPA capacity pricing plus requested additional sum
Santa Rosa PPA	**REDACTED**	**REDACTED**	**REDACTED**	TS STF-DEA-3-6 Attachment B - "Santa Rosa" tab - row 39
Moody BESS	**REDACTED**	**REDACTED**	**REDACTED**	TS STF-DEA-3-6 Attachment C - "Financial Engine" tab - row 18
Robins BESS	**REDACTED**	**REDACTED**	**REDACTED**	TS STF-DEA-3-6 Attachment D - "Financial Engine" tab - row 18
Co-located BESS	**REDACTED**	**REDACTED**	**REDACTED**	TS STF-DEA-3-6 Attachment E - "Financial Engine" tab - row 18
Co-located Solar	**REDACTED**	**REDACTED**	**REDACTED**	TS STF-DEA-3-6 Attachment F - "Financial Engine" tab - row 18
Other BESS	**REDACTED**	**REDACTED**	**REDACTED**	In line - assumed to be in proportion to Robins BESS
Plant Yates Units 8-10	**REDACTED**	**REDACTED**	**REDACTED**	TS STF-DEA-3-6 Supplemental Attachment G - "Financial Engine" tab - row 18
Transmission Capex*	**REDACTED**	**REDACTED**	**REDACTED**	TS STF-DEA-3-6 Attachment H - "Transmission" tab - row 32
Amortization of Reg Asset	**REDACTED**	**REDACTED**	**REDACTED**	"Deferral Calculation" tab
Total Estimated Incremental Revenue Requirement	$190	$581	$618	Sum

2023 IRP Update - Estimated Incremental Revenue Requirements for Net Deferred Costs of PPAs

Values stated in millions of dollars. Estimates are subject to change. Fuel costs not included in estimated incremental revenue requirements.
Estimates do not include revenues from any future remarketing of remaining PPA capacity which will further offset the net deferred costs.

	2024	2025	2026	2027	2028
Mississippi Power PPA	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Regional Sale PPA	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Santa Rosa PPA	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Total Amount Deferred	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Reg Asset Beginning Balance	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Amortization	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Reg Asset Ending Balance	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Deferred Tax Liability	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Average	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Pre-Tax Weighted Average Cost of Capital	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Financing Cost on Reg Asset	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

2023 IRP Update - Estimated Incremental Revenue

These are preliminary estimates isolated to only the 2023 IRP Update proposed resources and external adjustments for won and potential large load pro
Values stated in millions of dollars. Estimates are subject to change. Fuel revenues not included in estimated incremental revenue.
**Estimated revenues based on 2023 IRP Update external adjustments for won and potential large load projects.*

	2026	**2027**	**2028**	**Source**
Estimated Incremental Revenue due to Load Growth'	$339	$679	$864	TS STF-DEA-3-6 Attachment I - "Summary" tab - cells N6:N8

Total Revenues

Values stated in millions of dollars. Estimates are subject to change.

	2026	**2027**	**2028**
Budget 2023 Total non-fuel Revenues	$8,077	$8,124	$8,195
Fuel (FCR26 settlement budget)	$2,889	$2,540	$2,562
Total Revenues	$10,966	$10,664	$10,757
Net Incremental Revenue Requirement	-$150	$50	-$150
Grossed up for MFF impact	-$154	$51	-$154

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-19

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-19 ("Response"). In the Response, the Company has provided data supporting the economic analysis of projects proposed in the 2023 IRP Update including an acquisition with sensitive pricing and confidential details (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information includes competitively sensitive details specific to the resources under contract, proposed to be acquired or developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current or future negotiations, as counterparties may use the Information as a bargaining tool in negotiations or fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

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STF-JKA-2-19

Question:

For each of the following, unit acquisitions, BESS resources, Mississippi PPA, Santa Rosa PPA, Yates CTs, REDACTED BESS + Solar,

a. If not already provided, provide copies of all PPAs or other agreements/commitments/corporate board approvals for the resources the Company plans to acquire.

b. Has the Mississippi Power PPA been approved by the Mississippi Public Service Commission?

c. Separately for each resource above, provide justification for the $3/kW additional sum charge that the Company included. Why does the Company consider $3/kW the appropriate charge for each resource?

d. Identify which resources received the accounting lease cost and provide an explanation and provide workpapers for how the lease cost was derived, electronically and with all formulae intact.

e. Identify which resources received sales revenues and explain how the sales revenues were derived and provide workpapers for how the sales revenues were derived, electronically and with all formulae intact.

f. Identify where the PTC and ITC calculations for resources may be found, and explain any differences in the PTC and ITC calculations for the Economic Analysis of Resources versus what was used in the Generation Resource Mix study. Also, explain why PTC was selected instead of ITC, or why the ITC was selected instead of PTC.

g. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**

h. For each resource, provide a timeline when the Company first began consideration of the resource acquisitions, counterparty negotiations, discussions with site owners, important activities, etc.

i. For each resource, provide documentation supporting the timeline activities, including agreements, PowerPoint presentations, memos, letters, term sheets, analyses, electronically with all formulae intact.

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Response:

a. Please see TS Technical Appendix Mississippi Power PPA and TS Technical Appendix Santa Rosa PPA for a copy of the power purchase agreements ("PPAs"). This information was included in the 2023 IRP Update filing and provided to Commission Staff on October 27, 2023. Please see TS STF-JKA-2-19 Attachment A for an executed agreement for preliminary engineering and development services and option to purchase equipment ("PES") for Plant Yates Units 8-10. Please see the Company's response to STF-JKA-2-19 part (i) for additional information for the remaining resources.

January 12, 2024 Supplemental Filing Update: Please see TS STF-JKA-2-19 Supplemental Attachment P for the Agreement for Engineering, Procurement, and Construction between Georgia Power Company and a consortium of Mitsubishi Power Americas, Inc. and Black & Veatch Construction, Inc., with an effective date of January 12, 2024.

b. Mississippi Public Service Commission ("MS Commission") approval is not required for Mississippi Power to execute a PPA for the sale of capacity and energy with Georgia Power or any other off-taker; however, because Georgia Power is an affiliate of Mississippi Power, Mississippi Code § 77-3-10, requires filing the executed PPA with the MS Commission. Further, Mississippi Code § 77-3-42 requires a filing with the MS Commission as part of the MS Commission's general oversight of capacity resources of public utilities in Mississippi. No formal review or approval procedure is prompted by this filing. The filing is for informational purposes. Mississippi Power Company has completed the required notice filing with the MS Commission with respect to the Georgia Power PPA recently executed.

c. The Company included $3/kW-year of additional sum consistent with the 2022 IRP Stipulated Agreement and the 2022 IRP Final Order. The Company considers this an appropriate amount given it was approved in the last IRP for capacity resources.

d. The Company's Economic Analysis of Capacity resources includes accounting lease costs for the Santa Rosa PPA. The Company did not impute these costs on the other options in the economic analysis. The Company's derivation of lease costs was included in "TS SAM ('23) – 7.0.1 – Santa Rosa Final.xlsm" provided to Commission Staff on October 27th, 2023. Please see row 34 on the Santa Rosa tab in this workpaper for the accounting lease costs.

e. Please see the 2023 IRP Update Main Document for more information. The Company intends to remarket the capacity associated with the MPC PPA in the years prior to the winter of 2025/2026. The Company did not include wholesale sales revenues for other resources. The derivation of the revenue is based on the agreement the Company has for the remarketed capacity. Please see TS STF-JKA-2-19 Attachment B for a copy of this agreement. The revenues from remarketing that capacity in 2024-2025 were quantified in the Technical Appendix "TS Economic Analysis of Capacity Resources.xlsx" file. On the Annual Economics

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tab, cells H64 and I64 show the capacity payment revenue derived by multiplying the capacity of the sale, the number of months, and the monthly capacity payment revenue received.

f. The Production Tax Credits ("PTC") and Investment Tax Credits ("ITC") calculations can be identified in the SAM workpapers provided to Commission Staff on October 27, 2023 and in the Aurora model files provided to Commission Staff on October 30, 2023.

Both the Company's economic analysis and Resource Mix Study assume BESS resources would utilize the ITC. Likewise, both evaluations assume solar resources would utilize the PTC. The economic analysis does not assume domestic content or energy community benefits at commercial operation for the proposed projects given the chosen locations and likely source of materials for construction. However, the BESS augmentations are expected to receive bonus credits for domestic content. The Resource Mix Study assumes either energy community or domestic content benefits will be available for generic renewable or BESS additions. Therefore, the Resource Mix Study assumes those Inflation Reduction Act ("IRA") benefits.

BESS facilities only qualify for ITC. Solar facilities qualify for either the PTC or ITC benefits. In general, PTC are typically more economic than ITCs for solar resources for the Company. However, the decision is likely to be situation specific. The Company will continue to evaluate the selection of ITC or PTC for solar resources. As additional information becomes available, the Company will seek to select the most economic option available.

g. **REDACTED REDACTED REDACTED

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through September 2023, the Company began its due diligence on the assets, scope, risks, and applicable regulatory requirements for the potential acquisition. Between early October 2023 and end of November 2023, the parties engaged in active negotiations regarding the terms and conditions for the proposed asset purchase agreement. However, on November 30, 2023, the parties agreed to suspend negotiations and not move forward with the transaction at this time. As stated in the direct testimony filed on December 4, 2023, the Company is no longer pursuing the potential acquisition of additional ownership interests in an existing generation asset within the Southern Company footprint.

Santa Rosa PPA:
Initial conversations with Santa Rosa began in late July 2023. After working through confidentiality items, the Company and Santa Rosa worked together to draft a non-binding term sheet before discussing a more detailed and actionable PPA. This non-binding term sheet was finalized in early September 2023. A PPA was then negotiated and executed on October 23, 2023. A copy of the PPA was included in the 2023 IRP Update filing on October 27, 2023.

Mississippi Power PPA:
Initial conversations occurred in late July 2023. A non-binding term sheet was agreed upon before discussing more a detailed and actionable PPA. PPA negotiations began in late August. The PPA was subsequently executed on October 11, 2023. A copy of the PPA was included in the 2023 IRP Update filing on October 27, 2023.

BESS Resources

In July 2023, the Company began an initial screening to aid in selection of potential BESS resources that could achieve commercial operation by November 2026. The initial screen contained a constraint analysis, survey analysis, environmental analysis, and substation analysis. By August, a preliminary screening for Robins and Moody identified these were suitable sites for BESS development.

In addition to the site screening, a request for information ("RFI") was sent out to battery vendors in June to develop an updated understanding of BESS pricing and equipment lead times. By August, the Company had evaluated the existing land leases at Moody and Robins Solar and made notifications to the landowner at Moody Solar. In late August, the Company held a call with the Central Georgia Joint Development Authority ("CGJDA") regarding the planned addition of a BESS at Robins Solar. The Company is working with CGJDA to modify any existing agreements. In late September and early October, the Company received preliminary layouts and single-line diagrams for both BESS projects. The incremental interconnection application requests were submitted for Robins BESS and Moody BESS on October 26 and November 3, respectively. In November, the Company sent out a request for

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proposal ("RFP") to battery suppliers to determine a vendor for the Robins BESS and Moody BESS and an Engineering, Procurement, and Construction ("EPC") RFP to determine a contractor for the Robins BESS and Moody BESS.

REDACTED BESS + Solar

In April 2023, the Company executed a Non-Disclosure Agreement with the developer to pursue a renewable focused project to submit into an upcoming RFP. In July 2023, the Company began a due diligence exercise to evaluate the BESS + Solar opportunity. The Company is currently negotiating an Asset Purchase Agreement with the developer. In August 2023, a project team was pulled together consisting of subject matter experts from departments such as land, environmental, engineering, legal, tax, generation development, and finance. In early October, transmission completed the screening analysis described in the Technical Appendix to the 2023 IRP Update. Also, in early October, the developer provided indicative pricing, which was included in the SAM files and economic analysis. A site visit with the developer occurred on November 8 in support of developing an EPC agreement. On October 13, the developer executed an amendment with SCS Transmission to extend the commercial operation date into 2027, and on November 20, the developer executed a subsequent amendment to identify specific phases including this 200 MW BESS / 200 MW solar opportunity achieving commercial operation on November 1, 2026.

Yates Resources

In July 2023, the Company began the process of developing simple cycle combustion turbine ("CT") plans for Plant Yates. The Company previously developed a Company-owned combined cycle ("CC") proposal at Plant Yates, and this served as the basis for simple cycle due diligence.

In August 2023, the Company formally established a project team to begin development and negotiation of the project. Negotiations with the Consortium of Mitsubishi Power Americas and Black & Veatch also began in August and will continue until the anticipated fully negotiated turnkey EPC and companion long-term service agreement ("LTSA") are complete (anticipated in mid-January 2024). In addition, the Company submitted interconnection applications for each of the units. On October 2, 2023, the Company executed an agreement for preliminary engineering and development services and option to purchase equipment.

January 12, 2024 Supplemental Filing Update: Please see TS STF-JKA-2-19 Supplemental Attachment P for the Agreement for Engineering, Procurement, and Construction between Georgia Power Company and a consortium of Mitsubishi Power Americas, Inc. and Black & Veatch Construction, Inc., with an effective date of January 12, 2024.

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i. Below is a list of additional documents that support the timeline of activities.

Attachment Name	Facility	Description
TS STF-JKA-2-19 Attachment A	Yates CTs	PES Agreement
TS STF-JKA-2-19 Attachment B	Wholesale	Wholesale sales revenues agreement
TS STF-JKA-2-19 Attachment C	Santa Rosa	Non-binding term sheet
TS STF-JKA-2-19 Attachment D	MPC PPA	Non-binding term sheet
TS STF-JKA-2-19 Attachment E	BESS Resource	Initial Site Screening Kick-Off
TS STF-JKA-2-19 Attachment F	BESS Resource	Notification to Moody Air Force Base Solar Landowner
TS STF-JKA-2-19 Attachment G	BESS Resource	Layouts and Single-Line Diagrams for Moody BESS and Robins BESS
TS STF-JKA-2-19 Attachment H	BESS Resource	Incremental Interconnection Application for Robins BESS
TS STF-JKA-2-19 Attachment I	BESS Resource	Incremental Interconnection Application for Moody BESS
TS STF-JKA-2-19 Attachment J	REDACTED BESS + Solar	Non-Disclosure Agreement
TS STF-JKA-2-19 Attachment K	REDACTED BESS + Solar	LGIA Amendment executed 10/13
TS STF-JKA-2-19 Attachment L	REDACTED BESS + Solar	LGIA Amendment executed 11/20
TS STF-JKA-2-19 Attachment M	Yates CT #1	LGIP-Application
TS STF-JKA-2-19 Attachment N	Yates CT #2	LGIP-Application
TS STF-JKA-2-19 Attachment O	Yates CT #3	LGIP-Application
TS STF-JKA-2-19 Supplemental Attachment P	**Yates CTs**	**EPC Agreement with an effective date of January 12, 2024**

AGREEMENT FOR PRELIMINARY ENGINEERING AND DEVELOPMENT SERVICES AND OPTION TO PURCHASE EQUIPMENT

by

SOUTHERN COMPANY SERVICES, INC.

and

REDACTED REDACTED REDACTED

&

REDACTED REDACTED REDACTED

AGREEMENT FOR PRELIMINARY ENGINEERING AND DEVELOPMENT SERVICES AND OPTION TO PURCHASE EQUIPMENT

This Agreement is for the reservation of manufacturing capacity for long lead equipment and performance of preliminary engineering and development services (**"Agreement"**) by and between Southern Company Services, Inc., for itself and acting in behalf of its affiliate Georgia Power Company (**"Purchaser"**) with a place of business located at 600 North 18th Street, Birmingham, Alabama 35203 and REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED, (collectively **"Contractor"**). Contractor and Purchaser are hereinafter referred to individually as a **"Party"** and collectively as the **"Parties."**

RECITALS

A. Contractor and Purchaser plan to finalize the terms of an Engineering, Procurement, and Construction Agreement inclusive of the Long Lead Services & Equipment as defined below (the **"EPC Agreement"**) pursuant to which Purchaser will purchase from Contractor three (3) REDACTED simple cycle combustion turbines (individually **"Unit"** or collectively **"Units"**) for the engineering, procurement, and construction of a dual fuel power plant on a turnkey basis (the **"Project"**).

B. The Purchaser desires the Units achieve substantial completion by no later than (i) December 1, 2026, for the First Unit; (ii) December 1, 2026, for the Second Unit; and (iii) April 1, 2027, for the Third Unit (collectively the **"Guaranteed Substantial Completion Dates"**).

C. Purchaser desires Contractor to maintain an equipment delivery schedule to support the desired Guaranteed Substantial Completion Dates. As such, Contractor needs to procure certain services and long lead equipment and materials (those services and materials, as more particularly described in Exhibit A, are hereafter referred to as the **"Long Lead Services & Equipment"**) while the Parties negotiate in good faith the terms of the EPC Agreement.

D. The Parties agree to negotiate in good faith and execute the EPC Agreement on or before December 1, 2023.

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, agree to the following:

1 EPC AGREEMENT

It is the intent of the Parties to sign and execute an EPC Agreement (inclusive of the Long Lead Services & Equipment) for the Project that will supersede the terms and conditions of this Agreement upon the effective date of such EPC Agreement. Notwithstanding the foregoing, Purchaser shall have the option to purchase the Long Lead Equipment through an equipment purchase agreement in lieu of the EPC Agreement.

2 PRICE AND PAYMENT TERMS

2.1 Purchaser has agreed to advance payment to Contractor in a lump sum amount of REDACTED the "Reservation Fee", by no later than October 30, 2023, to secure engineering services and reserve manufacturing capacity of such Long Lead Services & Equipment as set forth in Exhibit A of this Agreement.

2.2 Purchaser will make separate payments to each of the Contractors as set forth in this Article 2. One payment will be made by Purchaser to REDACTED in the amount of REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED and a separate payment will be made by Purchaser toREDACTED the amount of REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED in accordance with the following wiring instructions.

WIRING INSTRUCTIONS for REDACTED
Will be provided on its invoice

WIRING INSTRUCTIONS for REDACTED
Will be provided on its invoice

3 TERMINATION

3.1 In the event (i) Purchaser and Contractor cannot, having negotiated in good faith, reach mutual agreement by December 1, 2023, to either (a) the EPC Agreement; (b) an equipment purchase agreement; (c) amend this Agreement; or(d) apply the Long Lead Equipment to another Purchaser project; or (ii) Purchaser terminates this Agreement in accordance with Section 3.2, then Purchaser agrees to waive in full the reimbursement of the Reservation Fee paid to Contractor. Notwithstanding anything to the contrary, if Purchaser terminates this Agreement, REDACTED agrees to use commercially reasonable efforts to secure another customer's contractual commitment to use the REDACTED Long Lead Equipment by no later than March 31, 2024, and in such event the Party repurposing the REDACTED Long Lead Equipment shall negotiate in good faith with Purchaser a credit equal to the value of the portion of the repurposed REDACTED Long Lead Equipment amount paid by another customer for such Long Lead Equipment (excluding Long Lead Services and REDACTED Long Lead Equipment). In no event shall any Long Lead Services performed under this Agreement be applied to another project or be credited to Purchaser.

3.2 Purchaser has right to terminate this Agreement, with or without cause, at any time upon written notice to the Contractor. The Parties acknowledge and agree that the Reservation Fee (less any credit, if any, as described in Section 3.1) constitutes a liquidated damage, and that such amount is a reasonable and appropriate measure of the damage that may be incurred by Contractor in connection with any termination hereunder and is not a penalty.

4 NOT USED

5 CONFIDENTIALITY

5.1 Protected Information. **"Protected Information"** means tangible and intangible non-public and/or proprietary information and data that is owned by, controlled by, or in the possession of a Party or any of its affiliates that is treated as confidential, proprietary, or otherwise not subject to public disclosure, whether or not so marked, including, without limitation, technical, business, financial, economic, marketing, operational, and strategic information. Protected Information includes: (i) information and data furnished or disclosed by or on behalf of a disclosing Party (**"Discloser"**) to another Party (**"Recipient"**) in connection with or pursuant to this Agreement; (ii) the existence and terms of this Agreement and the negotiation of the Agreement or EPC Agreement; (iii) trade secrets as defined by applicable law; and (iv) any document, note, or other tangible or intangible material that contains, reflects, or is generated from any Protected Information. Protected Information does not include information that: (a) is or becomes publicly available other than through fault or negligence of Recipient; (b) was, at the time of the disclosure, already in the Recipient's possession; (c) is disclosed to Recipient by a third party who, to the Recipient's knowledge, is not prohibited from disclosing the information under any agreement with Discloser; and (d) Recipient develops or derives without the aid, application, or use of the Discloser's Protected Information. Discloser shall use reasonable efforts to mark all materials containing Protected Information, but Discloser's failure to mark information does not by itself disqualify information from being Protected Information if other factors or circumstances, or a Party's course of performance, clearly indicate to Recipient at the time of disclosure or the Recipient acknowledges that the information should be treated as Protected Information. Recipient shall not remove markings and shall include markings on permitted copies.

5.2 Treatment of Protected Information. Protected Information is made available by the Parties solely for use in carrying out the Agreement. Recipient agrees to hold confidential, refrain from unauthorized storage and disclosure of, and exercise reasonable efforts (including implementing and maintaining reasonable administrative and organizational measures to protect, through both physical and technical safeguards, against unauthorized access or unlawful use of data), consistent with the efforts Recipient exercises to protect information of its own that it regards as confidential (but in no case less than a reasonable standard of care), to keep in confidence and not disclose to unauthorized persons any Protected Information. The Recipient shall not use any Protected Information for any purpose other than as necessary to fulfill its obligations under this Agreement or as otherwise authorized by this Agreement. The confidentiality requirements in this Agreement will supersede any prior confidentiality agreement between the Parties. This Agreement will govern the treatment of Protected Information related to the Project.

5.3 Authorized Disclosure of Protected Information. Each Party agrees that it will not, without the written consent of the other Party (unless expressly allowed by this Agreement), disclose a Discloser's Protected Information to any third party, except that Recipient may disclose Protected Information: (i) to its affiliates, employees, subcontractors, consultants, agents, and advisors (collectively, **"Representatives"**) who (a) need to know the information in connection with Recipient's performance of its obligations under this Agreement; and (b) are subject to a contractual obligation to maintain confidentiality of Protected Information with terms no less restrictive than this Agreement; and (ii) to the extent required by applicable law and in accordance with Section 5.5 below. Recipient shall be responsible for any unauthorized disclosure of Protected Information, including but not limited to any Representative's unauthorized disclosure or misuse of Protected Information.

5.4 **Disclosure of Confidential Information to the Commission.** Contractor understands and agrees that, despite any other Agreement provision, Purchaser shall have a right to disclose Protected Information to the Georgia Public Service Commission ("**Commission**") in connection with Purchaser's regulatory obligations before the Commission. Purchaser will mark Protected Information as "trade secret" and will request confidential treatment of Protected Information in accordance with the Commission's trade secrets rule, but Purchaser gives no assurance or guarantee regarding the Commission's treatment of Protected Information.

5.5 **Disclosure Required by Applicable Law.** If applicable law requires disclosure of Protected Information, then, unless prohibited by applicable law, Recipient shall: (i) promptly notify Discloser in writing of any legal request or requirement that Recipient or any of its Representatives disclose Protected Information; and (ii) to the extent possible without violating such legal requirement, permit Discloser adequate time and control to exercise its legal options to prohibit or limit disclosure. If any disclosure is required, Recipient or Representatives must furnish only that portion of Protected Information that is reasonably required to comply with such request or requirement and must exercise commercially reasonable efforts to obtain a reasonable assurance that confidential treatment will be afforded Protected Information that is disclosed. Despite the forgoing, Purchaser shall have no obligation to notify Contractor of legal process served on Purchaser by, and any resulting disclosure to, a governmental or regulatory having authority over Purchaser.

5.6 **Notice of Unauthorized Disclosure.** Recipient shall immediately notify Discloser, and no other, of any actual or anticipated unauthorized disclosure of Protected Information in accordance with the Agreement's notice provisions and shall include the following information in the notice: (i) a specific identification of the Protected Information that was the subject of the unauthorized disclosure; (ii) the identity of the unauthorized recipient; and (iii) the remedial measures, if any, to recover Protected Information and to prevent future unauthorized disclosure.

5.7 Enforcement. Recipient recognizes that unauthorized use or disclosure of Protected Information may give rise to irreparable injury to Discloser for which monetary damages may be inadequate and that Discloser may seek and obtain injunctive relief against the breach or threatened breach of Recipient's obligations under this Agreement, in addition to any other legal remedies that may be available to Discloser.

5.8 Warranties. Discloser warrants that it has all necessary ownership rights, third party permissions, licenses, and assignments regarding Protected Information that it discloses and that it is in full governmental compliance regarding Protected Information. Discloser warrants that Protected Information disclosed will neither infringe on any copyright nor constitute misappropriation of trade secrets, unauthorized access under the Computer Fraud and Abuse Act, 18 U.S.C. § 1030, conversion or theft of the property of another, or otherwise violate any applicable law.

5.9 **Duration of Confidentiality Obligations.** The terms of this Article 5 (*Confidentiality*) shall survive for a period of five years after Agreement termination or expiration, except that, to the extent any Protected Information constitutes a trade secret under applicable law, Recipient's obligations under this Article 5 (*Confidentiality*) shall apply for the life of such trade secret. Despite the forgoing sentence, if the Parties execute an EPC Agreement, the Agreement's confidentiality terms shall be deemed subsumed and replaced by the EPC Agreement.

5.10 **No Rights Conferred.** Discloser does not confer upon Recipient any right, title, or interest in or to Protected Information absent a specific separate written license to that effect. No license or other right (express or implied) is granted to Recipient, including any license by implication, estoppel or otherwise, under any patent, Trade Secret, trademark, or copyright held or obtained by Discloser, whether or not licensable. Recipient will not sell, lease, license, or in any manner (directly or indirectly) assign, transfer, or dispose of any portion of Protected Information.

6 LIMITATION OF LIABILITY

For the avoidance of doubt, other than as described in Section 3.1, Purchaser shall not be liable to Contractor under this Agreement for any additional amounts. Except in the event of fraud or willful misconduct intending to cause harm, neither Party shall be liable to the other in contract, tort, or otherwise for any claims, liabilities, or losses for special, consequential, incidental, indirect, punitive, or exemplary damages of any nature, including, without limitation, lost income or profits, arising out of this Agreement (other than with respect to a breach of Article 5) or alleged to result from the failure to proceed with (i) an equipment purchase agreement or (ii) the EPC Agreement. The Parties hereby waive, in advance, any claims (whether such claims are based on breach of contract, tort, equity, or any other theory) based on any of the circumstances stated in the preceding sentence (and its exceptions); unless and until the (i) equipment purchase agreement or (ii) EPC Agreement is executed by the Parties.

7 GENERAL

7.1 Governing Law

This Agreement shall be governed in all respects by the laws of the State of Georgia, without regard to its conflict of laws principles.

7.2 Amendments

No modification, amendment, or waiver of any of the provisions of this Agreement will be effective without the written consent of the Parties hereto.

7.3 No Third-Party Beneficiaries; Assignment

This Agreement will inure to the benefit of and be binding upon each of the Parties hereto and their respective successors and permitted assigns, but otherwise shall not give rise to any third-party beneficiary rights or claims. Neither Party may assign any of its rights, interests, or obligations hereunder without the prior written consent of the other Party, except that either Party may assign this Agreement to one of its affiliates upon written notice to the other Party.

7.4 Waivers

No failure or delay in exercising any right, power or privilege hereunder will operate as a waiver thereof, nor will any single or partial exercise thereof preclude any other or further exercise thereof or the exercise of any other right, power, or privilege hereunder.

7.5 Counterparts; Facsimile and Electronic Copies

This Agreement may be executed by facsimile or sent in the form of a pdf electronic copy via email and in counterparts, all of which for all purposes shall be deemed to be an original and all of which shall, taken together, constitute one and the same instrument.

7.6 Relationship of Parties
Nothing in this Agreement shall be deemed to constitute, create, give effect to or otherwise recognize a joint venture, partnership, or formal business entity of any kind.

7.7 Other Business Activities
Except as set forth in future definitive agreements that may be executed by the Parties, this Agreement and the related discussions between the Parties shall in no way prohibit or restrain the Parties from engaging in any other present or future business activities or discussions with other persons or entities unrelated to this Project.

7.8 Effective Date
The Agreement will become effective when all Parties have fully signed it (the **"Effective Date"**). For the avoidance of doubt, the Effective Date of this Agreement will be the date it is signed by the last authorized signatory to sign it (as indicated by the date associated with that individual's signature).

7.9 Notices
Any notice from one Party to the other Party hereunder shall be made in writing, by first class mail, by overnight courier, by email or by facsimile with original copy to follow by first class mail or overnight courier to the following:

If to PURCHASER:

REDACTED
Manager, Generation Development & Technology Application
600 North 18th Street
BIN 16N-8294
Birmingham, AL 35203
PH: 205-257-7060

If to CONTRACTOR:

and to:

7.10 Survival
Notwithstanding anything to the contrary in this Agreement, the provisions of this Agreement set forth in Article 3, Article 5, Article 6, and Article 7 shall survive termination of this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date.

SOUTHERN COMPANY SERVICES, INC., "Purchaser"

By: _____

Name: Rick Anderson

Title: SVP & SPO - East

Date: 10/03/2023

[redacted]

[redacted]

Exhibit A

Long Lead Services & Equipment

	Long Lead Equipment
1	REDACTED Combustion Turbines (Longitudinal)
2	REDACTED Combustion Turbine Auxiliaries (ECA Cooler, TCA Cooler, Modular Enclosure, Control System)
3	REDACTED Generators
4	REDACTED Generator Auxiliaries (Control cabinets & packages including SFC/ EXC, SFC & excitation transformers, enclosures including neutral terminal enclosure)
5	Generator Step-up transformers (GSUs) (Purchaser Furnished)
6	REDACTED Generator Circuit Breakers (GCBs)
7	REDACTED Station Service Transformers
8	REDACTED Power Distribution Center complete with MV & LV Switchgear, MCC's, DC and UPS equipment, Relay Panels, Panel Boards.
9	REDACTED Diesel Generator
	Long Lead Services
10	Geotech / Subsurface Investigation
11	General Subcontractor (Undergrounds)
12	Engineering

EXHIBIT__(RS/BD-3)

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 2

STF-LA-2-20

Question:

How are the Additional Sum amounts for Renewable Energy PPAs treated in the Company's base rate case and Annual Surveillance Reports (ASRs)?

Response:

For both the base rate case revenue requirement and the ASRs, additional sum amounts for Renewable Energy PPAs are treated as a regulatory expense and are not recorded in the Company's general ledger, but are included in the Company's retail cost of service through a column adjustment.

Contact: Wilson Mallard

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 3

STF-LA-3-4

Question:

How does the Company propose to treat the Additional Sum amounts for the new Capacity and Energy PPAs in the Company's base rate case and Annual Surveillance Reports (ASRs)?

Response:

Similar to the current regulatory treatment of approved PPA additional sums, for both the base rate case revenue requirement and the ASRs, additional sum amounts for the new Capacity and Energy PPAs will be treated as a regulatory expense that is not recorded in the Company's general ledger but is included in the Company's retail cost of service through a column adjustment.

Contact: Jeff Grubb

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 3

STF-LA-3-5

Question:

How are the Additional Sum amounts for Capacity and Energy PPAs considered in the Company's economic valuation of Capacity and Energy purchases?

Response:

Additional sum was not a factor in the economic valuation of Capacity and Energy purchases. Any additional sum is applied to each PPA after it is selected and therefore does not change the relative position of the PPA in an RFP selection process.

Contact: Jeff Grubb

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 3

STF-LA-3-8

Question:

Show in detail how the existing $2.30 / kW annual Additional Sum amount was derived and explain in detail whether and how that Additional Sum amount was related to the quantified economic benefits from each of those PPAs.

Response:

The $2.30 per kilowatt-year additional sum is a fixed, stipulated amount adopted by the Commission in its Order Adopting Stipulation in Docket No. 11086, which was filed on March 30, 2000. In Georgia Power Company's Application for the Certification of the West Georgia Generating Company Power Purchase Agreement ("West Georgia PPA") and the Proposal to Construct Two Combined Cycle Units at Plant Wansley, which was filed on September 22, 1999, the Company requested an additional sum for the West Georgia PPA based on twenty percent of the projected savings provided by the PPA, which represented approximately $1.12 million per year, or $2.65 per kilowatt-year. The Company cited the additional sum authorized by the Commission in Docket Numbers 4900-U (Mid-Georgia Cogen - 1996) and 8837-U (Entergy PPA - 1998) for Georgia Power and Savannah Electric, respectively, as the basis for its request.

The settlement reached between the Advocate Staff, Georgia Power Company, and the Consumers' Utility Counsel Division of the Governor's Office of Consumer Affairs on February 24, 2000 ("the Stipulation") stated, "[w]hile basing the additional sum on projected savings may be appropriate, determination of the projected savings is problematic." The parties to the Stipulation agreed that the additional sum should be fixed at $2.30 per kilowatt-year of annual contracted capacity per the West Georgia Power PPA, and the Commission approved the stipulated additional sum for that proceeding.

Except for the Mid-Georgia Cogen PPA, the Company receives an additional sum of $2.30 per kilowatt-year for all its existing capacity PPAs, which were procured during the Company's 2009, 2010, and 2015 Requests for Proposals ("RFPs"). This additional sum is based on the previously stipulated amount and not on any quantified economic benefits provided by each PPA.

Contact: Jeff Grubb

EXHIBIT__(RS/BD-4)

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

STF-LA-1-4

Question:

Certification of the Mississippi Power's PPA. Refer to the Company's Direct Testimony that was filed on December 4, 2023. As it relates to the 950 MW of capacity that Mississippi Power Company ("MPC") must retire by 2027 (per the Commission's Order in Docket No. 2018-AD-145), on page 32 of the panel's testimony, the Company states that MPC plans to retire some of this capacity (which is available to GPC customers per the reserve sharing agreement with Southern Company) by the end of 2023 and that MPC is actively marketing the other capacity to be sold off-system.

a. Identify and provide all documentation that relates to MPC's plan to retire some of the 950 MW of capacity by the end of 2023.

b. Identify each generating unit that MPC plans to retire at the end of 2023?

c. What is the estimated remaining net book value at 12/31/2023 of each generating plant that MPC plans to retire at the end of 2023?

d. When MPC retires a generating unit that has not been fully depreciated, is the remaining net book value recorded as a regulatory asset by MPC? If not, explain fully and identify and provide the anticipated journal entries that would be made by MPC for the retirement of MPC's electric generating units by 12/31/2023.

e. For each year, 2020 through 2023, how much purchased power has Georgia Power obtained from MPC?

f. For each year, 2020 through 2023, were all purchases of power by Georgia Power from MPC at cost? If not, explain how those energy purchases were priced.

g. For each year, 2020 through 2023, has Georgia Power purchased any capacity from MPC? If so, how much in each year?

h. For each year, 2020 through 2023, were all purchases of capacity by Georgia Power from MPC at cost? If not, explain how those capacity purchases were priced.

Response:

a. Please refer to the Mississippi Power Company ("MPC") 2021 Integrated Resource Plan filed in Docket No. 2019-UA-231, provided in STF-LA-1-4 Attachment, for more information on MPC's generating unit retirement plans.
b. Please refer to the MPC 2021 Integrated Resource Plan, provided in STF-LA-1-4 Attachment, for a list of generating unit retirement plans.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

c. The Company does not have information on other retail operating company financial information.

d. The Company does not have information on other retail operating company financial information and accounting processes.

e. - h. There are no capacity and energy transactions between Georgia Power and Mississippi Power. Instead, Southern Company Services acts as agent on behalf of the retail operating companies for the monthly settlement of the Intercompany Interchange Contract ("IIC"), for both capacity and energy transactions among participants in the Southern Company pool. All payments are settled between Southern Company Services and each operating company.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-14

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-14 ("Response"). In the Response, the Company has provided cost and performance criteria for a variety of resource planning technologies. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details on the costs of carbon capture equipment as well as cost and performance criteria for generic generating resources included in the resource plan. Publicly disclosing these costs would allow bidders in future solicitations to tailor their proposals and potentially set an artificial floor on bidding, which would harm customers by not allowing the Company to conduct a proper solicitation and obtain the best cost estimates for future consulting work.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 IRP Update
STF-JKA Data Request Set Number 2

STF-JKA-2-14

Question:

See Candidate Expansion Unit Section 2.6.1

a. Please provide all reports, analysis, studies, etc., that supports the fact that Georgia Power could capture 90% of CO2 emissions.
b. Provide all reports showing where Georgia Power could possibly store 90% of the CO2 emissions from CC resources.
c. Explain why Georgia Power did not assume that CC units would operate on hydrogen instead of assuming that those CC resources would store 90% of the CO2 emissions.
d. Please provide a copy of any comments that Southern Company or Georgia Power filed on August 8th or later in response to the EPA's request for comments in review of the EPA Section 111 proposed rule.
e. Please explain why the Company chose to use the assumption that CTs "are assumed to operate with oil as a primary fuel source." Why not natural gas and what assumption was used for the secondary fuel source given that the CTs were assumed to be Dual-fuel CTs?
f. Explain what assumptions have changed associated with the following resources between the 2022 IRP and the 2023 IRP. This should include capacity, costs, modeling limits, etc.

   i. Solar
   ii. Battery Storage
   iii. Wind
   iv. CTs
   v. CCs
   vi. Nuclear

g. Explain why the Mississippi Power PPA was included as a resource option, and none of the other PPAs such as Santa Rosa, etc. were included as resource options.

Response:

a. Please see TS STF-JKA-2-14 Attachment A for details on the generic carbon capture equipment assumption included in the Resource Mix Study.

b. Please see STF-JKA-2-14 Attachment B for details on storage viability in the United States. STF-JKA-2-14 Attachment B is a Department of Energy/National Energy Technology Laboratory report on sequestration viability in the United States that details a large amount of storage capacity available in the southeast as well as ongoing projects in the region to characterize that storage.

c. Production and transport of low greenhouse gas hydrogen is currently not demonstrated to the scale required to qualitatively satisfy the requirements of multiple retrofit or expansion

resources operating at an 85% capacity factor assumption used for the generic combined cycle expansion units.

d. See STF-JKA-2-14 Attachment C for the Company's comments on the EPA section 111 proposed rule for Electric Generating Units.

e. The Company assumed oil dispatch for new generic combustion turbines ("CTs") because the pipelines serving the Company region have become increasingly constrained and less flexible in recent years. These constraints limit the amount of swing and daily imbalance through frequent issuance of daily Operational Flow Orders (i.e., curtailment of gas supply). These constraints bind the Southern Company retail operating companies' ability to operate any of its natural gas units on the same pipeline system, including new CTs. The Company can successfully manage this through the usage of fuel oil. Additionally, the ability to construct new pipeline infrastructure to alleviate pipeline constraints has been very challenging (e.g., Mountain Valley Pipeline). Therefore, assuming new pipeline infrastructure will be available for all future natural gas units is unrealistic. Given the current operational realities and the challenges facing the pipeline infrastructure industry, the Company assumes the most reliable operational plan for new generic expansion CTs is for them to be dual-fueled with the ability to burn fuel oil year-round and plan to be augmented with natural gas when it is available. The availability of firm natural gas supply is highly location dependent. Therefore, the Company will evaluate the applicability of firm transportation on a case-by-case basis as specific resource decisions are identified.

f. See TS STF-JKA-2-14 Attachment D for details on year-to-year changes in the requested technologies.

g. The Mississippi Power Company power purchase agreement ("MPC PPA") was the only proposed resource allowed to be selected in the Resource Mix Study. The MPC PPA negotiations were near final when the modeling was being conducted, and the Mississippi Power Company resources are already included in the model, making it easy to implement this assumption. The other proposed resources will be included in future modeling if approved in this docket.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-20

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-20 ("Response"). In the Response, the Company has provided information related to the strategy, provisions, and evaluation of the Mississippi Power power purchase agreement ("PPA"). All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive pricing and operational capability data, specific to the resources under contract within the PPA. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the PPA provide for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current or future PPA negotiations, as counterparties may fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 IRP Update
STF-JKA Data Request Set Number 2
PUBLIC DISCLOSURE

STF-JKA-2-20

Question:

Mississippi Power PPA

a. Why did the Company acquire the Mississippi Power resource as early as 2024 when there is no need for capacity that early?

b. Provide copies of any orders in which the Mississippi Commission required Mississippi Power to shut down resources or otherwise eliminate excess capacity that was ultimately relevant to the decision to enter into the PPA with Georgia Power.

c. Explain what issues will be addressed by the Operating Committee specifically related to the "day-to-day operating procedures".

d. Please explain all requirements for FERC approval and what the status of obtaining that approval is.

e. **REDACTED REDACTED REDACTED

Docket No. 55378
Georgia Power Company's 2023 IRP Update
STF-JKA Data Request Set Number 2
PUBLIC DISCLOSURE

Response:

a. The term of the Mississippi Power Company ("Mississippi Power") power purchase agreement ("PPA") begins January 1, 2024, because Mississippi Power was ordered to retire approximately 950 MW of capacity by the end of 2027 or show with detailed evidence why continued operation of the resources is in the best interests of its customers. Therefore, Mississippi Power planned to retire some of that capacity by the end of 2023 and was actively remarketing the remaining capacity to be sold outside of the Southern Company system. Had Georgia Power not executed the PPA for the full five years, the proposed resource very likely would not have been available for the last three years when the Company has a capacity need. By purchasing 750 MW from Mississippi Power through this PPA, Georgia Power ensures that this resource not only remains in the Southern Company pool but also provides dedicated, reliable, market-priced capacity and energy to Georgia Power's customers to meet its burgeoning short-term demand.

   For the benefit of customers, Southern Wholesale Energy ("SWE"), on behalf of Georgia Power, will attempt to remarket capacity for the years prior to the winter of 2025/2026. The Company has already contracted for the sale of 500 MW to a regional electrical service provider for January 1, 2024, through September 30, 2025, thereby recovering costs from a third party in a period before the capacity is needed to serve Georgia Power retail customers.

b. Please see STF-JKA-2-20 Attachment for the applicable order from Mississippi Public Service Commission in Docket No. 2018-AD-145.

c. Since both Georgia Power and Mississippi Power are members of the Southern Company Pool, which adheres to Southern Dispatch practices and the Intercompany Interchange Contract ("IIC"), "day-to-day operating procedures" will not be necessary. If the affiliate or pool relationship were to change during the term of the PPA, the Operating Committee would have responsibility for developing any subsequently needed operating procedures.

d. This PPA is executed under Southern Operating Companies' Market Based Rate Tariff ("MBR") with Mississippi Power as an electric utility operating company engaged in the sale of electric power at wholesale that has received authorization from the Federal Energy Regulatory Commission ("FERC") to provide wholesale power supply services at market-based rates. Transactions made under MBR do not require separate filings at FERC for approval. Further, Georgia Power is an electric utility operating company which provides retail electric service to end-use customers in its franchise service territory in the state of Georgia that is authorized to purchase wholesale power supply services.

e. As discussed in the response to subparts (a) and (b) above, purchasing 750 MW that can be met by any resources available to Mississippi Power prevented this capacity from being

Docket No. 55378
Georgia Power Company's 2023 IRP Update
STF-JKA Data Request Set Number 2
PUBLIC DISCLOSURE

removed from the Southern Company pool where it would no longer be available through system reserve sharing to serve Georgia Power customers. The Mississippi Power PPA was set up to be similar to system reserve sharing as allowed under the IIC, which is based on total capacity available from each Operating Company. Mississippi Power will continue to evaluate any necessary actions associated with the Mississippi Public Service Commission order in Docket No. 2018-AD-145.

f. As defined in the Power Supply Service Schedule, "seller generating resources" are, at any given time, the electric generating units owned or controlled by Mississippi Power that are in commercial operation and are submitted to Southern Dispatch. The PPA obligations can be met by any resources available to Mississippi Power.

g. Georgia Power and Mississippi Power both operate as part of the Southern Company system pool, and the expectation is that the conditions in Section 4.2 of the Power Supply Service Schedule would potentially occur under emergency situations, such as winter weather events, where the Southern Company system is impacted. Mississippi Power has every incentive for high levels of unit performance under the Southern Company system and its obligation to provide reliable service to its customers through the Southern Company system pool. No other data was acquired from Mississippi Power or Southern Company to evaluate the inclusion of this provision in the Mississippi Power PPA.

h. Please see the "9 TS Economic Analysis" folder in the Technical Appendix to the 2023 IRP Update for an economic assessment of the Mississippi Power PPA. This resource is available to meet near-term capacity needs. The results of the economic analysis demonstrate this PPA is competitive with other options. Furthermore, the capacity prices listed in Table 1 reflect the market price of capacity and are consistent with other recently executed contracts, such as TS STF-JKA-2-19 Attachment B. Finally, the 2024 reserve sharing rate as prescribed in the IIC and filed with FERC as part of the informational filing is $73.20/kw-year which is within REDACTED of the annualized rate in Table 1.

i. Please see the "TS Economic Analysis of Capacity Resources.xlsx" file in the "9 TS Technical Appendix Economic Analysis" folder of the "TS Technical Appendix," which was previously provided to the Commission Staff on October 27, 2023, in the 2023 IRP Update filing. The formulas associated with the contract capacity price and computed costs are on the "Cost Inputs" worksheet.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-4-19

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-4-19 ("Response"). In the Response, the Company has provided monthly forecasted load information. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains specifics around negotiating parties involved in potential energy sales for defined periods of time. Publicly disclosing this information would allow others to potentially come in and undercut the Company in negotiations resulting in no sale or less revenue which would hurt customers who will see the benefits of the additional revenues.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket Nos. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-JKA Data Request Set Number 4

STF-JKA-4-19

Question:

Regarding the Mississippi Power and Santa Rosa capacity:

a. See page 32, at line 20 of the testimony. Please compare all of the costs (fixed, variable, fuel by cost component) of the Mississippi Power capacity that would have been "available for Georgia Power customers in times of need due to reserve sharing within the Southern Company pool" versus all of the costs of the Mississippi Power capacity that is being acquired via the PPA contract.

b. See page 33, at line 13, which discusses the plan for SWE to remarket the Mississippi Power capacity for years prior to the winter of 2025/2026. Please provide the contract for the sale of the 500 MW and summarize the main terms of the contract, including identifying who the contract was sold to.

c. Given that the Mississippi Power capacity amounts to 750 MW, why wasn't the counterparty that acquired the capacity for 2 years interested in the full 750 MW?

d. Please explain what steps SWE has taken to remarket the Mississippi capacity and identify the entities that SWE has already spoken with about the remaining capacity.

e. See page 35 at line 3, which discusses the plan for SWE to remarket the Santa Rosa capacity for years prior to the winter of 2025/2026. Please explain what steps SWE has taken to remarket the Santa Rosa capacity and identify the entities that SWE has already spoken with about the sale.

Response:

a. There is no difference between the energy cost of the Mississippi Power Company ("MPC") PPA and the cost of receiving energy from the Southern Company pool. The capacity price of the MPC PPA is reflective of the market and similar to the reserve sharing rate for 2024. This contract guarantees that the capacity is available to serve Georgia Power customers throughout the term.

b. Please see TS STF-JKA-4-19 Attachment.

c. The counterparty has since requested additional capacity of 250 MW and negotiations are currently underway for the remainder of the 750 MW.

d. SWE is currently in negotiations to sell the additional 250 MW for 2024 and 2025. Due to ongoing negotiations, the parties involved cannot be identified.

Docket Nos. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-JKA Data Request Set Number 4

e. Once approved, SWE is prepared to include the Santa Rosa capacity during the period prior to winter of 2025/2026 in response to active Requests for Proposals. Due to potential negotiations, potential parties cannot be identified.

This file has been redacted in its entirety.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-6-5

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-6-5 ("Response"). In the Response, the Company has provided assumptions and information about proposed expansion projects used in the economic analysis of the resources proposed as part of the 2023 IRP Update. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details regarding sites that are being proposed for new BESS projects. If revealed to the public, a generation wholesaler, power marketer, or original equipment manufacturer could use the Information to arbitrarily tailor proposals with the intention of pricing products and services according to the Company's expected costs, which could undermine the Company's ability to procure the best cost products and services for customers. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-JKA Data Request Set Number 6
PUBLIC DISCLOSURE

STF-JKA-6-5

Question:

Regarding the Company's Request for Information Summary, Section 2.3, the Company states, "There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027."

a. Please explain if the Company could have considered an agreement outside of an RFP process, such as an unsolicited offer.
b. Please explain how the Company was able to negotiate the Santa Rosa PPA outside of an RFP, but did not consider negotiating an agreement for any of the RFI identified projects the same way.
c. Please explain how the Company was able to negotiate the Mississippi Power agreement outside of an RFP, but did not consider negotiating an agreement for any of the RFI identified projects the same way.
d. Please explain what transmission constraints are a barrier to the ESS projects identified in the RFI, but are not a barrier to the **REDACTED** Solar + BESS projects.

Response:

a. Yes, the Company could consider an agreement outside of a Request for Proposal ("RFP") process for the potential new or planned projects that responded to Georgia Power's Request for Information ("RFI"). However, the Company would need to solicit additional information, including pricing, from such projects and evaluate the generation and transmission costs and benefits for each response to determine which projects are viable, which projects are most cost-effective, and when the Company could receive delivery from each potential project. Any transmission upgrades required by new generation resources must be identified and constructed, which can take substantial time given the current long lead times on the procurement and supply of transmission equipment. Instead, as described in the Company's response to STF-PIA-4-16(d), the Company is currently focusing its efforts on identifying existing sites where battery energy storage systems ("BESS") can be deployed and deliver energy to the transmission system prior to November 2027.

b. The Santa Rosa Energy Center was a known, existing generation asset that was identified in July 2023 as a potential resource to meet the Company's 2023 IRP Update capacity needs. Given identification in July 2023 and the fact that it is an existing asset that can meet the Company's generation needs in the 2023 IRP Update without the construction of transmission projects, the Company was able to negotiate a power purchase agreement ("PPA") with Santa Rosa Energy Center, LLC, prior to filing the 2023 IRP Update on October 27, 2023. The Company issued its RFI in September 2023 to gather market

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-JKA Data Request Set Number 6
PUBLIC DISCLOSURE

information regarding the availability of existing and planned capacity resources for years 2026-2031. The RFI closed on October 24, 2023 and confirmed that no existing capacity resources could help meet the Company's capacity needs being addressed in the 2023 IRP Update. For potential new or planned projects, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

c. The Mississippi Power PPA consists of known, existing generation assets and was identified in July 2023 as a potential resource to meet the Company's 2023 IRP Update capacity needs. Given identification in July 2023 and the fact that it contains existing assets that can meet the Company's generation needs in the 2023 IRP Update without the construction of transmission projects, the Company was able to negotiate a PPA with Mississippi Power prior to filing the 2023 IRP Update on October 27, 2023. The Company issued its RFI in September 2023 to gather market information regarding the availability of existing and planned capacity resources for years 2026-2031. The RFI closed on October 24, 2023 and confirmed that no existing capacity resources could help meet the Company's capacity needs being addressed in the 2023 IRP Update. For potential new or planned projects, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

d. The **REDACTED** BESS plus solar project utilizes existing transmission interconnection infrastructure, and the Company's transmission screening analyses indicate that the project can deliver up to 200 MW of energy to the transmission system through the summer of 2029. Once prior planned transmission projects are completed by the summer of 2029, the project could deliver up to 415 MW to the grid. For potential new or planned projects in the RFI, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-PIA Data Request Set Number 10

STF-PIA-10-2

Question:

Please refer to the 2023 IRP Update at page 17, which describes the PPA with Mississippi Power: "The Company has already contracted for the sale of 500 MW to a regional electrical service provider for January 1, 2024, though September 30, 2025."

a. At what price has the Company contracted to re-sell the 500 MW of capacity?

b. Does the Company anticipate being able to re-sell the remaining 250 MW of capacity from the PPA? If so, to whom does it expect to sell the capacity, and what price does it expect to receive? If not, please explain why not.

Response:

a. See page 2 of TS STF-JKA-4-19 Attachment for the requested Contract Capacity Price.

b. Yes, the Company anticipates that it will be able to remarket the remaining 250 MW of capacity to a regional electrical service provider at a comparable price to the 500 MW.

Contact: Jeff Grubb

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-PIA-10-3

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-PIA-10-3 ("Response"). In the Response, the Company has provided information related to a potential wholesale power purchase agreement. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains specifics around capacity pricing involved in potential capacity and energy sales for defined periods of time. Publicly disclosing this information would allow competitors, other public utilities, and market participants to potentially disrupt and undercut the Company in negotiations resulting in no sale or otherwise artificially distort the pricing for the proposed sale, which would hurt customers who will benefit from the sale of the remarketed capacity. Further, the Company's competitors are not required to disclose this type of information and to require the Company to do so would place it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-PIA Data Request Set Number 10
PUBLIC DISCLOSURE

STF-PIA-10-3

Question:

Please refer to the 2023 IRP Update at page 17, which describes the PPA with the Santa Rosa Energy Center: "For the benefit of customers, SWE, on behalf of Georgia Power, will attempt to remarket capacity for years prior to the winter of 2025/2026."

a. Does the Company anticipate that SWE will be successful in re-selling this capacity?

b. If so, to whom does it expect to sell the capacity, and what price does it expect to receive? If not, please explain why not.

Response:

a. Yes, the Company anticipates that Southern Wholesale Energy ("SWE") will be successful in remarketing this capacity.

b. The Company expects to remarket the capacity to a regional electrical service provider at a capacity price **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**.

Contact: Jeff Grubb

EXHIBIT__(RS/BD-5)

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-LA Data Request Set Number 1

STF-LA-1-20

Question:

Inflation Reduction Act. On page 28 (lines 14-16) of the Company's Direct Testimony, the panel states: "The Company remains optimistic about the future of renewable resources, as well as the prospects of the Inflation Reduction Act "IRA") and its potential to reduce the cost of new renewables for customers."

a) Has the Company incorporated any benefits from the IRA with its resource requests (including renewables) in its 2023 IRP Update? If not, explain fully why not.

b) If so, please quantify and explain fully and in detail, all benefits from the IRA that were incorporated by Georgia Power and indicate which resource(s) to which such benefits were applied.

Response:

a) Yes, the Company incorporated expected benefits from the Inflation Reduction Act ("IRA") with its battery and solar requests in the 2023 IRP Update. Please refer to the Company's responses to STF-JKA-2-19, STF-PIA-4-9, STF-PIA-4-10, STF-PIA-4- 11, STF-PIA-4-12, STF-PIA-7-2, and STF-PIA-7-3 for further detail on how the Company considered funding opportunities available from the IRA for this filing. Please see the "TS Economic Analysis of Capacity Resources.xlsx" file in the "9 TS Economic Analysis" folder of the Technical Appendix to the 2023 IRP Update filed on October 27, 2023, for the Company's analysis of cost-effective solutions to meet projected capacity shortfalls, which includes benefits associated with the IRA for applicable technologies. The Company will continue to assess opportunities to leverage funding opportunities from the IRA and from other similar incentives, if any, for the benefit of customers.

b) The Company included assumptions that solar deployments will qualify to earn PTC benefits while BESS deployments will receive ITC benefits. The quantification of these benefits can be seen in the SAM files provided to the Commission Staff on October 27, 2023. Please refer to the response in part (a) for further references.

Contact: Mike Bush

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-PIA-4-9

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-PIA-4-9 ("Response"). In the Response, the Company has provided data supporting the economic analysis of projects proposed in the 2023 IRP Update including an acquisition with sensitive pricing and confidential details (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information includes competitively sensitive details specific to the resources under contract, proposed to be acquired, or proposed to be developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 IRP Update
STF-PIA Data Request Set Number 4
PUBLIC DISCLOSURE

STF-PIA-4-9

Question:

How did Georgia Power consider potential funding opportunities from the Inflation Reduction Act ("IRA") that would increase Company spending on infrastructure and/or generation assets for the IRP Update filing? Please describe how the IRA's Domestic Content Bonus Credit and Energy Community Bonus Credit were considered in resource selection.

Response:

The Company considered Inflation Reduction Act ("IRA") benefits in the 2023 IRP Update filing such as the Investment Tax Credits ("ITC") and Production Tax Credits ("PTC") for the applicable technologies. The Company included ITC benefits for battery energy storage systems ("BESS"), PTC benefits for solar and, wind, and the 10-year clean electricity PTC for nuclear as part of the Company's Resource Study Mix. Please see TS Technical Appendix 8 TS Resource Mix Study for more information on the modeling of these benefits in the Resource Mix Study. For BESS, the Resource Mix Study assumes a 40% ITC assuming BESS will qualify for the base tax credit with bonuses for labor and either the domestic content or energy community bonus credit.

The Company identified projects at Robins BESS, Moody BESS, and REDACTED Solar plus BESS that incorporate the benefits of the IRA. These benefits are reflected in the Company's Economic Analysis. Please see TS Technical Appendix 9 TS Economic Analysis for more information. The BESS projects all assume utilization of the ITC. The BESS projects also assumed that augmentations performed in later project years will qualify for the domestic content bonus credit. The solar component of the **REDACTED** Solar plus BESS project is assumed to generate PTCs. For the BESS and solar projects, the Company assumes the ability to earn the base credit plus the labor bonus credit. The Company will continue to look for opportunities to also leverage the domestic content or energy community bonus credits to bring further IRA benefits to customers where sensible. Please reference the Company's response to STF-JKA-2-19 part (f) for further detail and the SAM files provided to the Commission Staff on October 27, 2023 to see the application of the tax benefits of the IRA mentioned above in the asset worksheets.

The Company will continue to evaluate and optimize opportunities related to the IRA that provide benefits to customers.

Contact: Mike Bush

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-PIA Data Request Set Number 4

STF-PIA-4-10

Question:

How did Georgia Power consider potential funding opportunities from the IRA that would increase customer spending on behind the meter generation assets and battery storage in the IRP Update filing?

Response:

Georgia Power did not explicitly consider the potential funding opportunities from the Inflation Reduction Act ("IRA") on behind the meter generating assets such as solar or battery storage in the 2023 IRP Update filing.

Contact: Lee Evans

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-PIA Data Request Set Number 4

STF-PIA-4-11

Question:

How did Georgia Power consider potential funding opportunities from the IRA that would increase customer spending on electric transportation readiness and infrastructure in the IRP Update filing?

Response:

The Electric Power Research Institute ("EPRI") produces High, Medium, and Low electric vehicle ("EV") Market share scenarios each year. These scenarios are guided in part by external studies produced by outside researchers. The July 2023 Revision to the EPRI forecast includes at least one external study that considers EV incentives provided by the Inflation Reduction Act ("IRA") as part of the impact of a "supportive policy environment."

Georgia Power's forecast of electric vehicles utilizes EPRI's Medium scenario for the state of Georgia. To the extent that the impacts of the IRA are incorporated into EPRI's Medium scenario, then it is implicitly considered in the 2023 IRP Update. However, the Company did not make any explicit adjustments based on the expected impacts of the IRA on electric transportation readiness and infrastructure.

Contact: Francisco Valle

Docket No. 55378
Georgia Power Company's 2023 IRP Update
STF-PIA Data Request Set Number 4

STF-PIA-4-12

Question:

How did Georgia Power attempt to maximize funding opportunities available from the IRA in the 2023 IRP Update? How were the different funding sources used to determine where spending would result in the most cost-effective solution for Georgia Power's projected capacity shortfall?

Response:

Please refer to the Company's responses to STF-PIA-4-9, 10, and 11, for further detail on how the Company considered funding opportunities available from the Inflation Reduction Act ("IRA") for this filing. Please see Technical Appendix 9 Economic Analysis of Capacity Resources for the Company's analysis of cost-effective solutions to meet projected capacity shortfalls, which includes benefits associated with the IRA for applicable technologies. The Company will continue to assess opportunities to leverage the funding opportunities from the IRA and from other similar incentives, if any, for the benefit of customers.

Contact: Jeff Grubb

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-PIA Data Request Set Number 7

STF-PIA-7-3

Question:

Describe Geogia Power's efforts to maximize benefits to customers from the opportunities in the IIJA and IRA. How would these benefits be reflected in the Company's ASR filings?

Response:

The Company incorporates the assessment of potential benefits to customers from opportunities provided through federal incentives including both the recently created IIJA and IRA statutes. Note, that as federal agencies continue to update guidance related to these statutes, the Company will continue to assess the impact to any applicable projects and provide customers with these benefits.

The Company included assumptions for both production tax credits ("PTC") and investment tax credits ("ITC") for eligible facilities in its 2023 IRP Update. Please see STF-JKA-2-19 subpart (f) for more information on these assumptions. The Company did not directly incorporate IIJA benefit assumptions into its economic analysis of capacity resources or the Resource Mix Study. The Company will continue pursue opportunities to provide IRA and IIJA benefits to customers as those opportunities are identified and vetted. Any realized PTCs will be reflected as credit to federal income taxes payable and ITCs will be reflected as credit to amortization of ITCs in Sections 2 and 3 in the Company's Annual Surveillance Review ("ASR") filings.

Contact: Mike Bush

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February 22, 2024

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, S.W.
Atlanta, GA 30334-5701

RE: Georgia Power Company's 2023 Integrated Resource Plan Update; Docket No. 55378

In accordance with the Commission's Procedural and Scheduling Order, with respect to Docket No. 55378, please find enclosed the errata to the pre-filed testimony of Thomas Newsome, Phillip Hayet, and Leah Wellborn and the errata to the pre-filed testimony of Ralph C. Smith and Benjamin H. Deichman.

An electronic version of this filing has been served to all parties in this docket.

Sincerely,

Preston Thomas
Attorney

Enclosures

Cc: All parties of record (w/enclosure)

Errata to Pre-filed Testimony of Thomas Newsome, Philip Hayet, and Leah Wellborn

Page and Line Number	Change
Page 19, line 5	Strike "no over-forecast errors, just under-forecasted errors" and replace with "no under-forecast errors, just over-forecasted errors."
Page 74, Table 15, Row 2	Strike "Robins BESS" and replace with "Santa Rosa PPA."
Page 74, Table 15, Row 3	Strike "Santa Rosa PPA" and replace with "Robins BESS."

Errata to Pre-filed Testimony of Smith and Benjamin Deitchman

Page and Line Number	Change
Page 17, line 9-12	Insert "Company" between "the" and "in." Strike "produce" and replace with "result"
Page 17, line 16-19,	Strike "estimates the majority of new large load customer cost would be assigned to customers a large commercial customer class" and replace with "observes that a large proportion of the company's cost of service has historically been assigned to customers outside the large commercial customer class."

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	**Docket No. 55378**
Georgia Power Company's	)	
2023 Integrated Resource Plan Update	)	
	)	

CERTIFICATE OF SERVICE

I hereby certify that the foregoing **Staff's Errata to the Pre-filed Testimony of Thomas Newsome, Philip Hayet, and Leah Wellborn and Errata to Pre-Filed Testimony of Ralph Smith and Benjamin Deitchman** in the above-referenced docket was filed with the Commission's Executive Secretary, an electronic copy of same was served upon all parties and persons listed below via electronic mail, or unless otherwise indicated, as follows.

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So certified, this 22nd day of February 2024.

_____

Preston Thomas
Attorney

MS. DAVIS: Thank you.

CHAIRMAN SHAW: Gentlemen, go ahead.

A (Witness Smith) Good afternoon, Chairman, Commissioners. The purpose of our testimony is to address accounting and ratemaking issues presented in Georgia Power Company's 2023 Integrated Resource Plan Update proceeding. Our conclusions and recommendations are summarized on pages 6 through 8 of our testimony.

For cost recovery issues, the company is requesting approval for certain categories of costs, which will lead to a request for recovery of such costs in their next rate case.

Staff generally recommends that specific requests for cost approval, as well as for cost recovery, be addressed when the company's earnings and risks are considered, such as in the company's next rate case, which is scheduled to be filed in 2025 after the company's 2025 integrated resource plan.

The company has requested a number of new regulatory deferrals which would push costs from 2023, 2024, and 2025 into 2026 and subsequent years and thus put upward pressure on rates in the company's 2025 rate case.

Staff is recommending that the company's requests for new regulatory deferrals be rejected. Staff

has also recommended that the company's requests for additional sums for new capacity purchase power agreements be rejected for 2024 and 2025 for a number of reasons, including that the capacity is not needed for those years and that the new PPAs were not competitively bid.

The company has stated that it is their expectation that the addition of several new large load customers would put downward pressure on rates. For various reasons, the company's statements that it expects that there will be downward pressure on rates do not provide assurance that rates for all customer classes, such as residential and small business customers, would not be subject to increased rates if the company's requests in this IRP update proceeding were to be granted.

Moreover, several of the company's requests, such as, but not limited to, the company's request for new regulatory accounting deferrals and for new additional sums, would put upward pressure, not downward pressure on rates in the company's next rate case.

Staff recommends that the new cost deferrals and new additional sums requests that are being made by the company that would contribute to the upward pressure on rates be denied.

The new regulatory accounting deferrals proposed in the company's 2023 IRP update would put upward pressure on rates in the company's next rate case. The staff notes that the company has ample bandwidth within the return-on-equity range of 9.5 percent to 11.9 percent that was established in the company's most recent 2022 rate case, Docket 44280.

And within that bandwidth, the company should be able to absorb expense fluctuations which the company is requesting in this IRP update proceeding to defer.

To the extent that cost fluctuations fall within that earnings band, there is not a need to defer such costs into the company's next rate case. To avoid putting upward pressure on rates in the company's next rate case, staff recommends that no approval for new regulatory deferrals be granted in the current proceeding.

Staff also recommends that the company's requests for additional sums for two new capacity and energy purchase power agreements be rejected for 2024 and 2025. Staff finds that additional capacity provided for in the new PPAs with Santa Rosa and with an affiliate, Mississippi Power Company, is not needed in 2024 or in 2025. That's explained in the testimony of a previous staff panel and is acknowledged by Georgia Power itself.

Moreover, unlike the PPAs that were addressed in the company's '22 integrated resource plan, these two new PPAs were not obtained through an RFP and competitive bidding process. Ratepayers should not be charged for additional sums for these two new capacity PPAs for '24 and 2025. Staff recommends that the company's proposal for additional sums on the Santa Rosa and Mississippi Power Company capacity PPAs for 2024 and 2025, in the current IRP update proceeding, be rejected.

Our testimony also briefly discusses some of the new federal income tax incentives provided by the Inflation Reduction Act, or IRA, and how those incentives could affect resource selection. While the company was aware of and considered many of the tax incentives that have been made available by the IRA, it appears that impacts of new incentives for additional behind-the-meter resources and energy efficiency were not specifically considered by the company.

Therefore, there may be an opportunity for further development of energy efficiency measures and distributed energy resources that could provide resources beyond what the company has presented in its 2023 IRP update to help address growth and load and peak demand that the company is projecting related to adding several new large load customers within and outside of its

service territory. That concludes our summary.

MS. DAVIS: Mr. Chairman, the witnesses are now available for questions from Commissioners, as well as cross-examination.

CHAIRMAN SHAW: Thank you.

Commissioners, any questions for the panel?

VICE CHAIRMAN ECHOLS: You mentioned what -- the question that I had asked, you know, twice about the -- about the IRA stuff, the behind-the-meter stuff. Why do you think they didn't factor that in?

MR. SMITH: Because that's what they told us in response to discovery requests.

VICE CHAIRMAN ECHOLS: Did they tell you why? Did they give any kind of rationale to your satisfaction?

MR. DEITCHMAN: So on some of the energy efficiency programs, for example -- I mean, that's ongoing. And certainly, we will expect more as we get to the 2025 IRP, the regularly-scheduled IRP. GEFA is working on the plans for how some of that money will be distributed in the state. And certainly, there is, you know, the federal roll-outs ongoing with that sort of stuff.

VICE CHAIRMAN ECHOLS: Do you agree that it is -- that it is not going to last forever, that it

is a limited opportunity, that it is an asset that can help us with our issue? I am talking about the tax credits and other things that would incentivize behind the meter. Battery -- batteries, for example.

MR. SMITH: I think there is an opportunity for developing that further, and it is our understanding that that has not been included in the company's 2023 IRP update. I think they considered and quantified whatever they could, like for the company-owned resources, the battery energy storage. It looks like they have considered the production tax credits and investment tax credits.

But for behind-the-meter stuff, I am not sure if they just felt like they couldn't get a handle on it quickly enough. But it is our understanding that additional opportunities in that area have not been included by the company as potential resources that could address some of the need for capacity.

VICE CHAIRMAN ECHOLS: You know, we have got the two models sitting there; right? The Green Mountain Power where the utility, you know, owned the asset and they were renting it, basically leasing it, to the customer; right? With a monthly -- monthly fee. And then the Rocky Mountain

Power example where the customer is taking advantage of the tax credits. Utility is getting full visibility, full access.

So of those two examples, which do you like best to solve the problems that we have? Do you like the utility owning it and on bill pay -- or, you know, the customer, you know, is renting it, you know, at 69, 79, 89 a month, or the other way, where we are triggering the tax credit?

MR. SMITH: I think both models can work under the right circumstances. I think there might be interest from some of the large customers that are being added to also develop their own behind-the-meter resources. You know, most of these big data centers, I mean, like, Amazon, Google, Microsoft, each of those companies has stated goals for clean energy targets and for decarbonization, and yet, they also want reliable service to run their data centers.

So there is potentially a lot of opportunities there for the customers to develop additional resources and take advantage of available tax credits. And then -- I am not specifically familiar with either of the two models that you've referred to. But I know, like, even communities that may

not, you know, be taxable entities, there is additional opportunities to structure maybe construction of solar or community solar where some other party can provide part of the financing and, therefore, enjoy -- the party that would be providing the financing would be a taxable entity then and could take advantage of some of the tax benefits provided by the IRA.

I know they are doing that out in Hawaii on the island of Kauai. Their electric utility there is a cooperative. So for federal income taxes, they are treated as a nontaxable entity, and they have been able to develop solar and solar and battery projects with the special financing arrangements. So another party can step in and provide financing and then enjoy the tax benefits. And that's been able to help them bring some of those types of projects on more economically.

VICE CHAIRMAN ECHOLS: It seems like we reduce our risk for another rate increase, which is my absolute top concern here, by doing some of these things that you are -- that you are recommending, as opposed to letting the power company self-build all this stuff, and if some of this load falls away, then they come to us and say, We meant well. You

know, we thought we had this. And we didn't anticipate this bankruptcy of this data center or this Bitcoin company or, you know. And then all of a sudden, we now are really obligated to, you know -- to, you know, to raise rates in order to cover -- you know, to cover this revenue need.

So it seems like there is maybe a safer, less risky way for us to do this by engaging our folks out there who might want to be a part of this, you know, green energy revolution that's happening.

MR. SMITH: It does seem like there is other opportunities that could be developed and could help hold down the cost to ratepayers.

VICE CHAIRMAN ECHOLS: Thank you.

CHAIRMAN SHAW: Any other questions, Commissioners?

(No response.)

CHAIRMAN SHAW: All right. We will move on forward with cross. Advanced Power Alliance?

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association?

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone?

MR. GALLOWAY: No questions, Mr. Chairman.

CHAIRMAN SHAW: Georgia Association of Manufacturers?

MR. JONES: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. JONES:

Q Mr. Smith, Mr. Deitchman, good evening. How are y'all?

A (Witness Smith) Not bad.

Q Good. My name is Clay Jones. I am here on behalf of the Georgia Association of Manufacturers, and I have just a couple of questions for you. I want to spend time talking with you about the portions of your testimony related to regulatory deferrals.

On pages 2 to 3 of your testimony, really starting at the very bottom of page 2, you summarize staff's position and say that, "Staff believes that an IRP proceeding is not the appropriate forum for addressing ratemaking issues." Would you agree that's your testimony?

A (Witness Smith) Yes.

Q And you go on to support that position by pointing out that a rate case considers a whole dynamic range of issues, including revenues, expenses, earnings, risks, other factors. Would you agree with that?

A (Witness Smith) Yes.

Q And then on that basis, later on page 3, lines 9 to 11, you oppose the company's request for certain regulatory cost deferrals, arguing that they would shift current costs to the next rate case and, in your opinion, put upward pressure on customer rates; right?

A (Witness Smith) Correct.

Q And before I go any further along that line, would you agree with me that if the resources we add to meet this new load collectively come in at below the system average cost, that that would, in fact, put downward pressure on rates? Just as a general principle?

A (Witness Smith) I think there is a possibility that if all the revenue appears on time and the company's projected costs pan out -- and they haven't even quantified some of the costs yet -- that there is a possibility -- I wouldn't say a probability -- but there is a possibility that the revenues from adding these new loads from the large customers could end up exceeding the cost of -- the additional cost of providing service to them.

That is a possibility. I don't really think that's a probability.

Q Okay.

A (Witness Smith) And I think there is a greater

risk that it could go the other direction, where the costs are going to end up being higher. And, you know, by having these regulatory deferrals, all that's going to do is take costs that the company is incurring in 2023, 2024, and 2025 and push those out there for consideration in the company's next rate case. So all that's going to do is put upward pressure on rates.

Q Yeah.

A (Witness Smith) So we don't think that that's a good idea.

Q And so -- thank you for that answer.

But I guess my question was really more theoretical than specific to this case. The question was, you know, if resources that we bring on to meet new load are collectively lower than the system average cost, wouldn't you expect that to put downward pressure on rates, if that were, in fact, true?

A (Witness Smith) Well, I think it is theoretically possible; and, you know, we have been working with the company to get estimated numbers in discovery.

Q Right.

A (Witness Smith) And I think their preliminary estimate shows that there could be some downward pressure on rates, but then that apparently doesn't consider all

of the costs. And when you start factoring in some of these other costs that have been subsequently identified, it looks like it is going to go in the opposite direction.

Q Now, you understand that -- have you reviewed GAM's testimony, the testimony of Mr. Pollock? Are you familiar with that?

A (Witness Smith) Yeah. Yeah, I really enjoyed his testimony.

Q Thank you --

A (Witness Smith) I thought it was very good.

Q Well, I enjoy his testimony, too. Thank you. So we can agree on that.

You understand that GAM agrees with staff that the Commission should not approve these requested regulatory cost deferrals; right?

A (Witness Smith) That's what I thought his recommendation was, yes.

Q Right. So we agree on that. And so an IRP, as was stated earlier by Commissioner Pridemore and as I think you implied through your testimony, it's not a ratemaking proceeding; right? An IRP is not a ratemaking proceeding. Would you agree?

A (Witness Smith) I would agree, yes.

Q And the company is scheduled to file a new rate

case in 2025; right?

A (Witness Smith) Correct.

Q And you would agree with me that issues of cost allocation, cost-of-service studies, which one to use, rate design, all these things, in addition to the things that you have cited in your testimony, those are properly addressed in rate cases, not IRPs or IRP updates? Would you agree?

A (Witness Smith) I think, generally, yes; but, I mean, the company's filing in this IRP update proceeding and the testimony during the earlier hearing, I don't know how many times I counted downward pressure on rates as being something the company was, you know, saying that they expected.

So I think that's an issue here, you know, is what the Commission approves in this docket, is that going to put downward pressure on rates, or is it going to put upward pressure on rates? And I think everybody -- maybe everybody, other than the company, would like to see downward pressure on rates. And I think that's a goal that we have tried to keep in the back of our mind, in part, when making some of our recommendations.

We don't want to do anything that's going to put upward pressure on rates, and we would like to have

as much downward pressure on rates as can be a -- reasonably achieved, given all the uncertainties that are involved here.

Q Sure. So -- and, again, decisions in an IRP can impact rates. But you would agree with me that we don't address rate case issues in the IRP? We don't decide them here. We don't decide whose cost-of-service study to use, how to design rates, what the company's ROE should be, all of those things. Those are decided more properly in a rate case; correct?

A (Witness Smith) All the things you just mentioned are more properly decided in a rate case.

Q Okay.

A (Witness Smith) But I think what is on the table here is company requests for new and additional accounting deferrals and for additional sums on the two new purchase power agreements.

Q And you would --

A (Witness Smith) So those have to be decided here. And we are recommending that both of those company proposals be rejected.

Q And Mr. Pollock is recommending the same thing; right? So we are in agreement on that.

A (Witness Smith) He recommended the same thing on those two issues, so we are in agreement on that.

Q Now, yet, after -- I am sorry. I didn't mean to cut you off. Go ahead. Did you complete your answer?

A (Witness Smith) Yes.

Q Okay.

A (Witness Smith) I assume Mr. Pollock, I believe, are in agreement on those two issues.

Q Right. And yet, after making these points in your testimony, you then turn around on page 4, lines 1 to 5, and say that if the Commission does approve the regulatory deferrals, that it should decide in this IRP update case that the recovery of any of those deferrals should only be from the -- I think your quote is -- the large load customers that caused the company to file the update; right? That's your testimony?

A (Witness Smith) That's more of an incremental cost view, that if all these new costs that are being addressed in this 2023 IRP update proceeding, which is outside the normal integrated resource plan filing cycle, all these new costs are being caused by the addition of these new large load customers.

Q Okay.

A (Witness Smith) So I don't want to get into a detailed discussion about cost-of-service studies, et cetera, but we would like to make one single point, in that, when revenues and costs are accumulated in a

cost-of-service study, they know what rate class the revenues are coming from, so they -- all these new large load customers are going to fall into certain rate classes. Large commercial, and I think there was one other rate class that it looks like they would fall into.

So all the revenues from all these new customers can be specifically identified, and they are going to be accounted for as additional revenues from adding those new customers. But that's not generally the way that costs are treated. Costs are spread among all different kinds of customer classes using a wide range of allocation factors, such as demand, energy, you know, labor costs.

So while the revenues are going to be specifically identifiable to the rate classes into which these new customers are being added, the costs are likely to be spread over a much wider range of customers.

Q Right. Because the cost-of-service study is an inherently dynamic and complicated exercise. Would you agree?

A (Witness Smith) I would agree.

Q Okay. And whenever we have rate cases around here, often there are multiple cost-of-service studies filed and differing opinions about which one should be used and why. Would you agree?

A (Witness Deitchman) Correct.

A (Witness Smith) There tend to be a lot of controversies about how costs should be allocated.

Q And the -- sorry.

A (Witness Smith) Usually, there is not much controversy about which pot the revenue is going to, though.

Q Right.

A (Witness Smith) It is the cost allocations that, I think, raise a lot of issues that can be controversial.

Q All right. So this all -- this alternative recommendation you have -- and by the way, let me just clarify. When you say the new large load customers are the ones that should recover or be required to recover these new regulatory deferrals, you are really not referring to specific customers there. You are referring to the classes in which they fall into; is that correct?

You say "the new large load customers." I just want to be clear, you are talking about the classes, not the individual customers?

A (Witness Smith) Well, I think if you look -- this is buried in the highly trade secret data that was covered in the Trokey Daymark panel, but they have identified several new customers.

Q Right.

A (Witness Smith) That I think they are thinking they have a relatively high probability of being added. So it is not just like some amorphous group. There is a portion of those that are fairly specific to certain customers that have indicated they want to take service from Georgia Power Company.

Q Yeah. I am really trying to get at your alternative recommendation here; okay? So you have said that you oppose the regulatory deferrals. I understand that.

A (Witness Smith) That's our primary --

Q Agree with you.

A (Witness Smith) Right.

Q But you are saying that if the Commission disagrees -- we hope they won't. But if they do, they disagree with you and me and with Mr. Pollock -- that you would then say, and I think if we look on page 7, lines 1 to -- I am sorry. Lines 11 to 13 you say it again. "That the impact of all such incremental deferrals must be absorbed by the rate classes into which such large load customers are being added when such new regulatory assets would commence amortization starting in 2026." That's in your testimony; right?

A (Witness Smith) Right.

Q As an alternative recommendation?

A (Witness Smith) These would essentially be incremental additional costs that are directly caused by serving that new load.

Q Okay. And that's what I want to talk about, your alternative recommendations, because I think we agree on the rest of it. You said in your testimony you oppose single-issue ratemaking; right? You would agree with that?

A (Witness Smith) In general, we don't like single-issue ratemaking, but it is used throughout the country for certain items.

Q Well, right, but it is not preferred, because in a rate case you consider all kinds of factors. You don't just look at one set of costs. It is one of the reasons that we don't want these deferrals to be approved, because there is a whole wide variety of costs. When we get around to a rate case, we can look at all of them in a comprehensive way; correct?

A (Witness Smith) Correct.

Q And the same thing is true on costs and cost allocation. Whenever you look at a cost-of-service study, and there are different ways to look at them, you can -- you can consider a whole wide variety of data, instead of just as costs come up, identifying them and

putting them into buckets; right?

A (Witness Smith) Correct.

Q So you use an allocation model instead of, typically, in a rate case, rather than just directly assigning buckets of costs. So there is no cost-of-service study filed in this proceeding, to your knowledge, is there?

A (Witness Smith) Not yet. I think, you know, there is --

Q I know there has been a request for one.

A (Witness Smith) Trying to get one from the company in their rebuttal, but it hasn't been filed yet, to my knowledge.

Q Right. And so -- and there wouldn't have been one, because typically they aren't. Not just typically, but they are never filed in IRP cases, right, that you know of? Or that I know of.

A (Witness Smith) In my experience, they are not usually filed in IRP cases.

Q Okay.

A (Witness Smith) They are usually reserved for the rate case; but frequently, when, you know, drastic changes are being contemplated, commissioners are very interested in what is going to be the impact on, you know, the average residential customer if we do this

versus -- if we do alternative A versus alternative B.

In my experience, that's fairly common to want to consider what bill impacts are going to be based on what is being requested by the utility for approval.

Q Sure. And before we would want to make any decisions about how to allocate costs for purposes of ratemaking, which, again, will be in next year's rate case, we would want to have all the information we could have. We would want to allow parties the opportunity to test that information. We would want to have a full proceeding that considers all the evidence; not just individual pieces of evidence. Would you agree?

A (Witness Smith) I would -- that's a fair statement. I would agree with that.

Q Okay. And Georgia Power, the Commission staff, all the parties, they are all going to have an opportunity to submit testimony and recommendations on cost allocation, rate design, cost of service in the 2025 rate case. Would you agree? You will have the opportunity to do that?

A (Witness Smith) That's the expectation, yes.

Q Okay.

MR. JONES: That's all the questions I have. Thank you.

CHAIRMAN SHAW: Georgia Center for Energy

Solutions?

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments?

MS. BROWN: No questions.

CHAIRMAN SHAW: No questions?

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power and Light?

CROSS-EXAMINATION

BY MS. WHITFIELD:

Q Good evening, Panel.

A (Witness Deitchman) Hello.

Q I am Jennifer Whitfield. So I also want to ask a few questions about the same recommendation that Georgia Association of Manufacturers was just asking you about.

Starting on line -- page 17, line 17 to 19 -- and this is lines that are subject to your errata, so I am actually reading from the errata, not from the originally-filed testimony. You say that, "Staff observes that a large proportion of the company's cost of service has historically been assigned to customers outside the large commercial customer class."

Subject to check, does it sound about right or

would you agree that Georgia Power's test year cost-of-service study for 2022 allocated over 50 percent of gross plant cost to the residential class?

A (Witness Smith) That sounds right, and I don't have the residential class broken out separately; but we did look at, basically, two buckets, the classes into which the new large load customers would be added and then everybody else.

Q Um-hum.

A (Witness Smith) And we concluded that about 82 percent of gross plant, net electric plant, total investment, and depreciation expense were allocated to customers other than the large business and marginal class into which we think these new large load customers would be added.

So about 82 percent of the total costs in those categories were being added to other rate classes.

Q Okay. So --

A (Witness Smith) Or allocated to other rate classes. I am sorry.

Q Correct. And that's using the traditional cost-of-service study method that the company has used in the past?

A (Witness Smith) That is based on what we reviewed from a 2022 rate case. So it is kind of a

static look; and I would expect that, you know, some of the factors would change. But I think it still presents a concern that an overwhelming amount of costs that are being requested in this case to serve these new large load customers, there is a concern that those costs are going to get allocated onto other customers.

Q Okay. And I am also concerned about that. And traditionally, in a cost-of-service study, the costs are allocated the way you were describing. So in this case, you would anticipate, if I am hearing you correctly, 82 percent of the cost to be borne by the customer class that isn't -- for whom this request is not being made. But the revenues, the revenues that would come from these large load customers, would they also be shared, according to the traditional cost allocation methods?

A (Witness Smith) Well, there is two buckets to consider in the rate case. There is the overall revenue requirement and revenue deficiency, so that all the new revenues that the company would be getting would be considered in that analysis.

But then in terms of the cost-of-service study, the way I understand it, is that they -- they know where these revenue are coming from, like, they know what revenues they are getting from the residential class. They know the revenues that they are getting from the

large commercial class, small businesses. For every class that has a rate, they account for how much revenues they are getting from that class, and they have a really good idea of where the revenues are coming from.

So those don't have to be allocated. They know the revenue dollars. But it is the costs that have to be allocated, and that's where a concern comes in. Because the company is requesting approval for items that will cause potentially large increase in costs.

Q So business as usual in terms of allocation of costs. What I am hearing is that residential customers will get a large amount of the costs and won't get a large amount of the projected revenue attributed to their column in the cost-of-service study?

A (Witness Smith) I think that's a valid concern, and we have tried to point that out, that that is a concern.

Q Okay. There was a recommendation by staff that a cost-of-service study is filed as part of Georgia Power's rebuttal case. Traditionally, my understanding is that those cost-of-service studies are called embedded cost-of-service studies as opposed to marginal cost-of-service studies.

And if this is something that either of you can speak to, I am curious whether staff considered asking

the company to either file a marginal cost-of-service study instead or to file both, an embedded cost-of-service study and a marginal cost-of-service study?

A (Witness Smith) The recommendation to file a cost-of-service study was actually the previous panel. And I am not sure they thought it through in that level of detail as to what it should show. My general understanding is that I think what staff was looking to see is just not to do a complete new cost-of-service study from scratch but just take what they had from the last -- from their 2022 rate case and kind of overlay, if this new load appears, as the company is projecting, and these new costs appear, as the company is projecting, you know, give us some indication on how that is going to affect different rate groups.

Q Okay. I would also like to ask about GIPL's previously introduced Exhibit 1.

May I approach?

CHAIRMAN SHAW: Yes.

BY MS. WHITFIELD:

Q And I have previously described this exhibit; but as you can see, Attachment A is towards the back, and it includes affiliate transaction standards. And this is directly relevant to the costs of the Mississippi Power

PPAs. The first question, though, that's important is, are either of you familiar with this document?

A (Witness Deitchman) I am not.

Q The affiliated transaction standards?

A (Witness Smith) I think I am generally familiar, and we did make some inquiries about a PPA, as did the other panels. And we think it is under a different provision, not the affiliated transaction standard.

Q Okay.

A (Witness Smith) Based on the discovery responses we got back.

Q Okay. So do you have an opinion, and -- or do you have a finding, from the work that you have done, as to whether the Mississippi PPA is priced at the lower of fully distributed cost or the price of -- the market price?

Do you have an opinion about that?

A (Witness Smith) I don't have an opinion as to whether it is priced at the lower of those two. I -- basically what we have understood from the company, from their responses to our discovery about that, the pricing is based on a market price. It's a market transaction, under FERC regulation, between Georgia Power and Mississippi Power that was facilitated by one of their

other wholesale marketing affiliates.

Q Okay. So do you have any information about how it would compare to the fully distributed cost?

A (Witness Smith) No. We didn't have visibility into Mississippi Power's costs on that.

Q Okay.

A (Witness Smith) The 750 megawatts, how much that is really costing them.

Q Okay. Thank you. No further questions.

CHAIRMAN SHAW: All right. Thank you. I am -- we are about to get ready to take a break. I am just going to roll through the list and just see where we are at with who is going to be next up.

Georgia Solar Energy Association?

(No response.)

CHAIRMAN SHAW: Georgia WAND?

(No response.)

CHAIRMAN SHAW: Georgia Watch?

MS. COYLE: No questions.

CHAIRMAN SHAW: MARTA?

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft?

(No response.)

CHAIRMAN SHAW: Resource Supply Management?

All right. We are going to stop right there,

Mr. Baker, so you will be up next. What we will do is take a 50-minute break, so we will see everyone back here at 6:20.

(A recess was taken.)

CHAIRMAN SHAW: Let's get started again. We'll -- hopefully we'll be able to get through with staff's panels this evening. If not, we may have to start early tomorrow. Earlier, rather.

So, Mr. Baker, we will let you continue or start with your cross on this panel.

MR. BAKER: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. BAKER:

Q. Good evening, Panel.

A. (Witness Smith) Good evening.

Q. Can I get a clarification from you. Is a class cost of service study -- does it allocate costs to customer classes?

A. (Witness Smith) That's one of its functions, yes.

Q. To assign costs to a customer class?

A. (Witness Smith) Assigns or allocates.

Q. Is that like in a percentage basis or something like that?

A. (Witness Smith) Some class, I think, are

directly assignable and others are allocated, different factors demand energy, you know, labor costs, etc.

Q. Okay. And we've talked to -- off and on about upward pressure on rates, but would that upward pressure on rates increase dramatically if the new large loads materialized at lower than projected levels and go into service at a slower pace?

A. (Witness Smith) I think if the company incurs costs in anticipation of serving the new larger load, and if the revenues come in at a lower level or slower than what the company is anticipating that would present a scenario that would probably put upward pressure on rates.

Q. And turning to -- referring to page 21, does the retail jurisdictional rate base of approximately 26.9 billion for 2024 include the cost of Vogtle Unit 4?

A. (Witness Smith) If you're referring to page 21, I think we were using a retail jurisdictional rate base from 2022, based on the company's annual surveillance report, and it's my understanding that would not include Vogtle 4.

Q. Okay. Do you know how much more adding Unit 4 would add to the retail rate base?

A. (Witness Smith) No.

Q. If neither the staff nor the Commission has a

clear indication of the total dollar amounts of ratepayer exposure to these new company requests for new regulatory assets, shouldn't some type of limit be placed on the cost recovery or on the cost of these units so that we're not writing a blank check to the company?

A. (Witness Smith) Well, we're recommending that the company's requested additional regulatory deferrals all be rejected. The company's identified dollar amounts for some of those, but for others it's told us it can't estimate what the potential maximum amount could be. So I think rejecting the new cost deferrals and not allowing the additional sums for the Santa Rosa and Mississippi Power PPAs in 2024 and 2025 will help with the rate impacts.

Q. Well, hypothetically, let's say if the Commission were to approve the construction of the new Yates CTs and the additional 1000 megawatts of battery energy storage, wouldn't the final costs or a good cost estimate be important so that the Commission could evaluate whether to approve those requests?

A. (Witness Smith) Yeah. And I think the company has provided cost estimates, and they were reviewed by one of the earlier panels in their review of the resources that the company was proposing.

Q. Okay. And referring to page 40 of your

prefiled testimony, shouldn't the additional sums be included in the economic evaluation of the capacity PPAs, especially because those additional sums are going to be passed on to ratepayers?

A. (Witness Smith) We're recommending that these additional sums for these particular two PPAs not be approved and, therefore, they wouldn't be passed on to ratepayers.

Q. Well, let me just -- okay. If the additional -- if an additional sum is approved, hypothetically, if it's approved by the Commission, shouldn't those -- shouldn't the costs, whatever the additional sum is, whether it's a dollar or three dollars, as the company is asking for, be included in the evaluation of the PPA cost? I mean, because it is a cost that ratepayers are going to be paying for.

A. (Witness Smith) It is a cost that the ratepayers are going to be paying for. Again, we're recommending rejecting those additional sums for those two particular PPAs. It's my understanding that the company typically does not include additional sums in their economic evaluation, PPAs versus other resource alternatives.

Again, the previous panel was responsible for evaluating the company's cost benefit analyses with

respect to each of these proposed additional resources. It's my understanding the company didn't include the additional sum in their cost benefit analysis, and I'm not sure whether the staff panel did or not.

Q. Okay. Let me try to rephrase that.

A. (Witness Smith) I'm not sure it would have made any difference with respect to the recommendation on those two either.

Q. Okay. Should the additional sum amounts, whatever that is, whether it's one cent as staff is recommending or three dollars as the company is requesting, be included in the financial evaluation of the total cost of a PPA, or anything else, because ultimately that is a cost that is passed on to ratepayers? Shouldn't that be part of the total evaluation, economic evaluation?

A. (Witness Smith) I think I generally agree that costs that are passed on to ratepayers should definitely be taken into consideration. I think it depends on the context of what particular analysis is being performed.

I think when different resources are being compared you want to try to put those on as close to an apples to apples comparison as possible. In this case, it's my understanding the company did something called the RIM test, or rate impact measurement. And I think in

the RIM evaluation, I think the company did include additional sums in that evaluation.

And certainly if you're trying to ascertain impacts on future rates, it will be important to understand what costs could be potentially be passed on in terms of additional rate recovery from the company's customers.

Q. Okay. I appreciate that.

Were the potential additional sum costs included in the staff's evaluation of their ranking of the six assets -- I don't think it was your panel, but I think the previous panel had a ranking as far as their preferred -- most preferred to least preferred asset. Were any additional sum amounts included in those total costs for those assets when they were evaluated?

A. (Witness Smith) I'm not sure what went into the exact details of that analysis. I suspect they were not, but I'm not sure, and I don't know if it would have made any difference in the recommendation on the ranking.

MR. BAKER: All right. Thank you very much.

Thank you, Mr. Chairman.

CHAIRMAN SHAW: Thank you. Sierra Club?

No questions.

CHAIRMAN SHAW: SACE?

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy?

MR. MAHAN: No questions.

CHAIRMAN SHAW: Department of Defense?

MR. MCNUTT: No questions.

CHAIRMAN SHAW: Wal-Mart?

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power?

MR. MARZO: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. MARZO:

Q. Mr. Smith and Mr. Deitchman, good evening. I just have a few questions for you. Some have been answered, so I was able to scratch some things off, but I do first want to ask you general questions to make sure we have a common understanding.

Can we agree, gentlemen, that Georgia Power has an obligation to serve its customers' electric needs?

A. (Witness Smith) Yes.

Q. Can we agree that serving customers requires having the appropriate resources in place to meet customers' needs?

A. (Witness Smith) Generally, yes.

A. (Witness Deitchman) I think so.

Q. And you're aware the company has filed this IRP update to address those needs; correct?

A. (Witness Smith) To address needs of anticipated large customer additions, yes.

Q. And I realize the company and the staff may disagree on the timing of the need and how to address the need, but there's no dispute that the load has grown exponentially and there are needs that need to be met with additional resources; correct?

A. (Witness Smith) I think both staff and the company realize that there are additional needs, and there is some disagreement about maybe the pace of the additions and what resources should be selected to serve those needs, but I think there's a general agreement that the company's load is growing and the company does need some additional resources to serve that load growth.

Q. Can we also agree that placing downward pressure on rates is an anticipated byproduct of the revenues that will be generated by serving the new loads?

A. (Witness Smith) The company stated I don't know how many times in its direct testimony hearing about expecting downward pressure on rates, so I think that is the company's expectation. And the company did provide some kind of quantifications based on, I guess, what it was estimating at a certain point in time. And since then, additional information has become available, you know. These numbers are basically estimates at this

point --

Q. Yes.

A. -- that could wipe out all of the anticipated downward trajectory and rates that the company originally calculated.

Q. And I know that in your testimony you talk about some of the risk that could be involved that may have a different outcome in regards to a level of downward pressure on rates and other factors that might affect the complete outcome. But to be clear, if you produce more revenues than you do costs related to these particular resources, it's going to put downward pressure on rates; is that fair?

A. (Witness Smith) I think if the revenues do materialize and they're higher and the additional revenue requirement to serve those new customers, that by itself, almost by definition, would put downward pressure on the company's overall revenue requirement to serve all customers.

Q. Okay. And so the deferrals that staff is recommending denial of in this case are related to resources the company has brought forward in this case to meet a new customer economic load; is that correct?

A. (Witness Smith) I'm not sure I would agree with all the deferrals. I mean, there's a deferral for Santa

Rosa PPA. There's one for Mississippi Power PPA. There's one for the Yates combined cycle units. There's another one related to battery energy storage, I think. And then there's another one related to what the company's asked for is a flex plan, so that the flex plan -- I'm not sure that is really related to a specific resource. Some of the other ones are tied to specific contracts or specific project.

Q. Yeah. So --

A. The flex plan is kind of like a more general, just a generalized deferral to cover additional costs the company may in occur, I guess, between, what, now and your next IRP.

Q. But I guess my question to you, Mr. Smith, is, you understand that each of those deferrals you just stepped through, whether it's the developmental deferrals or it's related specifically to MPC and Santa Rosa, all of those deferrals are intended to -- or attached to, at least, resources that accompanied will either develop or thinks it needs to develop depending on outcome of additional load; correct? They're all related resources; right? They're all related to some generational resource?

A. (Witness Smith) Some are related resources. There's another category that's related to a flex plan,

which I haven't seen any resources identified to the flex plan.

Q. And no specific resources to the flex plan, but if there were a deferral-related flex plan, it would be attached to develop costs for a resource; correct?

A. (Witness Smith) Well, the company hasn't even been able to provide an estimate as to what that deferral amount would be, so, I mean, you're asking kind of for a blank check here.

Q. Well, you're kind of jumping ahead in questions. I'm just asking for a common understanding about what the deferrals are and what they're related to. And the deferrals themselves are related to resources that are going to be needed to serve customers?

A. (Witness Smith) Well, the Santa Rosa and the MPCo PPAs are not needed in '24 and '25. Those are not needed to serve customers in those years. Yet, the company wants deferrals of costs that it's not able to remarket for those. If it's not able to remarket sufficiently to cover its cost of those, the company wants to create new regulatory deferrals for each of those PPAs, which would shift those costs, then, into the next rate case and put upward pressure on rates.

Q. Okay. You say that they're not needed in '24, '25, but staff has recommended certification of the MPC

and Santa Rosa PPAs; correct?

A. (Witness Smith) Staff has recommended certification, but not because you needed that capacity in '24 and '25.

Q. And so to be clear, staff found that the contracting for those resources is in the public interest; correct?

A. (Witness Smith) But not because you needed that capacity in '24 and '25.

Q. Are you aware --

A. (Witness Smith) It's the period for which you're asking the deferrals for.

Q. Let's talk about that, but are you aware that the witnesses, Mr. Newsome, Mr. Hayet and Mr. Wellborn, they all testified that the resources were needed to mitigate risk and reliability?

A. (Witness Smith) For a period beyond 2025.

Q. And that those resources are only -- are the only ones currently in operation that are certain to be available at the time they are needed. Did you see that in their testimony?

A. (Witness Smith) They're currently in operation, but capacity need is not in a '24 or '25 for either of those resources.

Q. And have you reviewed the testimony of the

company witness panel: Grubb, Valle, Evans and Bush?

A. (Witness Smith) Yes.

Q. Okay. Do you understand that in order to secure the capacity the company had to enter into the agreements for the MPC PPA that started January 1, 2024?

A. (Witness Smith) The company signed those agreements of its own accord to secure that capacity, but the capacity need that it was addressing is not a capacity need in 2024 or in 2025. The capacity need is beyond 2025. That capacity under those two PPAs is not needed in any of those years, and those are the years you requested cost deferrals for, which will just put upward pressure on new rates in the company's next rate case.

Q. You're jumping ahead of me again, Mr. Smith, which my question is: Have you put forward any testimony in this case that suggests that the company could have executed the Santa Rosa and MPC PPAs in exactly the time period in which they were needed, or do you accept the company's position, which is essentially, that the company had to execute the PPAs when it executed them in order to secure them for customers?

A. (Witness Smith) I think we understand when the company entered into these contracts you started talking in, I think it was, July of 2023, and then a signed contract for MPCo occurred in October of 2023, and I

believe the Santa Rosa contract was also signed in 2023.

Q. Okay. And, I guess, Mr. Smith, let me ask this question again, and I'll try to make it maybe shorter this time: Do you have any evidence that the company could have secured these resources that the staff is recommending certification for in exactly the period when they were needed to serve customers?

A. (Witness Smith) I think the company signed those contracts when it did in order to secure that capacity for periods beyond 2025. You really didn't need it in '24 or '25, but because it was available, the company wanted to secure that capacity when it did but to provide for a capacity need that existed beyond 2025.

Q. And in the words of staff, because the company took those steps and secured those contracts as early as January 1, 2024, they mitigated a reliability risk? That's staff's own testimony; correct?

A. (Witness Smith) They mitigated reliability risk that was forecasted for years beyond 2025.

Q. Okay. And so your opposition to this is because the company has not matched the time period in which it was absolutely needed to the time period in which the contract was executed, that there should not be a deferral, even if the ultimate benefit to customers is still your mitigated reliability risk; is that correct?

A. (Witness Smith) No. The deferrals that the company has requested are in '24 and '25. The company stated it already remarked 500 megawatts of the Mississippi Power PPA and is trying to market the remaining 250. And the company's also trying to remarket the Santa Rosa -- I think that was the 230 megawatt capacity PPA -- to help offset its costs in '24 and '25 related to those new PPAs, because they were not needed for capacity in either of those years. And the company has already remarketed part of it, says it's trying to remarket the rest.

I think they even said in one of our data requests that they think they're going to be successful in remarketing the rest. So that's another reason for not including any deferrals for this. But the company should have some responsibility for mitigating its cost. So -- and it's trying to mitigate the cost for these two PPAs by remarketing the power.

And then another reason is that the company has a very wide bandwidth of equity earnings from its last rate case. So certain cost fluctuations of this magnitude --

Q. Mr. Smith --

A. (Witness Smith) -- be covered within that bandwidth.

Q. Mr. Smith, it's late in the evening, and I realize you want to answer more than my question. But if you could answer my question, we will give you an opportunity to talk to the other points you want to make. And your counsel can ask you on redirect if somehow you don't get an opportunity to say something. But in light of the time, if you could just answer the questions that I'm asking.

My question to you was: You provided no evidence in this case that the company could have secured reliability for customers with MPC and Santa Rosa by having a contract that matched entirely with the time period that it was needed; right?

A. (Witness Smith) We didn't address the issue of how the company had to purchase those in the time frame, but we are addressing the impact on '24 and '25. And you asked me previously about our reasons for recommending no regulatory deferral approval for those items. And I was -- and you suggested just one item as our reason.

And what I was explaining to you was, there are other reasons for rejecting those requested regulatory deferrals for those two PPAs.

Q. Okay. And I think one of the other -- let me ask you this real quick. There is no guarantee, right, that those resources, them MPC and Santa Rosa PPAs, would

have been available in 2026 if the company had waited to execute the PPAs; correct?

A. They may not have been available if the company didn't act when it did.

Q. Okay. Now, I believe you mentioned the earnings band a moment ago as part of your answer. And to be clear, the Commission has approved deferrals, correct, for, as far as I can tell, a couple of decades; correct?

A. (Witness Smith) But not for anything that was in this particular circumstance where you went out and bought capacity for a future year that wasn't needed in two years, and you're asking for deferrals for those years. And then you're also trying to remarket the power because the company knows it doesn't need that capacity in '24 and '25.

So I'm not aware of any exactly similar deferrals to these two new PPA requested deferrals that the commission has approved. And I think once you look at the full circumstances surrounding these, I think there's a very strong case for rejecting the company's deferral request for those two items.

Q. Well, let me ask you this, Mr. Smith: You state that the company's ample band within the earnings band to absorb the cost requested for deferral, so you

say there's no need for a deferral; correct? That's just a pure statement from our testimony; is that correct?

A. (Witness Smith) For these two deferrals, correct.

Q. Okay. Now, in fact, on page 7 of your testimony, you have a footnote that states, "The staff estimates the impact of deferrals in 2024 and 2025, would be an approximate ROE reduction of .25 percent to .40 percent in isolation"; is that correct?

A. (Witness Smith) That was an initial estimate. I think we provided in a data response an update to those numbers --

Q. But that's correct?

A. (Witness Smith) -- but they were in the ballpark, yeah.

Q. Okay. And taking staff's analysis on its face, not checking it, is it staff's position that the company should be penalized for the reduction ROE for taking prudent actions to protect the reliability for customers and to serve new economic development loads?

A. (Witness Smith) No. But we think the company should absorb some level of cost fluctuations between rate cases. And this band is extremely wide and other -- the company may get additional revenues.

I think it's been pointed out that the company

has already added some customers and is getting additional revenues. So you're trying to isolate just on one item for a cost deferral to push that office an additional cost in your next rate case and you're not taking into account other aspects that could affect the company's earnings during this same period.

Q. I'm trying to address the reasons you put in your testimony for denying the deferrals. And one of those reasons is that there's this earnings band. And you're aware that earnings band has been in effect since 1995; correct?

A. (Witness Smith) It's been revised somewhat or at least examined in each of the company's rate cases.

Q. There's been some band, whether it's been a different variable, there's been some band; correct?

A. (Witness Smith) There's been some earnings band, and generally, it's been fairly wide, extremely wide, in fact.

Q. And can we agree that the Commission, since 1995, has approved a number of deferrals for regulatory assets?

A. (Witness Smith) The Commission has approved -- some deferrals were justified, but these deferrals related to these new PPAs, we feel strongly that these are not justified.

Q. Is this the first time you've ever offered testimony that the earnings band should be used in lieu of a deferral?

A. (Witness Smith) The earnings band should be able --

(CROSSTALK)

Q. That's a "yes" or "no" question, Mr. Smith.

A. (Witness Smith) -- company to absorb earnings within a certain fluctuation.

Q. That's a "yes" or "no" question.

A. -- between rate cases. That's the whole purpose of having it.

MS. DAVIS: I would object. The witness is allowed to answer the question that was posed to him and he's allowed to give an explanation.

MR. MARZO: Ms. Chair, I understand we give witnesses a lot of leeway here, and I respect that. It is late in the evening. And I'm asking questions that he could preface with a "yes" and continue to answer, or "no," and we're just getting this long soliloquy of an answer that it may or may not be responsive.

CHAIRMAN SHAW: I do agree that it is getting late. So if there is anything we can do, whether it's from your point of view or from the witness

panel, I would appreciate it if we just answer the questions, and then if you need to follow up, you can do it in redirect.

MS. DAVIS: Yes, Mr. Chairman.

BY MR. MARZO:

Q. So we can agree that whether regulatory asset has been granted has never been based upon the existence of the earnings band; correct?

A. (Witness Smith) I'm not sure I would agree with that. I think the earnings band has been examined by staff in each rate case. And it's also looked at in conjunction with the annual surveillance report filings.

Q. Okay. You've made this recommendation before, is what I asked you previously, you made a recommendation like this before that's been rejected by the Commission, related to deferrals; correct?

A. I don't recall.

Q. Okay. You don't recall in prior rate cases suggesting that the earnings band be used to capture costs that are prudently incurred?

A. (Witness Smith) I know the earnings band has existed -- I don't remember recommending -- having a recommendation exactly parallel to these deferrals requested for these two PPAs.

Q. Now, you're aware that the Commission has had a

history of operating and allowing deferrals outside -- outside of the earnings band, and one example of that is the tax -- the JOBS Act.

Do you recall that?

A. I think when major changes have come along, the Commission has reacted to regulatory treatments for those changes.

Q. Okay. So there was an unprecedented event which was the taxing JOBs Act that allowed for a significant amount of dollars that could be refunded to customers. And this Commission, basically, deferred that amount and allowed for refunds to go directly to customers versus allowing that to flow through the earnings band; is that correct?

A. (Witness Smith) It's my recollection that that is correct with respect to the taxing JOBS Act.

Q. Now, Mr. Jones asked a number of questions about cost of service studies, so I'm not going to get -- not going to rehash that ground, understanding the lateness of the hour. However, I just want to ask, have you ever performed a cost of service study in Georgia?

A. (Witness Smith) Not in Georgia.

Q. Okay. Are you aware that the cost of service study filed in GPC's rate cases takes several months to develop?

A. (Witness Smith) Yes.

Q. Okay. And have you reviewed the cost of service study from prior rate cases in Georgia?

A. (Witness Smith) We did look at them, but not -- like, I think, the staff witness in the last rate case was Glen Watkins. We didn't look at it in any degree to the detail that he did.

Q. So are you aware, or maybe you're not aware, that there's more than 800 pages of data that goes all the way -- all the way down to the tariff level?

A. I am aware of the huge volume involved in a cost of service study. And I would like to clarify that -- I think there was a recommendation that the company file a cost of service study in its rebuttal, from the previous panel, that we didn't mean anything to that level of magnitude. We were more looking for some kind of update of just -- what would it look like if these new loads were added and the new costs were added, like a rough estimate and how that would impact the various classes.

Q. Okay. But you would agree that that type of clarity wasn't provided in the recommendation originally; correct?

A. (Witness Smith) Yeah. That clarity was not provided. And I can understand why the company may have

taken alarm at that type of request.

Q. Okay. And ultimately -- and if Mr. Jones asked this, I apologize, Mr. Smith. But, ultimately, cost of service study informs how rates are set but the ultimate adjustments that are made, those adjustments are things that are done, as Mr. Jones talked about, in the rate cases. Commission ultimately makes a decision about that. There's not a cost of service study that is adopted and necessarily used for the exact actual ratemaking; correct?

A. (Witness Smith) It's used to inform the rate design, but as I understand it, there's a lot of discussion involved in the rate design.

Q. Okay. Thank you, Mr. Smith. That's -- in the interest of time, I think most of my other issues have been covered. So thank you for your time.

CHAIRMAN SHAW: Redirect?

MS. DAVIS: Just one question.

REDIRECT EXAMINATION

BY MS. DAVIS:

Q. Is it staff's position that the PPAs should be approved and are in the public interest if ratepayers are not charged the deferral or the additional sum?

A. (Witness Smith) Yes. The previous panel recommended that those be approved, and they are in

public interest. That's a separate issue from whether additional cost deferrals should be allowed or whether additional sums should be allowed on those and charge ratepayers an additional cost.

MS. DAVIS: Thank you. I have nothing further. We would ask that the panel be excused and that staff's exhibits be entered in the record. And just for clarity and for the record, all of staff's exhibits for all panels should be marked as Staff's Exhibits 1 through 17.

(Staff Exhibits 12 through 17 were admitted into evidence.)

CHAIRMAN SHAW: Okay.

Gentlemen, thank y'all, and you can be excused.

MR. SMITH: Thank you.

Georgia Service Public Commission, you can begin calling up your next panel.

MR. PRESTON: Thank you, Mr. Chairman. At this time I call to the stand the panel of Doug Smith, Katherine Palacios, and I also call to the stand Michael Goggin, who will give a separate summary from the rest of the panel of his own prefiled testimony.

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Thereupon,

DOUGLAS SMITH,
KATHERINE PALACIOS,
MICHAEL GOGGIN,

having been duly sworn, testified as follows:

having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. THOMAS:

Q. And, Mr. Smith, could you please state your full name, by whom you're employed and your responsibilities for the record.

A. (Witness Smith) Doug Smith, vice president and principal consultant for Daymark Energy Advisors.

Q. Ms. -- I'm sure I'm mispronouncing it, Palacios?

A. (Witness Palacios) Palacios.

Q. Thank you. Same question.

A. (Witness Palacios) Katherine Palacios, managing consultant of the power grid services team of Daymark Energy Advisors.

Q. Thank you.

Mr. Groggin (sic)?

A. (Witness Goggin) Michael Goggin, vice president at Grid Strategies.

Q. All right. And, Mr. Smith, on February 15th of this year, did you file or cause to be prefiled 50 pages

of testimony in question-and-answer format, along with four exhibits marked as Exhibit SP-1 through SP-4?

A. (Witness Smith) Yes.

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

A. (Witness Smith) Yes.

MR. THOMAS: And, Mr. Chairman, the court reporter has also been provided with a copy of the prefiled direct testimony. I would ask that the direct testimony be copied into the record as if given here from the stand, and that the exhibits be marked for identification purposes as Staff Exhibits 18 through 21.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as Staff Exhibits 18 through 21.)

(Whereupon, the prefiled direct testimony of Douglas Smith, Katherine Palacios and Michael Goggin follows:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:

GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 55378**
2023 INTEGRATED RESOURCE PLAN	**)**	
UPDATE	**)**	

DIRECT TESTIMONY AND EXHIBITS

OF

DOUGLAS A. SMITH AND
KATHERINE PALACIOS

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

FEBRUARY 15, 2024
PUBLIC DISCLOSURE

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Staff Exhibit #	Description
Exhibit_SP-1	Resume for Douglas A. Smith
Exhibit_SP-2	Resume for Katherine Palacios
Exhibit_SP-3	[TS] 2023 GPC IRP Update - Transmission Planning - Analysis Overview
Exhibit_SP-4	PSC Informal Transmission Request – GPC Responses

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESS.

A. This testimony is being jointly offered by Douglas A. Smith and Katherine Palacios, both from Daymark Energy Advisors, Inc. (Daymark). Mr. Smith is a Principal Consultant and Ms. Palacios is a Managing Consultant and registered professional engineer in the state of Texas. Our business address is 370 Main Street, Suite 325, Worcester, Massachusetts 01608.

Q. PLEASE SUMMARIZE DAYMARK'S BUSINESS.

A. Daymark provides energy planning, market analysis, and regulatory policy consulting and advisory services to support decision making within the electricity and natural gas industries. We serve a broad range of clients in North America, including private and public utilities, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations, and other industry stakeholders. Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, and energy procurement, and contracting. Our experience includes detailed analyses of energy and environmental performance of the electric systems, economic planning for transmission, and market analytics.

Q. MR. SMITH, PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I have over twenty years of experience in the energy industry, primarily supporting clients advance or review infrastructure projects. I have advised clients regarding competitive transmission project development, including determination of need, solution building and outreach to stakeholders. I have led evaluations of proposed transmission projects, including assessment of regional benefits, in SPP, PJM, NYISO, ISO-NE and in the province of Manitoba. I have also evaluated non-wires alternatives in Vermont and Maine. Additional detail on my experience and qualifications is provided in my resume, attached hereto as Exhibit_SP-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. I have not previously testified before this Commission. I have previously appeared as an expert witness before regulatory commissions in Arkansas, Louisiana, Maryland, Maine, Rhode Island, and the province of Manitoba. A full list of my appearances is included in Exhibit_SP-1.

Q. MS. PALACIOS, PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I am a professional Electrical Engineer with a license in Texas. I have over 14 years of experience working in the energy industry, 12 of which, I was working in various roles in the Transmission Planning department for a major utility in Texas where I would perform various transmission analysis, set the planned 5-year budget, and develop supporting

documentation to advance projects through rate case filing. Throughout my career, I have performed dozens of load and generator interconnection studies, conducting and leading both steady-state and stability analysis to assess the impact of the proposed changes and develop robust and cost-effective solutions if any issues were observed. My experience includes performing analysis and evaluating projects in ERCOT, ISO-NE, PJM, NYISO, MISO, and SPP. Additional detail on my experience and qualifications is provided in my resume, attached hereto as Exhibit_SP-2.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. We are testifying on behalf of the Public Interest Advocacy Staff ("Staff") of the Georgia Public Service Commission ("Commission"). The purpose of our testimony is to respond to certain elements of Georgia Power Company's ("Company" or "Georgia Power") 2023 Updated Integrated Resource Plan ("IRP Update") filing. We address issues pertaining to the Company's transmission planning processes and the resulting proposed investments.

We reviewed the Company's analysis and conclusions related to the transmission system upgrades proposed in the IRP Update. Our scope included a thorough review of the Company's assumptions, methodology, and conclusions, including a review of the power flow analyses conducted by the Company in support of its filing.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Our recommendations are as follows:

1. We recommend that, pending resolution of the need for 3 Plant Yates CTs and the resolution of retirement dates of the units the Company has questioned in its 2023 IRP Update, that the question of advancing transmission solutions in support of the Plant Yates CTs be delayed and restudied in the 2025 IRP.
2. Should the question of the need for Plant Yates CTs be resolved in the affirmative in this docket, we separately recommend the following:
    a) The requested expense to advance Project 7 by one year should be denied. Determination of whether Project 7 remains the optimal solution to any future transmission needs should be considered as part of the Company's full 2025 IRP.
    b) Project 8 should be denied and the potential need for this or other similar projects should be reconsidered as part of the 2025 IRP transmission analysis.
3. The Company should consider expanding its potential transmission solutions to include non-wires alternatives as well as new substations and/or right of way solutions to ensure a robust test to find the most cost-effective solution.

Q. PLEASE EXPLAIN HOW THE REMAINDER OF THE TESTIMONY IS ORGANIZED.

A. Section II provides an overview of the Company's filing as it pertains to the transmission investment sought. Section III of the testimony describes the first round of transmission screening analysis and the results of the analysis as filed in the 2023 IRP on December 4, 2023. Section IV of the testimony addresses the second round of transmission planning analysis filed on January 12, 2024, and the updates made to the screening analysis results. Section V of the testimony describes our observations regarding the Company's transmission analysis and conclusions of the required transmission upgrades for Plant Yates. Section VI discusses our concerns with the assumptions regarding Plants Gaston and Plant Scherer unit 3 with respect to the transmission analyses performed. Section VII discusses our recommendation regarding Project 7 and Section VIII discusses our recommendation regarding Project 8. Section IX discusses our analysis and general observations regarding the analysis of Plant Yates transmission upgrades and the sensitivity of those results to the amount of planned capacity at Plant Yates. Section X discusses other transmission planning observations and Section XI concludes our testimony.

II. OVERVIEW OF COMPANY FILING

Q. PLEASE SUMMARIZE THE COMPANY'S FILING RELATED TO TRANSMISSION INVESTMENTS.

A. The IRP Update contains a request for approval of transmission infrastructure investments that the Company claims are required in support of the portfolio of new proposed supply resources. Specifically, the IRP states that "[t]he Company requests approval of the transmission investments necessary to accommodate the proposed resources and the Load and Energy Forecast in the 2023 IRP Update."[1]

Q. PLEASE CHARACTERIZE THE COMPANY'S FILING WITH RESPECT TO THE TRANSMISSION ANALYSIS PERFORMED.

A. The Company performed and submitted two rounds of transmission analysis and findings in this updated IRP. The first consisted of "transmission screens for various generation resource options considered by the Company," [2] which was as filed with the Company's IRP Update on October 27, 2023. This first analysis, referred to by the Company as the "Transmission Screening Analysis", studied the thermal impacts of the transmission grid from the addition of new loads[3] and potential supply options to serve that load.

The IRP Update included a Transmission Screening Analyses Overview in the Technical Appendix, which provides a summary of the conclusions of the Company's

[1] IRP Update, p. 28.
[2] Direct testimony of Jefferey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush, page 52, lines 7-8.
[3] In a November 27th technical conference, the Company presented the assumptions used in the Screening Analysis, which included approximately [redacted] of committed large loads.

Transmission Screening Analysis. As noted in this document, at the time of filing the IRP Update, the Company only had preliminary results, and additional studies were underway.[4]

The additional analysis was filed in part on January 12th and additional material was made available on January 19, 2024. In it, the Company studied higher levels of load to reflect the 2023 updated load forecast.

Q. HOW DO TRANSMISSION ANALYSES TYPICALLY RELATE TO IRP ANALYSES?

A. At the highest level, the objective of an IRP analysis is to forecast future needs for capacity and energy to serve customers and identify an optimized portfolio of infrastructure investments to meet those needs, subject to a variety of physical, economic, and policy constraints. Transmission analyses are an important component of an IRP because changes in load and generation can have a significant impact on the reliable operation of the transmission grid, and the need for transmission investments to serve certain loads or enable certain resource additions can have a significant impact on the economics of resource portfolios. Simply put, the transmission grid can limit the supply options that are available at any given time and chosen supply can have an impact on future transmission needs.

A typical transmission analysis in this context will evaluate specific load conditions and will use power flow models to evaluate whether the dispatch of the generation resources to meet load will lead to reliability violations on the transmission system. If

[4] IRP Update, Technical Appendix, Transmission Screening Analysis Overview, p. 2.

violations are identified, these analyses typically identify the upgrades needed to resolve the reliability issue and quantify the cost of those upgrades.

Q. PLEASE SUMMARIZE THE SPECIFIC CONCLUSIONS OF THE COMPANY'S TRANSMISSION SCREENING ANALYSIS AND THE COMPANY'S REQUESTS TO THE COMMISSION RELATED TO TRANSMISSION INVESTMENTS?

A. The initial Transmission Screening Analysis Overview filed with the IRP Update identified transmission projects needed to integrate the full capacity of the three Yates CTs, with an estimated cost of $80 million. No other transmission costs to integrate the requested supply were identified by the Company. In the supplemental analysis filed in January 2024, no new or different transmission needs or solutions were identified by the Company. The Company's estimated costs of the transmission solution to integrate the three Yates CTs was reduced by roughly $20 million to approximately $60 million. Daymark's review of these upgrades will be discussed in more detail in the following sections.

The Company also concluded that certain supply options did not require transmission upgrades. These supply options included a Power Purchase Agreement ("PPA") with Mississippi Power Company ("MS PPA"), a PPA with the Santa Rosa Energy Center LLC ("Santa Rosa PPA"), as well as up to 600 megawatts ("MW") of capacity at the Plant Yates site. The Company also concluded that it could incorporate up to 1,000 MW of battery

energy storage systems ("BESS") at various locations[5] without needing transmission upgrades.

In addition to these conclusions regarding the potential need for transmission upgrades, the Company's analysis was also used to rule out certain generation projects. Specifically, the Lindsay Hill PPA was eliminated as an option because the transmission screening determined that required transmission upgrades could not be completed in time to meet the anticipated capacity need.

Q. HOW DID THE COMPANY CHARACTERIZE THE STATE OF THE FILING BEFORE THE ADDITIONAL ANALYSIS WAS MADE AVAILABLE?

A. During the November 27th technical conference, the Company also provided some responses to informal requests made by Staff. In those responses, the Company characterized the IRP Update filing as "complete"[6] without the supplemental analysis. Furthermore, the Company stated that "Since the Company needed to move quickly on its filing, the full transmission investment required will be filed subsequently in January as a supplemental filing. Staff has been provided preliminary information to assist with their review of the transmission impacts and the Company will provide the remainder of the information in January."[7]

[5] The locations of the 1,000 MW include publicly identified, trade secret but identified and more generally targeted locations. The Company's conclusion was that for all of those known and estimated locations, existing transmission would be sufficient to bring the new BESS online.
[6] PSC Informal Transmission Request – GPC Responses, response to question 4.
[7] Ibid.

Q. HOW DID DAYMARK CONSIDER THE TWO ANALYSES GIVEN THIS CHARACTERIZATION?

A. Daymark reviewed both sets of analyses and offers observations and conclusions regarding each. However, we consider the transmission request to be predominantly based on the Transmission Screening Analysis. The loads in that analysis are those the Company has testified to as being the most concerning from a timing perspective. Additionally, the supplemental analysis, while producing different line loadings, did not identify any new transmission needs that had not previously been identified in the Transmission Screening Analysis.

III. DISCUSSION OF THE TRANSMISSION SCREENING ANALYSIS AND RESULTS

Q. PLEASE DESCRIBE THE DRIVERS FOR THE SCREENING ANALYSIS IN THE 2023 IRP UPDATE.

A. As presented by the Company, the update to the 2022 IRP was produced to meet the growing electrical demands occurring in Georgia. Largely driven by policy and emerging industries, the expected load forecast has increased significantly – with the Company projecting growth of 6,600 MW by 2030.[8] To meet this increase, Georgia Power stated that

[8] Georgia Power Company. 2023 Integrated Resource Plan Update. October 2023. Docket 55378, p. 10.

it needed to act quickly[9] to procure generation supply and upgrade the transmission grid to ensure the reliable integration of this new load and supply. The 2023 IRP Update describes the Company's forecast of:

- The magnitude of economic growth occurring in Georgia.
- The changes in the load caused by the forecasted rapid economic growth.
- The capacity needs resulting from the growth and the advancement of this capacity need.
- Plans to address the state's rapidly growing energy needs.

Q. PLEASE DESCRIBE THE SCREENING ANALYSIS PERFORMED BY GEORGIA POWER COMPANY IN THE 2023 IRP UPDATE.

A. A set of supply options and transmission upgrades were identified as potentially feasible means to serve the Company's projected capacity need. The updated loads and supply options served as the basis for the Transmission Screening Analysis[10]. The Company performed transmission screens for various generation resource options under consideration by the Company to support its generation resource needs. This analysis was performed by utilizing PSS/E, an industry standard planning tool, to identify thermal overloads caused by the new loads and assumed supply when tested under a standard set of seasonal base cases with stressed conditions applied. The development of these base cases is a typical step in transmission planning studies such as these, and they are designed

[9] Georgia Power stated in its responses to PSC Informal Transmission Requests that the generation portfolio wasn't finalized until October 2023. The initial transmission analysis was provided by the end of that month.

[10] See slide deck entitled "2023 GPC IRP Update: Transmission Planning Analysis Overview" presented by the Company in a Technical Conference on November 27, 2023.

to test the impact of changes to the system (new load, new and retired generation, new transmission, etc.) in the conditions that are most likely to result in a reliability violation. The seasonal base cases used by the Company in this analysis were a limited set compared to the complete list that is typically used in the Company's long-term transmission studies. For this analysis, the base cases modeled were:

Name	Abbr.	Load Level	Solar	Hydro	MISO Transfer
Summer Peak	S	Summer Peak	On	On	1000 S ⇒ N
Off Peak	O	Off Peak (70%)	On	Motor	1000 S ⇒ N
Daylight Shoulder	D	Shoulder (93%)	On	Motor	1000 S ⇒ N

- Summer Peak – This case represents the highest summer loading conditions for the planning horizon. Hydro units are online.
- Off Peak – This case developed with approximately 70% of the Summer Peak Demand. In this case, hydro generation acts as a synchronous condenser to supply voltage support to the grid – otherwise known as 'motoring' however they are not providing a significant supply of MW.
- Daylight Shoulder – This case represents the hour of the seasonal peak day just before hydro units ramp up. This case utilizes approximately 93% of the Summer Peak load. As in the Off Peak case, the hydro generation is acting as a synchronous condenser.

Q. WHICH GENERATION OPTIONS WERE EVALUATED IN THE SCREENING ANALYSIS?

A. According to the Company, the following supply scenarios were tested[11]:

Scenario	Description
Base	Includes all large loads which have selected Georgia Power (v2 base cases) and prior queued projects.
A1	Base scenario with other retail operating company potential unit extensions and the following Georgia Power resource extensions: • Gaston 1-4, Bowen 1-4, and Scherer 3 available through 2035 Base scenario with the following potential power purchase agreements ("PPAs"): • Lindsay Hill (895MW) years 2026-2035 • Santa Rosa (225MW) years 2024-2028
A2	Scenario A1 with Lindsay Hill PPA starting on 5/2029 (due to transmission constraints and project timing limitations)
B	Scenario A1 with proposed Yates CTs and their respective commercial operation dates: • 2 Units – 11/2026 • 1 Unit – 2/2027
C	Scenario B with proposed 200MW battery energy storage systems ("BESS") co located with 200MW solar project at [redacted] Solar.

[11] November 27th Technical Conference presentation, slide 9

As can be seen in the table above, the later scenarios built upon earlier ones. Scenario C was the final cumulative scenario in the screening analysis and produced the recommended transmission solutions.

Q. WHAT WERE THE FINAL SET OF SUPPLY OPTIONS STUDIED IN SCENARIO C?

A. According to the Company's technical presentation, the new supply studied in Scenario C are as follows:

- Mississippi Power PPA through 2028
- Santa Rosa PPA through 2028
- Yates CTs beginning 2026/2027
- BESS co-located with MW Solar (location is Trade Secret)

In addition to the new supply, the following units, originally designated for retirement by 2028 by the 2022 IRP Order[12] have been assumed to be extended in the transmission analyses as follows:

- Gaston Units 1-4 extended until 2035.
- Scherer Unit 3 extended until 2035.

[12] Docket No. 44160, Order Adopting Stipulation, July 29, 2022.

Q. FOR THOSE UNITS ASSUMED TO HAVE LIFE EXTENSIONS, WERE THEY DISPATCHED IN CASES THAT IDENTIFIED TRANSMISSION NEEDS?

A. Yes. [redacted]

Q. PLEASE DESCRIBE THE RESULTS OF THE SCREENING ANALYSIS.

A. The Company's Screening Analysis focused on the transmission upgrades that were identified as necessary to reliably use the supply options available to serve the Company's projected incremental load. The analysis determined that Mississippi Power Company PPA can be accommodated along with the PPA for capacity and energy from the Santa Rosa combined cycle facility with no required transmission project upgrades. Additionally, the Company determined that the proposed 200 MW of solar co-located with 200 MW of BESS did not require any transmission projects to accommodate the facility's full output. The initial transmission screens to fully deliver the combustion turbines proposed at Plant Yates revealed approximately $80 million in additional transmission upgrades to accommodate the full capacity of the facility. The transmission options considered in developing the proposed solution were limited only to "the use of operating guides,

generation redispatch, and transmission line rebuilds/reconductors to alleviate identified constraints."[13]

IV. DISCUSSION OF UPDATED TRANSMISSION ANALYSIS AND RESULTS

Q. CAN YOU DESCRIBE THE SUPPLEMENTAL ANALYSIS THAT WAS FILED IN JANUARY 2024?

A. The Supplemental analysis, filed on January 12, 2024, provided more power flow analysis on additional cases to reflect the 2023 IRP Update load forecast. In addition to the case modeling committed loads, the supplemental analysis added roughly [redacted] additional load for a total of nearly [redacted] of load growth. The supplemental filing evaluated the same portfolio of generation resources included in the 2023 IRP update.

According to the updated Supplemental Filing as filed on January 12, 2024, the transmission planning analysis was performed for the years 2024 through 2033. The study was performed using 2023 version 2 load flow cases with different seasonal cases: Summer- Peak, Off-Peak and Daylight Shoulder. The load level included in the 2023 version 2 base cases was [redacted] and the 2023 IRP Update forecasts [redacted] of load levels including committed and potential customer choice loads.

[13] Company response to STF-DEA-4-2.

Q. FOR THOSE UNITS ASSUMED TO HAVE LIFE EXTENSIONS, WERE THEY ALSO DISPATCHED IN THE JANUARY ANALYSIS?

A. Yes, at least some of them were. For example, [redacted]

Q. PLEASE DESCRIBE THE RESULTS OF THE JANUARY ANALYSIS.

A. In the Supplemental Filing the Company reaffirmed its position that the PPAs with Mississippi Power and Santa Rosa Energy Center can be accommodated without any transmission upgrades. A $19,334,000 reduction from $79,204,000 to $59,870,000 in the transmission upgrades cost attributable to the Yates CTs was noted from Transmission Screening Analysis filed as part of the 2023 IRP update. This change was not the result of any change in solution, but rather a correction in the amount of cost attributable to the Yates CT generation. Some of the Yates Attributable Transmission Projects were previously identified in the Company's Ten-Year Plan, so the cost of these projects attributable to the Yates CT request is the cost of accelerating the projects that are being proposed by the Company.

The analysis also determined that the Yates CTs will be limited to 600 MW of firm output until the required transmission upgrades are in service by the summer of 2028.

Additionally, the updated analysis limits the [redacted] BESS & Solar project to 200 MW output until the summer of 2029 when all prior planned transmission projects are in service.

V. DISCUSSION OF TRANSMISSION ANALYSIS AND TRANSMISSION UPGRADES FOR PLANT YATES

Q. PLEASE LIST THE TRANSMISSION PROJECTS ASSOCIATED WITH BRINGING THE THREE COMBUSTION TURBINES ONLINE AT PLANT YATES.

A. As provided in response to STF-DEA-4-1, the following projects were identified as being required to support the deliverability of the 1,350 MW of capacity from the Plant Yates turbines:

Project #	Project Description	Planning Grade Estimate	Lead – Time (months)	Need Date
P1	[redacted]	[redacted]	48	11/2026
P2	[redacted]	[redacted]	48	5/2027
P3	[redacted]	[redacted]	24	5/2027
P4	[redacted]	[redacted]	48	5/2027
P5	[redacted]	[redacted]	48	5/2027
P6	[redacted]	[redacted]	42	5/2027
P7	[redacted]	[redacted]	42	5/2030
P8	[redacted]	[redacted]	36	5/2032
	Total =	**$59,870,000**		

Q. BASED ON YOUR ANALYSIS, DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S CONCLUSIONS REGARDING THESE PROJECTS?

A. Yes, we do. Given the system assumptions modeled in the Company's analysis, we have the following concerns and observations:

i) Both analyses assume extensions of certain power plants targeted for retirement by the end of 2028. While the Company is saying that it plans to re-evaluate those retirements in the 2025 IRP[14], the assumption of an extension for each of those units in this analysis biases the results and assumes a result of the 2025 IRP with respect to those units that is unsupported in the record.

ii) Project 7, which is a plan to accelerate a previously approved project by one year, is not clearly shown as necessary in the Transmission Screening Analysis.

iii) Project 8, which is a rebuild of a line near the proposed Yates CTs, is not needed for 8 years and the thermal loadings in the Transmission Screening Analysis do not show a clear need for a decision on this project at this time.

iv) The remaining projects' needs are impacted by the assumed need for all three CTs to be constructed at Plant Yates. To the extent that the need for capacity can be mitigated, Projects 2-6 may not be necessary, or at least may not be most cost effective. If it is determined that the need for all three CTs has not been established, then additional analysis would be warranted before moving to approval of the associated transmission projects.

[14] Witness Grubb during the January 17, 2024 hearings: "In the 2022 IRP, the Commission approved a decertification of Plant Gaston in Alabama by the end of '28 and Scherer 3 by the end of '28. We will re-address those and reevaluate those in the 2025 IRP, but our capacity plan shows those retirements", page 0561, lines 20-25.

We will discuss these in more detail in the following sections.

VI. THE INCLUSION OF THE ASSUMED EXTENSION UNITS DESIGNATED FOR RETIREMENT IN THE 2022 IRP BIASES THE RESULTS OF THESE ANALYSES

Q. WHY IS THE INCLUSION OF THESE UNITS IN THE ANALYSIS PROBLEMATIC?

A. As discussed in Sections III and IV above, there are a few units that were ordered to be retired by the end of 2028 that the Company has indicated "the Company will likely evaluate extending the operation of certain units, particularly Plant Scherer Unit 3, beyond 2028. This evaluation will include updated unit retirement studies for these units in the 2025 IRP and may recommend extending their operation. In the 2025 IRP, the Company will make a formal recommendation at that time regarding the retirement or extended operation of the units."[15] For the purposes of the transmission analyses presented in the 2023 IRP Update, these units were assumed extended until 2035. This produces a disconnect between the capacity currently being assumed as online and available beginning in 2029 for supply purposes as compared to the capacity available for dispatch in determining transmission need.

The assumed extension of these units means there is close to 2,000 MW online in the transmission analysis that is currently not in the Company's long-term resource plan. The ability to run these units changes the dispatch utilized by transmission planners for their

[15] 2023 Integrated Resource Plan Update, Page 27

base cases and for the testing of new loads and supply. It is impossible to identify how thermal loading would be affected by the exclusion of these units without running all cases with them unavailable starting in 2029. At a minimum this calls into question the transmission needs identified for 2029 and further out.

VII. THE TIMING AND MAGNITUDE OF THE NEED FOR PROJECT 7 SUGGESTS THE REQUESTED EXPENSE TO ADVANCE THE PROJECT ONE YEAR BE DENIED

Q. PLEASE DESCRIBE THE OVERLOADS IDENTIFIED AND SOLUTIONS PROFFERED BY THE COMPANY RELATED TO THE COMPANY'S IDENTIFED PROJECT 7.

A. The Company's response to TS STF-DEA-4-1 lists an overload associated with Project 7 as [redacted] transmission line, given an outage of the [redacted]. This [redacted] transmission line is a section of the [redacted] transmission line. With the observed overload of the line section, the Company is recommending that [redacted] transmission line be reconductored in 2030. This line was already scheduled to be reconductored in 2031 based on the Company's existing transmission plan, so the incremental cost attributable to the IRP Update proposal is [redacted], which is the incremental cost to advance the project by one year. The total project cost is [redacted].

Q. HAS THE COMPANY ESTABLISHED A CLEAR NEED FOR PROJECT 7 AT THIS TIME?

A. No. The worst-case overload related to the Project 7 solution occurs in a scenario which represents a [redacted]. However, the thermal loading issue in question does not occur until 2030 and is at [redacted] in the Transmission Screening Analysis and only increases to [redacted] of its thermal rating in the January update. Furthermore, these overloads are occurring in years where the modeled dispatch is in question pending a resolution of the final status of the units targeted for retirement in the 2022 IRP Order.

The project itself is simply a one-year advancement of a previously approved project. Under the circumstances, there appears to be insufficient evidence in the record of the need to incur additional costs to advance the project one year. Given that the Company identifies the lead time for Project 7 at 42 months, the Commission should defer consideration of this upgrade until the 2025 IRP proceeding.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO PROJECT 7?

A. We recommend the requested expense to advance the project one year be denied at this time. Determination of whether Project 7 remains the optimal solution to any future transmission needs should be considered as part of the Company's full 2025 IRP.

VIII. THE TIMING AND MAGNITUDE OF THE NEED FOR PROJECT 8 SUGGESTS THE REQUESTED EXPENSE BE REJECTED PENDING A MORE COMPLETE ANALYSIS IN THE NEXT IRP

Q. PLEASE DESCRIBE THE OVERLOADS IDENTIFIED AND SOLUTIONS PROFFERED BY THE COMPANY RELATED TO THE COMPANY'S IDENTIFED PROJECT 8.

A. TS STF-DEA-4-1 lists an overload associated with Project 8 as a [redacted] transmission line, given an outage of the [redacted] transmission line. This [redacted] transmission line is a section of the [redacted] transmission line. With the observed overload of the line section, the Company is recommending that the [redacted] transmission line be rebuilt with a [redacted] cost. The overloads in question begin in 2032 and are approximately [redacted] of its normal thermal rating. Like the overloads associated with Project 7, these overloads also occur in years implicated by the uncertainty regarding the units designated for retirement in the 2022 IRP Order.

Q. HAS THE COMPANY ESTABLISHED A CLEAR NEED FOR PROJECT 8 AT THIS TIME?

A. No. The worst-case overload related to the Project 8 solution occurs in a scenario which represents a [redacted]. However, the overload in question does not occur until eight years from now, and the line in question is only approximately [redacted] overloaded. The solution being proposed

has a 36-month lead time, which provides the latitude to delay a final decision until the 2025 IRP which allows for full study of future transmission needs.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO PROJECT 8?

A. Such a small overload so far in the future suggests that the Company has time to incorporate this potential issue in a fuller study of the transmission needs of their system. We recommend that the requested project be denied and that the potential need for this or other similar projects be considered in the 2025 IRP.

IX. DISCUSSION OF DAYMARK'S ANALYSIS ON TRANSMISSION UPGRADES FOR PLANT YATES

Q. DID THE COMPANY PROVIDE ANY DATA INDICATING A STUDY OF PLANT YATES OUTPUT LIMITED TO LESS THAN THE FINAL COMPANY PLAN OF THREE UNITS??

A. No. The two rounds of transmission screening analysis results did not produce any analysis of Plant Yates combustion turbines below the full capacity of 1,350, or three CTs[16].

Q. PLEASE DESCRIBE THE ANALYSIS THAT WAS CONDUCTED BY DAYMARK.

A. The team used the provided power flow files from the transmission screening analysis and supplemental transmission filing, reducing the output of the modeled Plant Yates output from 1,350 MW to 900 MW. The team did not alter the modeled generation dispatches in

[16] Per the Company's technical filing, each CT has a capacity of 450 MW while burning natural gas. This capacity is what was modeled in the transmission cases.

any other way, using the modelled slack bus to account for additional generation. The team analyzed the five scenarios indicated in TS STF-DEA-4-1, which were deemed as worst-case scenarios for establishing the transmission upgrades needed to support the Plant Yates output at 1,350 MW. The same scenarios, or their close counterparts, from the January analysis were used to investigate the decrease in output.

Q. PLEASE DESCRIBE THE OVERLOADS IDENTIFIED WHEN YATES OUTPUT IS LIMITED TO THE CAPACITY OF TWO CTS IN THE DAYMARK ANALYSIS.

A. With respect to the project justifications identified in TS STF-DEA-4-1, the Daymark analysis showed line loadings are reduced by approximately 3.5 to 9.5% as follows:

Project	Constraint	Contingency	Rating (MVA)		Case	*Yates 1350*	*Yates 900*	*Percent Change*
			Summer	Winter				
P2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
P3			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
P3			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
P4			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
P5			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
P6			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

P6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
P7			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
P8			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. WHAT DID THE ANALYSIS INDICATE REGARDING THE POTENTIAL IMPACT OF A DECISION REGARDING TWO VERSUS THREE CT UNITS AT YATES?

A. The thermal analysis results when Plant Yates is limited to an output of 900 MW show a drop in thermal loadings for all impacted elements that drove the transmission need. While the Daymark analysis is indicative only, it does show that the third Yates CT has a material impact on the determination of need from a thermal loading perspective. Most notably, the impacts on the P8 line upgrade [redacted] are reduced to [redacted] in our analysis with only 900 MW dispatched at Yates. This is a nearly 5% reduction in thermal loading from [redacted] noted in the Screening Analysis. This analysis suggests that, should the third CT not be necessary, it is possible that some of the transmission solutions identified by the Company might also be unnecessary or that other solutions might be more cost effective.

X. OTHER OBSERVATIONS REGARDING THE SCOPE AND SCALE OF THE TRANSMISSION ANALYSIS PERFORMED

Q. PLEASE SUMMARIZE YOUR OBSERVATIONS REGARDING THE COMPANY'S TRANSMISSION ANALYSIS AND CONCLUSIONS.

A. Given the Company's characterization of the immediacy of the incoming load and the timing for completing analysis of options to serve that load, transmission analysis was necessarily limited as compared to a complete study as would occur in a standard planning cycle. This limitation did not lead to improper transmission planning analysis but did curtail the ability of the planners to fully consider options and to test for the resilience of the plan to uncertainty. Specifically, we observe that:

1. Transmission solution options considered were limited and did not include newer technologies and approaches that could provide rapid, more cost-effective solutions to some needs.
2. The analysis did not include an evaluation of the voltage and stability impacts of the proposed options to serve the load, nor did it include the cost for any reactive devices. Static synchronous Compensators ("STATCOMs"), Static VAR Compensators ("SVCs"), or other equipment needed to provide voltage support if deemed necessary.
3. There was limited modeling of key uncertainties including variations on the timing, location or volume of load or the potential impact of various retirement scenarios on potential future transmission needs.

Q. WHAT ALTERNATIVE SOLUTIONS DID THE COMPANY NOT CONSIDER?

A. Based on Daymark's analysis, the Company did not provide sufficient evidence of considering alternatives to traditional solution options that could be more cost-effective to the Company's proposed transmission upgrade projects filed in the 2023 IRP Update on January 12, 2024. Potential alternative solutions include FACTS devices, and other non-wires alternatives, such as dynamic line rating capabilities.

Q. PLEASE DESCRIBE POTENTIAL ALTERNATIVE SOLUTIONS TO THE TRANSMISSION UPGRADES ASSOCIATED WITH PLANT YATES.

A. Customers who are required to pay for transmission understandably want assurance that the existing cables are being used to their maximum capacity. The state regulators should ensure that efficient, low-cost options are being evaluated by the Company to achieve maximum ratepayer benefit from existing transmission assets. There are a set of technologies that can increase the flexibility, reliability, and utilization of the existing grid. While the Company's transmission planners may be aware of these technologies, stakeholders lack evidence of their consideration for this IRP update.

There are a number of emerging transmission technologies which may offer cost effective, expedient, and flexible solutions to the transmission issues that the Company has highlighted in this IRP update.

Dynamic Line Ratings, ("DLR") are designed to allow increases in the thermal limits of existing transmission lines. DLR supports grid resilience by offering condition-based line capabilities when contingencies occur.[17]

Topology optimization software is a technology that can be identify line reconfigurations and potential switching scenarios that can lead to a more robust operations solution to alleviate thermal loading conditions. While there is evidence that the Company has implemented several operating solutions to thermal loading concerns, the framework under which they have been evaluated has not been documented.

Flexible AC Transmission System Devices ("FACTS") devices can help push or pull power away from overloaded lines and onto underutilized lines. FACTS devices such as phase angle regulating transformers and thyristor-controlled series capacitors are proven technologies that can make the transmission system more flexible and able to react to shifting load patterns. By adjusting the voltage, phase angle, or impedance, the characteristics of the transmission grid can be changed to optimize the load flow on the grid, potentially unlocking capacity on the existing transmission lines.

Q. DID THE COMPANY PRESENT INFORMATION RELATED TO RISKS OTHER THAN THERMAL LOADS IN THIS DOCKET?

A. No. From the provided materials, no evidence was shown that the Company performed any analysis beyond thermal in their Screening Analysis.

[17] Jake Gentle, Warren Parsons, Michael West, Catherine Meibner, Philip Anderson, "Increasing Transmission Capacities By Dynamic Line Rating Based on CFD." https://watttransmission.files.wordpress.com/2017/11/2015_awea_dlr_validation_final.pdf

Q. FROM A TRANSMISSION PLANNING PERSPECTIVE, WHAT OTHER COSTS COULD HAVE BEEN EVALUATED IN THE ANALYSIS?

A. Both analyses were thermal studies, meaning they studied the potential for changes in the system to overload individual elements. To determine the full transmission impact of new generation plants and retirements, voltage and stability analysis should be performed as well. With the implementation of new solar, BESS plants and plant retirements on the horizon, there could be a scenario where additional voltage or reactive power support is needed to maintain a reliable and robust transmission system. Stability issues are typically resolved by implementing a dynamic reactive device ("DRD") that can react to system changes within cycles and provide the system with voltage support under contingency conditions.

The screening process implemented in this IRP update, from the evidence provided, does not evaluate the implications of possible upgrades needed to address any voltage, or stability issues nor does it delve into if voltage or stability issues were observed.

It is our understanding that these additional studies are a normal part of the Company's IRP process and therefore will be performed for the 2025 IRP. Until that time, there is no guarantee that the proposed set of generation and transmission solutions do not have additional transmission costs beyond those identified by the Company for solving thermal loading issues.

Q. HOW DOES THE RETIREMENT OF CONVENTIONAL GENERATION UNITS AFFECT GRID STABILITY AND VOLTAGE?

A. Conventional units, such as coal, natural gas, and hydroelectric generators provide essential inertia and reactive power to the grid largely due to their rotating mass. The retirement of these units would lead to a reduction in system inertia, making the grid more susceptible to frequency and voltage fluctuation. In turn, this could lead to the need for the development of new substations, line reconfigurations or new sources of reactive power support, including through dynamic reactive devices such as SVCs or STATCOMs to compensate for the loss of voltage regulation previously provided by the retired units.

Q. HOW DO THE LIMITATIONS ON SCENARIO ANALYSIS IMPACT THE COMPANY'S RECOMMENDATIONS?

A. There are risks related to either overstating or understating the range of inputs that are key drivers of transmission need. For example, load may grow faster or more slowly than forecast. It might differ in location or timing. Retirements may occur as currently planned or on a different schedule. Clean energy can be expanded at faster or slower rates and can occur in different locations within the state. All these uncertainties can have a significant impact on power flows and therefore on future transmission needs.

This can lead to suboptimal project design, building either too little or too much transmission relative to future needs. The risks of building too much transmission are clear: building transmission upgrades that are not ultimately needed will impose costs on ratepayers without providing value. There is also risk that the Company could decide to

pursue a certain set of upgrades based on a limited evaluation of scenarios, and then loads ultimately grow in such a way that a larger transmission solution may have been the optimal choice. This also represents a risk to customers of suboptimal deployment of investment dollars.

This uncertainty is at the heart of all IRP work and is a primary reason why plans that provide optionality are preferred over singular solution sets. Allowing for a feedback loop that can learn as trends in key variables unfold can reduce the risk of regretted decisions by delaying decisions until the point at which they need to be made, therefore increasing the amount of information available for each decision.

Q. GIVEN THE UNCERTAINTY IN THIS DOCKET, WHAT DOES THIS MEAN FOR THE COMPANY'S TRANSMISSION PLANNING?

A. Given the wide range of potential future outcomes, the impact of potentially doing the wrong thing could exceed the impact of doing nothing in this IRP Update proceeding, particularly with respect to the transmission related to the Plant Yates CTs. The Company is likely to learn a great deal with respect to how quickly their counterparties are turning to building the infrastructure these loads represent. The 2025 IRP will be another opportunity to investigate the needs and costs of serving that load and could provide clarity as to what generators should be assumed available for what timeframe. Also, a full IRP will provide more opportunity to optimize transmission solutions, whether larger or smaller.

Deciding these matters in this docket means doing so with only a limited amount of concrete information, and significant uncertainty regarding the location and timing of load

materialization and the future operation of existing resources. All these factors have a significant impact on the outcome of transmission analyses, and the Company has not conducted sufficient scenarios to support a comprehensive assessment of potential future conditions. Deciding on project capital spending should be a last resort when dealing with this much uncertainty.

Whether the 2025 IRP confirms the transmission solution as optimal or produces a different solution set due to additional information, in either case, stakeholders will have more confidence in the results.

XI. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Our recommendations are as follows:

1. We recommend that, pending resolution of the need for 3 Plant Yates CTs and the resolution of retirement dates of the units the Company has questioned in its 2023 IRP Update, that the question of advancing transmission solutions in support of the Plant Yates CTs be delayed and restudied in the 2025 IRP.
2. Should the question of the need for Plant Yates CTs be resolved in the affirmative in this docket, we separately recommend the following:
    a) The requested expense to advance Project 7 by one year should be denied. Determination of whether Project 7 remains the optimal solution to any

future transmission needs should be considered as part of the Company's full 2025 IRP.

b) Project 8 should be denied and the potential need for this or other similar projects should be reconsidered as part of the 2025 IRP transmission analysis.

3. The Company should consider expanding its potential transmission solutions to include non-wires alternatives as well as new substations and/or right of way solutions to ensure a robust test to find the most cost-effective solution.

Q. DOES THIS CONCLUDE STAFF'S TESTIMONY?

A. Yes.

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 55378**
2023 INTEGRATED RESOURCE PLAN	**)**	
UPDATE	**)**	

PUBLIC DISCLOSURE

DIRECT TESTIMONY

AND EXHIBITS

OF

MICHAEL S. GOGGIN

On Behalf of the

Georgia Public Service Commission
Public Interest Advocacy Staff

February 15, 2024

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Exhibit	Description
MG-1	Michael S. Goggin Background and Qualifications
MG-2	Georgia Power's response to data request STF-GS-1-1 in this docket
MG-3	Georgia Power's response to data request STF-GDS-4-7.e. in the 2022 IRP (Docket No. 44160)
MG-4	Georgia Power's responses to data requests STF-GS-1-8 and STF-GS-1-9 in this docket
MG-5	Georgia Power's response to data request STF-GS-1-7 in this docket

I. Introduction

Q. PLEASE STATE YOUR NAME AND JOB TITLE.

A. Michael S. Goggin, and I am a Vice President at Grid Strategies, LLC, a consulting firm based in the Washington, DC, area.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit MG-1. This exhibit summarizes my relevant experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am testifying on behalf of the Georgia Public Service Commission ("the Commission") Public Interest Advocacy Staff ("Staff").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION OR OTHER UTILITY REGULATORY BODIES?

A. Yes. I have testified before the Georgia Commission in the last three Georgia Power Integrated Resource Plan ("IRP") cases, in 2022, 2019, and 2016. I have also testified before state utility commissions in Arizona, Colorado, Illinois, Indiana, Iowa, Kentucky, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Virginia, Washington, and Wisconsin, as well as before the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address transmission-related aspects of Georgia Power

Company's ("Georgia Power's or "the Company's") 2023 IRP Update.

In Section II, I discuss the Company's proposed transmission upgrades to accommodate the addition of the Yates Combustion Turbines ("CTs"). Georgia Power acknowledges that it failed to consider alternatives like battery storage, demand response, and grid-enhancing technologies that can be deployed quickly and can cost-effectively reduce or eliminate the need for these grid upgrades. These can help serve as interim solutions until the Company can plan and complete the longer-term transmission expansion discussed in the next section of my testimony.

In Section III, I recommend a more effective transmission planning process that the Commission can require Georgia Power to adopt. Specifically, other regions have found proactive multi-value transmission planning results in large savings for ratepayers by maximizing net benefits to ratepayers and achieving economies of scale through investment in higher-capacity transmission. This approach optimizes the multiple benefits of transmission including accessing lower-cost generation, in contrast to Georgia Power's sole focus on meeting reliability criteria. It also proactively plans upgrades to meet expected changes in the generation mix and load growth over the long-term, and is co-optimized with generation planning, in contrast to Georgia Power's reactive transmission planning that is focused on the near term.

In Section IV, I highlight how the Company applying to interconnect the Yates CTs using Energy Resource Integration Service instead of Network Resource Interconnection Service creates risk that the Yates CTs will be curtailed during periods of peak need, limiting their value as capacity resources.

Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. In addition to my qualifications, which are in Exhibit MG-1, I have attached Exhibits

MG-2 through MG-5 which contain responses to discovery and other materials referenced in my testimony.

Q. WHAT IS SHOWN IN EXHIBIT MG-2?

A. Exhibit MG-2 is the Company's response to data request STF-GS-1-1 in this docket, in which Georgia Power confirms that "The Company did not study Battery Energy Storage Systems ("BESS") as options to reduce, defer, or eliminate the transmission upgrades identified in the 2023 IRP Update to facilitate the delivery of power from the proposed Plant Yates combustion turbines."

Q. WHAT IS SHOWN IN EXHIBIT MG-3?

A. Exhibit MG-3 contains Georgia Power's response to data request STF-GDS-4-7.e. in the 2022 IRP (Docket No. 44160), stating that "Alternative solutions such as energy storage or distributed energy resources have not been considered yet for various reasons." Those reasons include "the magnitude of storage or DER that would be needed makes those options untenable."

Q. WHAT IS SHOWN IN EXHIBIT MG-4?

A. Georgia Power's responses to data requests STF-GS-1-8 and STF-GS-1-9 in this docket, indicating that the Company does not evaluate demand response as a potential solution to localized transmission needs.

Q. WHAT IS SHOWN IN EXHIBIT MG-5?

A. Georgia Power's response to data request STF-GS-1-7 in this docket, in which the Company refers to Technical Appendix Volume 3 of the 2022 Georgia Power IRP (Docket No. 44160) to describe the transmission planning methods that were used in the 2023 IRP Update.

II. The Company did not adequately evaluate alternatives that can reduce or eliminate the need for the Yates transmission upgrades

Q. WHAT ALTERNATIVES TO ITS PROPOSED TRANSMISSION EXPANSION DID THE COMPANY EVALUATE?

A. The Company explains that it only evaluated reconductoring, generation redispatch, or operating guidelines as an alternative to transmission expansion.[1] As outlined below, the Company admits that it did not evaluate the use of battery storage, demand response, and grid-enhancing technologies as an alternative to the transmission expansion. As I explain in the following sections, these technologies, alone or in combination, offer significant potential to reduce or defer the need for transmission expansion capital investment. Battery storage and demand response can serve as both generating capacity resources and as solutions to alleviate localized transmission constraints, so they could both reduce the need for the Yates transmission upgrades and the Yates CTs themselves.

Q. HOW CAN BATTERY STORAGE, DEMAND RESPONSE, AND GRID-ENHANCING TECHNOLOGIES REDUCE THE NEED FOR TRANSMISSION UPGRADES?

A. These solutions can be deployed in load pockets or other congested parts of the grid, alleviating the need for transmission upgrades to deliver power into those areas during short-duration peak demand periods or system contingency conditions. All of these solutions are particularly viable alternatives for the upgrades Georgia Power claims are needed to deliver power from the Yates CTs to new loads during contingency events, such as the loss of a large generator and/or transmission system element. The transmission

[1] For example, see the January 16-17, 2024 hearing transcript in this docket ("Hearing Transcript") at page 257: "we looked at alternatives such as operating guidelines, redispatch, and then reconductering and rebuilding."Also see the question and answer at pages 342-343: "Did the company evaluate whether storage as a transmission solution could overcome those transmission barriers?

A (Witness Grubb) We did not. In the transmission screening, we looked at -- as we mentioned this morning, redispatch, operating guidelines, reconductoring."

upgrades Georgia Power claims are needed for the Yates CTs were triggered by [redacted]. Alone or in combination, battery storage, demand response, and grid-enhancing technologies are ideal for meeting these types of short-duration needs. These solutions respond quickly, [redacted].

Importantly, these solutions can defer the need for grid upgrades until longer-term, higher-capacity transmission upgrades can be completed. As discussed in the second part of my testimony, higher-capacity long-term transmission upgrades planned using proactive multi-value transmission planning are likely to be significantly more cost-effective than the Company's proposed near-term transmission upgrades. This could also buy time for the Company to bring online more cost-effective generation and capacity resources, and the transmission required to deliver them to load.

A. Georgia Power did not evaluate how batteries can alleviate the need for the proposed transmission upgrades

Q. DOES GEORGIA POWER OFFER A REASON WHY IT DID NOT EVALUATE BATTERY STORAGE AS AN ALTERNATIVE TO THE PROPOSED TRANSMISSION UPGRADES?

A. Yes. In response to discovery, the Company explains that it did not evaluate the potential to use battery storage to reduce or eliminate the need for transmission upgrades to accommodate the proposed Yates CTs.[2] The Company argues that it did not evaluate batteries as a solution for transmission upgrades because the need to charge batteries causes

[2] Please see the Company's response to data request STF-GS-1-1, attached to my testimony as Exhibit MG-2: "The Company did not study Battery Energy Storage Systems ("BESS") as options to reduce, defer, or eliminate the transmission upgrades identified in the 2023 IRP Update to facilitate the delivery of power from the proposed Plant Yates combustion turbines."

them to serve as a load.[3] This assumption is flawed, as the charging and discharging of storage resources is economically dispatched in response to system needs, so that batteries never charge and always discharge during periods of need. In fact, FERC Order 2023 now requires transmission service providers like Georgia Power to allow storage interconnection customers to specify charging and discharging behavior,[4] reflecting that interconnection upgrades are typically not needed to accommodate charging because batteries can be dispatched so that they do not charge during periods of peak transmission system usage.

Due to batteries' speed of dispatch, the ability of their power electronics to regulate voltage and reactive power and address local stability concerns, and their ability to be quickly deployed at points on the grid where they are needed, battery storage can be an effective alternative to transmission upgrades, particularly upgrade needs triggered by contingency conditions.[5] Batteries also serve as capacity resources, reducing the need for the Company's proposed generation additions including the Yates CTs.

Q. CAN BATTERIES BE DEPLOYED QUICKLY ENOUGH TO MEET THE NEAR-TERM NEEDS CLAIMED BY GEORGIA POWER?

A. Yes. Georgia Power correctly notes this benefit, writing that "The time to construct BESS is shorter than other types of generation and, therefore, can be more quickly deployed to help meet the earlier capacity needs identified in the 2023 IRP Update. Moreover, the Company's Resource Mix Study, provided in the Technical Appendix, selects BESS as an economically optimal resource beginning in the winter of 2026/2027…"[6] Modeling by

[3] For example, see Witness Grubb's statement in the Hearing Transcript at page 343: "We don't usually look at batteries as a potential to remove transmission projects mainly because they have to be charged and so they serve as a load. So most of our transmission contingencies are not usually solved with a battery."

[4] FERC, *Order 2023*, (July 2023), *available at* https://www.ferc.gov/media/e-1-order-2023-rm22-14-000, at 17

[5] See Brent Oberlin, *Storage as a Transmission Only Asset*, (May 2022), *available at* https://www.iso-ne.com/static-assets/documents/2022/05/a7_storage_as_a_transmission_only_asset.pdf, at 11-15; and Quanta Technology, *Storage as Transmission Asset Market Study*, (January 2023), *available at* https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf

[6] Direct Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush on behalf of Georgia Power Company, Docket No. 55378, at 37

Staff confirms that batteries are an economically optimal resource for meeting near-term capacity needs. Given that they can be deployed quickly, Georgia Power can use strategically-sited batteries as an interim solution to both its claimed transmission and generating capacity needs until it can complete longer-term high-capacity transmission upgrades.

Q. DID GEORGIA POWER EVALUATE DEPLOYING BATTERIES IN LOAD POCKETS?

A. Georgia Power explains that it is focused on deploying batteries at or near solar installations.[7] While deploying storage near solar resources can be an attractive solution for reducing renewable curtailment, only evaluating solar sites can lead to missed opportunities to locate batteries near expected loads to reduce the need for transmission upgrades into those areas. Given its small footprint and modular construction, storage can be deployed in optimal quantities and at optimal points on the grid to reduce or defer the need for transmission upgrades. For example, battery storage has been deployed in load pockets in Indianapolis,[8] San Diego,[9] New York City,[10] and other urban areas to offset the need for grid upgrades and support local reliability. Batteries could also be deployed at Plant Yates to utilize the interconnection equipment and transmission capacity that exists at the site.

Q. DID GEORGIA POWER EVALUATE BATTERY STORAGE AS A POTENTIAL

[7] For example, see page 35 of the Direct Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush on behalf of Georgia Power Company in Docket No. 55378: "The Company proposes to add 178 MW of 4-hour duration lithium-ion BESS to existing Company-owned solar facilities at Robins and Moody Air Force Bases and 200 MW of BESS plus 200 MW of solar at a new site." Also see the hearing transcript at page 580: "(Witness Bush) That's correct. We are actually engaging many of the PPA providers for Georgia Power Company that have large solar sites, engaging them to find their interest in allowing us to put a battery there at that site, in conjunction with the interconnection and delivery service that already exists at that site."

[8] AES Indiana, *IPL and AES leaders official open first battery-based energy storage in MISO region* (July 12, 2016), https://www.aesindiana.com/ipl-and-aes-leaders-officially-open-first-battery-based-energy-storage-miso-region.

[9] SDG&E, *SDG&E Unveils World's Largest Lithium Ion Battery Storage Facility* (Feb. 28, 2017), http://newsroom.sdge.com/battery-storage/sdge-unveils-world%E2%80%99s-largest-lithium-ion-battery-storage-facility.

[10] Aaron Larson, *New York City's Largest Battery Energy Storage System Nears Completion*, POWER (June 22, 2023), https://www.powermag.com/new-york-citys-largest-battery-energy-storage-system-nears-completion/.

TRANSMISSION SOLUTION IN ITS 2022 IRP?

A: No. In response to data request STF-DEA-3-39 in the 2022 Georgia Power IRP (Docket No. 44160), which asked "Has the Company studied the potential transmission deferral, congestion relief and reliability benefits associated with the siting location of BESS?," Georgia Power responded:

> No. Transmission deferral, congestion relief, or transmission reliability are not use cases evaluated for the 1000MW of BESS proposed to be deployed for generation resource reliability purposes. Georgia Power evaluated sites where the transmission system was least constrained in order to maximize the benefits (flexibility, capacity, production cost) at the lowest cost to customers.

In response to discovery in the 2022 IRP, Georgia Power also dismissed solutions like battery storage because it claimed that they were too small to meet the full need.[11] This ignores the ability to use a combination of battery storage, demand response, and grid-enhancing technologies to reduce or eliminate the need for grid upgrades. Even if a combination of these near-term solutions is insufficient to fully replace the need for transmission expansion, that does not mean they should not be pursued as a cost-effective option to reduce or defer need. These solutions provide significant value by enabling cost-saving changes in the generation mix and improvements in electric reliability to occur more quickly. Moreover, these interim solutions will continue to provide benefits even after long-term transmission solutions are completed, by continuing to alleviate congestion and improve reliability. As a result, they should not be viewed as alternatives, but rather as complements to the long-term solution of building new transmission lines.

Q. HAVE POLICY CHANGES SINCE THE 2022 IRP IMPROVED THE ECONOMICS OF BATTERY STORAGE?

A. Yes. Stand-alone batteries are now eligible for a 30% Investment Tax Credit ("ITC") under

[11] For example, see Georgia Power's response to data request STF-GDS-4-7.e. in Docket No. 44160, attached to my testimony as Exhibit MG-3, stating that "Alternative solutions such as energy storage or distributed energy resources have not been considered yet for various reasons." Those reasons include "the magnitude of storage or DER that would be needed makes those options untenable."

the Inflation Reduction Act ("IRA") that became law in August 2022, and that credit can be increased to 40% or 50% if "energy community" or domestic content requirements are met. Prior to enactment of the IRA, only battery storage resources deployed at renewable generators receiving the ITC were eligible for the tax credit. The census tract for Plant Yates and adjoining census tracts qualify as "energy communities" due to the closure of the coal plant,[12] so the Company could deploy or contract with a battery that would receive at least a 40% ITC in that area and use it to mitigate the claimed need for both generating capacity and transmission upgrades. The adjoining census tracts from Plant Yates extend quite far to the north and the east[13] towards the area where many new loads have applied to interconnect, giving the Company flexibility to optimally site battery storage additions to meet transmission system needs triggered by the addition of new generation or load. Any brownfield site can also qualify for the energy community bonus, giving Georgia Power further flexibility to site batteries at optimal locations.

B. Demand response or rate design can alleviate the Company's claimed need for transmission upgrades

Q. DID GEORGIA POWER ADEQUATELY EVALUATE DEMAND-RELATED SOLUTIONS TO ITS CLAIMED NEEDS?

A. No, the Company did not adequately evaluate customer-based solutions to the claimed need for transmission upgrades. These solutions include non-firm or interruptible service rate options, the use of customer-sited resources like battery storage, or demand response programs that would compensate those customers for curtailing their load during periods of need, [redacted]. It appears that the Company only evaluates the use of demand response for alleviating system-wide generating capacity

[12] See U.S. Department of Energy, *Energy Community Tax Credit Bonus*, *available at* https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d

[13] *Ibid.*

needs, not localized transmission constraints.[14] [redacted], it is likely that at least some of the new or existing customers in the load pockets would have more than enough time to reduce their load [redacted]. In particular, many types of data centers have demonstrated an ability to quickly reduce load in response to dispatch or price signals during periods of need, as those loads can be shifted later in time or to other data centers.[15] While data centers typically operate at high load factors, many computing loads are not time sensitive and thus can be curtailed during periods of need. If the proposed transmission upgrades are needed to address transmission system stability concerns, customer load reduction or the activation of battery storage can even be set to instantly trigger using a relay based on frequency or voltage. For example, some Loads Acting as a Resource in ERCOT are used as frequency-responsive contingency reserves because they are connected using relays that automatically shed load when frequency declines below a certain threshold.[16]

C. The Company did not evaluate the use of Grid-Enhancing Technologies as an alternative to the proposed transmission upgrades

Q. WHAT ARE GRID-ENHANCING TECHNOLOGIES, AND DID GEORGIA POWER EVALUATE THEM AS ALTERNATIVES?

A. Dynamic line ratings, power flow control devices, topology optimization techniques, and

[14] See Georgia Power's response to STF-GS-1-8 and STF-GS-1-9 in this docket, attached to my testimony as Exhibit MG-4

[15] For example, see Ana Radovanovic, *Our data centers now work harder when the sun shines and wind blows*, (April 2020), *available at* https://blog.google/inside-google/infrastructure/data-centers-work-harder-sun-shines-wind-blows/; and Energy Information Administration, *Tracking electricity consumption from U.S. cryptocurrency mining operations*, (February 2024), *available at* https://www.eia.gov/todayinenergy/detail.php?id=61364: "For example, in Texas, the grid operator ERCOT has created its Large Flexible Load (LFL) program, which enlisted up to 1,530 megawatts (MW) of large industrial consumers to curtail their use during peak demand periods. Cryptocurrency miners are major participants in the LFL program…."

[16] ERCOT, "2023 Annual Report of Demand Response in the ERCOT Region," available at https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=975814860, at 2

similar grid-enhancing technologies[17] can be deployed quickly, typically within a matter of months,[18] so they can play an important role in alleviating near-term transmission constraints so new resources or loads can be interconnected while longer-term transmission upgrades are implemented. However, at the hearing, Georgia Power admitted that it did not consider those solutions in its transmission screening analysis.[19]

Analysis by the Brattle Group found that 2,670 MW of additional wind capacity could be added in SPP by adopting dynamic line ratings, power flow control devices, and topology optimization, more than doubling the amount of wind capacity that can be added while keeping curtailment at an acceptable level.[20] Brattle found a one-time investment of $85 million in these technologies would yield annual production cost savings of $175 million.

Dynamic line ratings allow more power to safely flow on transmission lines by accounting for how ambient weather conditions affect the thermal limits of those lines. Transmission line ratings are typically based on worst case weather assumptions: hot weather with full sun and no wind cooling the line. Dynamic line rating devices measure the actual thermal limit of transmission lines, which under most weather conditions are much higher than the limits based on those worst-case assumptions. Due to the large potential benefits, FERC recently initiated an inquiry examining whether dynamic ratings should be required.[21]

Power flow control devices, also known as Flexible Alternating Current Transmission Systems devices, can also be deployed quickly to increase interconnection capacity on the

[17] Rob Gramlich, *Bringing the Grid to Life: White Paper on the Benefits to Customers of Transmission Management Technologies* (Mar. 2018), *available at* https://watttransmission.files.wordpress.com/2018/03/watt-living-grid-white-paper.pdf.

[18] *See* Idaho Nat'l Lab., *A Guide to Case Studies of Grid Enhancing Technologies*, 11, 26 (Oct. 2022), https://inl.gov/wp-content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf.

[19] Transcript at 257

[20] Bruce Tsuchida, Stephanie Ross, Adam Bigelow, *Unlocking the Queue with Grid-Enhancing Technologies*, at 8 (February 2021), *available at* https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

[21] FERC, *FERC Opens Inquiry on Use of Dynamic Line Ratings to Promote Grid Efficiency*, (February 2022), *available at* https://www.ferc.gov/news-events/news/ferc-opens-inquiry-use-dynamic-line-ratings-promote-grid-efficiency

existing transmission system. These are power electronics-based devices used to adjust the power transfer capabilities of the system and improve stability or controllability of the system under critical conditions. Topology optimization plays a similar role by taking specific transmission lines out of service to redirect power flow away from congested transmission elements and onto more optimal paths. Both of these solutions can play an important role in alleviating constraints during transmission contingency events.

III. Georgia Power should adopt better transmission planning practices to identify more optimal long-term transmission solutions

Q. WOULD HIGHER-CAPACITY SOLUTIONS BE MORE COST-EFFECTIVE THAN THE COMPANY'S PROPOSED TRANSMISSION UPGRADES?

A. Yes. The [redacted] transmission upgrades identified in the Transmission Screening Analysis as being needed to accommodate the Yates CTs are likely economically sub-optimal for ratepayers, and could even interfere with the ability to deploy higher-voltage transmission on that valuable right-of-way to meet future load growth or generation needs. Higher-voltage transmission lines offer large economies of scale and allow more efficient use of right-of-way due to their higher capacity. For example, MISO's annual estimate of transmission costs provides data illustrating the large economies of scale for higher-voltage and double-circuit transmission, which are used to calculate the results shown in Table 1 below.[22] On a $/MW-mile basis, which reflects the average cost of transmission to deliver one MW one mile, double-circuit 230-kV transmission is 36% less costly than double-circuit 115-kV, and 500-kV is 60% less costly than double-circuit 115-kV transmission. The Company's proposed upgrades to accommodate the Yates CTs are all [redacted] low-voltage transmission assets, making it likely that meeting longer-

[22] Midcontinent Indep. Sys. Operator, *Transmission Cost Estimation Guide for MTEP24* (January 2024 draft), https://cdn.misoenergy.org/20240131%20PSC%20Item%2005%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24%20-%20Redline631529.pdf (Table 1 was prepared using the reported Power rating (MVA) capacity data in Table 3.1.5 on page 43 and the estimated costs for Arkansas reported in Tables 4.1.1 and 4.1.2 on pages 47–49. Costs for Arkansas were used as they are in the middle of the range of MISO's cost estimates by state, and are likely to be more representative of costs in the Southeast. The Power rating (MVA) capacity data for the Double Circuit are twice the capacity for the Single Circuit.).

term needs using higher-capacity solutions would be more cost-effective.

Table 1: Economies of scale for higher-voltage transmission lines

	Voltage (kV)	69	115	138	161	230	345	500	765
Single Circuit	$M/mile	$1.7	$1.9	$2.0	$2.1	$2.2	$3.5	$4.4	$5.5
	MW or MVA	140	329	394	460	657	1792	2598	6625
	$/MW-mile	**$12,143**	**$5,775**	**$5,076**	**$4,565**	**$3,349**	**$1,953**	**$1,694**	**$830**
Double Circuit	$M/mile	2.5	2.8	2.9	3	3.6	5.8	NA	NA
	MW or MVA	280	658	788	920	1314	3584	NA	NA
	$/MW-mile	**$8,929**	**$4,255**	**$3,680**	**$3,261**	**$2,740**	**$1,618**	**NA**	**NA**

The cost of the Company's proposed transmission upgrades is quite high. The cost of the proposed upgrades to accommodate the Yates CTs is greater than the claimed $60 million [redacted] The $60 million [redacted] The $60 million [redacted] This is several times greater than typical interconnection upgrade costs for gas generators in other regions.[23]

The Company should conduct long-term transmission planning to assess if there are more

[23] Lawrence Berkeley National Laboratory, *Generator Interconnection Costs to the Transmission System*, (June 2023) *available at* https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_interconnection_cost_webinar.pdf, at 14, 15, 20, 24

optimal solutions for ratepayers than the Company's proposed low-voltage upgrades. This analysis should plan for long-term changes in load and generation and optimally meet reliability, economic, and generator interconnection needs. The Company should primarily focus on planning higher-capacity solutions, as Georgia Power's current reactive transmission processes fail to proactively identify the most cost-effective multi-value long-term solutions. These approaches will minimize the total cost of generation plus transmission by building the optimal amount of transmission to maximize net benefits for ratepayers.

Q. WHAT TYPE OF TRANSMISSION PLANNING IS NEEDED?

A. More optimal solutions for ratepayers can be identified using proactive multi-value transmission planning, which is the best practice used in other regions. Principles of proactive multi-value transmission planning identified in a report I recently co-authored with others at the Brattle Group and Grid Strategies include:[24]

1. *Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.*
2. *Account for the full range of transmission projects' benefits, and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.*
3. *Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.*
4. *Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.*
5. *Jointly plan across neighboring interregional systems to recognize regional*

[24] Pfeifenberger, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, BRATTLE GRP. & GRID STRATEGIES LLC, at iv (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

Q. HAVE OTHER REGIONS USED PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. Yes, and they have found that this type of planning minimizes the total cost to ratepayers of generation plus transmission by building the optimal amount of transmission. Over a decade ago, the Midcontinent Independent System Operator ("MISO") used a proactive multi-value transmission planning process to identify a holistic portfolio of transmission upgrades, called the Multi-Value Projects ("MVPs"), that were needed to meet reliability, economic, and state renewable energy policy needs.[25] All but one of those lines have since been completed, and analyses have confirmed that those projects are providing large net benefits.[26] MISO's process was informed by Texas's success in using proactive transmission planning to build the Competitive Renewable Energy Zone projects, a portfolio of upgrades that allowed the state to double its use of renewable energy.[27] The Southwest Power Pool ("SPP") also adopted a proactive multi-value transmission planning approach, and two subsequent studies have confirmed that those upgrades are providing large net benefits by meeting a range of economic and reliability needs.[28]

Proactive multi-value transmission planning has also been successfully used by vertically-integrated utilities outside of Regional Transmission Organizations. For example, Nevada Power's Greenlink Nevada project is designed to provide a range of benefits across

[25] Midcontinent Indep. Sys. Operator, *Multi Value Project Portfolio–Results and Analyses* (Jan. 10, 2012), https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.

[26] Midcontinent Indep. Sys. Operator, MTEP17 MVP Triennial Review–A 2017 Review of the Public Policy, Economic, & Qualitative Benefits of the Multi-Value Project Portfolio (Sept. 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf.

[27] *See, e.g.*, Lasher, *The Competitive Renewable Energy Zones Process*, ERCOT (Aug. 11, 2014), https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

[28] *See* Sw. Power Pool, *The Value of Transmission – A Report by Southwest Power Pool* (Jan. 26, 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf; *see also* Sw. Power Pool, *The Value of Transmission – A 2021 Study and Report by Southwest Power Pool* (Mar. 31, 2022), https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf.

categories including reliability, economics, proactively interconnecting a diverse portfolio of renewable energy resources, and expanding ties to neighboring grid operators.[29] Xcel's Colorado Power Pathway is another example of proactive transmission planning to realize multiple benefits.[30] Finally, Duke has proposed moving to multi-value transmission planning.[31]

In addition, the IRPs conducted by PacifiCorp, Xcel's Minnesota utility Northern States Power, and Xcel's Colorado utility Public Service Company of Colorado co-optimize transmission planning with generation planning for truly "integrated" resource planning. Vertically-integrated utilities like Georgia Power can synchronize generation and transmission planning. This avoids any risk that transmission developed in anticipation of market interest from generators will not be fully subscribed, though pro-actively planned transmission lines in Texas and other areas without vertically-integrated utilities have quickly been fully subscribed.

Q. DOES GEORGIA POWER USE PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. No. When asked about the transmission planning methods used for the upgrades identified in this docket, the Company pointed to the "Transmission Planning study and project development processes outlined in Technical Appendix Volume 3 of the 2022 Georgia Power Integrated Resource Plan ("IRP") (Docket No. 44160)."[32] The process outlined in that document is not proactive multi-value transmission planning for multiple reasons.

First and most importantly, all of the benefits Georgia Power's transmission planners assess

[29] NV Energy, *Greenlink Nevada* (Apr. 8, 2021), https://goed.nv.gov/wp-content/uploads/2021/05/Greenlink-Nevada-Presentation-4-08-21.pdf.

[30] Xcel Energy, *Colorado's Power Pathway* (last visited Mar. 24, 2023), https://www.coloradospowerpathway.com/project-description/.

[31] CTPC, *Multi-Value Strategic Transmission Planning*, (November 2023), *available at* http://www.nctpc.org/nctpc/document/REF/2023-12-08/Multi-Value%20Strategic%20Transmission%20Planning%20Process%20draft%2011-13-2023.pdf

[32] For example, see the Company's response to STF-GS-1-7, attached to my testimony as Exhibit MG-5

are related to reliability, not economic benefits or other benefits that are typically evaluated in multi-value planning or even standard utility practice transmission planning.[33] Other parts of the document confirm that transmission is only planned to resolve reliability problems: "For problems to be identified, situations exist where the system will operate in an unacceptable manner (as defined by the performance guidelines)."[34] Furthermore, no production cost models are included in the many models the transmission planning document lists as being used by Georgia Power planning, which is not standard utility practice for transmission planning. The economic dispatch of generators is only used as an input into load flow models, and not an output of the models as it would be in the production cost models used in standard utility practice.[35]

Georgia Power confirmed its transmission planners' focus on reliability and not economic and other benefits in response to data request STF-PIA-3-13 in the 2022 IRP. In addition, Georgia Power's planning methods focus on single problems, and with different problem statements for reliability, load growth, and generator interconnection,[36] preventing the identification of multi-value solutions or portfolios of network solutions, two of the essential aspects of proactive multi-value planning identified above that help minimize cost and maximize benefits to ratepayers.

Q. DOES GEORGIA POWER'S TRANSMISSION BENEFIT ANALYSIS MEASURE THE FULL BENEFITS OF TRANSMISSION?

A: No. As explained above, Georgia Power's benefits analysis only accounts for benefits

[33] Technical Appendix Volume 3 of the 2022 Georgia Power Integrated Resource Plan ("IRP") (Docket No. 44160), at 23-25

[34] *Id.*, at 23

[35] *Id.,* at 32: "Economic Dispatch Program: The Economic Dispatch Program was developed by SCS to interact with the Power Technologies Inc. load flow program, PSS/E. The program calculates an economic dispatch for a given load and spinning reserve requirement specified by the transmission planners and is based on the theory that the most economical dispatch is obtained by operating all on-line units at the same incremental cost (lambda). The transmission planners specify information to the program through terminal interaction and two data files with pertinent information on the availability of units, in-service date, retirement date, must run status, power generation limits, generator cost data, etc. The program allows the transmission planners to input the appropriate economic dispatch directly into files for future use with the PSS/E program."

[36] *Id.*, at 16

related to electric reliability, even though transmission provides many additional benefits. Multi-value transmission planning optimizes across transmission's multiple categories of benefits, maximizing benefits for ratepayers. For example, FERC has identified the following twelve categories of benefits that transmission provides:[37]

1) avoided or deferred reliability projects and aging infrastructure replacement,
2) either reduced loss of load probability or reduced planning reserve margin,
3) production cost savings,
4) reduced transmission energy losses,
5) reduced congestion due to transmission outages,
6) mitigation of extreme events and system contingencies,
7) mitigation of weather and load uncertainty,
8) capacity cost benefits from reduced peak energy losses,
9) deferred generation capacity investments,
10) access to lower-cost generation,
11) increased competition, and
12) increased market liquidity.

Q. DO TRANSMISSION PLANNERS IN OTHER REGIONS ACCOUNT FOR TRANSMISSION BENEFITS OTHER THAN REDUCED CUSTOMER OUTAGES?

A. Yes. The Company's analysis is highly unusual in that it does not account for how transmission upgrades provide production cost savings by reducing transmission losses and allowing lower-cost generation to displace higher-cost resources. Production cost savings are typically one of the primary benefits transmission planners account for when evaluating benefit-cost ratios for transmission projects. As FERC noted in its proposed rulemaking, "Most regional transmission planning processes currently estimate production cost

[37] See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC ¶ 61,028, 18 CFR Part 35, Dkt. No. RM21-17-000 (Apr. 21, 2022), https://www.ferc.gov/media/rm21-17-000, at paragraph 185.

savings."[38] Failing to account for that benefit understates the value of transmission, resulting in an underinvestment in transmission that harms ratepayers. As noted above, I recently co-authored a report providing examples of how transmission planners in other regions have accounted for economics and other benefits.[39]

The MISO and SPP studies cited above confirm that by only looking at reduced customer outages, Georgia Power's benefit analysis is only capturing a small share of transmission's total benefits. For example, SPP's analysis found that reliability benefits accounted for $3 billion out of the transmission portfolio's total benefits of over $27 billion, or only 11% of the total benefits of transmission.[40] SPP found production cost savings totaled over $20 billion, or 76% of the total benefits.

Q. ARE THE COMPANIES' PRACTICES PROACTIVE TRANSMISSION PLANNING?

No. In particular, the short horizon of Georgia Power's transmission planning[41] falls well short of the 20-year horizon requirement proposed by FERC to ensure that the rates paid by customers are just and reasonable.[42]

Q. DO SOUTHEASTERN REGIONAL TRANSMISSION PLANNING ("SERTP") PROCESSES CURRENTLY USE MULTI-VALUE PLANNING?

A. No. Similar to Georgia Power's transmission planning methods, the SERTP processes

[38] *Id.,* at paragraph 199

[39] Pfeifenberger, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, BRATTLE GRP. & GRID STRATEGIES LLC, Appendix D (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

[40] *The Value of Transmission – A 2021 Study and Report by Southwest Power Pool*, at 29.

[41] *Id.*, at 15: "The transmission planning process follows an iterative process with a planning horizon looking 10 years into the future. However, due to the dynamics of the assumptions and data used to develop the latter years of the system model, project proposals are usually fully developed for the first five years only (considered to be the near-term planning horizon). These projects and their mutual effects are tested throughout the full ten-year period. For issues in the last five years of the planning horizon, viable projects are identified but not fully scoped, estimated and budgeted unless long lead-time items such as right-of-way acquisition are included."

[42] FERC, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, 18 CFR Part 35, Dkt. No. RM21-17-000 (Apr. 21, 2022), https://www.ferc.gov/media/rm21-17-000, at page 82

greatly understate the benefits of transmission by only accounting for the benefit of deferring transmission upgrades needed to meet NERC reliability criteria. SERTP also uses siloed instead of multi-value transmission planning, with separate processes for evaluating reliability, economic, and public policy projects.[43]

Q. HAVE THERE BEEN CONSEQUENCES FROM GEORGIA POWER AND SERTP NOT USING PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. Yes. Georgia Power and SERTP trail other regions in transmission expansion, falling well short of the level of investment other regions have found maximizes net benefits for ratepayers. The U.S. Department of Energy's Transmission Needs Study found that the Southeast has greatly lagged other regions in building new transmission, building only 110 circuit miles per year on average over the period 2011-2020. This is less than one-quarter of the national rate on a load-weighted basis, with the Southeast building .21 miles/TWh of load versus a national average of .88 miles/TWh.[44] Similarly, Americans for a Clean Energy Grid recently released a report card scoring regions based on their transmission planning methods and their success in building transmission. The Southeast was the only region in the country to receive an "F" grade, and the only region that failed to build any transmission lines at or above 300-kV during the period 2020-2022.[45] Transmission expansion is essential for efficiently addressing load growth, changes in the generation mix, and reliability risks from severe weather. Continuing to rely on siloed and reactive processes that understate the benefits of transmission harms ratepayers by depriving them of affordable and reliable power.

Q. WHAT ARE THE BENEFITS OF PROACTIVE MULTI-VALUE TRANSMISSION

[43] See the separate submission forms for economic and public policy study requests at SERTP, *Reference Library: Forms*, *available at* http://www.southeasternrtp.com/reference_library.cshtml

[44] U.S. Department of Energy, *National Transmission Needs Study*, (December 2023), *available at* https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf, at 22

[45] *See* Zimmerman, et al., *Transmission Planning and Development Regional Report Card*, AM. FOR A CLEAN ENERGY GRID (June 2023).

PLANNING?

A. Proactively planning a portfolio of transmission projects that meets multiple long-term needs is much more efficient than a reactive process that meets shorter-term needs with more incremental costly investments. This is largely because transmission investment offers large economies of scale, as explained above, with higher-voltage and double-circuit lines carrying many times more power than lower-voltage lines with a less than proportional increase in cost.

Multi-value transmission planning is more efficient as it allows the selection of grid upgrades that simultaneously meet multiple objectives in providing economic, reliability, and generator interconnection benefits. Georgia Power's current siloed process, in which reliability transmission projects are planned separately from generator interconnection projects, misses opportunities to meet both needs with the same projects more efficiently.

Q. WHAT ARE COMMON REASONS FOR NOT USING PROACTIVE MULTI-VALUE TRANSMISSION PLANNING?

A. Siloed and reactive planning processes are often used so costs for different types of transmission can be assigned to different users of the grid. However, allocating the cost of upgrades to the bulk transmission network is challenging because the bulk transmission network allows all generators and loads to efficiently and reliably deliver power. In contrast, the cost of direct interconnection facilities, analogous to the driveway a resource uses to connect to the transmission system, is always allocated to the interconnecting resource as that cost can be directly attributed to that resource and network power does not flow across that transmission element.

Network upgrade costs assigned to generators ultimately flow to ratepayers when they are rolled into the cost of the new generation. Generators must recover network upgrade costs, as well as the cost of interconnection study fees, by charging a higher price when Georgia Power procures new renewable and storage resources, either through a power purchase agreement or an acquisition. As a result, developing a workable planning and cost allocation method that minimizes the cost and maximizes the net benefits of network

upgrades is more important, as the costs will flow to ratepayers regardless of how they are initially allocated.

Network upgrades are also a public good, in that all users of the transmission system benefit from them, including competing generators. As a result, interconnecting generators have little incentive to pay for network upgrades, which has driven the extremely high dropout rate in the interconnection queues of Southern Company and other grid operators. Assigning major network upgrade costs to an interconnecting generator is analogous to charging the next car entering a crowded highway the full cost of adding another lane. Proactively planning the needed network upgrades and broadly allocating the cost to ratepayers is a more efficient and workable policy, similar to how costs for other public goods like roads and sewer systems are allocated. While assigning network upgrade costs to interconnecting generators can theoretically induce generators to locate in parts of the grid where less costly upgrades are needed, the same benefit can be obtained by synchronizing generation and transmission planning and then broadly allocating network transmission costs to ratepayers, which is more workable than assigning upgrade costs to generators.

Q. DOES PROACTIVE PLANNING REDUCE INTERCONNECTION COSTS?

A. Yes. Proactive planning yields major savings by realizing economies of scale in transmission investment. Proactive planning allows investment in higher-capacity network transmission solutions that are more cost-effective for meeting longer-term needs than the lower-capacity upgrades that result from reactive transmission expansion processes, like the interconnection queue. The PJM grid operator recently found that proactive transmission planning could integrate 12.4 GW of offshore wind resources along with 14.5 GW of onshore wind, 45.6 GW of solar, and 7.2 GW of storage, for a total of just $2.2 billion.[46] This equates to a cost of $27/kilowatt for new generation capacity, a fraction of

[46] PJM Interconnection, *Offshore Wind Transmission Study: Phase 1 Results*, 16, Scenario 6 (Oct. 19, 2021), https://pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

the cost found through interconnection queue studies. For example, a Brattle Group analysis of PJM queue study results show $1.3 billion in total identified transmission upgrades for integrating 5.6 GW of PJM offshore wind resources alone,[47] which equates to a cost of $415/kilowatt, 15 times greater than costs under PJM's proactive plan. Other analyses found that integrating 15.5 GW of offshore wind under today's rules would lead to $6.4 billion in upgrades,[48] at a cost of $236/kilowatt.

Similarly, a proactive planning effort in New Jersey for offshore wind resulted in selections of onshore transmission upgrades that save New Jersey ratepayers approximately $1 billion for 6,400 MW of additional offshore wind, a two-thirds reduction relative to the costs identified through PJM queue studies.[49]

Q. IS A REFORMED TRANSMISSION PLANNING APPROACH NEEDED FOR GEORGIA POWER?

A. Yes, proactive multi-value planning of major transmission upgrades will alleviate the current burden from trying to plan high-capacity network elements through reactive processes like the generator interconnection queue. While FERC recently required utilities to move to a cluster interconnection study approach, which offers incremental improvements over a serial approach in which interconnection applications are studied one at a time, it still fails to address the fundamental problems that interconnecting generators have little incentive to pay for grid upgrades that are public goods, and that transmission planned to interconnect generators does not optimize economic and reliability benefits.

Other regions have found that interconnection queues, even with the use of cluster studies, are inadequate for addressing large-scale changes in the transmission system driven by

[47] Pfeifenberger, et al., *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report*, N.J. BD. OF PUB. UTILS., 180, Table A-2 (Oct. 26, 2022), https://www.brattle.com/wp-content/uploads/2022/10/New-Jersey-State-Agreement-Approach-for-Offshore-Wind-Transmission-Evaluation-Report.pdf.

[48] Burke, et al., *Offshore Wind Transmission White Paper*, BUS. NETWORK FOR OFFSHORE WIND, 40 (Oct. 2020), https://gridprogress.files.wordpress.com/2020/11/business-network-osw-transmission-white-paper-final.pdf.

[49] Pfeifenberger, *supra* at 92, Figure 4.

changes in the generation mix, as I explained in a recent report.[50] Across the country, interconnection queues have ballooned to more than 2,000 GW of generation under study as they have failed to efficiently drive network transmission development.[51] MISO has twice successfully used proactive multi-value planning to drive major transmission upgrades[52] when its interconnection queue has gotten bogged down with the same vicious cycle of problems that are plaguing interconnection queues across the country.

Q. WHAT ARE THE DRAWBACKS OF RELYING ON THE INTERCONNECTION QUEUE INSTEAD OF PROACTIVE PLANNING?

A. Relying on the interconnection queue instead of proactive planning causes high network upgrade costs, which drive developers to propose speculative projects, which results in a high dropout rate, which results in restudies for projects remaining in the queue, which introduces uncertainty to initial cost estimates and drives further withdrawals when updated costs are published for those other generators, which in turn drives further delays, cost, cost uncertainty. As noted above, all of these costs ultimately flow through to ratepayers, as these costs are recovered through a higher purchase price when the resources are contracted by Georgia Power.

Q. CAN USING PROACTIVE TRANSMISSION PLANNING INSTEAD OF A REACTIVE APPROACH HELP MITIGATE THE IMPACT OF INFLATIONARY COST PRESSURES?

A. Yes. As I explained above, economies of scale greatly reduce the cost of proactively planned transmission, as a small number of high-voltage transmission lines can carry the

[50] Goggin, et al., *Disconnected: The Need for a New Generator Interconnection Policy*, AM. FOR A CLEAN ENERGY GRID (Jan. 12, 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf.

[51] Berkeley Lab, *Generation, Storage, and Hybrid Capacity in Interconnection Queues – Projects in the Interconnection Queues for ISOs and Utility Service Territories*, Electricity Markets & Policy, https://emp.lbl.gov/generation-storage-and-hybrid-capacity.

[52] *See* Ethan Howland, *MISO board approves $10.3B transmission plan to support 53 GW of renewables*, UTILITY DIVE (July 26, 2022), https://www.utilitydive.com/news/miso-board-transmission-plan-midcontinent-renewables/628108/ (In addition to the MVPs discussed above, last year, MISO approved a portfolio of Long-Range Transmission Plan projects that were developed using a similar proactive multi-value planning approach).

same amount of power as many lower-voltage lines, saving ratepayers money by reducing material and labor expenses. This is particularly valuable given current inflationary cost pressures on a range of inputs, including steel and other metals used to build transmission towers and conductors, as well as labor shortages.

Proactive planning also reduces the cost and time burden of planning grid upgrades. Nationally, utilities and generation developers are facing significant shortages of qualified engineers to run interconnection studies due to the ballooning interconnection queues. A better use of this scarce resource is to let transmission planners proactively plan transmission, instead of repeatedly running reactive interconnection studies and restudies for generators that almost always drop out of the queue when they are assigned the cost of building major network upgrades.

Q. IN ADDITION TO UTILIZING PROACTIVE MULTI-VALUE TRANSMISSION PLANNING, CAN GEORGIA POWER ALSO RELY ON THE INTERCONNECTION QUEUE?

A. The current interconnection queue can be a useful input for transmission planning, by identifying areas where developers are interested in building generation projects, but it should not be the only input. The location of proposed projects in the queue is heavily shaped by where there is currently available transmission capacity, and new transmission build will change the topology of the system and create new unconstrained entry points for renewables. As a result, Georgia Power should also proactively plan transmission to new areas that are promising for low-cost renewable development. One way to do that is by using the results of a "Request for Proposals" or other solicitation to get market cost data from proposed generators in different locations. Georgia Power's renewable energy solicitations can serve as an important source of that cost information. Then, Georgia Power can determine the cost of potential grid upgrade portfolios to accommodate groups of those projects, and choose the grid upgrades that minimize the total generation plus transmission cost. This type of synchronized generation plus transmission planning is necessary to truly achieve "integrated" resource planning. Because transmission upgrades

work together to enable the efficient and reliable flow of power across the network, Georgia Power should plan and evaluate a holistic portfolio of upgrades rather than its current approach of evaluating single projects to address a single problem. Planning should also account for the economies of scale from higher-voltage and double-circuit transmission to right-size for the long-term need.

Q. WHAT TYPE OF TRANSMISSION PLANNING SHOULD THE COMMISSION REQUIRE GEORGIA POWER TO IMPLEMENT?

A. My recommendation is that the Commission should direct Georgia Power to conduct a synchronized generation and transmission planning process that attempts to minimize total costs for generation plus transmission to meet long-term needs, using proactive multi-value transmission planning to plan upgrades that maximize transmission's net benefits. MISO and others have successfully used a synchronized generation and transmission planning approach to minimize total costs to ratepayers. As illustrated in the following chart from the MISO planning document that led to the MVPs, synchronized planning minimizes the total cost to ratepayers of generation plus transmission by building the optimal amount of transmission.[53]

[53] Midwest Indep. Sys. Operator, *Regional Generation Outlet Study*, 3 (Nov. 19, 2010), https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.

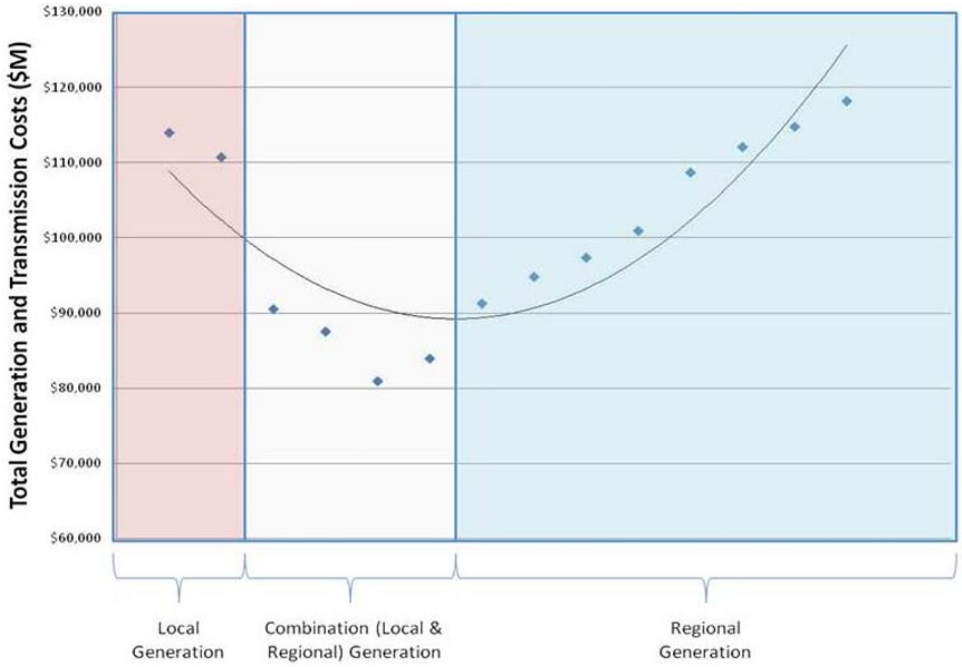

Figure 1: MISO chart showing how co-optimized generation and transmission planning minimizes cost for ratepayers

While planning and building longer-term transmission solutions can take time, Georgia Power can use the interim solutions discussed above, like battery storage, demand response, and grid-enhancing technologies, to defer the need for near-term upgrades.

IV. The proposed Yates CTs face curtailment risk that limits their value as a capacity resource

Q. WHAT TYPE OF TRANSMISSION SERVICE HAS THE COMPANY REQUESTED FOR THE YATES CT ADDITIONS?

A. The Company has requested Energy Resource Interconnection Service ("ERIS") and not Network Resource Interconnection Service ("NRIS") for the proposed combustion turbine additions at Plant Yates.[54] As Southern Company explains in its Large Generator

[54] See IC-1166, IC-1167, and IC-1168 in Southern Company, *Southern Companies' Transmission System Active OATT Generator Interconnection Requests*, page 2, *available at*: https://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/Active-Gen-IC-Requests.pdf;

Interconnection Procedures, a NRIS study assures that the full output of the studied resource is deliverable to load and allows the generator to be designated as a network resource.[55] In contrast, ERIS only makes the generator eligible to deliver its output using the "as available" capacity of the transmission system.[56] NRIS is typically used for generators like the proposed Yates CTs that are intended to be used as capacity resources, while ERIS is typically used for energy-only resources, as the "energy" in ERIS indicates.

Q. DOES THE COMPANY'S REQUEST FOR ERIS AND NOT NRIS FOR THE PROPOSED YATES CT ADDITIONS CREATE RISK?

A. There is risk that a lack of transmission capacity will result in curtailment of the Yates CTs' generation during periods of peak need, limiting the capacity contribution of the proposed Yates CTs, as transmission congestion often occurs during periods when the need for generating capacity is at its highest. The Company should quantify and clarify this risk to allow the Commission and other stakeholders to determine if the Yates CTs and the associated transmission upgrades are prudent capacity resource investments.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[55] Southern Companies, *Open Access Transmission Tariff: Large Generator Interconnection Procedures*, (February 2020), *available at* https://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/LGIP,LGIA,SGIP,SGIA_2020-02-18.pdf at 18 (Section 3.2.2): "Network Resource Interconnection Service Allows Interconnection Customer's Large Generating Facility to be designated as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. 3.2.2.2 The Study. The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Large Generating Facility's interconnection is also studied with Transmission Provider's Transmission System, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider's Transmission System, consistent with Transmission Provider's reliability criteria and procedures."

[56] *Id.*, at 17 (Section 3.2.1) "Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery."

Exhibit MG-1: Michael S. Goggin Background and Qualifications

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis "Is it Time for a Change? Science, Policy, and Climate Change"

Experience:

Grid Strategies Vice President February 2018-present

- Serve as a consultant on electricity transmission, grid integration, reliability, market, and public policy issues for consumer, grid operator, non-profit, and industry clients
- Have testified before FERC and in over 25 state regulatory commission cases

AWEA Senior Director of Research, other titles February 2008-February 2018

- Led team responsible for all American Wind Energy Association (now American Clean Power Association) analysis
- Served as primary technical and economic expert for market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (ISO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- Directed economic and power sector modeling to inform AWEA's policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Authored reports to promote AWEA's policy agenda, rebut misconceptions about wind energy, and explain complex energy topics to lay audiences
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. Research Analyst October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE's renewable energy R&D funding decisions

Union of Concerned Scientists Clean Energy Intern May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups Policy Analyst August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

Publications available at https://gridstrategiesllc.com/reports/

Exhibit MG-2: Georgia Power's response to data request STF-GS-1-1 (Docket No. 55378)

STF-GS-1-1

Question:

Has the Company evaluated the use of Battery Energy Storage Systems (BESS) to reduce, defer, or eliminate the need for the transmission upgrades identified in the Updated IRP? If so, please provide that evaluation and explain why BESS were not selected. If the Company has not conducted that evaluation, please explain why not.

Response:

Please refer to the Company's response to STF-DEA-4-15.

The Company did not study Battery Energy Storage Systems ("BESS") as options to reduce, defer, or eliminate the transmission upgrades identified in the 2023 IRP Update to facilitate the delivery of power from the proposed Plant Yates combustion turbines.

Exhibit MG-3: Georgia Power's response to data request STF-GDS-4-7.e. in the 2022 IRP (Docket No. 44160)

e. Alternative solutions such as energy storage or distributed energy resources have not been considered yet for various reasons. Some projects such as the Klondike switch replacement, are relatively inexpensive and easy to accomplish, so no such alternative is needed. For the identified strategic projects (second Heard County – Tenaska 500 kV line and the new Lagrange – North Opelika 230 kV line), the magnitude of storage or DER that would be needed makes those options untenable. The solutions for the other identified constraints are still under review. Other strategic solutions may replace some of the listed projects, and energy storage, DER, and operating guides will be considered in due time, before the listed projects are approved and budgeted.

Exhibit MG-4: Georgia Power's responses to data requests STF-GS-1-8 and STF-GS-1-9 (Docket No. 55378)

STF-GS-1-8

Question:

As a follow-up to the STF-JKA-4-5 question about discussing non-firm, interruptible, or lower service quality options with new customers, has the Company evaluated demand response programs that would compensate those customers for curtailing their load, particularly during the generation or transmission system contingency events that triggered a need for upgrades in the Transmission Screening Analysis? If so, please discuss that evaluation. If not, please explain why the Company has not conducted that analysis.

Response:

The Company is proposing a new Curtailable Load program, which will compensate customers for curtailing load during periods of extreme supply and demand conditions. The customer payment will be directly linked to the capacity value provided by the potential demand reduction.

STF-GS-1-9

Question:

As a follow-up to the STF-JKA-4-5 question about evaluating non-firm, interruptible, or lower service quality options with new customers, has the Company spoken with new customers about an option for potential reductions in interconnection costs or rates from deploying customer-sited battery storage or demand response resources? If so, please describe those discussions. If not, please explain why the Company has not offered that option.

Response:

Yes, the Company makes potential customers aware of rate options and programs available to them, including the Real Time Pricing rate. The Company also has current demand response programs and is proposing three new DER and DR customer programs as part of this IRP Update to enable both new and existing customers to receive credit for providing system value from customer-sited resources.

Exhibit MG-5: Georgia Power's response to data request STF-GS-1-7 (Docket No. 55378)

STF-GS-1-7

Question:

Has the Company evaluated whether the transmission upgrades identified in the Transmission Screening Analysis could be reduced, deferred, or eliminated with the deployment of grid-enhancing technologies including dynamic line ratings, topology optimization, power flow control devices, and similar solutions?

Response:

Please refer to the Transmission Planning study and project development processes outlined in Technical Appendix Volume 3 of the 2022 Georgia Power Integrated Resource Plan ("IRP") (Docket No. 44160) which notes how projects are evaluated and developed. Due to the timing of the transmission constraints, the most appropriate projects were developed. Additionally, please refer to the responses provided to STF-DEA-4-2 and STF-DEA-4-11.

MR. THOMAS: And, Mr. Chair, with your permission, I would like to ask that the panel be given the opportunity to give a summary of their prefiled direct testimony.

CHAIRMAN SHAW: Yes, go ahead.

MR. SMITH: Good evening. The testimony of this panel addresses the transmission studies -- and "by this panel," I mean, the work of Ms. Palacios and myself.

The testimony of this panel addresses the transmission studies performed and the conclusions reached by the company. It reviews both the initial screening studies presented by the company in its October filing, as well as the additional studies produced in mid-January.

It presents our conclusions regarding the proposed investment in transmission in support of the Plant Yates combustion turbines, as well as the general observations about the scope of the studies performed by the company, certain assumptions that the company makes, and considerations the company could have made with respect to potential transmission solutions.

Through this review, this testimony concludes that the transmission analysis performed was limited

in scope, had some questionable assumptions regarding plant availability, and that the need for the -- for at least some of the Plant Yates related transmission has not been established.

In the case of the Plant Yates transmission, we have also included an indicative analysis that shows the magnitude of the impact of assuming the third combustion turbine is needed or not. The conclusions and recommendations of this panel are included on page 4 of our direct testimony.

The company's analysis of the transmission needs for Plant Yates properly identified thermal loadings above normal line ratings that would need to be resolved before the full capacity of the proposed combustion turbines could be relied upon for their full capacity. However, there are reasons to delay a decision on that transmission, pending a more complete analysis that should be conducted for the 2025 IRP.

First and foremost, the transmission analyses that were performed by the company were a subset of the full suite of analyses that are typically performed in long-range-transmission studies, including IRPs. The lack of voltage instability studies means the company, intervenors, and the

Commission have an incomplete picture of transmission need.

Additionally, certain units that were marked for retirement by 2028, in the 2022 IRP, are assumed to be available throughout the study period for both the initial screening and the January sensitivity analysis. Several of the proposed transmission projects have an identified need -- date that is far enough in the future, that the delay to reconsider them in a more complete analysis plan for the 2025 IRP would not put the company's stated project schedule in jeopardy.

And, finally, the results of the limited analysis performed are sensitive to the assumptions of capacity needed at the Plant Yates site. Up to 600 megawatts can be delivered without transmission upgrades. That is more than enough space for the first combustion turbine. After that, the number and magnitude of overload is impacted by the assumptions that three CTs are needed to meet the company's low growth.

It is possible that a more complete analysis and scenarios with varied loads and supply options would unearth alternative solutions that should be considered, especially if the amount of capacity for

the 2022 IRP retired units is reconsidered.

Additional observations that we made were that the limited scope of transmission analyses for this update had other impacts. The potential solutions considered were limited, both smaller, cheaper solutions, such as grid-enhancing technologies, as well as larger, potentially more cost effective solutions, such as new rights-of-way or new substations were excluded from consideration.

This is potentially impactful as the company is planning, with a large degree of uncertainty, how quickly load will materialize, where the load that does arrive is sited, how quickly the fleet of thermal generators will be retired, and what new generation will be available as part of future capacity procurements, are all uncertainties that could drive the optimal transmission solutions toward different paths. We recommend those considerations be explored and a more full analysis in the 2025 IRP.

That concludes our summary. Thank you.

MR. GOGGIN: Again, thank you for having me. My name is Michael Goggin. My testimony addresses, also transmission-related aspects of Georgia Power's 2023 IRP update.

First, I discuss the company's proposed transmission upgrades to accommodate the addition of the Yates combustion turbines. Georgia Power acknowledges that it failed to consider alternatives to those upgrades like battery storage, demand response, and grid-enhancing technologies that can be deployed quickly and cost effectively and can reduce or eliminate the need for these upgrades.

These solutions can be deployed in load pockets or other congested parts of the grid, alleviating the need for transmission upgrades to deliver power into those areas. These solutions are particularly effective for meeting short-duration needs of a few hours or less, such as those that arise during system contingency events, like the loss of a transmission line and/or generator.

Alone or in combination, these options can help serve as interim solutions until the company can plan and complete the longer-term transition expansion that I discuss later in my testimony.

In discovering -- and at the hearing last month, the company explained that it did not evaluate the potential to use battery storage to reduce or eliminate the need for the transmission upgrades to accommodate the proposed Yates CTs.

Batteries are modular, and as the company themselves notes, can be deployed quickly, making them highly effective for addressing localized near-term transmission needs.

Batteries' power electronics allow them to respond in a matter of seconds or less to regulate voltage and reactive power and address local stability constraints. It can also stabilize frequency by balancing supply and demand. Batteries also serve as capacity resources, reducing the need for the company's proposed generation issues, including the Yates CTs.

The company argues that it did not evaluate batteries as a solution for transmission upgrades because the need to charge the batteries causes them to serve as a load. This assumption is flawed because the charging and discharging of batteries is economically dispatched in response to system needs, so that batteries are never charged and always discharged during periods of need. Particularly, the short-duration needs that are driving the upgrades in this case.

Standard utility practice as well as the interconnection requirements under FERC Order 2023, allow batteries to specify their expected charging

and discharging behavior at the interconnection -- in the interconnection process to reflect how they will be actually dispatched.

Batteries are also attractive because, as we've discussed, the Inflation Reduction Act provides tax credits up to 40 to 50 percent. I'm including the 10 percent bonus credit for energy communities, such as -- which includes Plant Yates. So, I think, the timing is very fortuitous for this.

Demand response programs, non-firm or interruptible rate options and/or customer-sited resources like battery storage or back-up generators for either new or existing customers could also serve the strategic parts of the grid.

The company evaluated these on a system-wide basis, but does not appear to have factored the location-specific benefits of strategically siting these resources in congested areas for alleviating the need for transmission upgrades.

Well, many types of data centers operate high-load factors, crypto currency, AI, and other computing needs, often can be price responsive or respond to emergency needs such as a demand-response call, and this has been demonstrated or caught in other markets because the timing of those loads

could be shifted to either other data centers or to later in time.

Demand response is short duration, and fast response is also well-suited for short-duration needs. Finally, grid-enhancing technologies, like dynamic line ratings, power flow control devices, and topology optimization can also help to meet these interim and near-term needs because they can be implemented very quickly.

The next section of my testimony, I'll kind of briefly walk through that and then the final one, is kind of more the long-term plan as we avoid getting into the situation of having to rush into service transmission upgrades in the future.

I recommend a more effective transmission planning process that moves to proactive multi-value transmission planning. This has been established as the best practice in other regions and provides large savings for ratepayers by maximizing their net benefits and achieving economies of scale by investing in higher-capacity transmission. This optimizes the most benefits of transmission, including economics and reliability in contrast to the company's current practice of only meeting reliability criteria.

It also proactively plans to meet expected changes in the generation mix and load patterns and load growth over the long-term. It could also be co-optimized with generation planning to give you truly integrated resource planning.

This long-term planning can identify more cost-effective solutions than the high cost and low-capacity upgrades that have been proposed in this proceeding. In the interim, while the company moves to that planning process and begins developing those transmission lines, the alternatives I've outlined can be used to meet the nearer-term needs.

Finally, we'll talk about the -- my testimony talks about the Yates CTs and the fact that the company has applied to use energy resource interconnection service instead of network resource interconnection service. And that is an important distinction because energy resource interconnection service can be curtailed during periods of peak need depending on the availability of transmission.

Capacity of resources, like the Yates CTs, are typically studied as network resource interconnection service to verify that they will be able to deliver their full output during times of need, whereas, energy resources are -- that is not

evaluated. They are, basically, studied with -- that they can deliver their energy on an as-available basis.

Because of the company's choice to use, energy resource interconnection service, there's a risk that the resources will be curtailed during peak periods, that they will not be able to designate it as capacity resources because there's not going to be -- there may not be sufficient transmission capacity.

This is the company that -- this is a risk that I think the company should quantify and clarify to allow the Commission and others here an understanding -- or ability to understand if these truly will serve as cost-effective capacity resources. Thank you.

MR. THOMAS: Mr. Chairman, the panel is available for questions from Commissioners and cross-examination.

CHAIRMAN SHAW: Thank you, Mr. Thomas.

Commissioners?

VICE CHAIRMAN ECHOLS: I have a couple of questions.

Mr. Goggin?

MR. GOGGIN: Yes.

VICE CHAIRMAN ECHOLS: Is that right? Just on that last couple of sentences you were talking about, the network resource versus energy resource. Help me understand this. Is the network resource, I guess, certification or study -- I'm not sure, precisely, what the right word is. Is it more costly? Is it more difficult to perform? Is that why maybe -- does it take longer? Is that maybe why the utility didn't go that way?

MR. GOGGIN: That's a possibility. It does typically take longer. It's a more intensive study process. Typically, the reason a resource would specify the energy resource as opposed to network resource, is the amount of upgrades that are going to be required. It implies -- you know, if you do network resource study, that implies, typically, more upgrades which has a higher-price tag and also a longer timeframe to complete those upgrades before the resource, can then come online.

And so that's typically the reason why something would apply as an energy resource is to reduce the time and cost burden for those upgrades.

VICE CHAIRMAN ECHOLS: So the CTs at Yates that you were referencing, would they in any way be throttled back or not able to -- not able to be

available because we didn't pursue it as a network resource, or does it not make any difference?

MR. GOGGIN: Thanks, Commissioner. I do believe that is a potential risk. Energy resource interconnection service, according to Southern Company's own Open Access Transmission Tariff, and I cite the relevant language in the footnote in my testimony, says that energy resource is -- only gives you use "as *available" of the transmission system. And so that means that you would be curtailed, you would have lower-priority service than resources that have paid for network resource interconnection service.

VICE CHAIRMAN ECHOLS: And would they have only pursued the energy resource study because they're only using the CTs for winter peaking? Is that -- would that be a rationale?

MR. GOGGIN: It could be. I would just be speculating on why the company did something. I don't know for sure.

VICE CHAIRMAN ECHOLS: Mr. Smith; is that right?

MR. SMITH: Yes.

VICE CHAIRMAN ECHOLS: You were talking about the voltage study, the more comprehensive study

was -- now, were you talking about the network versus energy? Was that what you were referencing, or was it something else?

MR. SMITH: No, this is a separate and more detailed set of studies that is necessary to fully study transmission upgrades.

MS. PALACIOS: Yeah, I can take it up.

The stability analysis that we're talking about is essentially a full study to understand not just the thermal impacts, but also the voltage impact. So that's a separate ball of wax than the ERIS versus -- or the energy versus network study.

VICE CHAIRMAN ECHOLS: Also, Mr. Smith, were you saying that the CT units at Yates won't be available right away after they're done because of the transmission constraints that might be done later?

MR. SMITH: So according to the company's testimony, there are 600 megawatts of capacity available until the upgrades are complete. So that's a limitation that will exist until these projects or other projects can solve the issues were brought online.

VICE CHAIRMAN ECHOLS: Which takes longer to do, the transmission or building the CTs, do you

think?

MR. SMITH: I'm not an expert.

MS. PALACIOS: Typically, it's the transmission because you have to coordinate outages. You also have to coordinate rights-of-way acquisition. And CTs, you know, you typically -- you can get those imported. And typically, what I've seen, transmission can take longer depending on the land availability and what you're building out.

MR. GOGGIN: And if I can chime in, I believe the timeline the company has put forward here does indicate that the transmission upgrades are going to take longer. The fact that they would be limited up to 600 megawatts, you know, the CTs can be done before the transmission.

VICE CHAIRMAN ECHOLS: Okay. Last question, Mr. Smith, you were talking about power flow technology and some other line enhancements. Are you sure those haven't been done extensively on the Georgia Power system, or are you speaking specifically that you know they need to be done, or are you just giving best practices?

MR. SMITH: So I think there's two points being made. In the case of this study -- or these studies, the company provided data response listing

the solutions that they considered. And they were limited to redispatch operation and some reconductoring and rebuild of line, so very limited set in this particular case.

Beyond that, we were talking -- and we have a section in our report, as well as -- Mr. Goggin, as well, about best practices. So it's sort of both in this case.

VICE CHAIRMAN ECHOLS: Okay. Thank you-all.

CHAIRMAN SHAW: Any other questions?

COMMISSIONER PRIDEMORE: I do. I have some. I have some questions for Mr. Goggin.

So when I went through your testimony, I knew you were familiar to me. So on page 1, on line 16, the question was answered, if you've ever testified before the Commission before or this Commission. And I'll give you your exact answer: "Yes. I've testified before the Georgia Commission in the last three Georgia Power Integrated Resource Plan cases in '22, '19 and 2016."

I think it's important, for the record, to specify, though, you did not testify on behalf of staff. You testified in 2019 and 2022 for the Southern Renewable Energy Association, which is represented in this case by Simon Mahan and

Whit Cox, and then, in 2016, by the Southern Wind Association.

The Southern Renewable Energy Association has -- as long as I've been on this Commission, has tried to encourage this Commission look at joining a regional transmission operator and has pushed RTOs as a solution. And so -- I don't know a lot about transmission, but I know some things. And I mostly knew, kind of, how Georgia stacks up against RTOs and the use of lots of different technologies but in particular GETS.

Was it considered, when you wrote your testimony, that the standard GETS is used frequently by Georgia Power within their transmission assets, such as dynamic line ratings and power device controls that those are commonly deployed and may not necessarily be in the detail of a prefiled testimony?

MR. GOGGIN: You are correct about who I've appeared for in those previous proceedings. On that specific question, I would echo Mr. Smith in saying that, what we were saying is that they were -- those solutions, the grid-enhancing technologies, were not evaluated in this proceeding as a way to avoid -- either eliminate or reduce the need for the

transmission upgrades.

And so that's what we're saying is that Georgia Power did not evaluate, you know -- and there's always an opportunity to do more with -- you know, there's a whole suite of grid-enhancing technologies, there's -- you know, it can also be combined with demand response and battery storage technologies. And so we're just saying that Georgia Power did not evaluate that opportunity to do more.

COMMISSIONER PRIDEMORE: Did you -- you mentioned an example about SPP on page 11 of your testimony. Why did you not provide examples in your testimony of utilities use of GETS or transmission planning outside of an RTO or ISO?

MR. GOGGIN: I only cited that one example because it had a Brattle Group analysis that was particularly focused on the issue of using grid-enhancing technologies to enable the interconnection of new resources. That seemed most relevant for the case here.

COMMISSIONER PRIDEMORE: Are you familiar that the Brattle Group commonly looks at vertically integrated deregulated markets and tries to encourage them to join market structure such as PJM?

MR. GOGGIN: I've seen the Brattle Group

testify to the fact -- that effect. The Brattle Group has a very large electric practice, so I think they say a lot of things.

COMMISSIONER PRIDEMORE: Okay. All right. Thank you, Mr. Goggin.

CHAIRMAN SHAW: Is that it?

COMMISSIONER PRIDEMORE: Yes, that's it. Thank you.

CHAIRMAN SHAW: All right. We will move on down the list for cross, starting with Advanced Power Alliance.

MR. CARVER: Thank you very much, Mr. Chairman.

CROSS-EXAMINATION

BY MR. CARVER:

Q. Panel, I'm Brad Carver on behalf of the Advanced Power Alliance. I've got some questions in particular for you, Mr. Goggins.

So as has been alluded to, you testified in the 2022 IRP, and in that same hearing, we represented the Georgia Large Scale Solar Association and the Advanced Power Alliance. And as you know from that testimony -- or from that hearing, we represent the utility-scale solar industry in Georgia, which does offer the lowest-cost choice of electric supply in the state.

So could you point to -- and at the time, you

testified in 2022 that should certain transmission upgrades and battery storage be deployed across the state, that that would unlock a lot of potential -- it would unlock a lot of potential siting locations in the state for utility-scale solar; is that correct?

A. (Witness Goggin) That's correct.

Q. And how would you compare -- because that was in 2022, so that's two years ago, this time two years ago.

Is your testimony today that that would be similar?

A. (Witness Goggin) If not greater, yes. As I mentioned, the availability of Inflation Reduction Act, credits for battery storage, I think, created a lot of opportunities to make those even more cost-effective and use them as transmission solutions. And, you know, I think there's a lot of just fundamental market changes, as well in terms of cost reductions, the IRA has a number of other credits for, you know, renewables, you know, moving solar to production tax credit. All these things, I think, further tip the scales towards, you know, the value that you can get out of greater access to those resources through transmission and batteries.

Q. Well, if I can, I'd like to point you to page 5 of your testimony, lines 12 through 14. You testified,

"This could also buy time for the company to bring online more cost-effective generation and capacity resources and the transmission required to deliver them to load."

Could you elaborate on what you mean by short -- basically, shorter-term solutions that could unlock better options for the ratepayers in the long-term?

A. (Witness Goggin) Sure. It's three main strategies that I was talking about in my summary. The strategic siting of battery storage, demand response and other demand solutions, and grid-enhancing technologies as -- all of those can be implemented very quickly. In the case of grid-enhancing technologies, in the matter of months, you know, battery storage and demand response, somewhat longer than that.

But these can be very powerful interim solution that can be, you know, strategically sited. They're very flexible in where they can be located. And that makes them very valuable in buying time for these longer-term upgrades to be completed.

Q. So let me turn you now to page 7 of your testimony, and it's lines 2 through 5, where you say, "Georgia Power can use strategically sited batteries as an interim solution."

So what would be the benefit to Georgia Power

ratepayers if that was done to the Georgia Power grid?

A. (Witness Goggin) Well, certainly, with the investment tax credit and recent declines in the cost of battery storage, they are very effective, and they provide a whole host of services. They are capacity resources. They can provide peak energy. They can serve as transmission assets and defer or eliminate the need for these upgrades because of their flexibility and ability to provide, you know, voltage reactive support and services like that.

So they can basically -- that value stack allows them to meet a number of needs and save costs in a very beneficial way for customers.

Q. So to elaborate on that, you're saying that if the investments are made in battery storage -- so, but, again, because you have to spend some to get this benefit. But can you elaborate on what that would mean in terms of -- I'm not talking exact numbers here, but how that investment could lead to significant savings for ratepayers?

A. (Witness Goggin) Sure. It would require evaluating the location-specific benefits of batteries, which the company has admitted it did not do in this case. And that's -- I think the primary recommendation we have is to look at those location-specific benefits of

batteries and how they can defer or displace the need for the proposed transmission upgrades.

That, I think is where -- we're just asking the company to look for ways to save ratepayers money by strategically siting those -- basically, finding applications of the batteries that offer benefits that are greater than their cost and pursuing those.

Q. Did you hear Mr. Trokey's testimony in the first staff panel today?

A. (Witness Goggin) Yes, sir.

Q. Okay. He referenced that there is a -- there's a battery storage RFP that's going to hit the streets here in 2024. That's for 500 megawatts. So from the 2022 RFP, we have the McGraw facility, approximately 170 megawatts, self-built from Georgia Power. But there was 500 megawatts that was to be procured from the market. That RFP is going to be in 2024. And in his testimony he said that what could be done is that we could add megawatts to that RFP.

Is that a way that this -- that we could attempt to put locationally beneficial storage on the Georgia Power grid?

A. Absolutely. I think that can be part of it. I think, also, looking at this locational value and making sure that's part of the analysis that's done in that RFP,

getting information from bidders, and then using that to evaluate those location-specific benefits, I think, would be valuable.

Q. But Georgia Power does have the best information where -- I mean, it's their grid -- their grid, they know where the constraints are. They know where the -- where the key locations that can unlock those potential value to the overall system.

So would you suggest that maybe that could be provided in a bid situation where the bidders could be told, Hey, these are the places that would be the most beneficial to the grid, and let the market compete?

A. (Witness Goggin) I believe that certainly could be done. I know I've seen -- I recall seeing similar things done in other procurement and solicitation, you know, some indication of areas that are particularly favorable. I think that could be done.

Q. Okay. Let's go to page 21 and 22 of your testimony. You discussed some of the differences in interconnection facilities. And the differences between interconnection facilities and network upgrades.

Are you familiar with that?

A. (Witness Goggin) Yes.

Q. Let me turn to that myself. You say -- let's see that's page 21, line 19, you say that for generators,

interconnection facilities are analogous to the driveway a resource uses to connect to the transmission system; correct?

A. (Witness Goggin) That's correct, yes.

Q. And because of that, you say the cost of interconnection facilities to assign to the interconnecting generator because the cost of those facilities can be directly attributed to that resource and network power does not flow across them.

That's -- I'm sorry, that's lines 21 and 22.

A. (Witness Goggin) That's correct.

Q. Okay. Now, you go on to contrast interconnection facilities with network upgrades. Can you summarize the difference in interconnection facilities and network upgrades for the Commission?

A. (Witness Goggin) Yes. So the interconnection facilities are kind of like the driveway where it's really only that one generator is using that, kind of, connect-to-the-bulk grid. The network upgrades are on that bulk grid. The network where all the power -- you know, bulk power from other generators going to other loads is all flowing on those network facilities. And so those network upgrades, therefore, have benefits that are --

Q. To the whole grid?

A. (Witness Goggin) -- to the whole grid that are broader than, you know, to just that one generator. So for that reason, there's typically a different -- the driveway is always allocated -- the cost of the driveway is always allocated to the generator because it's the only one using that. The network upgrades, however, can be more broadly cost allocated because they offer other benefits.

Q. So -- and I'm going to turn you now to page 22, so lines 3 and 4. You testify, "The network upgrades are public good and that all users of the transmission system benefit for them, including competing generators"; is that correct?

A. (Witness Goggin) That's correct.

Q. And then, lines 22 -- or, excuse me, page 22, lines 7 and 8, you say, "Assigning major network upgrades to an interconnecting generator is analogous to charging the next car entering a crowded highway, the full cost of adding another lane."

Is that a correct analogy?

A. (Witness Goggin) That's correct.

Q. All right. And then you urged the Commission to direct Georgia Power to undertake proactive transmission planning so that those lanes are added in a systematic way, which should reduce overall costs versus

adding them on an ad-hoc basis through interconnection applications; is that correct?

A. (Witness Goggin) That's correct.

Q. Now, I want to drill down, and I'm going to point you now to the top -- to this page 22 and then the top of 23 of your testimony, page 23. The information you cite there -- this is at the top of page 23, indicates that the cost building transmission upgrades for new generation can be many times less expensive if done through top-down planning versus bottom-up individual interconnection requests.

Can you please explain why that would be the case?

A. (Witness Goggin) It's primarily because of the economies of scale in transmission investment, and there's a table in my testimony that walks through the math on that. But the idea is that higher capacity, higher voltage transmission upgrades are much more cost-effective than lower voltage upgrades just -- primarily due to the amount of power that can flow across it. These higher voltage upgrades have a lot higher megawatt capacity, and so, therefore, the dollar-per-megawatt cost is much lower.

Q. So this multi-value transmission planning that you talk about, it identifies things that are -- things

like that are overloaded lines that need to be upgraded across the grid; is that correct?

A. (Witness Goggin) Yeah. It looks -- the idea of multi-value in particular is that it's not just focused on meeting reliability criteria. It also looks at economics and the other benefits of transmission. I outlined 12 benefits that FERC has identified for transmission, and it tries to maximize across some or all of those benefit categories as opposed to a kind of siloed planning where you plan lines just to meet reliability needs, and maybe over hear you're planning a line for interconnection -- generator interconnection. Multi-value planning attempts to address some or all of those benefits in one planning exercise.

Q. Well, let's go to that specifically. Page 18, I think, is where you have that table. Line 14 -- I want us to zero in on one part of it. It says, "Access to low-cost generation"; right?

A. (Witness Goggin) Yes.

Q. And, again, utility-scale solar pretty much produced cheaper in South Georgia than anywhere in the country. The issue is interconnection constraints. We have tons of projects that are in the queue, and we have a lot of these projects that could deliver -- could deliver value to the ratepayers but they're not being

done because of interconnection costs.

So would that be something that this multi-value transmission planning could unlock for Georgia?

A. (Witness Goggin) Absolutely. That is one of the biggest benefits of it.

Q. Thank you. And I believe in the 2022 IRP, when you testified, the numbers are pretty astounding in terms of -- if you put pretty limited upgrades to the transmission grid, that the value to the ratepayers because of delivering two- and three-cent-utility scale solar could be phenomenal numbers for the ratepayers of Georgia; is that correct?

A. (Witness Goggin) That's correct. And that's what has been found in these studies in other regions. And, you know, it's why others, like,, you know, including outside of RTOs, are moving to this proactive multi-value approach.

COMMISSIONER PRIDEMORE: Mr. Carver?

MR. CARVER: Yes.

COMMISSIONER PRIDEMORE: So these are studies. Who is doing this? Who is replacing high voltage, high capacity transmission with BESS right now?

And we have a lot of studies. We have a lot of research. We've got these groups that are out there

looking at it and proposing this as a solution. I mean, I'll ask you the same question I asked the first panel, because I feel like I need a battery engineer.

If what is being proposed by staff in this case is a two-hour lithium ion battery, the battery is going to be most necessary -- I mean, two hours doesn't even -- doesn't even get me to the nightly news after the sun has gone down, you know. It's certainly not getting me the "Jimmy Fallon Show."

So, I mean, think about that in terms of what the value of that from a time period is, is it -- a two-hour lithium ion battery, we're going to have to have a lithium ion battery on every utility-scale solar array the size of Mercedez-Benz Stadium to be able to capture or hold and then be able to turn that and generate that energy back out. I'm not getting it.

MR. GOGGIN: Commissioners, particularly here, what I'm focused on is the use of batteries as a transmission alternative, and those can be very short duration. In footnote 5, I cite two analyses, one for New York, one for New England, where batteries have been found to be very effective for dealing with these contingency situations, which are

short duration, you know, where you lose a generator or you lose a transmission line.

And basically you need to maintain the transmission system stability and reliability during that interim period while you restore the transmission system or restore generation.

And so a short-duration battery is ideal for that. It's also because the batteries have the voltage and the reactive power control through their power electronics. They can ensure that stability is maintained. And so that's really what we're talking about here. So it doesn't require a lot of duration to have this ability.

COMMISSIONER PRIDEMORE: But in your ISO New England example, you're using it only in the case of where there's like an interim power loss, a power blip, so to speak. You're not using it for the needs to be able to transport capacity from what Mr. Carver is talking about, to be able to send it to the load center of Atlanta.

MR. GOGGIN: Well, in that situation, what can be done, and this is how it's used in some locations, is the battery will clip the power, you know, the midday, you know, solar over-generation, and then store that up until, you know, the evening,

you know, once the sun is setting or has set. And then it buys you, basically, into that peak net-load period. It allows you to shift that solar that would have been curtailed and serve that energy in the capacity in the peak net-load period.

COMMISSIONER PRIDEMORE: But is it only keeping two hours?

MR. GOGGIN: I mean, it can be longer. I mean, four hours is standard for many batteries. It just depends on what your system need is. I know in past proceedings, the company has done analysis showing the capacity value of battery storage at different durations and at different penetrations of solar.

Batteries work very well with solar because solar itself shortens the duration of peak net load. Basically, what happens is you have solar in the afternoon. So peak load -- when you have a lot of solar on your system, you know, traditionally it was, you know, 3:00 to 7:00 p.m. in the summer.

When you have a lot of solar, you've got really good sun from 3:00, 4:00, 5:00 p.m., maybe even into 6:00 p.m. in the summer. And now your peak net load is, like, you know, 7:00 to 9:00.

COMMISSIONER PRIDEMORE: Right.

MR. GOGGIN: And so a two-hour battery can fill

that because when you have so much solar, whereas in the old system, without solar, you needed a longer duration.

COMMISSIONER PRIDEMORE: But on a 24-hour a day, I'm still, what, maximum, at 13 hours of capacity? Say, if I've got a four-hour battery, I'm at 15?

MR. CARVER: You've still have got all the base load power.

COMMISSIONER PRIDEMORE: But that's the question, because that's the point of the case, Mr. Carver, is that you need the base load. You've got to have the interruptible. You've got to have the gas. You've got to have the nuclear. You've got to have the coal, because that's where the load is served.

And a battery -- if a battery would get you from sundown to sunup, I think this is a different conversation, but they're simply limited, which I believe -- isn't that more risky as a replacement for transmission?

MR. GOGGIN: Commissioner, it's certainly the case that to have a cost-effective system, you will need energy resources overnight. And, you know, in mid-regions, that's wind energy. You can -- with

new transmission, that could be deliverable here. But there's a mix of other resources, existing resources primarily, that would serve as that, I think, in the interim.

MS. PALACIOS: And, additionally, Commissioner, while I'm not a battery engineer, I am an electrical engineer, and so I do understand the concept of batteries as a resource, as a transmission resource. And the upgrades that the company has proposed are for these temporary-outage scenarios, under contingencies, under generators being out, with lines out.

So a battery can act as a temporary resource under these special scenarios rather than paying millions of dollars to do a, you know, a 15-mile long transition line build and interrupting homes and businesses and taking outages. A battery can act as a temporary stop gap.

COMMISSIONER PRIDEMORE: Ms. Palacios, at the end of the day, a transmission line attached to dispatchful energy is guaranteed. There's a reliability consideration in that. That's not playing with battery technology to serve your blips.

Go ahead.

MR. CARVER: I'll just ask this comment. I

mean, even if all our coal plants in Georgia were eventually closed, we still have the two units at Hatch and four units at Vogtle that are going to be operating for the next 40, 60, 80 years; is that correct? And that's baseload resource that operates 24 hours a day.

MR. HEWITSON: That wasn't, at all, part of any of their testimony. I appreciate the nod to nuclear, but let's talk about their testimony.

MR. CARVER: All right. Fair enough.

BY MR. CARVER:

Q. All right. So in this IRP update, Georgia Power has proposed battery storage at three sites: Robins Air Force Base, Moody Air Force Base, and then a 200-megawatt utility-scale solar project. There'd be a 200-megawatt battery that'd be co-located with that 200-megawatt utility-scale solar project.

Would there potentially be benefits to pairing battery storage at some of the other very large utility-scale projects in the state?

A. (Witness Goggin) Potentially, I think this is the type of analysis the company should do and find what are the optimal sites for that, you know. There are attractive reasons to co-locate or locate batteries near solar, you know, the capturing of the curtailed solar

energy and shifting until the peak net-load period is part of that. It allows you to deal with some of the transmission interconnection issues.

So, I mean, that can be attractive, but batteries can also be, effectively, located in load pockets. They're very modular. And, in this case, you know, what we're really focused on is meeting localized need for transmission upgrades. And batteries can serve that need. Typically for that you want to put them in a load pocket, not, you know -- it's a different issue with solar.

So, I think, if we're trying to avoid the need for transmission upgrades due to load growth, you may want to look at putting them at other locations. But that's the analysis that we're suggesting the company needs to do, look at where it can use batteries at strategically sited places to displace the need for the transmission upgrades.

Q. And from your testimony, I mean, it seems that you support large 500 kV transmission lines because of the economics of scale that the very large transmission lines would bring; is that correct? I mean, you're not testifying that we shouldn't be relying on transmission lines.

A. (Witness Goggin) Well, absolutely. I mean, I

think batteries are particularly useful as an interim solution while we plan and build that longer-term transmission, that is, I think, going to be a big part of the long-term solution. So I think we need both. I think batteries work really well as an interim solution while we develop the longer-term solution.

Q. Okay. All right. So my final question is -- you also were asked, because you are very familiar with RTOs and SREA, in the past, and the Wind Association has supported RTOs. We don't have an RTO in the Southeast.

Are there -- can we remain the way the system is in the Southeast without an RTO? But are there changes we can make in the existing system to make it to unlock better value for the ratepayers and the opportunity to interconnect with adjoining utilities?

A. (Witness Goggin) Absolutely. All the recommendations I've made, I think, are equally applicable with or without an RTO, you know. The use of these interim solutions can be done -- and it may even be easier without an RTO for some of these, just to kind of -- with an integrated, vertically integrated system, you can kind of unilaterally go out and plan and pay for this transmission, you know, as -- you know, the interim transmission solutions.

You know, the proactive multi-value planning

that has been done in RTOs, it's being done in non-RTO places, as well.

Q. Well, you testified about Duke Energy; right? I mean, isn't that -- they're not in an RTO?

A. (Witness Goggin) Correct. I am currently engaged in those cases in the Carolinas, and we've been pushing it. And now they are adopting -- Duke is adopting proactive multi-value transmission planning. They see it as the most cost-effective way to accommodate the changes in the generation mix and the load growth they're seeing.

MR. CARVER: Thank you very much. That's -- I have no further questions. I appreciate it.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone?

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: Georgia Associations of Manufacturers.

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

MR. HUBBARD: No questions.

CHAIRMAN SHAW: Georgia Coalition of Local

Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MS. WHITFIELD: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND?

(No response.)

CHAIRMAN SHAW: Georgia Watch?

(No response.)

CHAIRMAN SHAW: MARTA?

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft?

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

Mr. Baker, notice I'm talking faster than normal.

MR. BAKER: Too much caffeine.

CHAIRMAN SHAW: And I'm from South Georgia.

MR. BAKER: You can tell the difference.

CROSS-EXAMINATION

BY MR. BAKER:

Q. Just a few questions for y'all, starting with

Mr. Smith and Ms. Palacios.

In your opinion, are transmission needs being driven by new large loads or the development of new peaking assets? Or both.

A. (Witness Smith) I would say both. There's -- you know, this case is about new loads and the need to serve those loads. And both loads and generation come with transmission requirements.

Q. At page 4, you have some recommendations, and your third recommendation is, "The company should consider expanding its potential transmission solutions to include non-wire alternatives, as well as new substations and/or the right-of-way solutions, to ensure robust test, to find the most cost-effective solution."

Have these alternative methods been used elsewhere to address large capacity issues such as the three Yates CTs?

A. (Witness Smith) I mean, I'll turn it over to my panel mates, as well, but I would say that's the conversation that we've just been having about both the potential for smaller, quicker solutions to work in the interim, as well as the potential for larger, more cost effective solutions to facilitate Georgia's longer-term needs.

Q. I understand, but has anybody actually done it?

Anywhere? Any utility?

A. (Witness Palacios) Yes. In my experience as a transmission planning engineer, when you plan a large facility or large upgrade, in this case, load additions that are paired with generation additions, you would typically look at finding a solution that is a more holistic solution, that isn't just a -- I guess the low-hanging-fruit solution.

Q. Can you point to one utility that has done that?

A. (Witness Palacios) In my experience at Center Point Energy, I have done that, yes.

Q. Okay. All right. Scenario A-1 assumes Gaston Units 1 through 4; Bowen Units 1 through 4; and Scherer Unit 3 are not retired as scheduled but extended for service from 2028 to 2035.

Would the extensions of these units require any transmission changes or additional expenses? I'm referring to page 12, the chart on page 12.

A. (Witness Smith) I don't know that they've studied -- in the 2022 IRP, which we were not part of, but my understanding is that some of those units were targeted for retirement. In my experience, when a unit is considered for retirement, transmission studies have to be performed to ensure reliable execution operation of

the grid without those units there.

Assuming that was done, there may have been costs at the time for their retirement that may not apply if they aren't retired. So, I guess, broadly, changes in the grid, whether it's new generation or reduced generation new load, all come with the potential for transmission cost. But I don't know that there's been a study. And we certainly didn't investigate whether the change in assumption of those changed the -- any costs to the transmission grid.

Q. Okay. So if those units were extended through 2035, you don't know of any additional transmission charges or costs that would be incurred?

A. (Witness Smith) I'm not aware of any.

Q. Okay. All right. Mr. Goggin, I have a question for you, sir. Referring to page 13 of your testimony.

Do you agree with the company's transmission cost estimate of $60 million for the new Yates CTs?

A. (Witness Goggin) That's the current estimate. This is -- some of this is trade secret, so I've got to be a little careful. But, basically, if you include the all-in cost of some of those projects, it is significantly higher.

Q. Okay. So you don't agree with the $60 million

figure is higher than $60 million?

A. (Witness Goggin) I believe so. For the entire project, yes.

Q. Okay. Would it be closer to the original amount that the company cited to of approximately $79 million?

A. The all-in cost for the full transmission projects is higher than that, even.

MR. BAKER: Okay. All right. Thank you very much.

CHAIRMAN SHAW: Thank you.

Sierra Club.

MR. MAHAN: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy Association.

MR. MAHAN: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. MCNUTT: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power.

MR. HEWITSON: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q. Good evening. Steve Hewitson on behalf of Georgia Power Company. Let me start with the Daymark analysis, if I can. On pages 20 and 21, you discuss the impact of including units in the transmission studies that are slated for retirement by the end of 2028. That's, I believe, what Mr. Baker was just talking to you about a couple of minutes ago. Do you see that testimony?

A. (Witness Palacios) Yes.

A. (Witness Smith) Yes.

Q. If those units had been assumed to be retired starting in 2029, the generation from those units would not be in the transmission analysis for the Yates project; right?

A. (Witness Smith) Could you just rephrase that, make sure that I...

Q. If they had assumed that the units had been retired in 2029, then there would be no generation from those units post 2029 in the transmission analysis; right?

A. (Witness Smith) Yes.

Q. Okay. But if they do not get retired when they're currently scheduled to, you end up with additional generation on the system post-2029; right?

A. (Witness Palacios) Correct.

A. (Witness Smith) Or the potential for it, dispatch being what it is, but yes.

Q. Right. And that could impact the transmission analysis, would you agree with that?

A. (Witness Smith) Yes.

Q. On page 24, lines 14 to 15, you testify that there was no transmission screening analysis of the Plant Yates projects below the full capacity of 1350-megawatts for the three CTs; right?

A. (Witness Palacios) Correct.

Q. Did you review all of the information submitted by the company in this proceeding?

A. (Witness Smith) I mean, we reviewed all the transmission files that were provided to us.

Q. Did you review the transmission supplemental filing from January 19th of 2024?

A. (Witness Palacios) Yes, we did.

Q. Did you see in that filing the load flow analysis with Yates limited to 600 megawatts?

A. (Witness Palacios) Yes, we did.

Q. Okay. So Georgia Power did study Yates at 600 megawatts generation; right?

A. (Witness Smith) Fair enough. I think we call that out somewhere in our testimony, so this probably

should have been at no increments between the 600 and the 1350.

Q. Now, Daymark undertook an indicative analysis of Yates if it was limited to 900 megawatts; right?

A. (Witness Palacios) Correct.

Q. Would you agree with me that when Georgia Power studies transmission needs for a given project, they should study the project as proposed and not every possible iteration of the project?

A. (Witness Palacios) No.

Q. Well, what if there was limited time to do the transmission analysis?

A. (Witness Palacios) Doing a sensitivity analysis with various sizing shouldn't take very long, shouldn't add too much additional time.

Q. On page 26, lines 12 to 15, you note that if only two CTs are needed at Yates, the transmission needs may be different; right?

A. (Witness Palacios) That's correct.

Q. And you would expect if the project changed like that, that Georgia Power would review the transmission needs of that project as revised; right?

A. (Witness Smith) If you're asking if, say, two CTs were approved and not a third, then transmission analysis would be done on the basis of that, and plans

would be adjusted to reflect that. Yes, I would expect that.

Q. Okay. And on page 30, lines 15 to 19, you mention the voltage and stability studies that will be completed for the 2025 IRP. Are you familiar with the company's ten-year planning process?

A. (Witness Palacios) Familiar, but I don't have it memorized.

Q. Are you aware that all transmission projects are studied on an ongoing basis through that annual process?

A. (Witness Palacios) I wasn't aware.

Q. Are you aware that some projects may be added, some may be removed, and some may be altered during that annual process?

A. (Witness Palacios) I wasn't aware.

Q. And that would include projects identified for Plant Yates, the projects that you reviewed, are not necessarily set in stone, if, as I said, during the annual transmission planning process they are reviewed again; correct?

A. (Witness Palacios) That would make sense in the context of the questions you asked.

Q. Okay. And are you aware that voltage and stability studies are also part of formal interconnection

study process in Georgia?

A. (Witness Palacios) Yes, we are.

Q. Now, I want to turn your attention specifically to project 7 and 8, and Georgia Power's requesting the IRP update is not necessarily for a specific list of projects, but rather for the transmission system improvements to accommodate the resources; right?

A. (Witness Palacios) I'm going to have to ask you to restate the question. I was flipping pages.

Q. Yeah. Sure, no problem. Georgia Power's request in this IRP isn't necessarily for the specific projects that you were talking about, but rather for the transmission system improvements to accommodate the resources going on in the system. Isn't that the request in the company's IRP filing?

A. (Witness Smith) I guess -- how best to answer this? They requested transmission to support the resources that they have identified is as required to meet the loads that they forecast. And they have provided analysis and additional support identifying what those projects are, including for Plant Yates, a number of projects that they've specifically identified and accumulated estimated costs for that we evaluated, that included those two projects.

Q. Right. But the specific projects get evaluated

during the annual ten-year planning process; right?

A. (Witness Smith) I will take your word for their process of updating their analysis, but for the purposes of this proceeding, they were identified as these specific projects that solved the transmission needs identified and the dates that those transmission needs came about.

Q. Okay. I'll accept that, Mr. Smith. Thank you.

On pages 28 and 29, you discuss non-wire alternatives. You discuss a few emerging transmission technologies that you would have liked to have seen studied for the Yates project; right?

Would you agree with me that emerging technology is called emerging because it hasn't been tested in the real world sufficiently and no one exactly knows the true capabilities or operational considerations?

A. (Witness Palacios) No.

Q. Well, do you believe it would be prudent for Georgia Power to rely on untested emerging technologies to meet the company's immediate needs?

A. (Witness Palacios) I would say they're untested in Georgia.

Q. Okay. So do you believe that it would be prudent for the company to use untested means to meet its

transmission needs?

A. (Witness Palaios) I wouldn't characterize them as untested. These are...

Q. Okay. Well, the first one you mention is dynamic line ratings or DLR. I believe it's also known as real-time thermal ratings; right? Do you know it as that as well?

A. (Witness Palacios) That's correct.

Q. Okay. And DLR is a transmission operation philosophy aimed at maximizing load on lines where environmental conditions allow it. Is that a fair statement?

A. (Witness Palacios) Yes.

Q. Would you agree that it's more of a real-time operational tool than a long-term planning tool?

A. (Witness Palacios) Typically, yes, but it can be used in the long-term planning cases.

Q. Are you aware of any utilities that are using DLR as a long-term planning tool right now?

A. (Witness Palacios) I believe so, yes, but...

Q. Which would those be?

A. (Witness Palacios) I don't recall any off the top of my head. I deal with a lot of files. I can't remember.

Q. Okay. Well, we may as well give you some time.

MR. HEWITSON: Can we make that a hearing request for them to identify the utilities who are using DLR as long-term planning tools?

CHAIRMAN SHAW: Yes, sir.

MR. HEWITSON: Okay. Thank you.

COMMISSIONER PRIDEMORE: Could we add RTOs and ISOs to that who are in charge of transmission?

CHAIRMAN SHAW: Yes.

COMMISSIONER PRIDEMORE: Thank you.

MR. SMITH: And I'll just note that that will have to be subject to us knowing it in a way that we can communicate it. We have to check for confidentiality as well before we will be able to answer.

BY MR. HEWITSON:

Q. The next technology you talk about is topology optimization software; right?

A. (Witness Palacios) That's correct.

Q. Okay. Are you aware that Georgia Power already evaluates topology optimization through transmission operating guides?

A. (Witness Palacios) Yes.

Q. Okay. And the last one, flexible AC transmission system devices, or FACTS, are devices that can help steer power to lines that have capacity; right?

A. (Witness Palacios) That's correct.

Q. Are you aware that Southern Company has deployed FACTS on its transmission system?

A. (Witness Palacios) I wasn't aware of any, but sounds like it's plausible.

Q. But it stands to reason that if FACTS is a tool that would prevent transmission upgrades, or topology optimization as a tool that would prevent transmission upgrades, Georgia Power is aware of it, right, since it deploys them and uses that software?

A. (Witness Palacios) Well, I can't speak to what Georgia Power is aware of. I think from the context of our testimony, they did not make it evident that they evaluated those as options in particular the Plant Yates upgrades.

Q. Mr. Goggin, if I remember correctly -- by the way, welcome back to Georgia.

You are not an engineer; right?

A. (Witness Goggin) That's correct.

Q. Okay. And you are not transmission planner; right?

A. (Witness Goggin) That's correct, although I've done a number of cases related to transmission planning.

Q. But you never designed a transmission system or planned for transmission system upgrades for utility,

have you?

A. (Witness Goggin) Not for a utility. I've participated in planning studies, but...

Q. You participated in planning studies as a subject matter expert or as an engineer, or just you participated as a participant in planning studies that are open to the public?

A. (Witness Goggin) I've been invited to be on the technical review panel for various transmission studies that have been conducted.

Q. In what role?

A. (Witness Goggin) As a reviewer, technical reviewer.

Q. As a technical reviewer?

A. (Witness Goggin) Yes.

Q. Okay. And what were those? Which studies were those?

A. (Witness Goggin) The Eastern Wind Integration Transmission Study, the Joint Coordinated System Plan, the Western Wind & Solar Integration Study, the Interconnection Seam Study, the Southwest Power Pool Wind Integration & Transmission Study.

There's probably others I can't remember. The Eastern Interconnection Planning Collaborative, I was part of that, those studies, about ten years ago. Short

list, there's probably more.

Q. Okay. On page 2, lines 4 to 7, you mention battery storage, demand response, and grid-enhancing technologies that you say can be deployed quickly and can cost effectively reduce or eliminate the need for these grid upgrades. Do you see that testimony?

A. (Witness Goggin) Yes.

Q. Okay. The grid upgrades you are talking about are transmission upgrades to accommodate the addition of the Yates CTs; right?

A. (Witness Goggin) Yes, and make it deliverable to load, yes.

Q. And those transmission upgrades are estimated to cost around 60 million; is that your understanding?

A. (Witness Goggin) In your estimate, yes.

Q. Okay. Did you perform any analysis to identify a specific battery storage solution that would eliminate any of the specific transmission upgrades identified for the Yates CTs?

A. (Witness Goggin) My recommendation is that the company do that analysis because you have the information to do it.

Q. You didn't perform any analysis or provide any examples or specifics?

A. (Witness Goggin) I don't believe I have access

to information that would allow me to do that.

Q. On page 6, lines 1 to 3, you mention the economic dispatch of batteries, and then on that same page on line 13, you testify that batteries also serve as capacity resources, which may reduce the need for Yates CTs. And I just want to clarify here, are you suggesting that the same batteries used for transmission planning can be used for generation?

A. (Witness Goggin) Yes, batteries can serve both, it depends. I mean, obviously, you can't -- sometimes -- again, batteries have value stack. And at some periods of time, some uses are inconsistent with other uses. You obviously can't use the same megawatt to do two things, you might have to do both at the same time.

But short of that, it is often possible to use the battery to do different things at different times, or sometimes it can do two services because they are doing different things, like, you know, downward flexibility can be provided on a capacity resource, for example.

Q. Okay. Would you agree that giving batteries double credit for capacity could be overstating the benefit of those batteries, if you give a credit for transmission and generation?

A. (Witness Goggin) The analysis would have to

carefully look at -- depending on what the use case is for the transmission, because that's a complicated analysis. The batteries have a lot of capabilities. Some of it is just the power electronics. Some of it involves, you know, the injection of power. So obviously an increase in injection of power would not be compatible with capacity resource, because it would already be maxed out.

So short of that, in general, you can often stack these values, and that's -- the analysis should account for that. Any interactions, any ability to provide two things at once should be accounted for in the value analysis.

Q. So do you agree it is not practical to discharge batteries economically for capacity purposes if it leaves them uncharged and unavailable when needed to address a transmission contingency?

A. (Witness Goggin) You're right. It could not be fully depleted and still serve as a contingency resource; however, you know, they have four-hour durations. So, you know, typically -- and typically, there's operating parameters on them and just for the longevity of the battery, they're not going to be, you know, discharged beyond a certain point. However, you can, if you really need to for contingency, then go

beyond that point.

So there's a lot of flexibility, but, yeah, I think the analysis, we need to look at all these things to figure out what values it can simultaneously provide or provide over different time periods.

Q. Now, any battery deployed for transmission contingency must be designed to be available for the length of that contingency; right?

A. (Witness Goggin) Either that or, you know, contingencies typically have, kind of, a step-wise process. You know, generation contingency, you know, you've got your spending resources that you need to start within 10 minutes, you've got non-spend that comes up within 30 minutes, and so there are different time frames in there.

You can also -- and my recommendation here was that batteries be studied in conjunction with, you know, the demand-based resources and the grid-enhancing technologies. And so it's a question of how do you use a combination of these, so it doesn't necessarily mean the battery has to last for the full thing, you know, the full duration of whatever you're trying to do.

Q. Okay. Well, let's use a specific example then. Let's say the contingency is the loss of a 500 kV line, right, and most of the overloads identified in the

transmission analysis were due to the loss of a 500 kV line in this case; right?

A. (Witness Goggin) Okay. Yes.

Q. You said "okay." Did you review --

A. (Witness Goggin) Yes. Yes.

Q. Would you agree that in the state of Georgia a common cause for the loss of a 500 kV line is damage due to a tornado or debris from tornadic winds flying into the lines?

A. (Witness Goggin) It's a possible cause, yes.

Q. Okay. And given the extent of damages, would you be surprised that a 500 kV line damaged by tornado-forced winds, may take a week to repair and get back into service?

A. (Witness Goggin) It depends, but it could. It could.

Q. Now, if you were to deploy a battery on the system for this scenario, that battery would need to be sized to be available and fully functional to charge and discharge to offset all overload conditions until that line is back in service; right?

A. (Witness Goggin) That's not correct. Again, the conditions that the company studied were, you know, short-duration demand, very high demand periods, coincident with contingencies on the transmission and

generation system. So it's really this perfect storm, and, you know, the transmission line might take a week. Generator contingencies, as I mentioned, you know, typically you're supposed to restore within 30 minutes. And then obviously peak demand periods have a shorter duration than a week, you know. It's a few hours typically. So, no, the battery doesn't need to deploy for a week straight.

Q. Okay. Are you familiar with NERC tpl-001-5?

A. Yes, sir.

Q. Are you aware of any battery system currently deployed in the United States today that serves as a NERC tpl-001-5 acceptable alternative to transmission project with the size necessary to cover the loss of a 500 kV line?

A. I don't think anybody has used a single battery for entire 500 kV line, but they can certainly help, and they can certainly replace lower voltage contingencies. I mean, again, it's not -- a single thing doesn't have to do the whole thing.

Q. What about a 230 kV line?

A. I'm not sure. I don't know.

Q. What about a l15 line?

A. I don't know. It's possible. Again, these technologies work together.

Q. On page 7, lines 9 to 14, you discuss locating batteries near expected loads to reduce the need for transmission upgrades. Do you see that testimony?

A. (Witness Goggin) I'm sorry. What page?

Q. Seven, lines 7 to 14.

A. (Witness Goggin) Yes.

Q. I think Mr. Carver sort of ended it near this area as well.

A. (Witness Goggin) Yes.

Q. Now, you wrote in your testimony that storage can be deployed in optimal quantities and at optimal points on the grid to reduce or defer the need for transmission upgrades. Do you see that testimony?

A. (Witness Goggin) Yes.

Q. Did you undertake any specific analysis of what the optimal quantity or where the optimal location would be to eliminate the need for the transmission upgrades?

A. (Witness Goggin) No. Again, that's the analysis I'm recommending the company do.

Q. If the transmission upgrades identified by Georgia Power in this case are on 115 and 230 kV lines, is that your understanding that the -- that most of the -- or all of the transmission upgrades identified by Georgia Power are on 115 and 230 kV lines?

A. (Witness Goggin) That's correct.

Q. They're not all on the same line, the projects are on different lines; right?

A. (Witness Goggin) Can you say that again? Sorry.

Q. Yeah. The projects are all not on the same 115 or 230 kV line, they're on different lines?

A. (Witness Smith) That's correct. They're generally at the same location but they are different lines, yes.

Q. So would you agree that there's no single battery storage project that would eliminate the need for all of the transmission projects?

A. (Witness Goggin) Probably not, but, again, there's no need for a single battery or even batteries alone to be able to solve this. Again, I think it's often in concert of, you know, these batteries, plus demand, plus grid-enhancing technologies that are going to either reduce or even potentially eliminate the need. So it doesn't have to be a single thing.

Q. Do you know what size battery would be needed to eliminate any of the transmission upgrade projects?

A. I mean, I could estimate based on, you know, the 600-megawatt limitation that the company put in based on the transmission upgrades, I mean...

Q. Did you do that analysis in your testimony?

A. No. Again, this is the analysis I'm recommending the company do.

Q. Okay. Do you know what duration the battery storage would be required?

A. (Witness Goggin) Again, this is part of the analysis the company should do, as I outlined, given the nature of the contingencies studied during these peak conditions. It doesn't need to be very long typically.

Q. But that's not provided in your testimony or in your analysis?

A. (Witness Goggin) No, it's a detailed analysis the company would have to do, based on its actual system model.

Q. Do you know how much those battery-storage projects would cost?

A. (Witness Goggin) So the analysis of the economics was not within my scope. I know generally, you know, what battery costs are, you know, with the tax credit and how that has reduced the cost. But, again, it's an analysis the company would have to do comparing the cost and the value.

Q. But in your testimony recommending the battery storage project should be studied to replace transmission projects, you did not provide any cost analysis of how much that would be; is that correct?

A. (Witness Goggin) It was not within my scope. That's correct.

Q. Now, batteries still need to be sited and interconnected to the system; right?

A. (Witness Goggin) That's correct, although they could typically be more easily interconnected because they can be flexibly dispatched, as I've talked about, and as FERC 2023 network requires. The timing of the charging and discharging can be timed so that it's not triggering overloads.

Q. Okay. And I'm guessing that you did not analyze how long it would take to identify a site for a battery storage project, and how long it would take to interconnect it to the system that eliminated any of the Yates projects?

A. (Witness Goggin) In the company's own testimony, and particularly in the hearing a month ago, was about how quickly, you know, in a matter of several years, these batteries can be brought online. So I -- you know, I refer to that, but I didn't do that analysis.

Q. Yeah. That was my question. You didn't do that analysis for the testimony, did you?

A. (Witness Goggin) No, I didn't. I pointed to the company's.

Q. So without doing any of this analysis, you

really can't say that a battery storage system can substitute for the Yates transmission upgrades in a cost-effective way, can you?

A. (Witness Goggin) Well, I mean, I have the company saying they can brought on with sufficient time. Other people have addressed the cost effectiveness of batteries. And I have, you know, outlined reasons to think that batteries are an important part of this solution for reducing or limiting the needs for these grades.

But that detailed analysis is beyond the scope or work ability of somebody without access to the detailed information that the company has. So my recommendation was for the company to do that analysis.

Q. Yeah. But in your testimony you said that battery storage projects could be deployed in a cost-effective manner to eliminate the transmission projects; right?

A. (Witness Goggin) I say, "These technologies alone or combination offer significant potential to reduce or defer the need for transmission expansion capital investment." I also say that they, you know, have potential to be cost effective. I think I appropriately caveated -- I believe I was careful in how I termed that.

Q. Now, generally you argue in section 3 of your testimony that Georgia Power should be focused on planning higher capacity solutions for transmission; right?

A. (Witness Goggin) That's correct.

Q. Okay. And on page 12, lines 12 to 16, you testify that the Yates transmission upgrades may interfere with the ability to deploy higher voltage transmission on that right-of-way; is that your testimony?

A. (Witness Goggin) I said they could even interfere with the ability.

Q. Do you know what it takes to change a 115 and 230 kV line to a 500 kV line?

A. (Witness Goggin) I mean, you would be rebuilding the towers. You need a larger right-of-way. There's a lot of -- it's a very different type of thing. And that was -- I think the point of my testimony is that, you know, the parallel circuits in this area we're talking about have a pretty wide right-of-way. It could be a more suitable location for moving to a higher voltage.

Again, that's a very detailed analysis that, you know, I, as an outsider, I just don't have the system information to do it. That's why I recommend the company

do it.

Q. Do you have any idea how long it would take Georgia Power to acquire additional rights-of-way to upgrade the -- any 115 or 230 kV line to a 500 kV line?

A. (Witness Goggin) It may not be necessary. Sometimes -- and I believe this is the case, at some locations we're talking about, their parallel circuits, you know, multiple parallel transmission lines. And so the right-of-way is quite wide, and so you could consolidate those, you know, four lower-voltage circuits into a single or two higher-voltage circuits, that's often possible, without needing a new right-of-way.

Q. I guess you're talking in theory. You haven't done any of the Georgia Power system to back that up, have you?

A. (Witness Goggin) Again, as I've said, this is an analysis that only the company can do, because it has the information on this.

Q. And I assume that you are aware that every piece of equipment touching the new 500 kV line would have to be changed to accommodate the increased voltage?

A. (Witness Goggin) Oh, sure, yeah. I mean, the terminals, you know, would have to have transformers and stuff. I mean, the company already has 500 kV transmission, so it has, you know, some of that

infrastructure depending on how the topography was configured. But, yes, it's -- I mean, there's a big difference between the 115 kV line and a 500 kV line.

Q. Right. And for your testimony did you calculate or analyze the cost of those upgrades at all?

A. (Witness Goggin) No, again, it was my recommendation that the company do that analysis.

Q. Okay. Now, on page 17, lines 2 to 4, you testify that Georgia Power's transmission planners only focus on reliability, not overall economic benefits for customers.

Do you see that testimony?

A. (Witness Goggin) Yes.

Q. You're aware that all NERC-registered utilities are required to plan to certain reliability standards, I imagine; right?

A. (Witness Goggin) That's correct.

Q. And is it your testimony that Georgia Power should put economic benefits ahead of reliability?

A. (Witness Goggin) No.

Q. Okay. Are you aware that Georgia Power already integrates its generation and transmission planning to identify the lowest cost option for customers while maintaining the required reliability standards?

A. I reviewed your planning criteria in detail,

and I've, you know, pulled out the various citations. What I did not see was a multi-value planning -- attempts to optimize across all of these. Lines are planned in silos, and the exclusive focus for most of the planning is reliability to meet these NERC criteria.

Some lines are getting planned in a separate process for generator connection, and then there is some -- it wasn't really fully described how it happens, but these problem statements can be combined if they're deemed to be potentially addressed by the similar solution. That's not an effective process.

Effective multi-value planning starts by identifying solutions that can solve multiple problems and then look to the value of that. And it's very different from what your approach is.

Q. Well, are you aware that Georgia Power proactively builds transmission to eliminate congestion and allow for the optimal economic dispatch of generation resources on the system?

A. (Witness Goggin) That wasn't really a driving factor in the planning documents I reviewed.

Q. So you're not aware of that?

A. (Witness Goggin) I didn't see any documentation of that in your documents. It's -- reliability was the driving factor in the document you

gave us in response to discovery when we asked about that.

Q. Well, you're aware of the Southeastern Regional Transmission Planning process or SERTP?

A. (Witness Goggin) That's correct.

Q. Now, in your critique of Georgia Power Transmission Planning process, you've never requested or reviewed modeling information available through the SERTP or from Southern Company, have you?

A. (Witness Goggin) Not through those processes, no.

Q. Have you actively participated in a SERTP meeting in the past three years?

A. I've looked at their meeting minutes. I've seen -- I know, I'm familiar with their process, and they also use a siloed process. There's separate categories for reliability and public policy and economic. And, again, that's not multi-value planning. That is siloed planning, which is the opposite of good multi-value planning.

Q. Okay. But in your -- you're critiquing the planning process without reviewing the documentation from that planning process?

A. (Witness Goggin) I've looked at the documents that are publicly available on the website. I've looked

at the studies. I'm familiar with what they produce.

Q. Okay. But you haven't requested anything specifically from SERTP or from Southern Company, have you?

A. (Witness Goggin) No. I mean, the studies are available generally, so no.

Q. On page 22, lines 9 to 18, you advocate that network upgrade costs should not be assigned to an interconnecting generator but rather allocated to all customers. Is that a fair reading of your testimony?

A. (Witness Goggin) I argue that there can be some broad, some broad cost allocation to reflect the benefits. Again, you know, the FERC standard is -- costs should be allocated broadly or roughly commensurate with the benefits, and because the benefits of high voltage network upgrades are broadly disbursed, therefore, the cost allocation should generally also be broad.

Q. Let me read the words that you put on the piece of paper and make sure I'm reading the same thing you are. "Assigning major network upgrade costs to an interconnnecting generator is analogous to charging the next car entering a crowded highway the full cost of adding another lane. Proactively planning the needed network upgrades and broadly allocating the costs to ratepayers is a more efficient and workable policy

similar to how costs for other public goods like roads and sewer systems are allocated."

Did I read that right?

A. (Witness Goggin) Yes, that's correct.

Q. Now, said another way, your position is that Georgia Power should proactively build out the transmission system to plan for additional load and generation, and then socialize the cost among all customers?

A. (Witness Goggin) No. Again, costs should be allocated roughly commensurate with benefits, which for high voltage transmission, which is all we're talking about here, these high voltage network upgrades, that is -- again, I would allocate that roughly commensurate with benefits. And you can do analysis of how those benefits are disturbed and allocate accordingly, but it generally is broad.

The individual interconnection facilities, again, the driveway for the generator, that's always going to go to that generator. That cost is always allocated to the generator. It's only these very high voltage network upgrades that have broad benefits. The cost allocations should reflect the benefits.

Q. Okay. Now, on page 28, lines 7 to 12, you argue that the Yates CTs are at risk of curtailing

because E-R-I-S, ERIS, service was requested, not N-R-I-S, NRIS. Is that your testimony?

A. Santa Rosa Combined Cycle Natural Gas Plant, Yes.

Q. And ERIS and NRIS are interconnection service types; right?

A. That's correct. They're interconnection studies, yeah.

Q. Are you aware that Southern Company does not grant delivery service based on ERIS nor NRIS designations but rather based on designation as a native load resource?

A. Yes. And I explained in the footnotes and in my testimony basically the process. And so, yes, it's -- the -- how the resource is studied is an important first step towards making something available as an intercon-- as a capacity resource.

And as I outlined, without doing that NRIS study to see if the resource can fully deliver its output to load, you're at risk of finding out that there's not sufficient transmission to make the resource deliverable and, therefore, being unable to make it a capacity resource. That's the concern. Studying as an ERIS resource means that you only have access to -- it's only studied as available -- with as-available transmission,

and that inconsistent with how something would need to be for capacity resource.

So, again, yes, I understand there's the -- the first step is to do the study, and then later then you do the designation, but studying something as an ERIS puts you at risk of not being able to do that second step.

Q. Are you aware that the company has already requested that the Yates CT be designated resources which is the appropriate designation in the Georgia Power system for firm delivery service?

A. But, again, there's the risk that they may not be fully deliverable if they weren't studied for their full deliverability.

Q. But are you aware that in the native load analysis to be designated, it is studied for deliverability?

A. Okay. Well, I just don't understand why it wasn't requested for NRIS then.

Q. Okay. I'll see if I can ask this a different way.

Did you analyze whether deliverability is studied during the designation native load process?

A. I know it is. I mean, that's -- yes, it has to be deliverable to be a capacity resource, yes.

Q. So then, therefore, if it was -- if the

deliverability study was completed and it was designated as a native load resource, it would not be at risk of curtailment, would it?

A. Again, I mean, the information is that the company submitted them as ERIS, so there's -- we don't know.

Q. Yeah, but that's not my question.

My question is, the deliverability study is completed to be able to be designated as a native load resource, and, therefore, it won't be curtailed?

A. If assuming that it has been designated and has been found deliverable, then, yes, I guess it's deliverable.

MR. HEWITSON: Okay. Thank you. That's all I have for the panel.

CHAIRMAN SHAW: Thank you.

Redirect.

MR. THOMAS: No redirect, Mr. Chairman, but I'd ask that the panel be excused and that the exhibits be entered into the record.

(Staff Exhibits 18 through 21 were admitted into evidence.)

CHAIRMAN SHAW: So marked.

Panel, thank y'all. You can be excused.

CHAIRMAN SHAW: All right. It's 8:20, we're

going to go a little longer. We are going to call up Mr. Dunbar next. And he has been kind enough to combine his two panels into one. Thank you, sir.

MR. DUNBAR: Thank you, Mr. Chairman. CEBA calls our witnesses, Priya Barua and Ron Lehr.

May I approach the court reporter?

CHAIRMAN SHAW: Yes, you may. Thank you. And one of your witnesses is appearing via Zoom; correct?

MR. DUNBAR: That's correct. And I was in touch with him about ten minutes ago. So I believe he knows we're going on. I can text him again.

CHAIRMAN SHAW: You can go ahead and let your witness go first with their testimony. If you want to just wait, you can swear your other witness in when they show up on the World Wide Web.

MR. DUNBAR: Ron, it sounds like maybe you have the YouTube doing in addition to -- I feel like I hear an echo.

MR. LEHR: Is that better?

CHAIRMAN SHAW: Yes, sir.

MR. DUNBAR: Ms. Barua and Mr. Lehr, would you please raise your right hands.

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Thereupon,

PRIYA BARUA,
RONALD LEHR,
having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. DUNBAR:

Q. Thank you. Ms. Barua, state your name and spell your last name for the record.

A. My name is Priya Barua. My last name is spelled B-A-R-U-A.

Q. And would you please state your employer and your position.

A. Sure. I'm a director of market and policy innovation at the Clean Energy Buyers Association.

Q. And did you cause direct testimony to be filed in this case on behalf of CEBA on February 15th and -- which has been remarked as CEBA Exhibit 1?

A. Yes.

(The document referred to was marked for identification as CEBA Exhibit 1.)

BY MR. DUNBAR:

Q. And if I asked you the same questions in that written testimony today, would your answers be the same?

A. Yes.

Q. Thank you.

MR. DUNBAR: Mr. Chairman, shall I go through

that routine with Mr. Lehr prior to the summaries? Is that your preference?

CHAIRMAN SHAW: Yes, that would be fine.

Q. Okay. Mr. Lehr, would you please state your name and spell your last name for the record?

A. Yes. My name is Ronald Lehr, L-E-H-R.

Q. And would you please state your employer and your position?

A. I'm self-employed. I do consulting work.

Q. And did you cause direct testimony to be filed in this case docket on February 15th that has been premarked as Exhibit CEBA 2?

A. Yes.

(The document referred to was marked for identification as CEBA Exhibit 2.)

BY MR. DUNBAR:

Q. And if I asked you the questions in that written testimony again today, would your answers be the same?

A. Yes.

MR. DUNBAR: At this time, Mr. Chairman, I would ask that Ms. Barua be permitted a few minutes to summarize her testimony.

CHAIRMAN SHAW: Yes, go ahead.

MS. BARUA: Commissioners, thank you for the

opportunity to be here today. I appreciate your leadership and dedication to maintaining a reliable, affordable, and safe electricity system in one of the fastest states in the country.

CEBA is a national business trade association with over 400 members that include voluntary energy customers of every type and size, corporate and industrial companies, universities and cities, as well as project developers and service providers.

CEBA's membership includes some of the largest buyers of renewable energy that conduct business operations across the United States and Georgia, including over 90 Georgia Power customers.

CEBA and its members support the strides Georgia Power and this Commission made in recent years to support economic development, in part, by adding more carbon-free energy to Georgia Power's electricity supply and increasing the availability of voluntary clean energy programs while maintaining reliable service.

Many large commercial industrial customers, including CEBA's members, have made public sustainability commitments that require them to power up their operations with clean energy. These customers often make decisions about where to locate

and expand operations based in part on their ability to access clean energy in different locations.

Georgia Power's proposals to add more fossil fuel resources into its resource mix in this docket send the wrong message to the business community and large customers evaluating Georgia as a place to do business. Georgia Power also proposes to acquire these resources outside of the normal RFP process, denying customers the benefits of competitive bidding.

While Georgia Power's witness panel said that they were generally aware that some of its customers have clean energy requirements, they acknowledged that Georgia Power did not account for these requirements when it developed its proposed plan.

CEBA urges the Commission to keep customers' clean energy requirements in mind when it evaluates Georgia Power's proposals in this docket. Georgia Power asserts that it's facing extraordinary circumstances with respect to its updated load forecast. Given the clean energy commitments of many C&I customers, CEBA recommends that the Commission empower customers to help Georgia Power address these extraordinary circumstances.

To that end, CEBA recommends that the

Commission direct Georgia Power to implement two bring-your-own clean energy supply options, or BYO clean supply for short. The first option we propose is a sleeved PPA program.

In this program, C&I customers would be able to identify their own dedicated clean energy resource and work with the developer to bring the project to Georgia Power. Georgia Power would then procure and sign a PPA for the resource on the customer's behalf, and the customer would pay for the full cost of the resource.

The primary benefit of a sleeved-PPA structure in these circumstances is that resources can be brought online quickly by relying on C&I customers to bring resources to Georgia Power and by bypassing the normal RFP process, which is unnecessary for any resource that is dedicated to a particular customer.

CEBA also proposes an onsite BYO clean supply option, which is essentially an expansion of Georgia Power's existing Customer Connect Solar Program. This program is currently limited to 25 megawatts of total program capacity, and limits the size of onsite solar facilities to 3 megawatts or 125 percent of customer's peak demand. We recommend removing these limitations to allow more customers

to participate and to allow larger systems to participate as well.

Finally, CEBA supports the basic structure of Georgia Power's proposed DER co-location program and DER-customer-owned program. We were disappointed that Georgia Power proposed to limit the programs to natural gas and diesel generators. We expect that more customers will be interested in participating in one of these DER programs if they could do so with onsite clean energy resources paired with battery storage.

We recommend that the Commission direct Georgia Power to open these two programs, two clean resources, paired with battery storage, or BESS, to empower more customers to help Georgia Power meet its peak demand. CEBA appreciates the opportunity to participate in this docket and share the voice of the many large energy customers that are demanding more clean energy. So I look forward to the Commission's questions.

MR. DUNBAR: Thank you, Ms. Barua.

At this time, Mr. Chairman, I would ask that Ms. Barua's prefiled written testimony be admitted into the record as if it were given here today.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimonies of Priya Barua and Ronald Lehr follows:)

BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE — **Docket No. 55378**

DIRECT TESTIMONY OF PRIYA BARUA ON BEHALF OF CLEAN ENERGY BUYERS ASSOCIATION

February 15, 2024

I. Introduction and Summary of Recommendations.

Q: Please state your name.

A: My name is Priya Barua.

Q: By whom are you employed and in what position?

A: I am Director of Market and Policy Innovation at Clean Energy Buyers Association (CEBA).

Q: Please describe your current role and your relevant professional experience.

A: I have been with CEBA since 2019 and have been the Director of Market and Policy Innovation since 2021. In my current role I oversee CEBA's Market Access Initiative, which is focused on increasing customer access to cost-effective, reliable clean energy, particularly in the Southeast and West regions, where customers do not have access to organized wholesale markets and are therefore more restricted in the ways in which they can procure clean energy. Previously, I worked at the World Resources Institute (WRI) for almost 8 years, where I worked with energy customers to develop the Renewable Energy Buyers' Principles[1] in 2014, which outlined six principles that customers are looking for from utilities and other suppliers when buying clean energy from the grid. This was signed by 75 corporate signatories. I then helped establish WRI's work on green tariffs. This work included tracking and analyzing utility green tariff programs that emerged across the country, starting with the first publication of *Emerging Green Tariffs in U.S. Regulated Electricity Markets* in 2014, and supporting subsequent iterations of that publication and

[1] https://cebuyers.org/programs/education-engagement/buyers-principles/.

associated maps, including the transfer of these resources to CEBA when I joined CEBA in 2019. I also fostered collaborations between utilities and large energy buyers in traditional, regulated markets, to develop customer clean energy programs that support an efficient and economic transition to clean energy resources, through customer-utility leadership forums between 2014-2018. This work included establishing and leading the Special Clean Power Council (CPC) for Utilities and Buyers,[2] a two-year initiative with six large IOUs and eight large commercial and industrial customers. I also authored the publication: *Implementation Guide for Utilities: Designing Renewable Energy Products to Meet Large Energy Customer Needs*[3] in 2017. I have a Masters degree in Public Policy from the Harvard Kennedy School and a Bachelor of Arts degree from Brandeis University.

Q: Have you previously provided testimony before the Georgia Public Service Commission?

A: No, I have not.

Q: Have you previously provided testimony in any proceedings before other regulatory commissions?

A: Yes. I recently testified before the Louisiana Public Service Commission in Docket No. U-36697, regarding the design of a new green tariff proposed by Entergy Louisiana.

[2] https://www.wri.org/initiatives/special-clean-power-council-customers-utilities-cpc.

[3] https://www.wri.org/research/implementation-guide-utilities-designing-renewable-energy-products-meet-large-energy.

Q: Please describe CEBA.

A: CEBA is a business trade association that activates a community of energy customers and partners to deploy market and policy solutions for a carbon-free energy system. CEBA's more than 400 members represent more than $7.5 trillion in annual revenues and 18.5 million employees and include institutional energy customers of every type and size – corporate and industrial companies, universities, and cities, as well as project developers and service providers. CEBA's membership includes one-fifth of the Fortune 500 and some of the largest buyers of renewable energy that conduct business operations across the United States and Georgia, including an estimated 90 Georgia Power customers. CEBA's corporate and industrial members include companies across a variety of sectors including information technology, data centers, auto manufacturing, clean energy manufacturing, heavy industry, food and beverage manufacturers, financial institutions, fast food restaurants, hotels, retail chains, and more.

Q: What is the purpose of your Direct Testimony?

A: Many of Georgia Power's commercial and industrial customers need access to clean energy to meet their sustainability commitments. Any utility with ambitious economic development goals, such as those stated by the Company in this proceeding, should understand that it must invest in clean energy to meet the needs of its customers. My Direct Testimony explains why it is critical for Georgia Power to meet its new load growth with clean generation resources and not the carbon-intensive resources Georgia Power has proposed to procure without the benefit of competitive bidding. Along with CEBA's other witness Mr. Ronald Lehr, my Direct Testimony supports specific recommendations for

how the Commission should resolve Georgia Power's 2023 IRP Update to ensure that Georgia can continue to support the clean energy needs of the businesses that power its economy.

Q: Please summarize your recommendations to the Commission.

A: I recommend that the Commission:

1. Keep commercial, industrial, and institutional customers' clean energy requirements in mind as it evaluates Georgia Power's proposals in this proceeding.
2. Direct Georgia Power to create a "sleeved power purchase agreement (PPA)" option that allows customers to identify and contract for dedicated clean energy projects through Georgia Power.
3. Direct Georgia Power to remove the program capacity and system size limitations in the Customer-Connected Solar Program.
4. Direct Georgia Power to allow clean energy resources paired with BESS to participate in both the DER Colocation Program and the DER Customer-Owned Program.
5. Adopt the recommendations of CEBA witness Mr. Ronald Lehr.

II. CEBA's Priorities and Goals

Q: What will you address in this section of your testimony?

A: In this section of my testimony, I will provide more background on CEBA and CEBA members' priorities and goals to help the Commission understand why CEBA intervened in this docket. This background provides context for CEBA's specific recommendations with respect to Georgia Power's requests.

Q: Please describe why CEBA was created.

A: CEBA, formerly named the Renewable Energy Buyers Alliance (REBA), started as a collaboration between four nonprofit organizations in 2014 to identify and address the challenges and common needs faced by energy customers pursuing clean energy to achieve their sustainability goals, and to educate and collaborate with key stakeholders in finding solutions to meet them. What started as a discussion with 12 companies, grew to a community of over 200 members, so REBA was "spun-off" as an independent stand-alone membership organization in 2019. While REBA pursued a vision of a resilient, carbon-free electricity system since its inception, it was rebranded as the Clean Energy Buyers Association (CEBA) in 2021 to better align with that broader vision. CEBA is a 501c6 business association that activates a community of energy customers and partners to deploy market and policy solutions for a carbon-free energy system. CEBA was founded based on a simple idea: energy customers pursuing clean energy should have one organization to go to for the resources necessary to achieve their clean energy goals. CEBA focuses on unlocking markets for energy customers, catalyzing communities of customers for deployment, and decarbonizing the grid for all.

CEBA coordinates closely with the Clean Energy Buyers Institute (CEBI), which is a 501c3 public good charity that works to solve the toughest market and policy barriers to achieve a carbon-free energy system. Together, the Clean Energy Buyers Association and the Clean Energy Buyers Institute form the Clean Energy Buyers Alliance and share a collective vision of customer-driven clean energy for all, with an aspiration to achieve a

90% carbon-free U.S. electric system by 2030 and to cultivate a global community of energy customers driving expanded demand for clean energy.

Q: In addition to participating in proceedings before state utility regulatory commissions, how does CEBA support its members?

A: CEBA provides a variety of educational resources and tools to help end-use energy customers learn how to procure clean energy in the U.S. and across global markets. This includes primers on procurement mechanisms, data on C&I clean energy procurement, a comprehensive report on utility green tariff programs across the U.S., and resources around decarbonizing supply chains, to name few. CEBA also provides peer-to-peer learning opportunities for members to share challenges, industry best practices, and to collaborate on solutions through industry conferences, monthly member calls, workshops, and procurement boot camps for companies that are new to procuring clean energy. In addition, CEBA advocates for federal and state legislative and regulatory policies that advance reliable, cost-effective clean energy, increase customer access to clean energy, expand and improve energy markets, and improve transmission planning.

Q: Please describe the role that large voluntary energy customers have had in clean energy development in the U.S.

A: Since 2014, more than 200 commercial and industrial (C&I) energy customers have voluntarily procured over 77 gigawatts (GW) of clean energy, equivalent to approximately 40% of all wind and solar capacity added to the U.S. grid during that time.[4] This represents

[4] Clean Energy Buyers Association, "CEBA Deal Tracker" available at https://cebuyers.org/deal-tracker/.

publicly announced procurement of clean energy by C&I customers through power purchase agreements (PPAs), green tariffs, bilateral deals with utilities, energy customer tax equity investments, and direct project ownership in the U.S. since 2014. In 2022, C&I customers announced a record-breaking 16.9 GW of new clean energy deals, equivalent to 70% of the carbon-free energy capacity added to the U.S. electric grid in 2022. C&I customers procured another 12.9 GW of clean energy in 2023.

CEBA's members have ambitious clean energy goals, and many of these members now consider, if not prioritize, their ability to access clean energy when determining where to locate new facilities and which existing facilities to expand.

Q: Why did CEBA intervene in this docket?

A: CEBA intervened in this docket because we are concerned that Georgia Power has proposed to meet the significant load growth it is facing largely with uncompetitively procured, and therefore costly, fossil fuel resources, including a PPA with its affiliate Mississippi Power, which was ordered by its regulators to retire fossil fuel steam generating capacity;[5] a PPA with the Santa Rosa Energy Center, a combined-cycle natural gas plant; and new utility-owned combustion turbines (CTs) that will be fueled by oil and natural gas. CEBA's members are also concerned that none of the resources Georgia Power has proposed in this docket would be procured through competitive bidding. Finally, CEBA is concerned that some of the new load that Georgia Power is forecasting may not materialize if Georgia Power increases the carbon intensity of its resource mix as it has proposed to do

[5] Missouri Public Service Commission Docket No. 2018-AD-145. https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=655509.

in this docket, since many of the customers bringing new load have clean energy targets. If this load does not materialize and Georgia Power overbuilds with fossil fuel capacity, it would result in higher costs for existing customers and make it more difficult for existing customers to meet their sustainability targets.

Q: At a high level, what are the outcomes CEBA would like to see in this docket?

A: CEBA witness Mr. Lehr and I both provide specific recommendations for how the Commission should resolve this docket. At a high level, CEBA supports the following outcomes for Georgia Power's 2023 IRP Update:

A. Georgia Power's forecasted future load should be met with least-cost, competitive clean energy resources.
B. All new capacity additions should be as clean and cost-effective as possible, without preference given to utility-owned gas generation resources or affiliate transactions.
C. Customers interested in voluntary clean energy purchases should be empowered to contribute to Georgia Power serving its forecasted load.
D. Georgia Power should make progress on transmission expansion plans and increasing the availability of market mechanisms to improve reliability and meet forecasted load growth.

I urge the Commission to keep these customer priorities in mind as it evaluates Georgia Power's proposals.

III. Customer Demand for Clean Energy.

Q: What will you address in this section of your testimony?

A: In this section of my testimony, I will address the importance of including clean energy in a utility's resource mix to meet customer clean energy requirements in states with vertically integrated utilities and no access to organized wholesale markets, like Georgia.

Q: Why do large energy customers like CEBA's members care about the amount of clean energy resources in a utility's resource mix?

A: As CEBA discussed in its Petition to Intervene in this docket, CEBA's members have ambitious sustainability commitments that require them to reduce the carbon emissions profile of their electricity consumption. Many of these companies have goals to match 100% of their energy consumption with renewable energy. For example, approximately 60 CEBA members have committed to RE100, which is a global corporate renewable energy initiative bringing together hundreds of large and ambitious businesses committed to 100% renewable electricity.[6] In addition, 131 members have set science-based emissions reduction targets through the Science Based Targets initiative (SBTi).[7] CEBA members purchase clean energy through a variety of procurement mechanisms including virtual power purchase agreements, physical power purchase agreements, retail contracts, onsite clean energy, and utility green tariffs, depending on the market structure in a specific area. Many C&I customers prefer to purchase energy from clean energy projects in the same state or region as their operations, rather than sign virtual PPAs for projects located in other

[6] *See* https://www.there100.org/.
[7] https://sciencebasedtargets.org/.

states, for example. In Georgia, customers do not have access to retail choice or organized wholesale markets and are therefore more restricted in the ways in which they can procure clean energy. In vertically integrated states like Georgia, CEBA members' ability to meet their clean energy commitments is largely tied to the emissions profile of their utility's resource mix and availability of customer clean energy programs offered by the utility that they may be eligible for. As a result, the ability of CEBA members that are Georgia Power customers to meet their clean energy commitments is dependent on the Commission approving a resource mix for Georgia Power's 2023 IRP Update that is as clean as possible while ensuring least-cost principles, economic development goals, and reliable service requirements are achieved.

Simply put, the ability of CEBA members that are Georgia Power customers to meet their clean energy commitments depends in large part on how clean Georgia Power's resource mix is.

Q: Did Georgia Power consider the clean energy commitments that many of its large customers have made when it developed its 2023 IRP Update?

A: No. Georgia Power's witness panel was asked at the hearing on Georgia Power's Direct Testimony whether they were aware of any specific clean energy commitments made by any of its customers. Georgia Power's witness panel stated that, while they were generally aware that some customers have made public commitments to purchase clean energy, they were not aware of any specific customers that had made such commitments.[8] Moreover,

[8] Hearing Transcript, January 16, 2024 at 280.

Georgia Power's witness panel confirmed that Georgia Power did not account for its customers' clean energy requirements when it developed its various proposals in this docket.[9]

Q: Why is this concerning?

A: It is concerning for two reasons. First, and fundamentally, it is concerning that Georgia Power does not appear to have designed a resource portfolio that is responsive to its own customers' needs and demands. In the competitive environments in which CEBA's members operate, companies exist to serve their customers and must respond to their customers' needs to be successful. While I understand Georgia Power's motivation to serve the many new commercial customers that want to do business in Georgia, Georgia Power's efforts to serve new customer load should not come at the expense of undermining the clean energy requirements of its existing customers. Second, Georgia Power's proposals to add more fossil fuel resources into its resource mix in this docket send the wrong message to the business community and large customers evaluating Georgia as a place to do business. It is possible that some of the load that Georgia Power is forecasting in this docket will not materialize if the Commission approves a resource mix that increases the carbon intensity of electricity supplied by Georgia Power.

Q: What do you recommend with respect to this issue?

A: I recommend that the Commission keep in mind the clean energy requirements of many of Georgia Power's current and prospective customers when evaluating Georgia Power's

[9] Hearing Transcript, January 16, 2024 at 280-281.

proposals in this docket. To empower customers to meet their clean energy requirements, the Commission should adopt CEBA's specific recommendations for resolving this docket, as set forth in my testimony and CEBA witness Mr. Lehr's testimony.

IV. Bring-your-own clean energy supply options.

Q: What will you address in this section of your testimony?

A: In this section of my testimony, I will describe how Georgia Power can help meet the load it forecasts in its 2023 IRP Update in part by enabling customers to bring dedicated supply resources into the resource mix. I refer to the two options I will describe as "bring-your-own clean energy supply" options or "BYO clean supply" for shorthand. CEBA proposes both an off-site BYO clean supply option based on a sleeved PPA structure and an on-site BYO clean supply option based on Georgia Power's existing Customer-Connected Solar Program, which I will describe below.

Q: Before you describe these proposals, why should the Commission consider voluntary clean energy customer programs in this docket, which is focused on resource planning?

A: I recognize that this is an IRP docket, which focuses on Georgia Power's load forecast and the resources Georgia Power needs to meet its forecasted load. However, Georgia Power characterizes the circumstances surrounding this 2023 IRP Update as extraordinary because of the unexpected and rapidly increasing load growth and capacity need it is facing. As the adage goes: extraordinary times call for extraordinary measures. The BYO clean supply options CEBA proposes are not extraordinary, but they are creative alternatives to Georgia Power's proposals, which are designed primarily to benefit Georgia Power and its

affiliates more than its customers. Given the very large capacity need Georgia Power says it is facing, all options for meeting this need should be on the table, including BYO clean supply options that empower customers to be part of the solution.

Q: Please describe the offsite BYO clean supply option that CEBA proposes.

A: The offsite BYO clean supply option that CEBA envisions is a program in which large C&I customers would have the ability to identify their own dedicated clean energy resources to purchase to meet new load and work with a third-party developer to bring the proposed projects to Georgia Power, which Georgia Power would then procure on behalf of that customer. This structure is known as a sleeved PPA because the clean energy resource is dedicated to a particular customer like a PPA but, because Georgia is a vertically integrated state, the PPA is "sleeved" through the utility. The customer to which a particular resource is dedicated would have a contract with Georgia Power through which the customer would pay for the cost of the resource along with reasonable delivery and administration costs. Through this agreement, the customer would receive all the environmental and financial benefits of the dedicated resource based on the resource's actual production. Georgia Power would confer the financial benefits of the resource to the customer in the form of a bill credit.

A sleeved PPA option should be modular in that it should allow customers to add capacity based on their actual needs and growth, allowing them to move at the speed of their business. Because customers pay the full cost of dedicated resources through sleeved PPAs, empowering customers to meet their capacity needs as their load grows through

sleeved PPAs is an effective way to mitigate the risk to all customers of Georgia Power overbuilding its capacity resources.

Q: Have utilities in other states offered sleeved PPA arrangements?

A: Yes. I have been involved in tracking and reporting utility green tariffs for several years, and as shown in CEBA's reports[10], sleeved PPAs are one of the three main types of green tariff programs offered by utilities across the country. CEBA has tracked at least 22 utilities in the U.S. that provide a sleeved PPA green tariff option to commercial and industrial customers, out of 42 utilities with green tariff programs.[11] Seven of those utilities specifically allow customers to work with third-party developers to identify a renewable resource to purchase through the utility. Other utilities allow a customer to work closely with the utility to select a new, dedicated renewable resource and enter into a long-term contract to purchase energy from that resource. Under the sleeved PPA model, the customer pays for all costs associated with the resource and receives bill credits for the energy and capacity value of the resources, as well as the RECs. Individual customer contracts and PPAs are approved by the state utility commission. Some examples include Duke Energy's Green Source Advantage program in North Carolina and South Carolina, Dominion Energy South Carolina's Voluntary Renewable Energy (VRE) Rider for RG Supply Agreements, Indiana Michigan Power's Go Green Program – Customer Agreement Option, Public Service Company of New Mexico's (PNM) Green Energy Rider, and NV Energy's Green Energy Rider.

[10] *See* https://cebuyers.org/solutions/procure-clean-energy/green-tariffs/.
[11] *See* https://cebuyers.org/solutions/procure-clean-energy/green-tariffs/.

Q: Georgia Power already offers green tariffs such as the Clean and Renewable Energy Subscription (CARES) Program and the CRSP and REDI programs, which provide C&I customers with various options to subscribe to new clean energy resources through specific tariff offerings. Why should the Commission direct Georgia Power to also offer a sleeved PPA program such as you have described?

A: There are several reasons. First, the CARES program and Georgia Power's other existing green tariff programs are subscription-based programs that have a set amount of capacity available for different types of customers to subscribe to. For example, CARES has 900 MW designated for existing customers and 500 MW for customers with new load additions of at least 15 MW. A sleeved PPA program can be designed to not have a cap on the total amount of capacity for the program or the number of customers that can participate. Any program caps should be on a per-customer basis (rather than a program cap) and be based on participating customers' current and forecasted load growth.

Second, the process of designing and conducting RFPs for the CARES Program takes significant time. CEBA is a strong supporter of competitive bidding for resources that Georgia Power procures on behalf of all customers (or on behalf of all customers that sign up for a voluntary program). However, there is no reason to require that a resource dedicated to a single customer through a sleeved PPA be procured through competitive bidding. Some large energy customers may even be willing to pay a premium to ensure their clean energy requirements are met in a timely manner. A sleeved PPA option would allow customers to bring clean energy resources to Georgia Power on a faster timeline than Georgia Power can procure resources for the CARES Program.

Finally, many C&I customers, including many of CEBA's members, are sophisticated players in the market for clean energy supply and have extensive nationwide experience and relationships with clean energy developers. Georgia Power's customers are currently unable to leverage their expertise or their relationships through the CARES Program because it is a subscription-based program and customers do not participate in selection of resources for the program. By leveraging customers' expertise and relationships, a sleeved PPA option would expand the pool of developers and development opportunities in Georgia to serve customers' needs.

Q: Please describe the onsite BYO supply option that CEBA proposes.

A: The onsite BYO supply option that CEBA envisions is essentially an expansion of Georgia Power's existing Customer-Connected Solar Program.[12] This existing program allows a customer to install a solar facility on or adjacent to the customer's property. Georgia Power purchases the electricity from the facility and retires the RECs on the customer's behalf. However, the existing Customer-Connected Solar Program includes several limitations that would prevent it from meaningfully contributing to Georgia Power's urgent capacity needs in its current form. Specifically, the current program is limited to 25 MW of total program capacity and limits the capacity of solar facilities to 3 MW or 125 percent of the customer's peak demand, whichever is less. These limitations also prevent some C&I customers from supplying all, or a meaningful portion, of their electricity consumption with onsite solar.

[12] https://www.georgiapower.com/business/products-programs/business-solutions/commercial-solar-solutions/customer-connected-solar.html.

Q: What modifications do you recommend to the Customer-Connected Solar Program?

A: I recommend that the Commission direct Georgia Power to remove each of the limitations I have just described. Given Georgia Power's urgent capacity needs, the total program capacity should be uncapped to allow as many customers that are willing to invest in onsite solar capacity to do so.

Similarly, there should not be any caps on the system size that a customer installs. Many large C&I customers will need to install systems larger than 3 MW to supply their electricity needs. The current size cap of 125 percent of a customer's peak demand is also needlessly restrictive because a solar facility's nameplate generating capacity is unrelated to a customer's peak demand. In most cases, customers' available roof space and/or vacant land will limit the size of the solar systems that customers install. If the Commission finds that some type of system size cap is necessary, I recommend that customers be allowed to install systems sized to supply no more than 125 percent of their average annual electricity consumption. A size limitation based on expected system output and customer consumption (rather than nameplate capacity and peak demand) will ensure that customers only install systems needed to supply their own needs.

Q: Are Georgia Power's other onsite solar programs viable options for customers?

A: Georgia Power currently offers two other onsite solar options: the Renewable and Nonrenewable Resources (RNR) Instantaneous Netting program and the Energy Offset option. The RNR program may be a viable option for smaller commercial customers given its system size cap of 250 kW but it is my understanding that the compensation rate for exported solar energy is subject to change after three years, so customers might be reluctant

to participate given this lack of long-term certainty. The Energy Offset option provides no compensation for exported power but may be a viable option for customers looking to offset only a small portion of their load or looking to install onsite storage. Improvements to both these programs could further support customers that are willing to invest their own capital in meeting their capacity needs. I am not recommending any changes to these programs in this proceeding but encourage Georgia Power and the Commission to explore improving these programs in the 2025 IRP.

Q: Georgia Power's proposals in this docket focus on Georgia Power's needs for firm capacity. How would these two BYO supply options you've described contribute to firm capacity?

A: Every technology has an inherent capacity value, including clean energy resources. The capacity value of all energy resources should be measured by the effective load carrying capacity (ELCC) that applies to that resource type. Clean energy resources can contribute to a utility's firm capacity needs based on their ELCC value just like fossil fuel resources. However, CEBA would support incorporating battery energy storage systems (BESS) in both BYO supply options we propose by providing additional value to customers for pairing BESS with the applicable resource.

There are likely multiple ways to structure the BYO supply options to include BESS. For the sleeved PPA option, participating resources can be paired with BESS located at the same site as the dedicated resource. The customer should pay for and receive the value of all energy produced by the clean energy resource, but Georgia Power could retain contractual or operational rights to the BESS to contribute to serving peak loads,

which will offset the cost of the BESS for the customer. For the expanded Customer-Connected Solar Program I described above in which Georgia Power purchases all electricity output of the onsite facility, Georgia Power could either pay the customer a capacity payment for pairing their solar system with BESS or pay time-varying rates that incentivize the customer to dispatch its battery during peak hours. These structures are just examples of how these programs could be structured to increase the capacity value of the clean energy resources they would support.

CEBA supports allowing any carbon-free resources to participate in the sleeved PPA option I have described, including baseload resources such as small modular reactors and geothermal facilities. Clean energy resources paired with long-duration storage should also be options that will contribute additional capacity value. CEBA recommends that only carbon-free resources be permitted to participate in the sleeved PPA option I have described, but the customer paying for a particular resource through a sleeved PPA should be able to choose their preferred carbon-free technologies.

Q: How would the two BYO supply options you've described impact customers that do not participate in either of the options?

A: Both the sleeved PPA option and the expanded Customer-Connected Solar Program option can be designed so they would not have any impact on nonparticipating customers. In a sleeved PPA, the cost structure can be designed so that the customer pays the full cost of the dedicated resource in exchange for its financial and environmental benefits based on the resource's actual energy production. The customer also pays reasonable costs to Georgia Power for administering the sleeved PPA and delivering the energy to them.

Nonparticipating customers would not be responsible for any costs associated with this option, but they would benefit because the dedicated resource represents avoided capacity that Georgia Power does not need to procure.

Similarly, in the Customer-Connected Solar Program, each participating customer pays for the full cost of the solar facility located on or adjacent to their property while Georgia Power purchases the electricity at an avoided cost rate approved by the Commission. The avoided cost purchase rate ensures that Georgia Power does not pay more for the customer's solar production than it would pay for electricity from other sources.

Similarly, if BESS were incorporated or required for either of the BYO supply options, the programs could be designed to ensure that Georgia Power does not pay more than it would otherwise pay for the capacity value of these resources. Because customers pay for the cost of the BYO supply resources in both the offsite and onsite options I have described, nonparticipating customers will benefit.

Q: Please summarize your recommendations with respect to the BYO clean supply options.

A: The Commission should direct Georgia Power to empower customers to contribute to meeting its urgent supply need through the two BYO clean supply options I have described. Specifically, the Commission should direct Georgia Power to:

- Create a "sleeved PPA" option that allows customers to identify and contract for a dedicated clean energy project through Georgia Power;

- Remove the program capacity and system size limitations in the Customer-Connected Solar Program.

V. CUSTOMER-SITED DER PROGRAMS

Q: What will you address in this section of your testimony?

A: In this section of my testimony, I will address Georgia Power's proposed DER Colocation Program (DCL-1) and DER Customer-Owned Program (DCO-1).

Q: What has Georgia Power proposed for the DER Colocation Program?

A: Georgia Power has proposed to "own, operate, maintain, and control dispatchable DER [distributed energy resources] at customer premises … ."[13] Georgia Power defines eligible DERs as natural gas generators, diesel generators, and "other technologies with firm fuel supply."[14]

Q: What has Georgia Power proposed for the DER Customer-Owned Program?

A: Georgia Power has proposed to "operate and control customer-owned, new dispatchable DER at customer premises and economically dispatch the resources to provide energy and capacity benefits to all customers."[15]

Q: Do you have any concerns with these proposals?

A: I do not have any concerns with the basic structure of these programs, which will support the deployment of onsite resources that can be used for both resiliency (backup) purposes and contribute to meeting Georgia Power's capacity needs. However, I am concerned that Georgia Power's proposal to limit these programs to fossil fuel resources will discourage

[13] 2023 IRP Update Main Document at 22.
[14] *Id.*
[15] *Id.*

participation in the programs and increase the emission intensity of Georgia Power's supply mix.

Q: Please elaborate.

A: I expect many C&I customers would be interested in participating in one of these DER programs if they could do so with onsite clean energy resources like solar paired with BESS. As I have explained, many large customers have clean energy requirements and are looking for opportunities to invest in clean energy resources. Many of these same customers also have reliability needs and are willing to invest in resources that can provide backup power in the event of an outage. Programs that provide two value streams – backup power and economic dispatch – can be a cost-effective way for customers to make progress on both their clean energy requirements and their reliability needs. Simply put, if Georgia Power allowed clean energy resources paired with BESS to participate in its two DER programs, I expect more customers would want to participate.

Q: Can clean energy resources paired with BESS provide comparable value in the DER programs Georgia Power has proposed as fossil fuel resources?

A: Yes. While batteries must be charged before they can serve as dispatchable resources, batteries with four-hour duration can provide effective backup power for most outages and can provide crucial dispatchable capacity value that contributes to Georgia Power's current capacity needs.

Q: What do you recommend?

A: I recommend that the Commission direct Georgia Power to allow BESS paired with clean energy resources to participate in both the DER Colocation Program and the DER Customer-Owned Program.

VI. Conclusion and Recommendations.

Q: Please summarize your recommendations to the Commission.

A: I recommend that the Commission:

1. Keep commercial, industrial, and institutional customers' clean energy requirements in mind as it evaluates Georgia Power's proposals in this proceeding.
2. Direct Georgia Power to create a "sleeved PPA" option that allows customers to identify and contract for dedicated clean energy projects through Georgia Power.
3. Direct Georgia Power to remove the program capacity and system size limitations in the Customer-Connected Solar Program.
4. Direct Georgia Power to allow clean energy resources paired with BESS to participate in both the DER Colocation Program and the DER Customer-Owned Program.
5. Adopt the recommendations of CEBA witness Mr. Ronald Lehr.

Q: Does this conclude your testimony at this time?

A: Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

Docket No. 55378

GEORGIA POWER COMPANY'S
2023 INTEGRATED RESOURCE PLAN
UPDATE

DIRECT TESTIMONY OF RONALD L. LEHR
ON BEHALF OF CLEAN ENERGY BUYERS ASSOCIATION

February 15, 2024

I. Introduction and Summary of Recommendations.

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

A: My name is Ronald L. Lehr. I am a consultant and the Board Chair for New Energy Economics. My business address is 4950 Sanford Circle West, Englewood, Colorado 80113.

Q: On whose behalf are you testifying in this proceeding?

A: As Board Chair for New Energy Economics, I am testifying on behalf of the Clean Energy Buyer's Association (CEBA).

Q: Please summarize your qualifications and work experience.

A: I advise clients regarding energy regulation and business matters. Current assignments include work for Western Grid Group on western grid-level system, operations integration, and transmission planning and work for a consortium of foundations interested in application of new financial approaches to address stranded utility assets resulting from retiring uneconomic generation plants. I have worked for the largest privately owned Swiss utility, private firms, trade and business associations, non-profit advocacy groups, national energy laboratories, and foundations on energy acquisitions, renewable energy policies, and commercialization strategies. I represented the wind industry in the Western U.S. on regional transmission and related issues for over a decade and have appeared as an expert witness, sponsoring testimony in administrative venues on utility planning and mergers, and in antitrust, employment, and government claim litigation. I am currently board chair of New Energy Economics, which supports competitive acquisition of new utility generation and demand resource portfolios to manage risks, based on rapidly changing

economic fundamentals. I served for seven years, from 1984 to 1991, as Chairman and Commissioner of the Colorado Public Utilities Commission. I served on corporate and foundation boards of directors and boards of advisors. I also completed terms as an appointed member of panels charged to make recommendations on electric industry restructuring, renewable energy resources, and transmission needs to the Colorado General Assembly, and as President and Commissioner of the Denver Board of Water Commissioners, the water utility for Denver and surrounding suburban areas. More details about my background are provided in Attachment RL-1.

Q: Have you previously provided testimony before the Georgia Public Service Commission?

A: Yes. I previously submitted testimony in Georgia Power Company's 2022 Rate Case, Docket No. 44280.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to provide analysis and recommendations regarding Georgia Power Company's (Georgia Power or the Company) proposals in its 2023 Integrated Resource Plan (IRP) Update. CEBA's other witness in this proceeding, Ms. Priya Barua, testifies that large energy customers demand clean energy and lists four high-level outcomes of this docket that CEBA and its members support. Along with Ms. Barua, I provide specific recommendations for how the Commission should resolve this docket to achieve these outcomes for the benefit of Georgia Power's customers and the State. I provide recommendations to address shorter-term issues that affect resource sufficiency in

the near-term as well as longer-term recommendations to improving Georgia Power's planning and procurement processes.

Q: What are the high-level outcomes that CEBA supports in this docket?

A: CEBA supports the following outcomes for Georgia Power's 2023 IRP Update:

A. Georgia Power's forecasted future load should be met with least-cost, competitive clean energy resources.

B. All new capacity additions should be as clean and cost-effective as possible, without preference given to utility-owned gas generation resources or affiliate transactions.

C. Customers interested in voluntary clean energy purchases should be empowered to contribute to Georgia Power serving its forecasted load.

D. Georgia Power should make progress on transmission expansion plans and increasing the availability of market mechanisms to improve reliability and meet forecasted load growth.

Q: Please summarize your specific recommendations to the Commission.

A: I recommend that the Commission:

1. Reject Georgia Power's requests for CPCNs for PPAs with Mississippi Power and Santa Rosa Energy Center LLC.
2. Reject Georgia Power's request to develop up to 1,400 MW of simple cycle combustion turbine (CT) resources at Plant Yates.
    a. In the alternative, allow Georgia Power to develop only one simple cycle CT at Plant Yates to account for the limited transmission capacity at that location.

3. Based on the capacity need the Commission finds is supported by the record of this proceeding, direct Georgia Power to procure the needed capacity through expedited RFPs that were approved in the 2022 IRP. Specifically, the Commission should direct Georgia Power to:
    a. No later than 60 days after the Commission's decision in this docket, issue the planned All-Source RFP for capacity resources for resources starting in 2026 rather than the winter of 2028/2029.
    b. Expand and accelerate the planned RFP for 500 MW of ESS.
    c. Evaluate bids from the CARES 2023 Utility Scale RFP for Renewable Generation to meet capacity needs.
4. Approve, with modification, Georgia Power's proposal to develop, own, and operate BESS resources at various sites. Specifically, the Commission should authorize Georgia Power to develop up to 2,000 MW of solar-paired BESS. The Commission should approve the specific projects Georgia Power identified in its 2023 IRP Update (178 MW of BESS at existing Company-owned solar facilities at Robins and Moody Air Force Bases and 200 MW of BESS located with 200 MW of new solar) but require Georgia Power to competitively procure all additional BESS capacity.
5. Revisit and lower the minimum percentage of supply-side resources that must be owned by Georgia Power pursuant to Commission Rule 515-3-4-.04(3)(f)(7). The amount of supply-side resources Georgia Power owns should be the result of the planning and procurement process that provides the best outcomes for customers.

6. Direct Georgia Power to study and report to the Commission the extent to which additional transmission development and upgrades, enhanced transmission connections with neighboring balancing authorities, and improved market mechanisms will facilitate Georgia Power's ability to meet customer load and improve reliability. These studies should be submitted in the 2025 IRP Initial Filing by the Company and be available to intervenors in the proceeding.
7. Direct Georgia Power to improve its planning processes for the 2025 IRP consistent with my recommended process improvements to reduce Georgia Power's and its customers' long-term planning risks and provide least-cost options that benefit all ratepayers.

II. The Critical Importance of Competitive Bidding.

Q: What will you address in this section of your testimony?

A: In this section of my testimony, I will explain why it is critical that the Commission rely on the competitive bidding processes required by the Commission's rules for meeting Georgia Power's capacity needs. Georgia Power has not justified its request to rely on the exceptions to competitive bidding allowed in certain narrow circumstances by the Commission's rules. Accordingly, the Commission should reject Georgia Power's proposed PPAs with Mississippi Power and the Santa Rosa Energy Center (Recommendation No. 1) and Georgia Power's proposed utility-owned CTs at Plant Yates (Recommendation No. 2). Instead, the Commission should work with Georgia Power to accelerate and expand several existing and planned RFP processes and direct Georgia

Power to expand its proposed BESS acquisition proposal and acquire most of the needed BESS capacity through competitive bidding.

Q: Before you address competitive bidding, is there a framing that you recommend for this docket?

A: Yes, I recommend that the Commission separate shorter-term issues that affect resource sufficiency in the near-term from decisions that will have long-term implications. Longer-term issues that can be handled in the next IRP should be resolved using the Commission's standard planning and procurement approaches. Using standard approaches to address longer-term needs will help avoid further encouraging the Company to bring emergency issues to the Commission and will reinforce the need for adequate load forecasting and use of the Commission's approved planning and procurement processes.

The Commission should focus on what needs to be done immediately while allowing more time and consideration for actions and investments that are less urgent and can wait until the 2025 IRP. This approach also provides time for more consideration of the load forecasts at issue in this proceeding. If currently anticipated load growth does not appear, or appears at levels lower than anticipated, or later than anticipated, the Commission can avoid costs to consumers that might not be needed. This approach has the benefits of reducing customer costs and matching resource inventory more closely to actual loads.

A. Georgia Power's requested exceptions to the competitive bidding requirement.

Q: Do the Commission's rules generally require that Georgia Power procure generation resources through competitive bidding?

A: Yes. Commission Rule 515-3-4-.04(f) requires Georgia Power to procure new supply-side capacity through competitive bidding unless certain narrow exceptions apply. Georgia Power argues that three of these narrow exceptions apply to its proposals to its proposed PPAs with Mississippi Power and the Santa Rosa Energy Center and its proposed CTs at Plant Yates. First, Georgia Power argues that these resources are "supply-side capacity resources of extraordinary advantage that require immediate action."[1] Second, Georgia Power argues that the Commission has authority to exclude any new supply-side resources from the competitive bidding requirements during an IRP proceeding pursuant to subparagraph 6.[2] Third, Georgia Power argues that the minimum percentage of utility-owned resources established in 2001 allows the Commission to exempt utility-owned resources from the competitive bidding requirements to ensure the percentage of supply-side resources owned by Georgia Power does not fall below 70 percent.[3] At hearing, Georgia Power's witness panel confirmed that Georgia Power views the current circumstances it is facing as extraordinary and that these extraordinary circumstances warrant relying on these exceptions to the competitive bidding requirements.[4]

[1] 2023 IRP Update at 24, citing Commission Rule 515-3-4-.04(3)(f)(3).
[2] 2023 IRP Update at 24, citing Commission Rule 515-3-4-.04(3)(f)(6).
[3] 2023 IRP Update at 24, citing Commission Rule 515-3-4-.04(3)(f)(7).
[4] Hearing Transcript at 287-288 (January 16, 2024).

Q: Has Georgia Power demonstrated that the circumstances it is facing justify exempting the PPAs with Mississippi Power and Santa Rosa Energy Center and the proposed CTs at Plant Yates from the Commission's competitive bidding requirements?

A: No. As I discuss more below, there are several ways Georgia Power can use competitive bidding processes to meet its capacity needs. Accordingly, there is no need to rely on the rules' narrow exceptions to the competitive bidding requirements. Moreover, these emission-intensive resources would undermine Georgia Power's past efforts to decarbonize its electricity supply and the clean energy requirements of many of its large customers. The Commission should be very reluctant to approve three resources that would increase the emission-intensity of Georgia Power's resource mix outside the competitive bidding process and traditional IRP process.

Using standard approaches to address capacity needs will help avoid further encouraging the Company to bring emergency issues to the Commission and will reinforce the need for adequate load forecasting and use of the Commission's approved planning and procurement processes.

Q: Do the PPAs with Mississippi Power and Santa Rosa Energy Center and the proposed CTs at Plant Yates represent "capacity resources of extraordinary advantage"?

A: No. The mere availability of the PPAs does not mean that they provide some sort of "extraordinary advantage" to Georgia Power's customers that competitively bid resources cannot provide. Similarly, Georgia Power's promised ability to deploy CTs relatively quickly on property it owns at Plant Yates is not by itself an "extraordinary advantage" for customers. If anything, these resources provide extraordinary advantages to Georgia Power

and Southern Company, not to Georgia Power's customers. Specifically, the PPA with Mississippi Power would provide an advantage to Georgia Power's parent company, Southern Company, because this PPA would allow Mississippi Power to continue running fossil fuel steam resources that the Mississippi Public Service Commission had ordered Mississippi Power to retire.[5] Similarly, the proposed utility-owned CTs at Plant Yates would add to Georgia Power's rate base and increase its profit opportunity. However, these benefits to Southern Company and Georgia Power would come at the expense of Georgia Power's customers that expect Georgia Power to continue decarbonizing its electricity supply and expect Georgia Power to pursue the most cost-effective resources through competitive bidding.

Q: Has Georgia Power demonstrated that these resources meet the other rule exemptions to the competitive bidding requirement?

A: No. CEBA will address Commission Rule 515-3-4-.04(3)(f)(6) in briefing, but it is my understanding that this provision simply requires the Commission to make an explicit determination whether or not to exempt any supply-resource from the competitive bidding requirements based on the exceptions specified in the rule. In other words, Commission Rule 515-3-4-.04(3)(f)(6) does not indicate that the Commission will approve exceptions to the competitive bidding requirement for reasons that are not specified in the rules. I will address the exemption at Commission Rule 515-3-4-.04(3)(f)(7) in more detail below.

[5] 2023 IRP Update at 17.

Q: What do you recommend with respect to Georgia Power's requests for CPCNs for the PPA with Mississippi Power, the PPA with Santa Rosa Energy Center, and the utility-owned CTs at Plant Yates?

A: I recommend that the Commission reject each of these requests. Georgia Power has not justified its request to rely on the narrow, limited exceptions to the Commission's competitive bidding requirements for these resources. Given the emission-intensity of these resources, the clear benefits of these resources to Georgia Power and Southern Company, and the lack of clear benefits to Georgia Power's customers, the Commission should be especially reluctant to allow Georgia Power to procure these resources outside the normal competitive bidding processes and the full analysis that a regular IRP requires.

Q: If the Commission is inclined to approve one of these three resources, do you have an opinion as to which it should be?

A: Again, Georgia Power has not justified its requests for any of these resources. However, if the Commission were to approve one of these three resources, I suggest that the Commission allow Georgia Power to build a single CT at Plant Yates. I view a single CT as the "least bad" option of these three fossil fuel resources because CTs are used to meet peak needs and typically do not run very often and so will likely produce fewer emissions than the two PPAs. I recommend that the Commission only allow Georgia Power to build a single CT because, according to Georgia Power, transmission constraints at Plant Yates would limit the capacity contribution of the proposed CTs to 600 MW until 2028.[6] There

[6] Georgia Power Direct Testimony at 38.

is simply no reason to allow Georgia Power to build 1,400 MW of CT capacity at Plant Yates as it has requested outside the normal IRP process given these transmission constraints. In addition, it would be more appropriate for Georgia Power to evaluate CTs in its 2025 IRP using the standard IRP process, which includes developing an environmental compliance strategy, attention to consumer cost impacts, and transmission and market studies.

Q: Do you have any other recommendations if the Commission approves one or more CTs at Plant Yates?

A: Yes. If the Commission authorizes any new CTs, it should require Georgia Power to provide an updated reserve margin study in the 2025 IRP and to evaluate the ability to use additional demand response resources and reserve sharing capabilities and report the results in the 2025 IRP. These reasonable analysis and reporting requirements will provide some assurance that Georgia Power will not face emergency capacity needs in the future or seek to address such needs with new utility-owned CTs.

B. Meeting the load forecast with competitive bidding.

Q: Why is it critical that the Commission require resources to be procured through competitive bidding in this docket?

A: In addition to being the default requirement under the Commission's rules, use of competitive bidding, adequately supervised by the Commission, is the most reliable and effective method for finding out what resources the market can supply, when, where, and at what cost. The only way for the Commission to ensure that the generation resources procured in an IRP are the best resources available for customers is for Georgia Power to

conduct a Request for Proposals (RFP) process to see what resources are actually available. Simply put, without an RFP there is a very high likelihood that customers will overpay for generation resources, especially when the utility has other reasons for procuring those resources such as increasing its rate base or providing a sales opportunity to an affiliate.

Q: How specifically can the Commission require Georgia Power to use competitive bidding processes to meet its capacity needs in this docket?

A: The Commission and Georgia Power have plenty of history and experience conducting RFPs for generation resources. Despite Georgia Power's protestations that there is not sufficient time to conduct an RFP to meet its forecasted load, Georgia Power can rely on three existing or planned RFPs that were approved in the 2022 IRP for its forecasted capacity needs. Specifically, I recommend that the Commission direct Georgia Power to:

a. No later than 60 days after the Commission's decision in this docket, issue the planned All-Source RFP for capacity resources for resources starting in 2026 rather than the winter of 2028/2029.

b. Expand and accelerate the planned RFP for 500 MW of ESS.

c. Evaluate bids from the CARES 2023 Utility Scale RFP for Renewable Generation to meet capacity needs.

These RFPs are already in process at various stages, which provides the Commission and Georgia Power with the opportunity to use them to meet the load forecast the Commission approves for planning purposes in this docket.

Q: Given the planned scopes and timing of these RFPs, is it appropriate for the Commission to expand or accelerate them?

A: Yes. To the extent the Commission agrees with Georgia Power that the circumstances it is facing with respect to a rapidly increasing load forecast are extraordinary, it is appropriate for the Commission to take steps that it might not otherwise take in business-as-usual circumstances. The benefits of competitive bidding for customers are such that the Commission should prefer to make the process modifications needed to expand or accelerate these RFPs to ensure that resources can come online more quickly, rather than approve Georgia Power's PPA and CT requests. With the help of Staff, I am confident the Commission can make any process modifications necessary while protecting the integrity of the competitive bidding process and instilling confidence in bidders. Potential process modifications include compressing the time for RFP development (in the case of the All-Source RFP and the ESS RFP), compressing the time for bid evaluation and selection, establishing deadlines for PPA negotiations, and establishing firm deadlines with penalties for winning bidders to construct their projects.

Q: The CARES RFP is designed to procure resources for Georgia Power's voluntary Clean and Renewable Energy Supply (CARES) program, not to procure resources to serve system load. Is it appropriate to use this RFP to procure system resources?

A: Yes. Even though this RFP is currently open, it would be both reasonable and fair for Georgia Power to notify bidders that it plans to evaluate bids based on their ability to meet the capacity needs the Commission approves in this docket, in addition to their ability to meet the needs of the CARES program. Bidders should have the option to opt-out of such

evaluation, but I expect most bidders would welcome additional opportunities to have their projects selected as winning bids.

Q: Why are you confident that Georgia Power would be able to procure sufficient resources to meet its load forecast through accelerated RFPs?

A: The Request for Information (RFI) that Georgia Power conducted in preparation for this 2023 IRP Update indicates that there are a substantial number of resources that could be available in the next few years. Specifically, the RFI found that a total of 1,110 MW of resources could be available in 2026, a total of 1,495 MW of resources could be available in 2027, and a total of 1,072 MW of resources could be available in 2028.[7] Georgia Power asserts that there is not actually enough time for these resources to come online in this timeframe,[8] but this assertion assumes that the RFP and certification processes will take the amount of time they usually take in ordinary circumstances. Given the extraordinary circumstances Georgia Power says it is facing, I am confident that these timelines can be compressed in a way that is fair to all bidders and that brings the needed capacity online in the timeframe it is needed.

Moreover, it is very likely that there are substantially more resources available by 2026 and 2027 than the response to the RFI indicates. As Georgia Power's witness panel acknowledged at hearing, the RFI did not offer respondents the opportunity to enter into a contract with Georgia Power.[9] There are likely many developers that did not respond to the

[7] 2023 Request for Information for Capacity Resources – Summary of Results, Section 2.3 (December 4, 2023).
[8] *Id*.
[9] Hearing Transcript at 296 (January 16, 2024).

RFI simply because they were too busy to respond to an RFI but that would respond to an RFP that offers real opportunities for contracts. I expect the Commission and Georgia Power will see just how many potential projects are available in the responses to the CARES RFP .

Q: Please summarize your recommendation with respect to the current RFP processes.

A: As stated above, the Commission should direct Georgia Power to meet the capacity need it had proposed to meet with the two PPAs and the proposed CTs starting in winter 2025/2026 by expanding and accelerating existing RFP processes. Specifically, the Commission should direct Georgia Power to:

a. No later than 60 days after the Commission's decision in this docket, issue the planned All-Source RFP for capacity resources for resources starting in 2026 rather than the winter of 2028/2029.

b. Expand and accelerate the planned RFP for 500 MW of ESS.

c. Evaluate bids from the CARES 2023 Utility Scale RFP for Renewable Generation to meet capacity needs.

C. Expanding and improving Georgia Power's BESS proposal.

Q: Should the Commission require Georgia Power to competitively procure the BESS resources it has proposed in the 2023 IRP Update?

A: In large part, yes. Georgia Power has identified and proposed three specific BESS projects: two BESS additions to existing Company-owned solar facilities at Robins Air Force Base and Moody Air Force Base for a combined total of 178 MW and one 200 MW BESS project

co-located with 200 MW of new solar.[10] Though I expect customers would be better served if these projects had been competitively procured, to the extent the Commission agrees that Georgia Power must take immediate action to meet its near-term load forecast, CEBA would prefer to see these projects move forward simply because they are clean energy resources that would not result in new emissions. However, Georgia Power has failed to support its request to build an additional 622 MW of Company-owned BESS resources up to a total of 1,000 MW of new BESS capacity outside the normal competitive bidding processes.

Q: Please explain.

A: As discussed above, the Commission's rules require new generation resources to be procured through competitive bidding unless they meet one of the specified, narrow exceptions.[11] The only one of these exceptions Georgia Power cites in its request to acquire these proposed BESS resources without competitive bidding is the need own at least 70 percent of its supply-side capacity.[12] The Commission should find that this is not a compelling reason to deny customers the benefits of competitive bidding.

Q: What do you recommend?

A: I recommend that the Commission approve the specific Company-owned BESS projects that Georgia Power identifies in the 2023 IRP Update – specifically, the 178 MW of BESS capacity at Robins and Moody Air Force Bases and the 200 MW of BESS paired with new

[10] 2023 IRP Update at 20.
[11] Commission Rule 515-3-4-.04(3)(f).
[12] 2023 IRP Update at 20.

solar. I further recommend that the Commission direct Georgia Power to procure the remainder of the BESS capacity through a targeted RFP. Given the dispatchability value of BESS, the Commission should also authorize Georgia Power to procure up to 2,000 MW of total BESS capacity provided it does so through an RFP.

III. No preference for utility-owned generation.

Q: What will you address in this section of your testimony?

A: In this section of my testimony, I will address the Commission's policy that Georgia Power maintain a minimum percentage of its supply-side capacity as utility-owned generation resources. This policy is established by Commission Rule 515-3-4-.04(3)(f)(7) and the minimum percentage has been set at 70 percent since 2001.[13] This policy can also be thought of as a cap on non-utility-owned resources. In other words, under this policy, no more than 30 percent of Georgia Power's capacity needs can be supplied by PPA resources.

Q: Recognizing that the Commission established the policy that Georgia Power should own at least 70 percent of its supply-side resource capacity, what does Georgia Power say in support of this policy?

A: Georgia Power's witness panel argues that the purpose of this policy is "to ensure system reliability and sufficient Commission oversight of the resources serving customers."[14] The witness panel further argues that if Georgia Power were to contract for all the capacity it

[13] 2023 IRP Update at 18, FN 28.
[14] Georgia Power Direct at 29.

expects to need through the winter of 2030/2031 it would "present system reliability risks."[15]

Q: Has Georgia Power presented any evidence to support its assertion that reliability would be negatively impacted if its ownership percentage fell below 70 percent?

A: No.

Q: Is there any reason to think that Georgia Power's reliability would be negatively impacted if its ownership percentage fell below 70 percent?

A: No.

Q: Do any other states require their utilities to own a certain percentage of their supply-side capacity?

A: While I have not conducted a 50-state survey, I am not aware of any other states that require investor-owned utilities to own at least 70 percent of their supply-side capacity or that have established any minimum utility ownership requirements. In many states, utilities do not own any generation assets. It has been over two decades since the 2001 California energy crisis and in that time, PPAs and other contractual arrangements and market mechanisms have proven to be effective at both keeping the lights on and providing cost-effective energy for customers.

[15] *Id.*

Q: Are there any benefits to requiring Georgia Power to own at least 70 percent of its supply-side capacity?

A: The only clear benefit of this policy incurs to Georgia Power's shareholders in the form of a rate base that is higher than necessary and the resulting profit opportunities. Customers derive few, if any, benefits from this policy.

Q: Why is the Commission's minimum ownership policy a concern?

A: As I have discussed, part of Georgia Power's purported justification for constructing Company-owned CTs and Company-owned BESS without the benefit of competitive bidding is that its ownership percentage will fall below 70 percent without these utility-owned resources. In this way, the minimum ownership policy serves as a constraint on resource procurement decisions that has nothing to do with what the optimal resource option is or what is in the best interest of customers.

Q: How should the Commission establish a minimum ownership percentage for Georgia Power?

A: For the reasons discussed, it is entirely unnecessary to establish a minimum ownership percentage for Georgia Power. However, recognizing that this policy is enshrined in the Commission's rule, I recommend that the Commission revisit the current 70 percent ownership policy and greatly reduce that percentage, if not do away with the minimum threshold altogether. The amount of supply-side resources Georgia Power owns should be the result of the planning and procurement process that provides the best outcomes for customers and not be predetermined.

IV. Additional recommendations to address short-term needs before the 2025 IRP.

Q: What are the roles of planning reserve margins and power pool agreements in meeting short term emergency needs?

A: Both reserve margins and pool agreements should be analyzed to define roles they might play in meeting resource requirements in the next few years. If Georgia Power is maintaining a 26% winter target planning reserve margin for the stated purpose of contributing to reliability, a portion of that reserve might meet short term needs. Consumers have been paying extra to have those reserves in place, which is like paying the premium for an insurance policy. Now that Georgia Power's load forecast has dangerously increased, consumers should get some relief by calling on the insurance they bought. When the planning reserve margin falls closer to the industry-wide rule of thumb of 15%, and all short-term options outlined above have been exhausted, then the Company can return to the Commission if it needs additional authority for more resources. Reducing the winter reserve margin from 26% to a range closer to the standard 15% would free up capacity to serve new loads through winter 2026/2027 of the load forecast emergency, giving more time for RFPs to be completed to address capacity needs.

Likewise, Georgia Power has power pooling agreements with other neighboring utilities. These are, like planning reserve margins, available to contribute in defined, extraordinary circumstances. The Commission should require the Company to investigate and report on these agreements to determine whether and how much they might contribute to resolving the resource needs proposed in this docket. Like reducing the excessive planning reserve margin, calling on power pool resources to the extent allowed by these

agreements could be part of the mix of solutions to exigent circumstances the Company claims in this docket. In summary, the high level of reserve margin preferred by the Company suggests that the system assumptions and agreements around reserve margin requirements and sharing are ripe for review by this Commission to identify inefficiencies in the system and solutions to support a least-cost plan in this IRP update.

V. The need to study transmission development and market mechanisms.

Q: What will you discuss in this section of your testimony?

A: In this section of my testimony, I will provide recommendations for studies and analyses Georgia Power should undertake before the 2025 IRP to ensure the Commission has a more complete picture of the tools and strategies available to Georgia Power for meeting its load forecast. These recommendations are long-term planning improvements for the Commission's consideration.

Q: What can be done to achieve diverse resource options by developing market options?

A: The Commission should direct Georgia Power to evaluate and report on consumer benefits of an energy imbalance market. Georgia Power participates in the Southeast Energy Exchange Market (SEEM),[16] but no widely available information has been located that details how much economic benefit SEEM has produced, or what impacts it has had on market options that allow Georgia Power to benefit from additional resource diversity. No consistent source of SEEM benefits seems to be available.

[16] https://southeastenergymarket.com/.

Contrast that lack of transparency with the CAISO Western Energy Imbalance Market (WEIM), which has produced about $5 billion in savings since it launched in 2014.[17] Contrast these two regional markets: the Western EIM has substantial savings detailed on its web page; SEEM does not. Since WEIM operates on the CAISO full market model, all participants share the same information about resources that are available and use the EIM dispatch to rationalize access to regional resources that participate voluntarily. Aside from reliability benefits that flow from EIM adding "real time grid awareness" through operators' access to its grid model, it is widely known that EIM dispatch has largely replaced the prior system of short-term bilateral utility power trading that preceded it. EIM trading is automated and efficient; the bilateral trading it replaces much less so. Note that CAISO EIM calculated and reported dollar benefits measure not only consumer savings but also the inefficiency, limitations, and waste that was previously maintained by the utility bilateral market system. I note that SPP's Western Energy Imbalance Service (WEIS) produced an estimated $31.7 million in benefits in 2022.[18]

Q: Are there opportunities for broader market coordination in expanding power pools and regional resource adequacy planning?

A: Yes. Again, the West, akin to the Southeast in lacking access to Regional Transmission Organizations (RTO) and Independent System Operators (ISO), has developed incremental progress in shared, voluntary, regional resource adequacy planning. Led by the Western

[17] https://www.westerneim.com/pages/default.aspx.
[18] Benefit of the Market – SPP Energy Imbalance Service (available at: https://spp.org/documents/69127/2022%20weis%20benefit%20of%20market%20report.pdf).

Power Pool,[19] a voluntary group of utilities have developed the Western Resource Adequacy Program (WRAP) which has established standards for planning and sharing information about resource adequacy. By planning together, and sharing information about available and planned resources, WRAP participants hope to increase system reliability and reduce costs for backup power.[20]

Like the WEIM, WRAP is voluntary, and is much less than a fully developed regional transmission organization on the FERC model. But it does provide progress toward a more regional approach to reliability planning. It is expected to reveal opportunities for utilities to make more optimal use of their existing resources, add resources that serve both their loads and help to meet regional resource needs, and to avoid unneeded and uneconomic investments in resources that, given regional planning and information sharing, would be surplus to requirements, uneconomic, and potentially stranded assets.

Georgia Power could be helping to plan and execute a regional reliability and resource assessment program like WRAP. Georgia Power's next set of resource portfolios should be planned to include resources from these market and regional resource adequacy planning options.

[19] https://www.nwcouncil.org/reports/columbia-river-history/northwestpowerpool/.
[20] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

Q: Are there best practices you can recommend that the Commission might direct Georgia Power to undertake to improve transmission planning?

A: Yes. In my experience, transmission planning as typically practiced engages with less than full attention to all transmission benefits. Economic and operational reliability are commonly addressed and important values that allow utilities planning transmission to justify (or avoid) investments. Economic benefits are typically calculated in production cost models. Reliability benefits obtained in load flow and similar studies can be measured by reduced loss of load probability and potential savings from reduced planning reserve margins. More comprehensive assessments of all transmission benefits would give more complete information for both utility decision makers on whether, when, and where to invest in transmission, and give decision makers more information to inform their decisions about whether to approve transmission proposals. A report from Brattle in 2013 contains the most exhaustive examination of transmission benefits and how to address them of which I am aware. It describes planning approaches for comprehensive treatment of benefits, and advice to planners on how to address each benefit.[21]

Q: Should transmission planning be proactive, or reactive to demonstrated current needs?

A: In my view, transmission planning, including all the benefits found in the Brattle report, should anticipate transmission needs proactively rather than reacting to transmission shortages that constrain resource options and consumer benefits, as Georgia Power has

[21] Chang, J., Pfeifenberger, J., and Hagerty, J., "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," A WIRES Report, Brattle, 2013. 193 pages.

experienced in this docket. Instead of providing transmission after resource needs and locations are identified, as appears to be the present approach by the Company based on its testimony, the Company should be anticipating transmission needs, making needed investments in advance of need. In order accomplish this, the Commission should direct the Company to engage in proactive transmission planning process that allows for customer and impacted stakeholder feedback – which would enable the Company to proactively address customer and resource needs in support of more cost-effective planning.

In part, proactive transmission planning is required because transmission projects can exhibit longer lead times than resource development projects, particularly those that are adaptable to many locations (like solar and batteries) and modular (like solar, batteries and wind). Proactive planning would allow Georgia Power to identify the best areas for resource development and system integration, using locational diversity to manage output variability, steering development in advance for best overall system outcomes.

Q: Over what proactive term and geographies should transmission planning proceed?

A: I recommend a 20 year "vision" plan, accompanied by 5 and 10 year action plans. The CAISO has embarked on planning with these longer terms, which promises to help rationalize resource development locations and timing. MISO, SPP, and ERCOT all provide examples of longer-term planning and nearer-term investments, with abundant consumer benefits resulting. Expanded geographies for transmission planning should replace planning that only looks at transmission needs within the utility service area boundary. The ability to reach diverse resources is important both for risk management and for reliability. For example, transmission systems need to be broader than the area impacted

by extreme weather. It should appropriately reach the best, most diverse resource locations, both to access location-dependent resources like wind, and to spread resources across geography to minimize output variability. If clouds are cutting into solar production in one area, adequately planned transmission can access other solar resource areas likely be cloud-free. If a hurricane strikes, it is important to have transmission access to other areas than can continue to produce needed energy.

Q: What should be the role of non-wires transmission alternatives?

A: Grid Enhancing Technologies (GETS), including rewiring with modern wires technologies, sensors that allow real time and improved operations, and flow based operations that replace deterministic line ratings[22] (and many other innovations) are all being widely demonstrated and used right now. These approaches help to speed up transmission provision and improve transmission efficiency. The Commission's planning rules should specifically reference and encourage Georgia Power to plan transmission that incorporates new technologies and approaches, and to report its progress as inputs into its resource planning, because resources and transmission need to proceed together. The current docket shows how delayed transmission provision, rather than proactive planning, reduces access to resource options, drives up costs, and results in inefficient resource provision. Furthermore, a consistent cost-benefit methodology should be applied by the

[22] APS data system: https://www.tdworld.com/grid-innovations/distribution/article/20971578/arizona-public-service-leverages-data-for-advanced-distribution-management . FERC tariff approval https://www.rtoinsider.com/31320-aps-can-adopt-flowgate-methodology-ferc-rules/.

Company to facilitate evaluation of transmission solutions and alternatives that support least-cost planning.

Q: Isn't transmission hard to route and site?

A: Yes, it is. Rewiring or rebuilding on existing rights of way, using land adjacent to rights of way (including those devoted to rail and road transportation and gas and oil pipelines) can provide options that might be easier to access than new rights of way on virgin ground. "Smart from the start" transmission planning that has been heavily developed in the West emphasizes avoiding siting barriers like wildlife and other recognized national, state, and local preserves. Engaging early with groups who devote themselves to protecting such places is another way to avoid siting and routing controversies. Cultural resources for indigenous people are another category of challenges that can be avoided by "smart from the start" transmission planning.[23]

Q: Based on this discussion, what do you recommend?

A: I recommend that the Commission direct Georgia Power to study and report to the Commission the extent to which additional transmission development (including grid enhancing technologies, non-wires alternatives, and flow-based transmission operations), enhanced transmission connections with neighboring balancing authorities, and improved market mechanisms will facilitate Georgia Power's ability to meet customer load and improve reliability. These studies should be submitted in the 2025 IRP.

[23] https://cleanenergygrid.org/wp-content/uploads/2013/01/Pam-Eaton.pdf.

VI. Reducing long-term planning risks.

Q: What will you address in this section of your testimony?

A: In this section of my testimony, I will provide a number of recommendations for how the Commission and Georgia Power can conduct more effective resource planning. My goal in this section of my testimony is to provide advice for how Georgia Power and the Commission can avoid facing another interim IRP in the future in which Georgia Power cites exigent circumstances as justification for procuring expensive, emission-intensive resources on short notice and outside the required competitive bidding processes.

Q: Do you have recommendations for how the Georgia Power planning and procurement process might be improved?

A: Yes. The most important longer-term task for the Commission is to give Georgia Power guidance on how to improve resource planning and procurement. The goal here is to rely on competitive procurement to reveal economic values of all alternatives that should be considered for inclusion in resource portfolios going forward. The Commission should take responsibility for improving the partnership between utility and regulators, since both have important roles in improving outcomes. Georgia Power must diversify its suppliers and resources to manage risks. Regulators must drive toward low costs, consistent with risk management through diverse resource portfolios. They must be aware of utility monopsony and regulate its incentives. The improved process must encourage suppliers, while providing utility approvals and shareholder returns commensurate with both well managed risks and the public interest.

Q: How can planning and procurement processes be improved to manage risks more effectively?

A: Financial economics provides a starting place for considering how to understand and manage risks in obtaining the best utility resources to meet loads and reasonable cost. The most common and effective way investors manage investment risks is by investing in diversity in their investment portfolios.[24] Utilities, with Commission encouragement, should likewise endeavor to manage their risks by investing in diverse resource portfolios. Risks here are simply costs that a given investment faces that could give rise to higher than anticipated costs. By diversifying as many aspects of a utility's resource pool as possible, the utility can mitigate the risk that any single investment will impose significant costs on the utility and its ratepayers.

Certainly Georgia Power and the Commission have enough experience with project completion risks to know fully how important these can be to both shareholders and consumers. There are other important risks to focus on in the context of this filing. Here is a representative but not exhaustive set of risks that I recommend to the Company and the Commission focus more attention on in upcoming planning and procurement work:

1. Fuel risks.
2. Load forecast risks.
3. Resource adequacy and reliability planning risks.
4. Economic, technology, and policy risks.

[24] https://www.investopedia.com/terms/m/modernportfoliotheory.asp.

Fuel Risks

Q: What approaches do you recommend to help manage gas price and availability risks?

A: First, the Commission and Georgia Power should reduce or eliminate any new natural gas capacity additions, consistent with my recommendations above to reject the Santa Rosa Energy Center PPA and the proposed CTs. Georgia Power's resource portfolio is already top-heavy with gas generation, accounting for the largest share of any generation resource, about 48% of its total.[25] Throughout the resolution of this docket and the next planning cycle, the Commission should encourage more diversity in resources and shy away from adding more gas. Key steps here include assigning gas generation resources more complete assessment of risks inherent in more reliance on gas, consistent with "risk aware" planning.[26]

In modeling costs of service for potential portfolios that include more gas resources, gas price spike risks require higher assumed future gas costs in planning. The only thing that can be said with certainty about gas prices forecasts, particularly in longer time frames, is that they are highly likely to be wrong. From a risk management perspective, it is altogether better for gas price forecasts to be wrong and too high than wrong and too low. I recommend that the Company and Commission choose from among reasonable, but

[25] Georgia Power 2023 Facts and Figures, https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/facts_figures_2023.pdf See also: https://utilitytransitionhub.rmi.org/map/.

[26] Binz, R., Sedano, R., Furey, D., Mullen, D., "PRACTICING RISK-AWARE ELECTRICITY REGULATION: What Every State Regulator Needs to Know, How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection," A Ceres Report April 2012. http://www.rbinz.com/Binz%20Sedano%20Ceres%20Risk%20Aware%20Regulation.pdf

higher forecasted gas price projections, since risks to consumers from gas prices spikes are entirely asymmetrical; that is, consumers face heavy economic burdens when gas prices are forecasted too low, but benefit if the forecasts are too high.

Q: What about how gas costs are recovered in rates?

A: This Commission and other Georgia policy makers are well aware of consumer discontent following gas cost increases that resulted very high bills from the last big gas price spike. Since 100 percent of gas costs are recoverable through energy or fuel cost riders on consumers' bills, there is a severe "moral hazard" problem for utilities planning whether to include additional gas resources in future portfolios and procurements. Moral hazard arises because utilities' gas resource acquisitions have minimal or no economic impacts on the utility and its shareholders, since consumers pay the gas bill, not utilities. Reforms are being discussed now among Georgia policy makers, including this Commission[27] and legislators, about how to share gas cost recovery responsibility between consumers and shareholders to moderate this moral hazard problem. In its resource planning and procurement, the Commission should remain aware of this problem and vigilant to protect consumers against the convenient, morally hazardous utility preference for gas resources.

All of these issues with more gas in the Georgia Power system – sudden, extreme price spikes, current overreliance, impossibility of forecasting prices accurately, moral hazard due to cost recovery from customers, risks from increasingly harmful weather extremes, lack of availability due to gas supply chain failures – present risks that can be

[27] In re: Georgia Power Company's 2023 Fuel Cost Recovery (FCR) Application, Docket No. 44902.

well managed by increasing attention to customers' side of the power equation. Instead of adding more gas related risks, the Commission should favor clean energy resources paired with storage, customer-driven resources, and clean distributed energy resources, consistent with CEBA's recommendations.[28]

Load Forecast Risks

Q: Should the Commission order better load forecasting going forward?

A: Yes. A good first step would be to order the Company to present more adequate explanation for why Georgia Power's load forecast in the 2022 IRP did not capture the very high load growth Georgia Power forecasts in this IRP Update. Next, the Commission should require more robust reforms, including a focus on end use data collection. Both of these actions are currently required by the Commission's IRP rules, but specific regulatory attention to why the previous load forecast was so far off the mark and improved end use data collection could help to achieve more accurate load forecasting going forward.

Q: What load forecasting improvements is the Company proposing?

A: Georgia Power states that it has:

> … developed a forecasting model to better capture the uncertainties related to new large loads, including state selection, electric service provider selection, project delays, and the materialization of load. With this additional information, the Company made certain external adjustments to the load forecast each year over the twenty-year planning horizon to account for the recent growth in projected load and incorporate the ramp rates for such large load additions by month and year.[29]

[28] *See* CEBA's specific recommendations, above pages 4-5.
[29] Georgia Power Direct at 9.

While these improvements appear to provide more information about new loads that might be useful, it is not clear from Company testimony how useful the new information gathered will be. For example, what new sources of information have been developed? Who provided the new information and in what time frame? Do the new sources have a long and distinguished track record of accuracy, or not? What methodology did the Company use to make its "external adjustments" to its forecasting model and is it using the appropriate methodology? Why did the Company choose to use P95 for its projected load rather than a lower, more likely scenario? How did Georgia Power determine the "ramp rates" that are included in the adjustments? What will Georgia Power do if actual load growth is lower than its projections?

Resource Adequacy and Reliability Planning Risks

Q: Why are resource adequacy and reliability included in your assessment of important planning risks?

A: Planning reserve margins, added to assumptions about resource amounts and ability to meet load requirements, determine the total amount of new capacity a utility needs to meet its future forecasted load. The key to planning is the "loads and resources table" where totals of loads and needed resources are shown, with added amounts to represent planning reserve margins, which are assumed to contribute to system reliability. These amounts are typically shown in capacity or MW terms.

Having adequate capacity is a good outcome that is necessary, but no longer sufficient to define either resource adequacy or reliability. Portfolios of future resources should both provide sufficient energy at the time needed across all hours of the year, (from

diverse resource portfolios constructed out of competitive bids) to avoid, or manage, the major risks discussed here. Having enough capacity to meet peak day requirements, adding a planning reserve margin, and equating the outcome with reliability is one way to plan for reliability, but now seems out of date given best thinking by innovative utility system engineers.

Q: Has CEBA recently made a contribution to explaining modern approaches to planning for resource adequacy and reliability?

A: Yes. A good introduction to CEBA's priorities and outlooks is provided in a very recent report "Energy Customer Priorities for Meeting Resource Adequacy Needs."[30] While this report deals with reliability planning from a large customer perspective, it contains both introduction to CEBA's goals and a short but complete summary of the best current thinking about how reliability planning should be undertaken. These sensible reforms include:

- Regional planning to share resources across more diverse generation resources and geographies.
- Use of more than industry standard loss of load expectation (LOLE) on a one event in ten-year horizon to incorporate additional industry standards. These standards, like "Expected Unserved Energy" (EUE) measure other parameters of assuring service, like

[30] Clean Energy Buyer's Alliance, "Energy Customer Priorities for Meeting Resource Adequacy Needs," JANUARY 2024 (https://cebuyers.org/wp-content/uploads/2024/01/CEBA_Energy-Customer-Priorities-for-Meeting-Resource-Adequacy-Needs_January-2024.pdf). There is a useful bibliography of recent work on reliability planning, including reference to the Energy Systems Integration Group's seminal report, "Energy Systems Integration Group. "Redefining Resource Adequacy for Modern Power Systems." 2021. https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf. ESIG describes principles and details methods, including proposing that reliability be tested as an economic issue.

reliability events' durations and impacts. Simply put, they more fully explore different aspects of reliability. Use of consistent and up-to-date resource capacity accreditation methods like "Effective Load Carrying Capacity" (ELCC) that treat all resources consistently and fairly is another recommended approach that helps to improve reliability planning.

- Use of increased and more severe weather impacts in planning, employing consistent sources for weather data and modeling.
- Assessing transmission's role in providing access to more diverse resources to manage reliability risks.
- Increased attention to demand side resources' contributions to maintaining reliability against challenges to the bulk power system.

I recommend that the Commission and its Staff fully investigate and report how improved reliability planning could avoid power interruptions due to failure to plan adequately for reliability.

Economic, Technology, and Policy Risks

Q: What perspectives do you have on planning risks from changes in the economy, technology developments, and policy changes?

A: My sense is that Georgia Power has enough experience with these planning risks to address them competently, particularly with regard to economic and business cycle risks and policy changes. I testified in the recent Georgia Power rate case that the Company and Commission should take full advantage of benefits for consumers available from recent

federal legislation, most importantly the Inflation Reduction Act.[31] My testimony was included in the case record without challenge. I believe that there is more useful work to be done to bring all these federal benefits to Georgia Power customers.

But I would add that with rapid technology development, planning becomes more difficult, since there is less time to gather information about rapidly changing technologies and apply that information in planning. It would also be worthwhile looking deeper into technology adoption research that focuses on conditions in which some technologies penetrate markets very rapidly. Artificial intelligence is a good example. Cell phones rapidly became commonplace, but some reports suggest that AI will eclipse their adoption rates. Good to know in advance if you are an electric provider like Georgia Power, since AI is also electricity intensive. Was Georgia Power tracking AI adoption rates and anticipating accurately how those rates would impact its load forecast? Apparently not well enough to avoid big load forecasting surprises.

I. Conclusion and Recommendations.

Q: Please summarize your recommendations to the Commission.

A: I recommend that the Commission:

1. Reject Georgia Power's requests for CPCNs for PPAs with Mississippi Power and Santa Rosa Energy Center LLC.

[31] Georgia Power Company's 2022 Rate Case, Docket No. 44280.

2. Reject Georgia Power's request to develop up to 1,400 MW of simple cycle combustion turbine (CT) resources at Plant Yates.
    a. In the alternative, allow Georgia Power to develop only one simple cycle CT at Plant Yates to account for the limited transmission capacity at that location.
3. Based on the capacity need the Commission finds is supported by the record of this proceeding, direct Georgia Power to procure the needed capacity through expedited RFPs that were approved in the 2022 IRP. Specifically, the Commission should direct Georgia Power to:
    a. No later than 60 days after the Commission's decision in this docket, issue the planned All-Source RFP for capacity resources for resources starting in 2026 rather than the winter of 2028/2029.
    b. Expand and accelerate the planned RFP for 500 MW of ESS.
    c. Evaluate bids from the CARES 2023 Utility Scale RFP for Renewable Generation to meet capacity needs.
4. Approve, with modification, Georgia Power's proposal to develop, own, and operate BESS resources at various sites. Specifically, the Commission should authorize Georgia Power to develop up to 2,000 MW of solar-paired BESS. The Commission should approve the specific projects Georgia Power identified in its 2023 IRP Update (178 MW of BESS at existing Company-owned solar facilities at Robins and Moody Air Force Bases and 200 MW of BESS located with 200 MW of new solar) but require Georgia Power to competitively procure all additional BESS capacity.

5. Revisit and lower the minimum percentage of supply-side resources that must be owned by Georgia Power pursuant to Commission Rule 515-3-4-.04(3)(f)(7). The amount of supply-side resources Georgia Power owns should be the result of the planning and procurement process that provides the best outcomes for customers.
6. Direct Georgia Power to study and report to the Commission the extent to which additional transmission development and upgrades, enhanced transmission connections with neighboring balancing authorities, and improved market mechanisms will facilitate Georgia Power's ability to meet customer load and improve reliability. These studies should be submitted in the 2025 IRP Initial Filing by the Company and be available to intervenors in the proceeding.
7. Direct Georgia Power to improve its planning processes for the 2025 IRP consistent with my recommended process improvements to reduce Georgia Power's and its customers' long-term planning risks and provide least-cost options that benefit all ratepayers.

Q: Does this conclude your testimony?

A: Yes.

MR. DUNBAR: And turning to Mr. Lehr. We would ask that Mr. Lehr be permitted a few minutes to summarize his testimony.

CHAIRMAN SHAW: Yes, sir, please, proceed.

Thank you, Commissioners. And thanks virtually. It's a real boon.

As Ms. Barua described, CEBA is concerned that Georgia Power's proposals in this document send the wrong message to the business community, that the state of Georgia wants to attract and retain, given the clean energy requirements of many of these large energy customers.

Ms. Barua's testimony offers several recommendations for how the Commission can empower Georgia Power address the extraordinary circumstances it says its facing. These companies want to participate.

My testimony provides recommendations with respect to Georgia Power's specific request, as well as recommendations for improving future IRP processes. I recommend that the Commission reject Georgia Power's request to approve a PPA with its sister company Mississippi Power; reject its request for a PPA with the Santa Rosa combined cycle natural gas plant, and its request to build and own three

large CTs at the Yates facility. These are fueled by natural gas and oil, and CEBA doesn't support adding more of that kind of resource to the system.

None of these resources have been demonstrated to be competitive because they were not selected through competitive bidding. In addition, each of these resources would decrease the emissions' intensity of Georgia Power's energy supply, which already relies heavily on natural gas.

Next, I recommend that the Commission direct Georgia Power to meet its capacity need through expedited and expanded RFPs that were approved in the 22 IRP. Specifically, Georgia Power should issue its planned All-Source RFPs as soon as possible, and no later than 60 days after the Commission's final order in this docket, but amended to acquire resources starting in 2026.

Georgia Power should also expand and accelerate the planned RFP for 500 megawatts of batteries and evaluate bids it's just received through the CARES 2023 Utilities Scale RFP to help meet capacity needs beyond the needs of the CARES program.

I also recommend to the Commission approve with modifications Georgia Power's battery energy storage system proposals, and specifically I support Georgia

Power's proposal to move forward with specific battery projects it has identified, but urge the Commission to require Georgia Power to procure the remainder of the battery capacity through competitive bidding.

CEBA supports Georgia Power procuring up to 2000 megawatts of solar paired with batteries through these efforts. I recommend the Commission revisit the 70 percent utility ownership policy.

The amount of supply side resources Georgia Power owns should result from the outcomes of the planning and procurement process and not be predetermined. Let the utility compete with others in the marketplace to win its ownership percentage, rather than winning it through a regulatory decision. I agree with staff that this rule should not be a factor in the outcome of this docket.

Finally, as I mentioned, I provide two recommendations for actions Georgia Power can take now to improve future IRPs. First, I recommend that the Commission direct Georgia Power to study and report to the Commission the extent to which additional transmission development and upgrades, enhanced transmission connections with neighboring balancing authorities, and improved market

mechanisms will facility Georgia Power's ability to meet customer load and improve reliability. These studies should be submitted in the 2025 IRP initial filing and be available to intervenors and the Commission in that proceeding.

Second, I recommend that the Commission direct Georgia Power to improve its planning processes for the 2025 IRP, consistent with the discussion in my written testimony regarding long-term planning risks, particularly fuel-related risks, load forecasting risks, and risks resulting from incomplete planning for resource adequacy.

Better addressing these risks and planning All-Source competitive procurements can provide least-cost options that benefit all ratepayers, and increase investor confidence and shareholder returns.

Thanks very much for letting me summarize my testimony. Happy to have questions. Thank you.

CHAIRMAN SHAW: Thank you, Mr. Lehr.

MR. DUNBAR: Mr. Chairman, these witnesses are available for cross. Thank you.

CHAIRMAN SHAW: Thank you, sir.

Commissioners, any questions for these panels?

(No response.)

CHAIRMAN SHAW: All right. We're going to move on down the list.

Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association. That's their panel. It's getting late.

Heelstone Renewable Energy.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MS. WHITFIELD: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

(No response.)

CHAIRMAN SHAW: Georgia WAND.

(No response.)

Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions.

CHAIRMAN SHAW: Sierra Club.

MR. MAHAN: No questions.

CHAIRMAN SHAW: Southern Alliance for Clean Energy.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewal Energy Association?

MR. MAHAN: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. MCNUTT: No questions.

CHAIRMAN SHAW: Wal-Mart.

MS. EATON: No questions.

CHAIRMAN SHAW: Mr. Lehr, you probably did good by saving yourself some travel time.

Georgia Power.

I'm hoping it's earlier wherever you are and it's not 8:40 -- 8:35.

It's 6:00 where I am and just getting dark.

MR. MARZO: Thank you, Mr. Chairman. I'll try to keep it short in light of the hour, but I did have some questions. Because the panels were -- it wasn't a panel originally, I do have the questions separated out by witness, so I'll ask some question to you first, Ms. Barua.

Sure.

MR. MARZO: And then to you, Mr. Lehr, afterwards, if that's okay.

CROSS-EXAMINATION

BY MR. MARZO:

Q. Ms. Barua, one of the recommendations in your testimony is that the Commission keep commercial industrial institutional customers clean energy requirements in mind as the Commission evaluates Georgia Power's proposing in this proceeding; is that correct?

A. That's correct.

Q. Now, you're aware that the company has over 2.7 million customers; correct?

A. Correct.

Q. And do you understand that the company

considers the needs of all of its customers through the Integrated Resource Planning process?

A. Yes, I do.

Q. And have you reviewed the Commission's Integrated Resource Plan rules at all?

A. I have not reviewed all of the rules for the Integrated Resource Plan, no.

Q. Now, are you aware that the rules require that the IRP balance the interest of all of Georgia Power's customers, not just your members?

A. Absolutely, yes.

Q. And do you think one of the primary reasons that economic development is growing so much in the state is because the Commission's IRP process considers the interest of all customers?

A. Absolutely.

Q. Okay. Now, are you aware that the company routinely engages with its commercial and industrial customers?

A. Yes.

Q. And are you aware that the CARES program, the CRSP program and the REDI programs that you mentioned in your testimony were all developed with input from various commercial and industrial customers?

A. Absolutely. In fact, I helped facilitate some

of those conversations.

Q. Okay. So you would be aware, then, that CEBA members were a part of that?

A. Absolutely.

Q. Okay. And I know that CEBA's new to this particular proceeding, but you're aware that the company's routinely been able to reach settlements with commercial, industrial, and governmental customers in IRP and rate cases?

A. Uh-huh.

Q. Okay. Now, I want to talk briefly about your specific proposals. Am I correct that CEBA supports meeting the needs of new economic development load; correct?

A. Correct.

Q. And you didn't offer any analysis in your testimony regarding the capacity needed or the timing of that need; correct?

A. I did not offer analysis, no.

Q. In fact, you state in your testimony that the process of designing and inducting IRPs for the CARES program takes significant time; is that correct?

A. That's correct.

Q. And do you understand that the IRP process or CARES program is substantially the same process used for

any other IRP conducted by Georgia Power?

A. Yes.

Q. And so we agree, then, that designing and conducting the RFPs to meet the rapidly expanding needs facing Georgia Power in this case is not a viable solution?

A. Yes. That's why I was suggesting an alternative which would be to actually have customers help Georgia Power in meeting that solution by directly accessing their networks of developers and others to help meet that need, yes.

Q. Okay. And I was going to ask, so you spend some time in your testimony talking about some various solutions that you have that are customer driven style solutions; correct?

A. (Nods head.)

Q. Now, you understand that the company is trying to address in this IRP update a firm capacity need; correct?

A. Correct.

Q. And I notice that the only Q and A in your testimony that acknowledges that the capacity need that is the reason for this particular case is on pages 19 and 20, and it's CEBA's position that CEBA would support incorporating battery energy storage in both your

BOY (sic) you called them BOY supply options; is that correct?

A. That's correct.

Q. Now, you understand that the type of BOY supply program you're proposing is a fundamental change to the subscription program that has been in place for C&I customers?

A. Yes.

Q. And are you aware that the time and work that went into -- well, let me ask you: You worked on those, but are you aware about the time and work that went into the REDI, CRSP and CARES programs?

A. Yes.

Q. And you understand there's substantial time in developing those programs?

A. Absolutely, yes.

Q. Okay. And even if the company or Commission wanted to consider a new green tariff style program, you provided no evidence in this case to support that the BOY options that you are bringing forward provide the firm capacity component that's necessary to meet the needs identified in this case; correct?

A. Well, what I did provide is a recommendation, recognizing that this is not going to -- meet the full need, but that this is an option or solution to help

close that gap for that need.

Q. Okay. I think are you talking about meeting the need long term, like, as we continue to grow, there's an opportunity for a new green tariff program? Is that generally CEBA's position?

A. Well, so there are already green tariff programs that's exist, which you mentioned, so the CARES program is a green tariff program, and we do support having an RFP process, so there's competitive bidding to meet that need for all customers.

What I'm suggesting with the BYO clean supply program is that customers are empowered to help with that solution by actually, you know, procuring that clean energy resource as a sleeved option through Georgia Power, so that would not necessarily, again, given the extraordinary circumstances that you're facing and that this immediate need, this was a solution to help fill that gap for that immediate need.

Q. Okay. But you provided no evidence or evaluation, in fact, I think you agreed with me earlier that it takes significant time to put together this type of program, and you provided no support that this program would support this particular need; correct?

A. The entire need, that you --

Q. Any portion of the need? I mean, I think you

presented an idea, and ideas are great, but my point is, as I look at your testimony, what I don't see is evidence that supports that a new program like this somehow addresses the specific needs in this case.

A. Well, I mean, I think that given these extraordinary circumstances, I think all options need to be on the table before making investment decisions around it. So, yes, it is a proposed solution to help meet that need.

Q. Okay. And you've read Mr. Lehr's testimony, I take it?

A. Yes.

Q. And you understand that one of the things he talks about in his systems is a framework for considering this case, and I believe Mr. Lehr, and I'll ask him in a moment, but I believe he separated out what was an immediate action, immediate steps that need to be taken, what could actually be done in the 2025 IRP?

A. Yes, absolutely.

Q. Okay. And to the extent that CEBA has provided no evidence that supports that a new BYO option would meet the needs in this case, isn't that something that the Commission could look at in the 2025 IRP?

A. It could be looked at in 2025, as well, but, you know, I think it could be looked at more immediately

as well.

Q. Okay. And as you mentioned before, CEBA has, I think, also produced in periodicals that the Georgia Power Company has a number of what you call green tariff programs; correct?

A. Absolutely.

Q. Thank you.

Mr. Lehr, I think the rest of my questions are probably for you.

Now, you -- your position in this case is that the MPC PPA or the Santa Rosa PPA do not provide an extraordinary advantage under the Commission's rules exempting these resources from the RFP process; is that correct?

A. Yes. That's correct.

Q. And I think you said the mere availability of the PPAs does not mean that they provide an extraordinary advantage. Have you reviewed the testimony of Georgia Power Company and the Commission's staff in this case?

A. I'm sorry. Could you repeat that?

Q. Yes.

Have you reviewed the testimony of the panel of Newsome, Hayet and Wellborn or the panel of Grubb, Valle and Evans and Bush in this case?

A. Yes. I've reviewed that testimony.

Q. Okay. And you're aware that at least on that particular issue, both the company and staff agree that the Santa Rosa and MPC PPA's are needed to mitigate a reliability risk?

A. I think that's an adequate statement of what the company and staff think. I don't agree with it.

Q. But you provided no testimony that supports contrary finding; correct?

A. Supports contrary findings in what sense?

Q. In the sense that you didn't -- one of the reasons that the MPC and Santa Rosa PPAs are so valuable is there are existing resources that can meet the 2025-2026 winter need. I look at your testimony, I don't see another option that you're presenting that meets the 2025-2026 winter need; is that correct?

A. I think I'm testifying on behalf of CEBA, and CEBA would prefer clean resources to be developed out of the existing IRP generated RFPs and batteries that are on the table for those short-term solutions.

Q. But, I assume, Mr. Lehr, that CEBA also would like to keep the lights on; correct?

A. Well, everyone would like to keep the lights on.

Q. Now, you also talk about the winter and summer reserve margins in your testimony; is that correct?

A. That's correct.

Q. And you state on page 21, lines 13 through 16, that reducing the winter reserve margin from 26 percent to a range closer to a standard 15 percent, would free up capacity to serve loads through the winter of 2026 to '27; is that correct?

A. You're referring to page 21 what line?

Q. Yes. Page 21, lines 13 through 16?

A. Yes, that's correct.

Q. Now, you're aware there is a difference between a winter and summer reserve margin; correct?

A. Yes.

Q. And you state the standard winter reserve margin is 15 percent; is that correct?

A. I think the standard industry reserve margin is 15 percent.

Q. Okay. Did you happen to take a look at utilities in the Southeast?

A. We're looking at a utility in the Southeast --

Q. I'm sorry. Go ahead, Mr. Lehr.

A. We're looking at a utility in the Southeast in this docket.

Q. And you understand reserve margin in this case for Georgia Power is 26 percent?

A. I understand that.

Q. And are you aware that TVA's reserve margin is 25 percent?

A. I don't have a comparison to TVA in mind here. What I'm saying is that, you know, the ratepayers have been paying for these reserve margins, and in the emergency situation like the one you've presented here, it's time to cash in that insurance policy, at least to some extent, that's a possible contributor to the solutions.

Q. I'm sorry. Mr. Lehr, finish.

A. It's a possible contribution to solutions in the short term.

Q. Well, I read your testimony in suggesting that the standard winter reserve margin is 15 percent, so, therefore, Georgia Power has the ability to take its reserve margin down to that level in order to address needs; is that not your testimony?

A. Well, my testimony says, Look, you've got a very extravagant, in my view, extravagant reserve margin. You can call on that, on some of that, to be part of the solution to your immediate needs.

Q. Are you aware that MISO has a 25.5 percent reserve margin for the winter?

A. No.

Q. Are you aware PGM has a 27-target percent

reserve margin for the winter?

A. No.

Q. Okay. And are you aware that the company had been at 15 percent in the winter during previous winter storms, like Elliott and the Polar Vortex, as you've proposed, the company would have had to shed load?

A. Well, I don't know that. I suppose that's your testimony. Is that right?

Q. Well, you know, if you're going to make a recommendation to move the reserve margin or take advantage of the reserve margin down to 15 percent, I would think you would have looked to see about the critical circumstances that occurred where that could be an issue that causes load shed. But if that's not the case, it's not the case.

A. Again, I'm not going to -- if you want to testify, I'm not going to complain about it. Go ahead.

MR. MARZO: Okay. Well, thank you, Mr. Lehr. Thank you, Ms. Barua. I appreciate your testimony here today.

Mr. Chairman, no more questions.

CHAIRMAN SHAW: All right. Redirect?

MR. DUNBAR: Just one question, Mr. Chairman, I think.

//

REDIRECT EXAMINATION

BY MR. DUNBAR:

Q. Mr. Lehr, on that last point that you were just discussing with counsel for Georgia Power, did you recommend that Georgia Power reduce its winter reserve margin from 26 to 15 percent, or did you recommend that Georgia Power reduce it somewhat below its 26 percent?

A. I think it was more the latter, than the former. My testimony says, Look, you've got a big reserve margin there. It's for purposes of handling emergency circumstances. This is an emergency circumstance, at least according to the company, and you've got to look to that reserve margin as part of the solution:

How far should it go? Depends on what else you've got in mind, what other options you have. But it's one thing that could be added to the mix to make the immediate situation better.

MR. DUNBAR: Thank you.

That's all I have, Mr. Chairman.

CHAIRMAN SHAW: All right. Thank you, sir.

MR. DUNBAR: Thank you.

CHAIRMAN SHAW: Do you have any items and exhibits to go in the record?

MR. DUNBAR: Every state does this in a

different order. I apologize. We would move that CEBA Exhibit 1 and CEBA Exhibit 2 be admitted in the record in this proceeding.

CHAIRMAN SHAW: And your panel is ready to be excused?

MR. DUNBAR: They certainly are.

CHAIRMAN SHAW: All right. So marked.

Panel, thank you for you time and you can be excused.

(CEBA Exhibits 1 and 2 were admitted into evidence.)

MR. DUNBAR: Thank you, Mr. Chairman.

CHAIRMAN SHAW: All right. Thanks everyone for hanging in there late with us tonight. I've had a little difference of opinions when polling some folks about what time to start tomorrow, whether to start early or whether to not.

Some of us have four-hour commutes home in the rain and some don't. I think we need to get started a little earlier, but are there any objections if we get started a little earlier? 8:45, I'm thinking. Start out with the Georgia Manufacturing Panel next, and then we will break somewhere around 9:30, when we finish that first panel and do our public witnesses and then proceed. Any objections to

getting started a little early on a Friday? Any objections?

(No response.)

CHAIRMAN SHAW: We will adjourn, and we will see everybody back at 8:45 a.m.

(Hearing adjourned at 8:51 p.m.)

C E R T I F I C A T E

We, Kelley Marie Nadotti, Debbie A. Eickhoff, and Brenda P. Elwell, Certified Court Reporters, 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.

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5090-9084-2699-3664

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:	)	
	)	
Georgia Power Company's 2023 Integrated Resource Plan Update	)	**Docket No. 55378**
	)	**Volume II**

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Friday, March 1, 2024

The above-entitled matter came on for hearing Pursuant to Notice at 8:45 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman
FITZ JOHSON, Commissioner
TRICIA PRIDEMORE, Commissioner

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Patty Durand				
By Mr. Sherrier	1374			

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By Mr. Fabish	1413		1435	
By Mr. Hewitson		1427		
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GIPL:		
A - Chart and Tables	1304	1321
2 - Trade Secret Version of Ms. Hotaling's Prefiled Direct Testimony	1304	1321
3 - Chelsea Hotaling Consultant Professional Summary	1304	1321
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1 - Corrected Testimony of Glick & Metz	1414	1414
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2 - The HVDC Transmission: A National Security and Energy Resilience Imperative	1719	1878
3 - Regulatory Considerations for Utility Investments and Defense Energy Resilience	1719	1878
4 - Transmission Expansion for National Defense, or TREND	1719	1878
5 - DOD Energy Fact Sheet	1719	1879

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1 - Mr. Walters' Testimony	**1762**	**1828**
2 - CCW-1 (Walters' Exhibit)	**1762**	**1828**
3 - CCW-2 (Walters' Exhibit)	1762	1828
4 - Mr. Fitzhenry's Testimony	**1762**	**1828**
5 - CTF-1 (Fitzhenry's Exhibit)	**1762**	**1828**
6 - CTF-2 (Fitzhenry's Exhibit)	1762	1828
WALMART:		
1 - Lisa V. Perry Resume	**1869**	**1877**
2 - Updated Prefiled Direct	**1869**	**1877**
GPC:		
10 through 14		**1878**

P R O C E E D I N G S

CHAIRMAN SHAW: All right. We'll go ahead and call the meeting to order. This is Docket No. 55378: Georgia Power Company's 2023 Integrated Resource Plan Update.

Today is March the 1st, 2024. We'll start by calling for appearances.

Georgia Public Service Commission.

MR. THOMAS: Good morning. Preston Thomas and Ginny Davis on behalf of Public Interest Advocacy Staff.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: Good morning. Steve Hewitson, Brandon Marzo, and Allison Pryor on behalf of Georgia Power Company.

CHAIRMAN SHAW: Good morning.

Advanced Power Alliance. Where is Brad?

MR. TURNER: He's coming.

Noah Turner and Brad Carver on behalf of APA.

CHAIRMAN SHAW: Thank you.

Clean Energy Buyers Association.

Clean Energy Buyers Association.

(No response.)

CHAIRMAN SHAW: Heelstone Renewable Energy.

(No response.)

CHAIRMAN SHAW: Traffic must be bad.

Georgia Association of Manufacturers.

MR. JONES: Clay Jones on behalf of GAM.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

(No response.)

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MS. WHITFIELD: Good morning, Commissioners. Jennifer Whitfield and Bob Sherrier on behalf of Georgia Interfaith Power & Light.

CHAIRMAN SHAW: Good morning.

Georgia Solar Energy Association.

MR. MORELAND: Good morning. Don Moreland on behalf of Georgia Solar Energy Association.

CHAIRMAN SHAW: Good morning.

Georgia WAND.

(No response.)

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: Metropolitan Atlanta Rapid Transit Authority.

MS. STURM: Good morning. Kimberly Sturm on behalf of MARTA.

CHAIRMAN SHAW: That will be heretofore -- it will be called MARTA.

Microsoft Corporation.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: Good morning. Robert Baker on behalf of RSM, Inc.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: Good morning. Zach Fabish on behalf of Sierra Club.

CHAIRMAN SHAW: Southern Alliance for Clean Energy.

MR. JACOB: Bryan Jacob for Southern Alliance for Clean Energy.

CHAIRMAN SHAW: Southern Renewable Energy Association.

MR. MAHAN: Good morning. Simon Mahan and Whit Cox for the Southern Renewable Energy Association.

CHAIRMAN SHAW: Good morning.

United States Department of Defense and all other Federal Executive Agencies.

MR. McNUTT: Good morning, Mr. Chairman. John McNutt on behalf of DOD.

CHAIRMAN SHAW: Walmart.

MS. EATON: Good morning. Stephanie Eaton here for Walmart, Inc. Thank you.

CHAIRMAN SHAW: All right. Are there any housekeeping matters to take up at this time before we move on?

I guess the only thing I'll add is just that we are trying to finish today at a decent time. Hopefully we'll -- for those of us heading south, we won't get caught up in the -- I understand the First Lady is in town today. And I'm not talking about Marty Kemp.

So her -- I think she's speaking at 3:00 somewhere. So I'm not sure how long that will take, but just trying to keep that in mind, as well, for those of us going south as fast as we can.

All right. We'll go ahead and get started with where we -- Mr. Dunbar, are you here?

MR. DUNBAR: I just wanted to make my appearance. Scott Dunbar for CEBA.

CHAIRMAN SHAW: I was giving you a little break since you went last last night.

MR. DUNBAR: Thank you.

CHAIRMAN SHAW: All right. Anyone else that came in after we started appearances?

(No response.)

CHAIRMAN SHAW: All right. We'll get started where we left off with Georgia Association of Manufacturers.

Mr. Jones, you can call up your Panel.

MR. JONES: Thank you, Mr. Chairman.

CHAIRMAN SHAW: Swear in your witness.

MR. JONES: Mr. Jeff Pollock.

Jeff, would you please raise your right hand.

MR. POLLOCK: Yeah.

Thereupon,

JEFFRY POLLOCK,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. JONES:

Q Mr. Pollock, could you state your name for the record.

A Jeffry Pollock.

Q And how are you employed?

A I'm the president of J. Pollock, Incorporated.

Q And have you testified here before this Commission before?

A A few times, yes.

Q Okay. Did you cause to be filed in this docket on February 15th, 34 pages of Q and A redacted public

disclosure testimony, along with two appendices, for a total of 44 pages?

A Yes.

Q And are there any changes you need to make to your testimony this morning?

A No.

Q And if I were to ask you those same questions that appear in your prefiled written testimony, would your answers be the same?

A Yes.

MR. JONES: Mr. Chairman, I would ask that the witness' prefiled redacted public disclosure testimony be copied into the record as if given orally from the stand.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled redacted public disclosure testimony of Jeffry Pollock follows:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's	**)**	**Docket No. 55378**
2023 Integrated Resource Plan Update	**)**	

REDACTED – PUBLIC VERSION

Testimony & Exhibits

of

Jeffry Pollock

On Behalf of

Georgia Association of Manufacturers

December 12, 2022

J. POLLOCK
INCORPORATED

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
Georgia Power Company's	)	**Docket No. 55378**
2023 Integrated Resource Plan Update	)	

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LIST OF EXHIBITS

Exhibit	Description
JP-1	S&P Ca□ta□l□ PRO, *Duke Looks to Add More Gas, Offshore Wind to Meet Demand Boom in NC, SC*, F eb. 5, 2024
JP-2	A□ended and Restated So□t□ern Co□ □an□S□ste□ Interco□ □an□Interc□an□e Contract
JP-3	So□t□ern Co□ □an□Ser□ces, Inc. 2024 In□or□at□ona□Filing – IIC – Docket □o. ER10-171-000, Sc□ed□e 3.

GLOSSARY OF ACRONYMS

Term	Definition
APC	A□a□a Po□er Co□ □an□
BESS	□atter□ Ener□□ Stora□e S□ste□
DER	D□str□□ted Ener□□ Reso□rce
DPEC	De□and P□s Ener□□ C□rta□□ent
DR	De□and Res□onse
GAM	□eor□a Assoc□at□on o□Man□□act□rers
GPC	□eor□a Po□er Co□ □an□
IIC	So□t□ern Co□ □an□ Interco□ □an□ Interc□an□e Contract
IRP	Inte□rated Reso□rce P□an
kW	K□o□att
MPC	M□ss□ss□□□ Po□er Co□ □an□
MW	Me□a□att□s□
MWh	Me□a□att-□o□r
PPA	Po□er P□rc□ase A□ree□ent
RFP	Re□□est □or Pro□osa□s
ROE	Ret□rn on E□□t□
Santa Rosa	Santa Rosa Ener□□ Center□□□C

TESTIMONY OF JEFFRY POLLOCK

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Jeffry Pollock. My business address is 1323 South Central Avenue, Suite 200, St. Louis, MO 63105.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of the firm of Pollock Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from the University of Missouri. Since graduation in 1979, I have been employed in a variety of consulting assignments including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A list of appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Coalition of Energy Users (CEU). The members of CEU are customers of Grain Belt Power Company (GBPC). The consumers are large industrial electric customers taking service under a variety of rate schedules.

Q DID YOU ALSO SPONSOR TESTIMONY ON BEHALF OF GAM IN GPC'S 2022 INTEGRATED RESOURCE PLAN (IRP) FILING?

A Yes.

Q WHAT ISSUES ARE YOU ADDRESSING IN THIS IRP UPDATE?

A First I discuss the extraordinary circumstances leading to PPC's update its 2022 approved IRP. Second I sa address each of the following issues:

- Deferred accounting
- Additional ss
- Specific capacity additions and
- Proposed Distributed Energy Resource DER and Demand Response DR targets

Q DOES THE FACT THAT YOU ARE NOT ADDRESSING ALL ISSUES IN THIS PROCEEDING CONSTITUTE AN ENDORSEMENT OF GPC'S POSITIONS ON THE ISSUES?

A No The fact that I a not addressing every issue should not be interpreted as an endorsement of GPC's proposals in this proceeding.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A Yes I a sponsoring **Exhibits JP-1 JP-2** and **JP-3**

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A Given the extraordinary circumstances surrounding the IRP update specifically the dramatic increase in load growth projections PPC to accelerate future capacity additions, the Commission should be highly skeptical of GPC's proposals on deferred accounting and an additional ss My findings and recommendations are as follows

Deferred Accounting

- Deferred accounting is an extraordinary regulatory practice. It should only be used when it is necessary either to prevent material harm to the utility's financial integrity that threatens its credit rating or ability to provide more stable rates, thereby averting rate shock for the benefit of the utility's customers.
- GPC has failed to demonstrate the need for deferred accounting in this proceeding. The net deferred capacity costs that GPC will incur under the power purchase agreements (PPAs) with Mississippi Power Company (MPC) and Santa Rosa Energy Center, LLC (Santa Rosa) are only a fraction of the incremental non-fuel revenues that GPC will recover because of accelerated load growth in 2025 and 2026, even prior to remarketing additional capacity.
- GPC has already remarketed 200 megawatts (MW) of capacity from the MPC PPA and is currently negotiating to remarket the remaining MPC capacity as well as capacity under the Santa Rosa PPA. To the extent this additional capacity is remarketed, GPC will receive fuel revenues to offset the capacity payments.
- Under the rates approved in the 2022 rate case, GPC has more than adequate earnings headroom to absorb the PPA capacity costs and still earn within the authorized return on equity (ROE) and, further, GPC has consistently earned above the authorized mid-point ROE and in seven of the last eleven years its earned ROE exceeded the top end of the authorized range.
- The Commission should reject GPC's deferred accounting proposals.

Additional Sum

- GPC's proposing a 3-year look back for each year of the nine-year terms of the MPC and Santa Rosa PPAs. If approved, GPC could receive $200 million per year (nearly $1 billion over the nine-year terms) and these payments would flow immediately to GPC's earnings.
- Unlike the six PPAs approved in the 2022 IRP that were competitively procured, GPC had few good options to increase capacity to meet dramatic and unexpected load growth.
- Because of the dramatic increase in load growth, GPC does not need an incentive to procure capacity. Further, the capacity price under the MPC PPA is lower than the capacity equalization rate prescribed under the Southern Company Intercompany Interchange Contract (IIC). According, there are no shared savings. Combined with changed circumstances, specifically the greater risks to retail customers for accelerated load growth and the absence of any cost reductions, the MPC and Santa Rosa PPAs do not meet the criteria for an additional sum.

- The Commission should reject PC's proposed additional s on the MPC and Santa Rosa PPAs.

Specific Capacity Additions

- The purchase of capacity from a PC affiliate MPC is occurring through a separate PPA rather than through the on-stand IIC.

- The IIC provides a contractual basis for the continued operation of the electric facilities of the Southern Operating Companies as a fully integrated power pool. In addition to short resource planning and scheduling of short-term sales/purchases the IIC provides a mechanism for sharing temporary capacity surpluses and deficits between and among each Operating Company. The "reserve sharing" payment is based on the installed cost of a displaced peaking resource.

- The IIC is based on each Operating Company planning sufficient resources to meet its own needs in the long-term. However there is no prohibition or restriction on the duration of reserve sharing transactions.

- GPC's assertion that MPC would have retired the capacity in the absence of the PPA is contrary to the IIC and prudent resource planning. MPC could not have implemented its proposed retirement plan until the retired capacity was needed by the Operating Companies to maintain reliability and MPC has compensated for the costs of these resources.

- PC fully recovers all purchased capacity costs under the MPC PPA than under the IIC. This is yet another reason for rejecting an additional s on the MPC PPA.

- The planning of a battery energy storage system (BESS) and solar arrays at the [redacted] site are part of the cost ensemble of the proposed capacity additions in this IRP update. The excess cost is not due to the BESS but is not significantly different than the costs of the proposed BESSs at the Robins and Moody battery bases — rather it is due to the solar arrays that would be used solely to charge the BESS.

- The cost of using solar arrays to charge the BESS at [redacted] is projected to be significantly higher than GPC's projected avoided energy cost under all planning scenarios except for the [redacted] case with $20/ton carbon cost in 2030. In other words absent [redacted] prices and a $20 carbon adder it would be more cost-effective to use the grid to charge the BESS.

- According to the Commission allows the [redacted] project it should only do so for the standalone BESS component.

Proposed DER and DR Tariffs

- GPC is proposing two new rate schedules (DCO-1 and DCO-1) to expand the installation of DERs and a new DR rate schedule (DC-1).
- While expanding DERs and DR can encourage action by customers to alleviate projected capacity shortages, these also increase residential customers' bills and have to be able to properly assess the risks and benefits before committing serious consideration to these alternatives. In this respect, GPC's proposals should have included discretion in determining the amount of the credits/payments, renewable energy tariffs, and other significant terms and conditions. Accordingly, the Commission should not approve the proposed DER/DR rate schedules as filed.
- Specific improvements should include:
  - Providing a specific definition of "system value" and requiring GPC to seek Commission review and approval of the methodology and assumptions used in describing the methodology and providing a specific quantification used to determine system value prior to approving the new rate schedules' implementation each year.
  - Requiring GPC to provide at least six months advance notice before any DER/DR rate schedule is discontinued and obligating GPC to compensate customers for any investments that have become stranded as a result of premature termination.
- Additional changes should include:
  - Schedule DC-1 should be revised to allow the customer to be directly involved in connecting the DER and related equipment.
  - Schedule DCO-1 should not limit the size of a customer-owned DER to 10 MW. It should be clear that the customer can outsource the installation, including any upgrades, and to ensure that the customer can continue to use any other energy produced by the DER activity even when this is dispatched by GPC to meet system needs.
  - Schedule C-1 should be revised (1) to include a more specific definition of the circumstances that constitute a Demand Response Event, (2) to set the credits to reflect the lower, not discounted, avoided cost of capacity, including transmission investments can occur due to shortages or congestion, (3) the compliance incentive should not exceed the value of the credit, and customers should have the option to choose from among a menu of options including contract duration and curtailment hours and receive credits that reflect the value of the selected option.

2. OVERVIEW

Q WHAT CIRCUMSTANCES ARE DRIVING GPC TO UPDATE THE IRP THAT WAS JUST APPROVED IN 2022?

A The IRP update is precipitated by a significantly higher load growth than was projected in the 2022 IRP. GPC is now projecting winter peak demand growth at a compound annual rate of 2.5% for the period 2023 through 2033. This is in stark contrast to the 0.8% per year growth rate projected by GPC in its 2022 IRP. The accelerated growth could translate into a 4,000 MW increase in peak demand by the year 2033. As a consequence of the higher-than-projected load growth, GPC's winter reserve margins are projected to fall below the target reserve margin by the winter of 2025-26 triggering a capacity need. Previously, GPC did not project a capacity need until the winter of 2025-26.

Accelerating load growth and capacity needs are indeed extraordinary circumstances. Meeting the challenges created by these extraordinary circumstances will require creative rather than business-as-usual solutions.

Q HAS GAM OPINED ON THE REASONABLENESS OF GPC'S UPDATED LOAD FORECAST?

A While GAM shares and understands the concerns about the sudden change and the unprecedented amount of load growth that GPC is now projecting, GPC is not alone in experiencing accelerated load growth.

Due to the increase of data centers, battery and electric vehicle manufacturing and related industries the Southeast is experiencing rapid load growth, thereby necessitating a more rapid increase in capacity resources. For example, GPC anticipate

A□a□a□a Po□er Co□ □an□ □APC□□as □ss□ed a Re□□est □or Pro□osa□s □R□P□□or ne□ ca□act□ reso□rces a□a□a□e to co□ □ence ser□ce □□ Dece□ □er 1□202□□[1] □□rt□er□ D□ke Ener□□ Caro□nas and D□ke Ener□□ Pro□ress recent□ □□ed □□dated IRPs c□t□n□ □ "unprecedented economic development □ro□t□ t□ro□□□ 2023 t□at □s □e□□e□ond t□e □ Companies' □stor□ca□e□□er□ence□ res□t□n□ □n s□□stant□a□□ □ater□a□c□an□es □n t□e □ Companies' load forecast since the Companies prepared their initial Plan."[2] T□ese □□dated IRPs □ro□ect "eight times the □eak load growth" anticipated just less than t□o □ □ears a□o □ncreas□n□ 2030 □eak de□ and □□ a□o□t 2□100 M□ □[3] T□e □□□□er □oad □ro□t□ □s □ro□ected to tr□□□er add□t□ona□needed ca□act□□ A recent S&P Ca□ta□ □ PRO 10 art□c□e d□sc□ss□n□ t□e □□dated IRPs □s □ro□ded □n **Exhibit JP-1.**

11 **Q ARE THERE BOTH BENEFITS AND RISKS ASSOCIATED WITH LOAD GROWTH?**

12 A □es□ I□t□e □ro□ected □oad □ro□t□ does not □ater□a□□e□□PC □o□d □nc□r add□t□ona□ 13 costs t□at □o□d e□t□er □a□e to □e reco□ered □n rates or t□ro□□□ sa□es o□s□r□□s 1□ ca□act□ to ot□er □t□□t□es t□at □a□e a ca□act□ need□ On t□e ot□er □and□□□at □oad 1□ growth does materialize will produce additional revenues that reflect GPC's current 1□ s□ste□ costs□ □nc□□d□n□ t□e recent□ co□ □□eted Vo□t□e □n□t □o□3 and soon to □e 1□ co□ □ss□oned □n□t □o□□□ □oad □ro□t□ □eans t□at □PC □□□□e se□□n□ □ore e□ectr□c□t□ 1□ to c□sto□ers□T□s□n t□rn□□ □□create add□t□ona□sa□es and re□en□es over which GPC's

[1] □tt□s□//□□□□a□a□a□a□o□er□co□/content/da□/a□a□a□a-□o□er/□d□s-docs/co□ □an□/r□□/a□c-2023-ca□act□-r□□□□d□

[2] *In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)*□ Docket □o□E-100□S□□ 1□0□Ver□□ed A□ended Pet□t□on □or A□□ro□a□o□2023-202□ Car□on P□an and Inte□rated Reso□rce P□ans □or D□ke Ener□□ Caro□nas□□□C and D□ke Ener□□ Pro□ress□□□C at 11 □an□ 31□202□□□

[3] *Id.* at 11-12□

system costs including the substantial additional costs associated with Vote Net Loss 3 and can be spread over more kWh sales thereby placing downward pressure on rates.

For example, under its P50 projected load growth for 2021 and 2022 I estimate that PC will recover [redacted] of additional non-fuel energy sales to offset incremental production capacity costs. These additional energy sales could be even lower based on the PC forecast used by PC in its revised load forecast.

Further, the projected capacity additions including the six PPAs approved in the 2022 IRP and the two additional PPAs proposed in this IRP update are expected to have lower incremental fixed costs than GPC's existing capacity resources. Thus, these capacity additions will also place downward pressure on rates.

Q GIVEN THE EXTRAORDINARY CIRCUMSTANCES SURROUNDING THE IRP UPDATE, SHOULD THE COMMISSION TAKE A "BUSINESS-AS-USUAL" APPROACH TO ADDRESSING THE ISSUES RAISED IN THIS PROCEEDING?

A No. In particular the Commission should be highly skeptical of GPC's proposals to defer expenses and earn additional profits for the reasons discussed in the following sections.

[1] A P50 projection means that there is an equal likelihood that load growth could be lower or higher than the projected load.

3. DEFERRED ACCOUNTING

Q WHAT IS DEFERRED ACCOUNTING?

A Deferred accounting is a process where a utility is authorized by the Commission to defer rather than immediately expense a specific cost or recover in a future period a cost in immediately expensed that could have an immediate and potentially material impact on a utility's earnings; whereas, deferring the expense would match the expense with future revenues by spreading the burden of that cost into the future.

Q IS DEFERRED ACCOUNTING A NORMAL REGULATORY PRACTICE?

A No. Deferred accounting is an extraordinary regulatory practice. It is only used when it is necessary either to prevent material harm to the utility's financial integrity or to provide more stable rates that are affordable by shifting rate stock for the benefit of the utility's customers.

Q IS DEFERRED ACCOUNTING ALWAYS APPROPRIATE?

A No. Deferred accounting shifts regulatory risk from a utility's shareholders onto customers. This is contrary to the regulatory compact in which a utility should have an *opportunity* — not a *guarantee* — to earn a reasonable return on its investment in the facilities used in providing electric to its captive customers. Therefore, deferred accounting should be used sparingly in circumstances such as when a utility incurs an extraordinary cost such as storm damage or fuel costs necessary to spread recovery of that cost over a reasonable period to prevent harm to a utility's financial integrity or avoid rate shock for customers.

1 **Q IS DEFERRED ACCOUNTING AN ACCEPTED PRACTICE IN GEORGIA?**

2 A Yes.

3 **Q WHAT COST IS GPC ASKING THE COMMISSION TO DEFER FOR FUTURE**
4 **RECOVERY?**

5 A GPC is asking the Commission to defer recovery of the capacity amounts under both
6 the MPC and Santa Rosa PPAs and certain development costs. The proposed PPA
7 capacity deferrals are summarized in Table 1.

Table 1
Estimated Incremental Revenue Requirements for Net Deferred Costs of PPAs
(Millions)

Description	2024	2025	2026	2027	2028
Mississippi Power PPA	[redacted]				
Regional Sale PPA					
Santa Rosa PPA					
Total Amount Deferred					
Reg Asset Beginning Balance	[redacted]				
Amortization					
Reg Asset Ending Balance					
Deferred Tax Liability					
Average					
Pre-Tax WACC					
Financing Cost on Reg Asset					

Source: GPC Trade Secret Response to STF-DEA-3-1(Supplemental Attachment A)

[1] Georgia Power Company's 2023 Integrated Resource Plan Update Main Document at 11.

As can be seen, PC projects that the impact of the two PPAs would increase net operating expenses by [redacted] and [redacted] in 2020 and 2021, respectively. This projection assumes, however, that on the 200 MW of the MPC PPA capacity is remarketed. PC is actively marketing the remaining 200 MW of the MPC PPA capacity as well as capacity from Santa Rosa. If these efforts are successful in further mitigating the impact of the new PPAs on future earnings.

Q HOW WOULD THE DEFERRED CAPACITY PAYMENTS BE RECOVERED?

A Under GPC's proposal, the $[redacted] of accumulated deferred capacity payments would be recovered over three years beginning in 2021. The recovery of the deferred capacity payments would coincide with the incurrence of capacity payments under both the MPC and Santa Rosa PPAs.

Q IS GPC'S ACCOUNTING PROPOSAL NECESSARY TO AVERT EITHER DETERIORATING FINANCIAL INTEGRITY OR TO STABILIZE ITS EARNINGS AND REVENUES?

A No. At first, when PC is not successful in marketing more than the 200 MW that is already under contract, the resulting deferrals in 2020 and 2021 are immaterial and would have little impact on GPC's authorized ROE. If, on the other hand, GPC's efforts to remarket additional capacity from the two PPAs are successful, there will be little or no impact.

Second, as previously mentioned, PC will collect an additional [redacted] of non-fuel revenues due to projected load growth in 2020 and 2021 that would more than offset the deferred expenses.

[redacted] PC Response to STC-KA-1.

Third, GPC has had no difficulty earning its authorized 10% ROE. In seven of the last eleven years, GPC's earned ROE has exceeded 12%. Most recently, the Commission determined that GPC had earned a 13% ROE, and as a consequence, GPC incurred $23 million of excess revenues.[1] The revenue spread between a 10% and 11% ROE would exceed $20 million per year, which is more than [redacted] times the annualized cash expense under the MPC and Santa Rosa PPAs. Thus, GPC has more than ample "headroom" to expense, rather than defer, the MPC and Santa Rosa PPA capacity costs and not sustain any material harm in its financial integrity or credit rating.

Finally, the Company's proposal would effectively allow a double-return on the deferred costs. This is because GPC is proposing to add carrying charges on the amortized balance of the deferrals. The also recovering an additional $[2]

Q WHAT DO YOU RECOMMEND?

A The Commission should reject GPC's deferred accounting proposal. Given the extraordinary circumstances of this IRP update, deferred accounting should only be used to the extent the Company could make a material adverse impact on the utility or would destabilize rates. GPC already has more than adequate earnings to absorb the expense without any material adverse impact on earnings and its efforts to settle the remaining capacity are successful, there will be no impact.

[1] *In Re: Georgia Power Company's 2019 Rate Case*, Docket No. 42516, Order on Georgia Power Company's 2022 Annual Surveillance Report at 1 (Dec. 31, 2023).

[2] The difference in the pre-tax rate of return between an 11% and a 10% ROE is approximately 1.[redacted] GPC's projected 2024-2028 rate base averages $20[redacted] billion. This 1.[redacted] of $20[redacted] billion is $2[redacted] million.

4. ADDITIONAL SUM

Q IS GPC PROPOSING TO RECOVER AN ADDITIONAL SUM ON THE MPC AND SANTA ROSA PPAS?

A Yes. GPC is proposing to recover $3 per kW-year for each year of the three-year terms of the two PPAs. This includes the years 202[illegible] and 202[illegible] during which GPC concedes it does not need the capacity from the PPAs. If approved, GPC could receive $2[illegible] million per year and these payments would flow immediately to GPC's earnings. Over the three-year terms, GPC could receive nearly $1[illegible] million of additional earnings.

Q WHY IS GPC REQUESTING AN ADDITIONAL SUM ON THE TWO NEW PPAS?

A GPC states that its request is consistent with the additional sums approved on the six capacity PPAs in the 2022 IRP.[1]

Q IS CONSISTENCY A NECESSARY AND SUFFICIENT REASON TO GRANT AN ADDITIONAL SUM ON THE MPC AND SANTA ROSA PPAS?

A No. As previously discussed, the extraordinary circumstances surrounding this IRP update proceeding clearly warrant a significant policy change.

For example, the two PPAs are among the very few good options available to obtain the capacity GPC needs on a short-term basis to maintain reliable for all retail customers — existing and new. Further, accelerated load growth could limit the Company's ability to competitively procure capacity additions. Neither the MPC nor the Santa Rosa PPAs were procured competitively. This is clearly a changed circumstance unlike the six capacity PPAs approved in the 2022 IRP that were procured through a competitive process. Further, as discussed later, the PPA with

[1] Direct Testimony of Forrest Ransisco Valentine Evans and Michael Alvis at 33-3[illegible]

alternate MPC could have been procured through an existing mechanism at a lower cost. Finally, retail customers are clearly at risk if GPC's load projections are, in retrospect inaccurate.

Q WHAT ARE THE REQUIREMENTS FOR AWARDING AN ADDITIONAL SUM?

A The requirements are stated in the Commission Rules:

> The certified or actual cost of the power purchase or an certificated non-tariff power purchase shall be recovered in rates in the utility's next general rate case after the addition as determined by the Commission ***to encourage such purchases. The Commission shall consider lost revenues, if any, changed risks, and an equitable sharing of benefits between the utility and its retail customers***…[10] (emphasis added)

Q DID THE MPC AND SANTA ROSA PPAS MEET THESE REQUIREMENTS?

A No. First as discussed above, even the limited options available there is no need to provide GPC an incentive to procure the least cost alternative — neither the nor options offer a choice or one could be encouraged. Second because the PPAs were not competitively procured there are no benefits to be shared with retail customers as a self-owned resource or other capacity alternatives. In fact as discussed later the MPC PPA more expensive than its capacity had been procured through the IIC. Third retail customers are clearly at greater risk due to the potential impact on system reliability due to accelerated load growth – a circumstance that has clearly changed since the 2022 IRP.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject the proposed additional sum on the MPC and Santa Rosa PPAs.

[10] Cal Code Regs. Title 20 § 1-3-11 (Cost Recovery and Financial Incentives). *See also* OAC Rule A-3A-

5. SPECIFIC CAPACITY ADDITIONS

Q WHAT CAPACITY ADDITIONS ARE YOU ADDRESSING?

A I s□a□d□sc□ss t□e MPC PPA and t□e [redacted] □ESS/So□ar Pro□ect□

MPC PPA

Q YOU PREVIOUSLY STATED THAT GPC COULD HAVE PROCURED CAPACITY FROM MPC THROUGH THE IIC. WHAT IS THE IIC?

A T□e IIC □s a □ERC-a□□ro□ed tar□□□□ and □et□een APC□□PC□MPC and So□t□ern Po□er Co□□an□ (collectively, the "Operating Companies") which operate as an □nte□rated e□ectr□ □t□□t□ s□ste□ and So□t□ern Co□□an□ Ser□ces□Inc□ A co□□ o□t□e c□rrent□□e□ect□e IIC □s □ro□ded □n **Exhibit JP-2**□

Q WHAT IS THE PURPOSE OF THE IIC?

A T□e IIC □ro□des a contract□a□□as□s □or t□e cont□n□ed o□erat□on o□t□e e□ectr□ □ac□□t□es o□t□e O□erat□n□ Co□□an□es to ac□□e□e t□e □a□□□ □□ □oss□□e econo□□es cons□stent □t□ t□e □□□□est □ract□ca□□e re□a□□t□ o□ser□ce□and to □ro□de a □as□s □or e□□□ta□□□ s□ar□n□ t□e costs assoc□ated □t□ t□e o□erat□on o□□ac□□t□es t□at are □sed □or t□e □□t□a□ □ene□t o□a□□t□e O□erat□n□ Co□□an□es□ T□□s□t□e O□erat□n□ Co□□an□es s□are a□□t□e □ene□ts and □□rdens□ □nc□□d□n□ co□□□□□n□ □□t□ o□erat□n□□ d□s□atc□ and reser□e re□□re□ents□ □art□c□□at□n□ □n o□□ort□n□t□ sa□es transact□ons□ and □ear□n□ res□ons□□□□t□ □or t□e□ □ort□on o□□□rc□ases□

Q DOES THE IIC ALSO PROVIDE A MECHANISM FOR REVIEWING GENERATION EXPANSION PLANS OF EACH OF THE OPERATING COMPANIES?

A □es□ Art□c□e IV o□t□e IIC □ro□des t□at a des□nated re□resentat□□e □ro□ eac□ o□t□e

Operating Companies together with a representative of Southern Company Services, Inc., shall constitute as an "Operating Committee." The Operating Committee is responsible for reviewing and recommending generation expansion plans for all the Operating Companies that relate to the operation coordinated operation of the Southern electric system.

Q GPC ASSERTS THAT THE IIC PROVIDES A MECHANISM FOR TEMPORARILY SHARING CAPACITY SURPLUSES OR DEFICITS AMONG THE OPERATING COMPANIES. DOES THE IIC DEFINE A "TEMPORARY" CAPACITY SURPLUS OR DEFICIT?

A No. Under Section 11 the IIC is required on each of the Operating Companies to maintain adequate resources to reliably serve its own obligations. However it also recognizes that in any given year one or more of the Operating Companies may have a temporary surplus or deficit of capacity as a result of coordinated planning or due to load uncertainty and other circumstances. Given the extraordinary nature of the proposal that GPC is now requesting the IIC should not have been so narrowly interpreted as the Company is now suggesting.

Q DO THE OPERATING COMPANIES COMPENSATE ONE ANOTHER FOR THE COST OF CAPACITY THAT IS SHARED AMONG THEM?

A Yes. Section 12 of the IIC provides that the costs associated with reserve sharing capacity are settled on a monthly basis where each deficit company purchases capacity from a surplus company at the rate that reflects the cost of the most recently acquired peaking plant resource that is available for year-round operation and scheduling. This is the rate the IIC requires each Operating Company to be set-

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Q GPC ASSERTS THAT IT COULD NOT HAVE ACQUIRED CAPACITY FROM MPC THROUGH THE IIC AND THAT A SEPARATE PPA WAS ESSENTIAL. HAS GPC PROVIDED SUBSTANTIAL EVIDENCE TO SUPPORT THIS ASSERTION?

A □o□ □□rst□□nder t□e IIC□t□e O□erat□n□ Co□ □ □ttee□n □□c□ □PC □as a des□nated re□resentat□□e□ann□a□□ re□□e□s □eneration □ann□n□ dec□s□ons□ T□s □o□d □nc□□de □ot□ t□e t□□ n□ and a□o□nt o□an□ □anned ca□act□ add□t□ons and reassess□n□ an□ □r□or dec□s□ons to ret□re □eneration ca□act□□ T□□s□□□en □PC □eca□e a□are t□at MPC □as □ann□n□ to ret□re ca□act□ t□at s no□ needed to □a□nta□n re□a□□□t□ □or t□e O□erat□n□ Co□ □an□es□ t□ co□d □a□e arran□ed to □roc□re t□s ca□act□ t□ro□□□ t□e IIC to ass□re t□at t□e reso□rces □o□d cont□n□e to □e □sed and □se□□□□ □□e co□ □ensat□n□ MPC □or t□e cost to kee□ t□e reso□rces □n o□erat□on□

Q DID MPC PROPOSE A RETIREMENT PLAN TO REDUCE 976 MW OF GENERATION CAPACITY BY YEAR-END 2027?

A □es□ MPC □as ordered □□ t□e Co□ □ ssion to □□e a □an to ret□re a□□ro□□ate□ □□0 M□ o□□eneration ca□act□ □□ □ear-end 202□□[11] In 2021□MPC □□ed t□e □ro□osed □an in its IRP. Table 2 summarizes MPC's proposed retirements from the 2021 IRP filing.

[11] *Mississippi Power Company's Reserve Margin Plan*□Docket □o□201□-AD-1□□□Order at □-□ □Dec□ 1□□2020□□

Table 2 Mississippi Power Company Planned Capacity Retirements (MW)		
Generating Unit	**Net Capability**	**Planned Retirement**
Watson 4	2□□	Dec□2023
Greene County 1	103	Dec□202□
Greene County 2	103	Dec□202□
MPC Daniel Coal	□02	Dec□202□
Total	□□□	
Source: M□ss□ss□□□Po□er Co□ □an□□MPSC Docket □o□201□-□A-231□2021 IRP □□n□at □ □A□r□1□□2021□□		

Several facts about MPC's planned ca□act□ ret□re□ents are note□ort□□□ □□rst□t□e □ast □a□or t□ o□t□e ca□act□ □o□d not □a□e □een ret□red □nt□□ Dece□ □er 202□□ Second□t□e □reene Co□nt□ □n□ts are □o□nt□□o□ned □□MPC □□0□ □and APC □□0□ □□[12] As t□e □a□or t□ o□ner□APC □o□d □a□e so□e sa□ □n t□e ret□re□ent dec□s□on□ T□rd□ des□te t□e □anned ret□re□ents□MPC □as not □ro□ect□n□an□ca□act□need □nt□2031 or □ater □nder t□e □ar□o□s □ann□n□ scenar□os cons□dered □□□c□ a□so □nc□□ded t□e add□t□on o□□ESS and □t□t□-sca□e so□ar and □□□□er car□on □ress□re scenar□os□□[13]

Q WHY WAS MPC ORDERED TO FILE A RETIREMENT PLAN?

A T□e M□ss□ss□□□P□□□c Ser□ce Co□ □ □ss□on □as concerned t□at MPC not on□□ □ad a capacity surplus until at least 2031, but a portion of MPC's □oss□□□e□□eet □as

[12] *Mississippi Power Company's 2021 Integrated Resource Plan Filing*□Docket □o□201□-□A-231□ M□ss□ss□□□Po□er 2021 IRP □□n□at □-□ □A□r□1□□2021□□

[13] *Id*□at □□

marginally economic.[1] These concerns are similar to the concerns discussed in GPC's 2022 IRP, which identified Plant Bowen and Plant Scherer as marginally economic.

Q WAS THE DECISION TO RETIRE 976 MW OF GENERATION CAPACITY IRREVOCABLE?

A No. The retirement planned by MPC in its 2021 IRP was in response to a Commission directive to either downsize MPC's generation fleet by no later than 2027 or to propose an alternative to offer an IRP. There is a difference — it is not an irrevocable action that the elected regardless of the actual circumstances. To assert otherwise would be contrary to prudent system planning.

Furthermore, certain plants are found to be marginally economic under certain specific circumstances, this finding alone is not a sufficient reason to irrevocably commit to retiring these resources. MPC could have marketed the capacity and generated revenues that effectively insulated retail customers from the economic costs of these resources. There is no reason to believe that MPC would have actually elected its retirement plans if the capacity was needed elsewhere in the Southern Company system.

Q HOW DOES THE COST OF CAPACITY UNDER THE MPC PPA COMPARE WITH THE COST OF RESERVE SHARING UNDER THE IIC?

A In 2021, the cost of reserve sharing capacity is $3.20 per kW-year, which is equivalent to $10 per kW-month. This is shown in **Exhibit JP-3**, Schedule 3

[1] Docket No. 2017-AD-1, *Order* at 5-6 (Dec. 1, 2020).

rom the 2021 IIC Information in contrast the capacity added under the MPC PPA starts at [redacted] per kW-month in 2021 and gradually escalates to [redacted] per kW-month in 2031.[11] This seven additional years of the MPC PPA capacity is more than an adjustment reserve sharing capacity purchase under the IIC.

Q WHAT DO YOU RECOMMEND?

A GPC could have procured capacity from MPC through the IIC and the reserve sharing capacity price should have been based on a market-based capacity price. Paying more than the IIC price for capacity fails to balance the benefits for GPC's retail customers. This is yet another reason for denying an additional seven years on the MPC PPA.

[redacted] BESS/Solar Project

Q PLEASE DESCRIBE THE PROPOSED BATTERY AND SOLAR RESOURCES GPC IS PROPOSING TO PROCURE AS PART OF ITS IRP UPDATE PLAN.

A GPC's IRP update includes three new BESSs that could be paired with solar resources.[12] Two of these batteries totaling 100 MW could be installed at the sites of existing Company-owned solar facilities at the Robins and Moody Air Force bases. However there is currently no existing resource that the third battery could be co-located. This GPC is proposing to add a new 200 MW solar project to pair with this third battery also sized to 200 MW. Collectively this combined resource is referred to as the [redacted] BESS/Solar Project.

[11] Power Supply Agreement and between Mississippi Power Company and Georgia Power Company Service Schedule at Oct 11 2023

[12] 2023 IRP update at 20

Q HAS GPC CONSIDERED THE COSTS OF THE BESS RESOURCES IN AN ECONOMIC ANALYSIS?

A Yes. GPC conducted an economic analysis of the resources included in its IRP update. These results are summarized in Table 3 below.

Table 3
Summary of Updated Economic Analysis
Under MG0 Scenario
($/kW)

Project	Cost
Robins BESS	[redacted]
Moody BESS	
MPC PPA	
Santa Rosa PPA	
Yates 8–10 CTs	
[redacted] BESS/Solar	

Source: TS Updated Economic Analysis of Capacity Resources Supplemental 1-12-2021

As Table 3 shows, the BESSs that would be installed at Robins and Moody Air Force bases are among the least expensive resources included in GPC's IRP update. Conversely, the [redacted] BESS/Solar Project would be among the most expensive resource included in GPC's portfolio. Specifically, GPC's projections show that [redacted] BESS/Solar Project would be [redacted] more expensive than the Robins BESS and [redacted] more expensive than the Moody BESS on a per kW basis.

Q ARE THE BATTERY RESOURCES INCLUDED IN GPC'S IRP UPDATE FUNDAMENTALLY SIMILAR?

A Yes. GPC has stated that the Robins and Moody BESSs would be based on lithium-

on tec□no□o□□□[1□] A□t□o□□□ □PC □as not □et s□ec□□ed t□e tec□no□o□□ □or t□e □ro□osed □ESS at [redacted] □□t□□□□-on tec□no□o□□ s t□e □re□a□ent tec□no□o□□ t□□e □or □t□□t□-sca□e □atter□es□ As s□c□□t□ s reasona□□e to ass□□e t□at t□s □ro□ect □□□a so □t□□□e t□e sa□e tec□no□o□□□

Q ASSUMING THAT THE BESS INCLUDED IN GPC'S IRP UPDATE ESSENTIALLY USES THE SAME TECHNOLOGY, WHAT IS THE DRIVER OF THE DRASTIC PRICE DIFFERENCES OBSERVED BETWEEN THE BESS RESOURCES IN GPC'S ECONOMIC ANALYSIS?

A □eca□se t□e □ESSs are □□nda□enta□□ s□□ □ar□t□e on□ d□□erence o□ser□ed □et□een t□e Ro□□ns and Mood□ □ESSs □□en co□ □ared to t□e [redacted] □ESS t□at can acco□nt □or t□e e□tre□e □r□ce d□□erences □s t□e so□ar □ro□ect t□at □s □ro□osed to □e □a□ed □t□ t□e □atter reso□rce□

Q WHY IS GPC PROPOSING TO PAIR THE BATTERY AT THE [redacted] SITE WITH A SOLAR RESOURCE?

A □PC states t□at □t □s necessar□ to s□□□ort t□e □ESS □t□ □enerat□n□ reso□rces □eca□se t□e□ are □□□ted □□ t□e□ d□sc□ar□e d□rat□on and need to □e c□ar□ed□[1□] Conse□□ent□□□□ PC □ro□osed to □a□ t□e [redacted] □ESS □t□an acco□ □an□n□ so□ar reso□rce□ □o□e□er□ t a□so stated t□ co□□d □e c□ar□ed □□ ener□□ □ro□ t□e □rd de□end□n□ on t□e a□a□a□□t□o□□r□ trans□ ss□on ca□act□□[1□]

[1□] D□rect Test□□on□o□□e□re□R□□r□□□□□□ranc□sco Va□e□□ee E□ans□and M□c□ae□A□□□s□ at 3□□

[1□] *Id*□at 3□□

[1□] *Id*□at 3□□

Q IS IT REASONABLE FOR GPC TO ASSUME THAT A SOLAR RESOURCE IS THE ONLY OPTION WITH WHICH TO CHARGE THE PROPOSED [redacted] BESS?

A [o]a [a]red so[a]r reso[r]ce [s] not t[e] on[] et[od] [][][]c[] a [ESS can [e] c[ar[ed[]

 As [PC reco[n[es[t[s [oss[]e to c[ar[e a [ESS [t[ener[][] ro[t[e [rd[In [act[

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 [ro[osed [ESS[as s[o[n [n Ta[e [e[o[[

Table 4
Comparison of [redacted] Solar Costs to GPC's Avoided Cost ($/MWh)

Year	[redacted] Solar	MG0	LG0	HG0	MG20	HG20	Average
2027	[redacted]						
2028							
2029							
2030							
2031							
2032							
2033							
2034							
2035							
2036							

Source: TS SAM ('23) – [0[1 – [redacted] [ESS [na[and TS ST[-[KA-2-[Attac[[ent A[

Q PLEASE EXPLAIN TABLE 4.

A Ta[e [co[[ares t[e cost [er M[[o[t[e [ro[osed [redacted] so[ar [ro[ect [t[

 GPC's projected avoided cost under each of its planning scenarios for the first ten years of the project's operating life. The avoided cost under each planning scenario [as ca[c[ated [[a[era[n[t[e [o[r[a[o[ded cost [or t[e [o[rs [ro[[a[[[to [

□□□ □□or eac□ da□ o□t□e □ear to re□resent t□e □o□rs □□en t□e s□n s s□□n□ and a so□ar reso□rce □o□d □res□□ a□□□ □e o□erat□n□□

As t□e ta□□e s□o□s□t□e cost o□t□e [redacted] so□ar □ro□ect exceeds GPC's a□o□ded cost □nder a□□□ann□ scenar□os □ro□ [redacted] t□ro□□□ [redacted]□ In s□□se□□ent years, the cost of the solar project is below GPC's avoided cost only under the HG20 scenar□o□

Q PLEASE SUMMARIZE YOUR FINDINGS REGARDING THE PROPOSED [redacted] BESS/SOLAR PROJECT.

A T□e [redacted] □ESS/So□ar Pro□ect s the most expensive project included in GPC's IRP □□date□ A t□o□□□ t□e cost □or t□e □ESS co□ □onent s co□ □ara□□e to t□at o□ot□er BESSs proposed, its high cost is driven by GPC's assumption that the □ESS s□o□d □e c□ar□ed □□a ne□ □co-□ocated so□ar □ro□ect□ T□ere□ore t□e [redacted] □ESS □o□d □e □ore cost-e□ect□e□ c□ar□ed t□ro□□□ ener□□ □ro□ t□e □rd rat□er t□an t□ro□□□ a ne□ so□ar reso□rce□

Q WHAT DO YOU RECOMMEND?

A I reco□ □end t□at □t□e Co□ □ ssion a□□ro□es t□e [redacted] □ro□ect□t s□o□d on□ do so □or t□e nd□□d□a□□ESS co□ □onent□ T□e so□ar co□ □onent o□t□e □ro□ect s□o□d □e re□ected as t re□resents an e□tre□e□ e□□ens□e o□t□on □or c□ar□n□ t□e □ro□osed □ESS□

6. DISTRIBUTED ENERGY RESOURCE/DEMAND RESPONSE TARIFFS

Q OTHER THAN THE PREVIOUSLY DISCUSSED CAPACITY ADDITIONS, HOW IS GPC PROPOSING TO FILL THE PROJECTED CAPACITY NEED?

A GPC is proposing to offer new rate schedules to expand the installation of DERs and a new DR rate schedule. The three proposed DER/DR rate schedules are:

- DER Colocation Schedule DCL-1
- DER Customer Owned Schedule DCO-1 and
- Certain Large Load Rider Schedule CL-1

Q PLEASE DISCUSS SCHEDULE DCL-1.

A Schedule DCL-1 would be applicable to "qualifying" commercial and industrial customers who agree to allow GPC to install a company-owned DER at a new or existing facility that has a minimum contract demand of 10 MW. The customer would be charged an unspecified rate based on the capital costs and operating expenses of the GPC-owned DER in addition to any energy or electricity used under the otherwise applicable rate schedule.

The DER would be dispatched solely at the Company's discretion to provide system benefits by offering during times of electric service outage the DER would be used to provide the participating customer with "resiliency" service to support the customer's operations. The term resiliency is not defined.

Further as stated in the proposed schedule the DER technology that will be utilized must meet Company minimum technical requirements and meet current regulatory requirements for non-emergency operation.

Q PLEASE DESCRIBE SCHEDULE DCO-1.

A Sc□ed□e DCO-1 s ar□e□ s□□ ar to DC□-1 e□ce□t t□at t□e c□sto□er□rat□er t□an □PC □□o□d □ro□de t□e DER and re□ated e□□□□□ent□ T□e c□sto□er □o□d rece□e an □ns□ec□□c credt □ased on t□e ca□ta□cost and o□eratn□ e□□ense o□t□e DER□n addton to □a□n□ or e□ectrc□t□ □sed □nder t□e ot□er□se a□□□ca□e rate sc□ed□e□ □o□e□er□t□e ter□s and condtons are □ore restrct□e□ □or e□a□□e□□n□ke Sc□ed□e DC□-1 t□e DER □ □st □a□e a □ n□□ □□ ca□act□o□1 M□ and□c□n□ □otenta□ o□erat□ona□r□sk□□PC s □ro□osn□ to □□t t□e s□e o□a c□sto□er-o□ned DER to 10 M□ □[20] T□e DER □ □st a□so □e ne□□□ an□act□red and nsta□ed □t□ a co□ □erc□a□ o□erat□on date s□□se□□ent to t□e cert□□cat□on o□t□e reso□rces □□t□e Co□ □ ss□on□

Q PLEASE DESCRIBE SCHEDULE CL-1.

A Sc□ed□e C□-1 □o□d □e an a□ternat□e to t□e De□and P□s Ener□□ C□rta□□ent □DPEC□Sc□ed□e and □o□d a□□□□ to c□sto□ers □□o a□ree to red□ce t□e□r □oad to a des□nated □r□-de□and □e□e□ d□r□n □er□ods o□ e□tre□e s□□□□□ and de□and cond□tons *□.e.*□a De□and Res□onse E□ent□□t□n no □ess t□an 30 □ n□tes ad□ance not□ce□ A C□-1 c□sto□er □o□d rece□e an □ns□ec□□ed credt □ased on □□□ o□t□e ca□act□ □a□e □ro□ded o□er t□e contract and □dent□□ed □n t□e c□sto□er a□ree□ent□ □□rt□er t□e de□and credt □o□d □e □□ed o□er t□e n□ta□s□□-□ear ter□ □□□t t□ □o□d □e □□dated d□r□n□ eac□ s□□se□□ent ann□a□rene□a□ □o□e□er e□t□er □PC or t□e c□sto□er □a□dec□ne to rene□ t□e a□ree□ent□

[20] □PC Res□onse to ST□-PIA-□-3□

The customer would also be required to demonstrate its ability to curtail load each year and would be subject to substantial costs if it fails to comply with any Demand Response Event or demonstration.

Q ARE THERE ANY DESIGN ELEMENTS COMMON TO ALL THREE OF THE PROPOSED NEW SCHEDULES?

A Yes. In addition to not specifying the amount of the required credits/payments, GPC also reserves the right to terminate service in any related agreement if it or that penalty or other obligation.

- Termination is allowed if the Commission
- The participating customer fails to meet *any* obligations or requirements under the rate schedule or accompanying agreement or
- Where termination is otherwise consistent with GPC's electric service Rules and Regulations.

Q DO YOU HAVE ANY CONCERNS WITH THE THREE PROPOSED NEW RATE SCHEDULES?

A Yes. GPC would have undue discretion in determining the amount of the credits/payments renewal terms, penalties and other significant terms and conditions.

For example, the credits/payments would be based on "system value" as defined by GPC, neither the term system load nor the methodology for quantifying system load is specified in any proposed new rate schedules. This would give GPC sole authority in determining the amount of the payments and/or credits and the customer would have no opportunity to either get the proposed credits/payments or seek a reduction from the Commission if it knows the specific credit or even the specific methodology and assumptions used in determining the credits. Potential customers cannot properly assess the risks and benefits of opting in or out of the

proposed new rate schedules. In essence, all the risks would be placed on the customers.

The risk-shifting is further accelerated because PC can terminate the DER/DR rate schedules at short notice and at short further obligation at its discretion. This is especially important because to the extent a customer is required to pay for DER facilities or pay more additional investment to comply with certain requirements under Schedule C-1 premature termination at short or no notice could result in "stranding" the customer's investment.

Q DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING PROPOSED SCHEDULE DCL-1?

A Yes. As previously stated PC will install, operate, maintain and control the Company-owned DER and related equipment as determined by PC. All the costs will be recovered in base rates and PC will earn a return on the associated rate base. However, there is no requirement for PC to competitively procure the DER and related equipment to be installed at the premises of a particular customer and the customer and the customer apparently has no input into the decision about the manufacturer and the equipment to be installed at the customer's facility.

Q DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING PROPOSED SCHEDULE DCO-1?

A Yes. First as previously stated PC proposed limiting the aggregate DER capacity to 10 MW, citing operational risk. Whereas there are no similar constraints in the proposed Schedule DCL-1. However there are operating risks associated with any generation equipment regardless of the operating party. Regardless of who owns

own/operate the DER the enabling agreements should provide a clear set of standards consistent with generally accepted operating and maintenance practices to ensure compliance. Further, PC should be more than case by case conducting due diligence of a third-party owned and operated generator including periodic inspections and operational reviews to help minimize the risk of forced outages. Ultimately, the customer should be able to demonstrate compliance with the Company's dispatch orders or face either financial penalties or termination.

Second, to the extent the customer is required to own and install the equipment and provide several categories of information, including providing a list of the Company approved operational control including disclosing the resource sold at its discretion. It is unclear why an customer who has also requires the thermal energy produced from the facility or operating process should be limited to the PC operational control that assurances that PC cannot arbitrarily curtail the thermal energy source.

Q DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING PROPOSED SCHEDULE CL-1?

A Yes. First, the customer should be required to execute a six-year rolling term that is automatically extended unless PC or the customer declines the renewal. The customer should have to opt or out to six years before returning to full service. PC has not explained why a six-year term is necessary or why a customer must opt six years to return to full service. Second, why years that PC could terminate the customer or agree to continue with a curtailment based on a capacity value that could be lower than the credit that the Company is currently paying.

Third, the term Demand Response Event is not defined in the Application. It is my understanding that PG&E wants to certain load during extreme weather events such as Winter Storm Elliot or the Polar Vortex. The circumstances in which PG&E should call for certain events should be defined more specifically. Examples of more specific circumstances requiring PG&E to declare a Demand Response Event should include:

- Projected shortage of available generation and/or transmission capacity to maintain service to firm native load customers
- Local area protection
- System emergency

Q WHAT DO YOU RECOMMEND?

A First, none of the three proposed new rate schedules should be approved as filed.

Second, PG&E should be required to disclose the methodology and assumptions for determining how credits/payments under the rate schedules are determined and provide a specific quantification of the current, projected system resource capacity/energy values at least annually during the term of the corresponding agreements. Further, the methodology and assumptions should be subject to Commission review and approval in each subsequent Year. This should provide customers with sufficient information to assess their level of interest prior to making a long-term commitment.

Third, customers should be given *at least* six months advance notice before service is terminated. Further, upon termination of the proposed rate schedules, PG&E should be obligated to compensate the customer for any costs incurred to qualify for service under each rate schedule. This should require compensation to the customer

or the remaining look-alike portion of the equipment installed and paid for by the customer. This is similar as PPC expects to be compensated when it retires a generating unit.

Q DO YOU HAVE ANY RECOMMENDED CHANGES TO SCHEDULE DCL-1?

A Yes. Generation is not a natural monopoly. Any incremental monopoly to install generation behind a customer's meter at a discounted price to the customer where recovering the remaining costs included in a return on rate base from its customer base would confer a competitive advantage over other non-related generation providers who do not have captive customers to recover their costs. To ensure that PPC does not disadvantage competitive generators, PPC should be required to competitively procure the DER and related equipment from third-parties. Further, the customer should be informed throughout the RFP process included in the preparation of the RFP, identifying anticipated providers, evaluating the proposals, and selecting the winning bidder.

Q DO YOU HAVE RECOMMENDED CHANGES TO SCHEDULE DCO-1?

A Yes. Limit Schedule DCO-1 to 10 MW's potential participant-competitive. The customer should have the ability to reserve the right to utilize the DER activity to provide any needed transmission when the activity is being dispatched to serve system needs. Further, it should be clear that the customer will be allowed to outsource the design and develop and implement supporting the on-site DER provided to ensure that the customer is willing to certify that the equipment selection and the maintenance plan are consistent with generally accepted industry practices. PPC has not justified the 10 MW limitation on the size of a customer-owned DER. To do so would clearly discourage a customer from owning a DER in lieu of the Company ownership option

there is no connection. The Commission should reject the 10 MW connection. Alternatively, the 10 MW connection is retained, then it should also apply to Schedule DC-1.

Q DO YOU HAVE ANY PROPOSED CHANGES TO SCHEDULE CL-1?

A Yes. First, the specific circumstances that constitute a "Demand Response Event" should be identified (*e.g.*, a shortage of available generation and/or transmission capacity, area protection, or a system emergency). Second, the credit should reflect the avoided cost of generation capacity. In the event that a Demand Response Event can occur due to shortages or congestion on the transmission system, the credit should also reflect avoided transmission capacity costs. The credit should not be discounted because to do so would undermine the customer and limit to recognize the benefit to firm customers who, as a result of increasing DR, will have more reliable service and less exposure to potential cost shortages.

Third, customers should have the option to choose among different options such as contract duration and payment (daily/monthly/annual) arrangements, and the credit should reflect the value of the option selected. For example, longer contract terms and/or more firm exposed to curtailments should result in a higher credit. This would allow a customer to better align its appetite for risk with the potential benefits.

Finally, the compliance incentive should not exceed the capacity value reflected in the current avoided cost agreement.

7. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON YOUR ASSESSMENT OF GPC'S IRP UPDATE?

A The Commission should make the following findings:

- Reject GPC's deferred accounting of capacity payments and development costs.
- Reject GPC's proposed additional sums on the MPC and Santa Rosa PPAs.
- Reject the proposed solar array at the [redacted] site.
- Reject the new DER/DR rate schedules DCO-1, DCO-1 and CO-1 as proposed.
- Reuse the DER/DR rate schedules to at a minimum:
  - Include a definition of system gain.
  - Require GPC to seek Commission review and approval of the methodology and assumptions underlying the methodology and provide a specific quantification used to determine system gain prior to approving the new rate schedules initially and in each subsequent year.
  - Require GPC to provide at least six months advance notice before any DER/DR rate schedule is discontinued and ultimately GPC to compensate customers for any investments that become stranded as a result of premature termination.
- Approve the following specific changes:
  - Allow customers on Schedule DCO-1 to be directly involved in competitive procurement of DER and related equipment.
  - Revise the 10 MW limitation on DER capacity under Schedule DCO-1 to provide a clear set of standards consistent with general accepted industry practice that the customer does not control in order to meet the contract terms and ensure an uninterrupted source of energy to meet the customer's needs.

- Revise Schedule C-1 to include a definition of Demand Response Event reflect the avoided cost of capacity including transmission investments can occur due to shortages or congestion in the transmission system the compliance incentive should not exceed the value of the credit and customers should have a menu of options to choose from such as longer/shorter contract duration and greater or lesser curtailment hours and receive credits that appropriately reflect the capacity value of the selected options

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Jeffry Pollock. My business address is 1323 South Clinton Street, Suite 200, Town and Country, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of the firm Pollock Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a number of graduate courses in finance and accounting.

Upon graduation in June 1969, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc. active since 1963. From April 1970 to December 2001, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes research in financial and economic studies of investor-owned cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 2 states and several Canadian provinces and have testified before the federal Energy Regulatory Commission, the Ontario Energy Board and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wisconsin. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (aka Santee Cooper), the Connecticut Power Administration, Travis County, Texas, District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	23-E-0418 23-G-0419	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Electric Customer Charge	11/21/2023
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	Industrial Customer Group	2023-154-E	Direct	SC	Integrated Resource Plan	9/22/2023
MIDAMERICAN ENERGY COMPANY	Google, LLC and Microsoft Corporation	RPU-2022-0001	Rehearing Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	9/8/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Cross-Rebuttal	TX	Class Cost-of-Service Study; LGS-T Rate Design; Line Loss Study	8/25/2023
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-633-ER-23	Direct	WY	Retail Class Cost of Service and Rate Spread; Schedule Nos. 33, 46, 48T Rate Design; REC Tariff Proposal	8/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revenue Requirement; Jurisdictional Cost Allocation; Class Cost-of-Service Study; Rate Design	8/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Multi-Year Rate Plan; Class Revenue Allocation; Rate Design	7/19/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00286-UT	Direct	NM	Behind-the-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	4/21/2023
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44902	Direct	GA	FCR Rate; IFR Mechanism	4/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Stipulation Support	NM	Standby Service Rate Design	4/10/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	53931	Direct	TX	Fuel Reconciliation	3/3/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Cross-Answer	IN	Class Cost-of-Service Study; Class Revenue Allocation	2/16/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Testimony	IA	Application of Advance Ratemaking Principles to Wind Prime	2/13/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	54234	Direct	TX	Interim Fuel Surcharge	1/24/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Direct	IN	Class Cost-of-Service Study; Class Revenue Allocation	1/20/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022

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CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Cross-Rebuttal	TX	Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins	8/5/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Direct	IA	Application of Advance Ratemaking Principles to Wind Prime	7/29/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Direct	TX	Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri	7/6/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/22/2022
DTE ELECTRIC COMPANY	Gerdau MacSteel, Inc.	U-20836	Direct	MI	Interruptible Supply Rider No. 10	5/19/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44160	Direct	GA	CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum	5/6/2022
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Cross-Rebuttal	TX	Rate 38; Class Cost-of-Service Study; Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021

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SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020

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Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019

To access a downloadable list of Testimony filed from 1976 through the prior year, use this link: **J. Pollock Testimony filed from 1976 through the prior year**

Duke looks to add more gas, offshore wind to meet demand boom in NC, SC

Monday, February 5, 2024 3:48 PM CT

By Abbie Bennett
Platts

Projecting massive load growth in the Carolinas, Duke Energy Carolinas LLC and Duke Energy Progress LLC have amended resource plans to add more gas plants, advanced nuclear and wind.

"We're already projecting eight times the load growth we anticipated just two years ago," Duke North Carolina President Kendal Bowman and Duke South Carolina President Mike Callahan said in separate Jan. 31 statements.

The Duke Energy Corp. utility subsidiaries told state regulators in the Carolinas their load forecast through 2030 had increased by about 2 GW compared to the forecast used to develop prior plans.

That projected growth is due primarily to significant economic development planned in North Carolina and South Carolina, particularly manufacturing and technology, both industries that often "operate around the clock" and may require more on-demand energy resources, Duke Energy spokesperson Bill Norton told S&P Global Commodity Insights.

"This load growth is an industry-wide challenge — and the states that move decisively to build new generation will be best-positioned to take advantage of the positive trend in economic development opportunities while protecting affordability and reliability," Norton said.

North Carolina

In November 2023, Duke warned North Carolina regulators that "unprecedented economic development" well above the company's "historical experience" in the Carolinas was driving projected load growth across both states that "substantially exceeds even the high-load growth case" included in the company's resource plans filed in August 2023. The company reiterated those projections in its Jan. 31 filings.

To meet that growth, Duke proposed two large fossil gas plants, each at 1,360 MW, including at least one in Person County. The new gas plants would also be "hydrogen-capable," though that technology is not yet commercially available. Duke's proposed additions total nearly 9 GW of new gas before 2035, nearly tripling the gas generation proposed in its first carbon plan regulators approved in 2022.

"This plan is tripling down on the coal-to-gas transition, saddling customers with risky investments in new polluting power plants and failing to deliver the clean energy future called for in [North Carolina] state law," Will Scott, Southeast climate and clean energy director at the Environmental Defense Fund, said in a Feb. 1 statement. "We're hopeful the NC Utilities Commission will require Duke to pursue a path that controls costs for customers while meeting North Carolina's 2030 carbon emission reduction goal on time."

Duke's proposal also includes continued support for a new advanced nuclear facility in North Carolina, with an additional site to be determined in 2025.

"These breakthrough nuclear technologies are not anticipated to be available for deployment ... until the mid-2030s," Duke said in its filing.

Duke proposed 2,400 MW of wind generation offshore North Carolina by 2035 in its updated plan and 1,200 MW of new onshore wind for the Carolinas by 2033.

"Duke's updated modeling and supplemental portfolio clearly illustrates how important offshore wind will be to providing the large quantities of carbon-free electricity needed to reliably run the grid," Southeastern Wind Coalition President Katharine Kollins said. "Offshore wind is an incredible resource that will diversify power generation and provide electricity when we need it most — winter mornings and summer afternoons."

In North Carolina, Duke's newly amended plans include options for paths to 70% carbon emission reduction by 2030, 2033 and 2035. North Carolina state law mandates a 70% reduction in carbon pollution in the electric power sector by 2030.

North Carolina regulators ordered Duke to file with its updated plan a state-mandated portfolio that meets a 70% reduction in carbon emissions by 2030. Duke's preferred resource plan, however, targets a 70% reduction by 2035 or 2037. Offshore wind and advanced nuclear are key to reaching even those goals, Duke said.

That plan, according to the utility, would be the "most reasonable, least cost and least risk pathway to inform the near-term reasonable steps required to progress the reliable and orderly transition of the Carolinas system."

Future updates to North Carolina regulators will continue to include portfolio options targeting a 70% reduction by 2030, according to the law, Norton said.

A decision from the North Carolina Utilities Commission on the updated plan is expected by the end of 2024, according to Duke. Hearings for the plan are scheduled for spring and summer 2024.

South Carolina

South Carolina had the fastest-growing population in the US in 2023. To prepare for the load that will accompany future growth, Duke is proposing a new combined-cycle gas plant for South Carolina.

"This additional demand for energy is unprecedented — historic in both size and speed," Callahan said. "To meet customer needs, we're proposing more of nearly every resource available to us as we maintain our diverse 'all of the above' approach to maintain reliability and affordability."

The Carolinas plan includes advanced nuclear, gas, pumped hydro storage and renewables along with energy efficiency and demand-side management programs to target peak energy use reduction of nearly 2.8 GW by 2038, according to Duke.

At least one of several new gas plants Duke proposed is expected to be located in South Carolina.

Duke's amended Carolinas plans also include more solar energy than prior proposals, with a forecast for 17,500 MW of additional solar across both states within the next 15 years.

"We need power — a lot of it — and we need to take action today," Callahan said.

On Jan. 25, the South Carolina Public Service Commission approved Duke's proposal to provide additional information on its resource plan and reset the previously approved regulatory schedule. The new schedule now plans for a hearing in mid-September. Regulators are expected to decide on the plan as early as November.

This article was published by S&P Global Market Intelligence and not by S&P Global Ratings, which is a separately managed division of S&P Global.

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RATE SCHEDULE NO. 138

AMENDED AND RESTATED
SOUTHERN COMPANY SYSTEM
INTERCOMPANY INTERCHANGE CONTRACT

BETWEEN

ALABAMA POWER COMPANY,
GEORGIA POWER COMPANY,
MISSISSIPPI POWER COMPANY,
SOUTHERN POWER COMPANY,
AND
SOUTHERN COMPANY SERVICES, INC.

Dated July 13, 2022

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AMENDED AND RESTATED
SOUTHERN COMPANY SYSTEM
INTERCOMPANY INTERCHANGE CONTRACT

ARTICLE I - RECITALS

Section 1.1: This contract is made and entered into as of July 13, 2022, by and between Alabama Power Company, a corporation organized and existing under the laws of the State of Alabama with its principal office in Birmingham, Alabama; Georgia Power Company, a corporation organized and existing under the laws of the State of Georgia with its principal office in Atlanta, Georgia; Mississippi Power Company, a corporation organized and existing under the laws of the State of Mississippi with its principal office in Gulfport, Mississippi; and Southern Power Company, a corporation organized and existing under the laws of the State of Delaware with its principal office in Birmingham, Alabama, all such companies being hereinafter collectively referred to as the "OPERATING COMPANIES"; and Southern Company Services, Inc., a subsidiary service company ("AGENT" or "SCS").

W I T N E S S E T H:

Section 1.2: WHEREAS, the common stock of the OPERATING COMPANIES is owned by The Southern Company, a public utility holding company; and

Section 1.3: WHEREAS, the OPERATING COMPANIES can be operated as an integrated electric utility system; and

Section 1.4: WHEREAS, the OPERATING COMPANIES have so operated their respective electric generating facilities and conducted their system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of an interchange contract among

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themselves, the most recent of which being The Southern Company System Intercompany Interchange Contract dated February 17, 2000, as modified effective July 1, 2006 to reflect an intra-corporate reorganization ("the 2000 Contract"); and

Section 1.5: WHEREAS, the OPERATING COMPANIES desire to replace the 2000 Contract with an amended and restated contract; and

Section 1.6: WHEREAS, all of the OPERATING COMPANIES will continue to share in all of the benefits and burdens of this IIC, including complying with operating, dispatch and reserve requirements, participating in opportunity sales transactions, and bearing responsibility for their portion of purchases.

Section 1.7: NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements hereinafter stated, the OPERATING COMPANIES agree and contract as follows:

ARTICLE II - TERM OF CONTRACT

Section 2.1: This contract will be referred to as the Southern Company System Intercompany Interchange Contract ("IIC"). The IIC shall become effective as provided in Section 2.2 hereof, and shall continue in effect from year to year thereafter subject to termination as provided hereinafter. When this IIC has become effective, it shall supersede and replace the 2000 Contract, and references to a section of such superseded intercompany interchange contract in other agreements of the OPERATING COMPANIES shall be taken to mean reference to the section of substantially like import in this IIC.

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Section 2.2: This IIC was submitted as part of a filing in compliance with the orders of Federal Energy Regulatory Commission ("Commission" or "FERC") in Southern Company Services, Inc., Docket Nos. EL05-102, et al., 117 FERC ¶ 61,021 (2006) and Southern Company Services, Inc., Docket Nos. EL05-102, et al., 119 FERC ¶ 61,065 (2007). Pursuant to the Commission's acceptance of such compliance filing, this IIC is effective as of May 1, 2007.

Section 2.3: This IIC may be terminated at any time by mutual agreement of the OPERATING COMPANIES or may be terminated at any time by any OPERATING COMPANY by its giving to each of the other OPERATING COMPANIES and the AGENT written notice of its election to so terminate its participation in this IIC at least five (5) years prior to the date of termination. This IIC shall continue in full force and effect as to each OPERATING COMPANY until terminated as hereinabove provided.

ARTICLE III - PRINCIPAL OBJECTIVES OF INTERCOMPANY INTERCHANGE CONTRACT

Section 3.1: The purpose of this IIC is to provide the contractual basis for the continued operation of the electric facilities of the OPERATING COMPANIES in such a manner as to achieve the maximum possible economies consistent with the highest practicable reliability of service, with the reasonable utilization of natural resources and effect on the environment, and to provide a basis for equitably sharing among the OPERATING COMPANIES the costs associated with the operation of facilities that are used for the mutual benefit of all the OPERATING COMPANIES.

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Section 3.2: It is recognized that reliability of service and economy of operation require that the energy supply to the system be controlled by means of centralized economic dispatch and that this will require adequate communication facilities and the provision of economic dispatch computer facilities and automatic controls of generation.

Section 3.3: It is recognized that the IIC provides for the retention of lowest cost energy resources by each OPERATING COMPANY for its own customers. Energy in excess of that necessary to meet each OPERATING COMPANY's requirements is delivered to the Pool as Interchange Energy and may include: (i) energy generated from plants other than conventional hydro or nuclear; and (ii) purchased energy.

Section 3.4: It is recognized that, under this IIC, each OPERATING COMPANY will share in the benefits and pay its share of the costs of coordinated operations as agreed upon in accordance with the terms hereof. All costs and revenues associated with wholesale transactions under this IIC will be shared among all OPERATING COMPANIES on a comparable basis through the application of the governing procedures and methodologies to all such OPERATING COMPANIES.

Section 3.5: It is recognized by the OPERATING COMPANIES that coordinated electric operation contemplates minimum cost of power supply upon the interconnected system, consistent with service requirements and other operating limitations. Benefits of integrated operation accruing to the respective OPERATING COMPANIES are predicated upon cooperative efforts toward this objective and are so reflected in all IIC determinations.

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Section 3.6: This IIC is applicable only to the transactions described herein, as specifically set forth in ARTICLE VII – INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, ARTICLE VIII – INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, and ARTICLE IX – PROVISION FOR OTHER INTERCHANGE TRANSACTIONS. Otherwise, sales between the OPERATING COMPANIES (including, but not limited to, sales from Southern Power Company to the other OPERATING COMPANIES or sales from the other OPERATING COMPANIES to Southern Power Company) require an appropriate filing under Section 205 of the Federal Power Act and acceptance thereof by the Commission.

ARTICLE IV - ESTABLISHMENT OF OPERATING COMMITTEE AND DESIGNATION OF AGENT

Section 4.1 – Establishment of Operating Committee: A designated representative from each of the OPERATING COMPANIES, together with a designated representative of the AGENT who shall act as chairman, shall form and constitute an Operating Committee to meet as needed to determine the methods of operation hereunder.

Section 4.2 – Duties of Operating Committee: The Operating Committee's areas of responsibility include such matters as developing the concepts, terms and conditions of this IIC; providing guidance and direction to the AGENT regarding economic power system operations and the costs associated therewith; reviewing and recommending generation expansion plans for approval by the respective OPERATING COMPANIES pursuant to Section 4.3; and addressing other power system matters that relate to the overall coordinated operation of the Southern

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electric system. Each OPERATING COMPANY representative has one vote and all decisions must be unanimous.

Section 4.3 – Review and Recommendation of Generation Expansion Plans: The Southern Power Company representative on the Operating Committee will not participate in reviewing and recommending generation expansion plans of the other OPERATING COMPANIES or the system, nor will the Southern Power Company representative have access to materials developed in conjunction with the formulation of such generation expansion plans. Notwithstanding Section 4.2 above, the Southern Power Company representative shall not be eligible to vote with respect to these expansion plans. Moreover, Southern Power Company will not receive market information from the other OPERATING COMPANIES through its participation in the Operating Committee.

Section 4.4 – Transmission Information: The Operating Committee does not have any duties or responsibilities with respect to transmission-related activities (including transmission reliability) and, consistent with the Standards of Conduct, will not receive non-public transmission information. The IIC (including Operating Committee membership) is not to serve as a means whereby non-public transmission information is shared in a manner contrary to the Commission's Standards of Conduct. Further, Southern Power Company is to be treated as an Energy Affiliate under the Commission's Standards of Conduct and therefore cannot receive any non-public transmission information.

Section 4.5 – Operating Committee Discretion: Certain provisions of the Manual afford a degree of latitude to the Operating Committee with regard to decisions that it is authorized to make

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thereunder. When such discretion is exercised, the AGENT will summarize the decision in an informational filing to be submitted to the Commission within ten (10) business days.

Section 4.6 – Designation of AGENT: SCS, as a party to this IIC, is designated as AGENT of the OPERATING COMPANIES for purposes of this IIC. In addition, SCS may serve as AGENT and represent the OPERATING COMPANIES, or any of them, in all things to be done in the execution of and operation under existing contracts with nonaffiliated utilities or entities (hereinafter referred to as "OTHERS"), or contracts supplemental thereto.

Section 4.7 – Duties of AGENT: The AGENT is responsible for all administrative and coordination functions in order to effectuate the terms and conditions of this IIC. From time to time, the OPERATING COMPANIES, or any of them, may also have contracts with OTHERS that provide for the purchase and/or sale of capacity and/or energy by the OPERATING COMPANIES. The AGENT will make the payments associated with purchases under these contracts and under any other contracts or arrangements under which it acts as agent for the OPERATING COMPANIES. Each OPERATING COMPANY will reimburse the AGENT for its portion of such total payments in accordance with the arrangement in effect with respect to the particular contract. Similarly, the AGENT will collect the payments due for sales under these contracts (and under any other contracts or arrangements under which it acts as agent) and will distribute such payments among the OPERATING COMPANIES in accordance with the arrangement in effect with respect to the particular contract.

Section 4.8 – Term of Agency: The provisions of this IIC providing for authority for the AGENT to act on behalf of the OPERATING COMPANIES, or any of them, shall be deemed to refer, insofar as applicable, to all contracts under which the AGENT acts as agent for the

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OPERATING COMPANIES and, notwithstanding anything to the contrary in ARTICLE II hereof, this IIC shall continue in effect insofar as it pertains to other contracts under which the AGENT acts as agent for the OPERATING COMPANIES during the life of any such contracts. The OPERATING COMPANIES may, however, designate a new agent to act hereunder by giving thirty (30) days written notice thereof to the AGENT, whereupon such new agent shall be the AGENT hereunder.

ARTICLE V - OPERATION AND MAINTENANCE OF ELECTRIC GENERATING FACILITIES

Section 5.1: The OPERATING COMPANIES agree to maintain their respective electric generating facilities in good operating condition and to operate such facilities in coordination with those of the other OPERATING COMPANIES as an integrated electric system in accordance with determinations made from time to time by the Operating Committee in order that an adequate power supply shall be available to meet the requirements of the customers of the respective parties hereto at the lowest cost consistent with a high degree of service reliability.

Section 5.2: With respect to its participation in this IIC, Southern Power Company may have access to information regarding the operation of its own plants or other generation resources (such as those acquired by contract) that it has committed to the Pool ("Pool resources"), but it may not otherwise have access to information regarding the operation of Pool resources of the other OPERATING COMPANIES.

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ARTICLE VI - INCORPORATION OF THE ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION MANUAL

Section 6.1 – Incorporation of Manual: The mechanics and methods for determining the charges for reserve sharing capacity and for energy purchased and sold between the OPERATING COMPANIES, the monthly capability requirement determinations, and the monthly billings and payments between the OPERATING COMPANIES are described in detail in the Allocation Methodology and Periodic Rate Computation Manual ("Manual") attached hereto and incorporated herein by reference. The Manual also supplies more detailed explanation of provisions of this IIC and is necessary to effectuate its intent.

Section 6.2 – Purpose of Manual: The Manual contains a description of the methodology and procedure used to calculate the charges provided for in this IIC. The OPERATING COMPANIES recognize that the costs underlying these charges will change during the term of this IIC for reasons such as changes in loads, investment and expenses, as well as the addition of electric generating resources. Thus, in order for the OPERATING COMPANIES to share equitably in the costs associated with this IIC, it will be necessary to revise or update, on a periodic basis, the cost, expense, load and investment figures utilized in the derivation of the charges hereunder. The Manual will serve as a formula rate allowing for periodic revision of the charges to reflect changes in the underlying cost components.

Section 6.3 – Revision of Charges and Regulatory Filings: The Manual provides that charges derived by application of the formula rate will be shown on Informational Schedules. Since the charges under this IIC will be computed in accordance with the formula rate method and procedures established in the Manual, these submissions will not be initial rates or changes in rates that would require a filing and suspension under the Federal Power Act and the applicable

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Rules and Regulations of the Commission. On or before November 1 of each year, the Informational Schedules will be submitted to the Commission for informational purposes to show the application of the formula rate and the resulting charges. Work papers will also be included showing a detailed application of the formula rate contained in the Manual.

Section 6.4 – Revision of Manual: If the Operating Committee determines that revisions to the formula rate are appropriate or necessary, it will direct the AGENT to file the revised Manual with the Commission in order to obtain timely approval or acceptance thereof.

ARTICLE VII - INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 7.1 – Provision for Sharing of Temporary Surpluses or Deficits of Capacity Between Operating Companies: It is a fundamental premise of this IIC that each OPERATING COMPANY is expected to have adequate resources to reliably serve its own obligations. Nevertheless, the OPERATING COMPANIES recognize that in any given year one or more of them may have a temporary surplus or deficit of capacity as a result of coordinated planning or by virtue of load uncertainty, unit availability, and other such circumstances. It is among the purposes of this IIC to share among the OPERATING COMPANIES the benefits and burdens of their coordinated system operations, including the cost associated with such capacity ("Reserve Sharing"). Reserve Sharing among the OPERATING COMPANIES is accomplished pursuant to transactions (referred to as "purchases" and "sales") effectuated on a monthly basis in accordance with ARTICLES IV and V of the Manual.

Section 7.2 – Charge for Monthly Reserve Sharing Among the OPERATING COMPANIES: The OPERATING COMPANIES recognize that capacity reserves in the Pool are predominantly

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made up of peaking plant or equivalent purchased resources. Accordingly, the monthly charge for Reserve Sharing among the OPERATING COMPANIES will be based on the most recently acquired peaking plant resource that is available for year-round operation and scheduling. Each OPERATING COMPANY's monthly charge for reserve capacity sold to the Pool is developed in accordance with the formula rate set out in ARTICLE V of the Manual. The monthly capacity charge for each OPERATING COMPANY, as developed in accordance with such formula rate, will be shown on Informational Schedules. Each selling OPERATING COMPANY will sell at its charge shown on such Informational Schedules and the buying OPERATING COMPANIES will purchase at the weighted average charge of the sellers.

ARTICLE VIII - INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 8.1 – Provision for Interchange Energy: Coordinated system operation, utilizing principles of centralized integrated system economic dispatch, results in energy transfers among the OPERATING COMPANIES. Such energy transfers are accounted for on an hourly basis and are referred to as "Interchange Energy." The methodology for determining the amount of Interchange Energy supplied to or purchased from the Pool is set out in ARTICLE II of the Manual. Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 8.2 – Charge for Interchange Energy: The charge for Interchange Energy sales by an OPERATING COMPANY during any hour will be based on the variable costs of the generating

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resources that are considered as having supplied the Interchange Energy. The methodology for determining the charges for Associated and Opportunity Interchange Energy sales to the Pool during any hour is set out in ARTICLE III of the Manual.

ARTICLE IX - PROVISION FOR OTHER INTERCHANGE TRANSACTIONS

Section 9.1 – Assignable Energy: Assignable Energy is defined as energy derived from internal sources or from OTHERS at a cost that renders it unusable from an economic dispatch perspective. Assignable Energy is assigned to one or more of the OPERATING COMPANIES consistent with the purpose for which it is acquired. Such assignment will be accomplished by first identifying the beneficiary (or beneficiaries) of the Assignable Energy and then determining the appropriate share for each such OPERATING COMPANY. For example, these shares might be based on a Peak Period Load Ratio ("PPLR") in proportion to the PPLRs of other beneficiaries or weighted participation in a bilateral sale. Once assigned, Assignable Energy will not be delivered to the Pool unless it becomes economically usable on the integrated system.

Section 9.2 – Hydroelectric Operation During Periods of Minimum Steam Operations: During certain periods of the year when unusually good flow conditions prevail, certain steam generating units may be taken out of service to increase the utilization of hydro energy. The OPERATING COMPANY having such hydro generation may elect to take a fossil fired generating unit out of service. In the alternative, if another OPERATING COMPANY takes a fossil fired generating unit out of service for the purpose of utilizing such hydro energy, the energy rate between the two OPERATING COMPANIES for that transaction will be the average of the operation and maintenance cost of such hydro energy and the variable cost of the fossil fired generating unit.

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Section 9.3 – Tie-Line Frequency Regulation by Hydro Capacity: Tie-line load control and frequency regulation by hydro involves additional costs because of increased expenditures associated with such regulation. The charge for these transactions is computed in accordance with the formula rate contained in ARTICLE VI of the Manual.

Section 9.4 – Pool Transactions with OTHERS: Capacity and energy transactions with OTHERS that are entered into on behalf of the Pool will be governed by the following principles:

Section 9.4.1 – Pool Purchases of Capacity and Energy: The AGENT may periodically purchase capacity and energy from OTHERS for the benefit of the integrated system. Such Pool purchases will initially be allocated at cost to all OPERATING COMPANIES in proportion to their PPLRs, as provided for in ARTICLE X of this IIC. Purchases so allocated may be sold as Interchange Energy when they are economically usable on the integrated system. Adjustments may thereafter be made in order to reconcile any inequitable effects of this process among the OPERATING COMPANIES, with the intent being that none of the individual OPERATING COMPANIES should be adversely impacted by a purchase that benefits the system as a whole. These impacts will be determined through a system simulation that calculates each OPERATING COMPANY's cost of generation that is avoided by the purchase. This avoided cost will be compared on an hourly basis to the cost of the purchase. To the extent the avoided cost exceeds the purchase cost, the effect is "positive" (i.e., cost savings) for that hour. These hourly results will be summed to determine the effect on each OPERATING COMPANY for the day. In situations where individual OPERATING COMPANIES are adversely impacted by a purchase that benefits the system as a whole, such adverse impacts will be offset through a proportional

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reduction in the positive net benefits realized by the other OPERATING COMPANIES. In the event the net result for the day is negative, that result is shared among the OPERATING COMPANIES on a PPLR basis.

Section 9.4.2 – Pool Sales of Capacity and Energy: The AGENT may from time to time arrange for the sale to OTHERS of capacity and energy available to the Pool at rates provided for in contracts or at rates mutually agreed upon. The capacity and/or energy obligation for the sale, as well as the associated cost, is allocated to each OPERATING COMPANY on a PPLR basis. Payments by OTHERS are also distributed to the respective OPERATING COMPANIES on the basis of PPLRs.

The Pool has the exclusive right to use generation resources committed to the Pool ("Pool resources") to engage in opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week. Neither Southern Power Company nor any of the other OPERATING COMPANIES can use Pool resources for its own benefit in those wholesale opportunity markets. To the extent Southern Power Company engages in other transactions solely for its own benefit, it must do so using personnel (staff) separate from the personnel (staff) that conducts similar activities on behalf of the other OPERATING COMPANIES.

ARTICLE X – UTILIZATION OF PEAK-PERIOD LOAD RATIOS

Section 10.1 – Certain Allocations and Payments to be Based on Peak-Period Load Ratios: The AGENT is responsible for the annual development of Peak-Period Load Ratios ("PPLRs") for each of the OPERATING COMPANIES. These PPLRs will be utilized for allocation of certain costs, payments, receipts and other obligations, as provided for in this IIC or the Manual. The

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procedure and methodology for developing the PPLRs are set out in ARTICLE I of the Manual and the resulting PPLR values are shown on an Informational Schedule.

ARTICLE XI - TRANSMISSION SERVICE

Section 11.1 – Applicability of Network Integration Transmission Service: Network Integration Transmission Service ("Network Service") provides for the integration, economic dispatch and regulation of current and planned Network Resources to serve Network Load. Since the OPERATING COMPANIES integrate, economically dispatch and regulate their generating resources to serve their bundled and grandfathered native load ("Native Load") pursuant to this IIC, the associated use of the transmission system is in the nature of Network Service. Except for provisions related to rates and charges, the transmission service provided to these Native Load customers is comparable to Network Service under the Open Access Transmission Tariff ("OATT"). Since the OPERATING COMPANIES' Native Load is specifically included in the determination of the load used to derive the charge for Network Service under the OATT, the OPERATING COMPANIES are bearing a cost responsibility for transactions hereunder comparable to that assigned to other Network Customers.

Section 11.2 – Transmission Service for Other Transactions: All transmission service provided to any or all of the OPERATING COMPANIES (other than service to their Native Load, as described in Section 11.1) is subject to the OATT in all respects, including adherence to the same rates, terms and conditions applicable to other market participants. Any such transmission service will be obtained pursuant to the OATT and/or from other transmission providers.

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Southern Power Company specifically commits to take all of its transmission service under the OATT of Southern Companies or from other transmission providers.

ARTICLE XII - BILLING AND PAYMENT

Section 12.1 – Recording and Billing of Energy Transactions: Each OPERATING COMPANY will transmit to the AGENT such data and other information for each hour of the year as is necessary to develop accounting and monthly billing for the various energy transactions specified under this IIC. The AGENT is responsible for assembling all of the data and information and for preparing intercompany energy billing for each month in accordance with the provisions of this IIC. The bills shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

Section 12.2 – Month-End Adjustment of Daily Energy Determinations: It is recognized that the sum of the daily totals of receipts and deliveries (which are based on instantaneous integrated meters) will not exactly equal corresponding amounts determined at month-end (which are based on accumulating meters). Such differences in energy receipts and deliveries are billed or credited to each OPERATING COMPANY at the average cost of Associated Interchange Energy to the Pool for the month.

Section 12.3 – Billing for Reserve Sharing Transactions: The AGENT is responsible for preparing a monthly bill to the OPERATING COMPANIES for all capacity transactions related to Reserve Sharing, as contemplated by this IIC. The bill shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

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Section 12.4 – Billing and Payment Date: The AGENT renders all bills provided for in this IIC not later than the 10th day of the billing month. All payments by the OPERATING COMPANIES are made by the 20th day of the billing month.

Section 12.5 – Billing Corrections: If the AGENT discovers missing or erroneous data of a material nature pertaining to prior billings, a correction adjustment applicable to those billings will be based on the period affected by such missing or erroneous data, but not to exceed forty-five (45) days from the date of such discovery ("correction period"). If the correction period is forty-five days, then the period actually used for the calculation will extend to the beginning of the billing month in which the forty-five day period falls. Interest does not accrue on any such adjustment. The resulting billing correction will be applied as soon as practicable to the regular monthly bill.

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IN WITNESS WHEREOF, the parties hereto have caused this instrument to be signed by their duly authorized representatives on the Operating Committee, which signatures may be set forth on separate counterpart pages.

ALABAMA POWER COMPANY

By: DocuSigned by: Jim P. Heilbron
5D07C7F70B6E4CF...
Jim P. Heilbron
Its Senior Vice President & SPO-West

MISSISSIPPI POWER COMPANY

By: DocuSigned by: Michael W. Smith
13BA90BBBE0C42A...
Michael W. Smith
Its Vice President & SPO

GEORGIA POWER COMPANY

By: DocuSigned by: R Allen Reaves
33A36C6B17A4A0...
R. Allen Reaves
Its Senior Vice President & SPO-East

SOUTHERN POWER COMPANY

By: DocuSigned by: DANA P CLABURN
ABDCBAD286204FF...
Dana P. Claburn
Its Senior Vice President & SPO

SOUTHERN COMPANY SERVICES, INC.

By: DocuSigned by: Scott Teel
2EEA94D0EECB48E...
Scott Teel
Its Senior Vice President-Commercial Operations

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ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION PROCEDURE MANUAL

Section 0.0 – Description and Purpose of Manual: This Manual is provided for in the Southern Company System Intercompany Interchange Contract ("IIC") entered into the 1st day of May, 2007, and contains a formula description of the methodology and procedure used to calculate the charges under the IIC. The Manual is divided into six (6) basic articles as follows:

ARTICLE I	-	Methodology for Determination of Peak-Period Load Ratios
ARTICLE II	-	Methodology for Determination of Amount of Interchange Energy Sold To and Purchased From the Pool
ARTICLE III	-	Rates for Interchange Energy
ARTICLE IV	-	Methodology for Determination of Monthly Amount of Reserve Sharing Capacity To Be Sold To or Purchased From the Pool
ARTICLE V	-	Rate for Monthly Reserve Sharing Capacity for Each Operating Company
ARTICLE VI	-	Rate for Tie-Line Load Control and Frequency Regulation by Hydro Facilities

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ARTICLE I

METHODOLOGY FOR DETERMINATION OF PEAK-PERIOD LOAD RATIOS

Section 1.1 – Provision for Peak-Period Load Ratios: This article of the Manual establishes and provides for the annual derivation of Peak-Period Load Ratios ("PPLRs") that are utilized in energy and capacity transactions and in other allocations as provided for in the IIC. These ratios are shown on Informational Schedule No. 1.

Section 1.2 – Methodology for Determining Peak-Period Load Ratios: The Contract Year in the IIC is defined as January 1st through December 31st. The peak period is defined as the fourteen (14) hours between 7:00 a.m. and 9:00 p.m. (Prevailing Central Time) of each weekday, excluding holidays.

The Peak-Period Load Ratios for the Contract Year are based upon the prior year's actual peak period energy in the months of June, July, and August for each OPERATING COMPANY. The system peak period energy is equal to the sum of all the OPERATING COMPANIES' peak period energy, excluding: (i) opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week; and (ii) any energy sales transactions that are settled on a financial basis.

The Peak-Period Load Ratios are determined by dividing each OPERATING COMPANY's summation of the June, July, and August actual weekday peak-period energy by the total system June, July, and August actual weekday peak-period energy.

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ARTICLE II

METHODOLOGY FOR DETERMINATION OF AMOUNT OF INTERCHANGE ENERGY SOLD TO AND PURCHASED FROM THE POOL

Section 2.1 – Methodology for Determination of Amounts of Interchange Energy: Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 2.1.1 – Determination of Associated Interchange Energy: The amount of Associated Interchange Energy purchased or sold is computed hourly on the basis of the following:

1. Net receipts and deliveries, which is the total of energy delivered by each OPERATING COMPANY to all other OPERATING COMPANIES and to OTHERS, less the total of energy received by each OPERATING COMPANY from all other OPERATING COMPANIES and from OTHERS;

2. Adjustments for schedules of the OPERATING COMPANIES and OTHERS, for energy movements received from or delivered to sources within or outside the territory of the OPERATING COMPANIES and settled for under arrangements made for such energy movements;

3. Adjustments for Opportunity Interchange Energy, as determined pursuant to Section 2.1.2 below; and

4. Adjustments to account for: (i) the effects of remote generation to which an OPERATING COMPANY is entitled and remote load for which an OPERATING COMPANY is responsible; and (ii) hydro energy losses due to tie-line frequency regulation.

Section 2.1.2 – Determination of Opportunity Interchange Energy: The amount of Opportunity Interchange Energy purchased or sold is computed hourly for each opportunity sale in order to account for the difference between an OPERATING COMPANY's responsibility for

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an opportunity sale and the amount of energy actually generated by that OPERATING COMPANY in connection with such sale.

ARTICLE III
RATES FOR INTERCHANGE ENERGY

Section 3.1 – Procedure for Economic Dispatch: Centralized economic dispatch is accomplished by dispatching system generating resources and purchases to meet the obligations of the OPERATING COMPANIES and to supply energy for sales to OTHERS. System generating resources are dispatched based on marginal replacement fuel cost, variable operation and maintenance expenses, in-plant fuel handling costs, emission allowance replacement costs, compensation for transmission losses, and other such energy related costs that would otherwise not have been incurred. A purchase is recognized in economic dispatch on the basis of its energy cost. The above-referenced cost components are collectively referred to as the "variable dispatch cost."

Section 3.2 – Associated Interchange Energy Rate: The Associated Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the incremental resource(s) that serve the collective obligations of the OPERATING COMPANIES. For each hour, an OPERATING COMPANY supplying Associated Interchange Energy to the Pool will receive a payment determined by multiplying the applicable Associated Interchange Energy Rate by the quantity of kilowatt-hours sold to the Pool. For each hour, an OPERATING COMPANY purchasing Associated Interchange Energy from the Pool will be charged an amount determined by multiplying the Associated Interchange Energy Rate by the quantity of kilowatt-hours purchased from the Pool.

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Section 3.3 – Opportunity Interchange Energy Rate: The Opportunity Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the resources that supplied such energy in connection with a given opportunity sale. This rate will be applied to each OPERATING COMPANY's energy obligation for that transaction to derive the payment due from such OPERATING COMPANY. The resulting payments will then be used to reimburse the cost of the OPERATING COMPANIES that supplied the Opportunity Interchange Energy.

Section 3.3.1 – Opportunity Interchange Energy Rates Related to Certain Contracts and Other Obligations of the Operating Companies: The OPERATING COMPANIES are currently obligated to supply various types of energy under certain contracts with Florida Power & Light Company, Jacksonville Electric Authority, Florida Power Corporation, and South Mississippi Electric Power Association. For purposes of these contracts, the variable dispatch cost of resources supplying the energy shall be the same as described in Section 3.1 of the Manual, except that blended replacement fuel cost will be used instead of marginal replacement fuel cost.

Section 3.4 – Variable Operation and Maintenance Expenses For Fossil Fired Units: The variable Operation and Maintenance expenses for fossil fired units for the Contract Year are derived by summing the following budgeted/forecasted components for each unit: (i) all operating material, non-labor, and on-site contract labor charged to FERC Accounts 502 and 505 (Fossil Steam); and (ii) all maintenance material, non-labor, and contract labor charged to FERC Accounts 512 and 513 (Fossil Steam), and 553 (Combustion Turbine). These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the

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values to dollars per megawatt-hour. The variable Operation and Maintenance expense for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.4.1 – In-Plant Fuel Handling Costs for Fossil Fired Units: In-Plant fuel handling costs for each fossil fired unit for the Contract Year are based on the budgeted/forecasted expenditures for in-plant fuel handling expenses charged to FERC Account 501. These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the values to dollars per megawatt-hour. The in-plant fuel handling cost for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.5 – Blended Replacement Fuel Cost: Blended replacement fuel costs are determined monthly by the AGENT and are defined as the weighted average cost, escalated for the current dispatch period, of fuel receipts for the previous month (both long-term contract and spot market receipts) and the projected fuel receipts for the current month.

Section 3.6 – Marginal Replacement Fuel Cost: Marginal replacement fuel costs for coal are determined at least monthly by the AGENT and reflect the current market price for additional coal needed at a generating facility at the time of such need. For natural gas or oil-fired units, the marginal replacement fuel costs are updated each business day based upon next day market prices.

Section 3.7 – Emission Allowance Replacement Costs: The replacement costs of emission allowances are determined at least monthly by the AGENT and reflect the current market value of such allowances.

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Section 3.8 – Revisions in Methodologies: The procedures described in Sections 3.6 and 3.7 will be periodically reviewed by the AGENT and may be revised upon the approval of the Operating Committee.

ARTICLE IV

METHODOLOGY FOR DETERMINATION OF MONTHLY AMOUNT OF RESERVE SHARING CAPACITY TO BE SOLD TO OR PURCHASED FROM THE POOL

Section 4.1 – Formula for Determination of Monthly Reserve Sharing Capacity Sales/Purchases: The monthly capacity sale to or purchase from the Pool for each OPERATING COMPANY for reserve sharing purposes is determined from the following formula:

CS or CP = RS - R

Where:

CS or CP = Capacity sales to the Pool (CS) or capacity purchases from the Pool (CP) by an OPERATING COMPANY for reserve sharing purposes. A negative value indicates a sale to the Pool and a positive value indicates a purchase from the Pool.

RS = Reserve responsibility for each OPERATING COMPANY (See Section 4.1.1).

R = Reserve capacity for each OPERATING COMPANY (See Section 4.1.2).

Section 4.1.1 – Reserve Responsibility (RS): The responsibility for the reserve capacity on the integrated electric system is allocated among the OPERATING COMPANIES on the basis of peak hour load ratios for each month.

RS = L/L' x R

Where:

RS = Reserve responsibility for each OPERATING COMPANY.

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L = Monthly peak hour load responsibility of each OPERATING COMPANY (See Section 4.3).

L' = Monthly peak hour load of the integrated electric system (See Section 4.3).

R = Sum of the reserve capacity for all of the OPERATING COMPANIES.

Section 4.1.2 – Reserve Capacity (R): The reserve capacity for each of the respective OPERATING COMPANIES is determined monthly by the following formula:

R = C - CR

Where:

C = Total capacity available to the OPERATING COMPANY (See Section 4.2).

CR = Total capacity required to meet reliably the OPERATING COMPANY's load responsibility.

The capacity required to meet the OPERATING COMPANY's load responsibility is determined by the following formula:

CR = LC + LCR

Where:

LC = Portion of the total capacity required to meet reliably the OPERATING COMPANY's load responsibility that is available for load service ("available portion").

LCR = Portion of the capacity required to meet reliably the OPERATING COMPANY's load responsibility that is unavailable for load service for any reason (including forced outage, partial outage or maintenance outage) during the ten (10) highest system peak hours during each month averaged over the most recent three-year period ("unavailable portion"). These unavailable portions of capacity are determined by identifying unavailability specific to each individual OPERATING COMPANY by each generation type. Individual OPERATING COMPANY unavailability factors for each type of

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generating capacity will be applied to their respective owned resources in determining their unavailable capacity associated with load service.

The available portion of the total capacity is determined from the following formula:

LC = RPS + DSO + Cha + Cna + Coa

Where:

RPS = Reserved contract purchases from and sales to OTHERS.

DSO = Demand side option equivalent capacity.

Cha = Total conventional hydro capacity less the unavailable portion of conventional hydro capacity.

Cna = Total nuclear capacity less the unavailable portion of nuclear capacity.

Coa = Total available pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity required to meet the remaining portion of the OPERATING COMPANY's load responsibility, calculated as: L - RPS - DSO - Cha - Cna.

The unavailable portion of the total capacity is determined from the following formula:

LCR = Chu + Cnu + (Coa/(1 - (Cou/Cot)) - Coa)

Where:

Chu = Unavailable portion of conventional hydro capacity.

Cnu = Unavailable portion of nuclear capacity.

Cou = Total unavailable pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

Cot = Total pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

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Section 4.2 – Determination of Capacity Available to Each OPERATING COMPANY (C): The capacity available to each OPERATING COMPANY is determined monthly as the sum of available owned, leased, purchased or otherwise available generating units, reserved contract purchases from and sales to OTHERS, and seasonal or other power exchanges, all as established by the Operating Committee as part of the coordinated planning process. The capacity available is determined from the following formula:

C	=	Cc + Cn + Cog + Ccc + Cp + Cct + Ch + Cpsh + DSO + RPS + PRC

Where:

Cc	=	Coal capacity.
Cn	=	Nuclear capacity.
Cog	=	Oil and gas steam capacity.
Ccc	=	Combined cycle capacity
Cp	=	Peak Load capacity.
Cct	=	Combustion turbine capacity.
Ch	=	Conventional hydro capacity.
Cpsh	=	Pumped storage hydro capacity.
DSO	=	Demand side option equivalent capacity.
RPS	=	Reserved contract purchases from and sales to OTHERS.
PRC	=	Purchased resource capacity.

The components of the above formula shall be computed as detailed below. The capability demonstrated in accordance with such procedures shall be used in establishing the following year's capacity values. Where seasonal references are made, the seasons shall be defined as

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follows: Summer (June through September); Fall (October through November); Winter (December through February); and Spring (March through May).

Section 4.2.1 – Certified Rating: The production officer at each OPERATING COMPANY will certify the full load capability of each coal electric generating unit (excluding units from which Unit Power Sales and other similar bulk power sales are made), oil and gas steam electric generating unit, combined cycle unit, and combustion turbine unit. Southern Nuclear Operating Company will certify the capability of each nuclear steam electric generating unit. These certified ratings ("Full Load" ratings) shall represent the full load capability expected to be available continuously on a daily basis, under normal operating conditions, with all units at a given plant operating concurrently. Where appropriate, certified ratings shall be adjusted to reflect cogeneration and seasonal impacts. The production officer at each OPERATING COMPANY will also certify the peak load capability of generating units demonstrating such capability ("Peak Load" capability). The Peak Load capability shall represent the additional amount of generation obtained for a limited period of time by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. These unit ratings will be included in the informational filing submitted in accordance with ARTICLE VI of the IIC.

Section 4.2.2 – Coal (Cc)and Nuclear (Cn) Capacity: The Full Load rating of each coal and nuclear steam electric generating unit shall be based on the unit's capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.3 – Oil and Gas Steam Capacity (Cog): The Full Load rating of each oil and gas steam electric generating unit shall be based on the unit's demonstrated capability during

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hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.4 – Combined Cycle Capacity (Ccc): The Full Load rating of combined cycle generating units shall be based on the unit's demonstrated capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings. During the other months, an adjustment will be made to the Full Load rating to reflect the unit's capability at expected ambient temperatures for such non-summer period.

Section 4.2.5 – Combustion Turbine Capacity (Cct): The Full Load rating of combustion turbine units is based on the demonstrated output of such unit and the manufacturer's base design curve rating. Combustion turbine units shall demonstrate daily sustained capability during the months of June through August, adjusted for any temporary identifiable deratings. During the fall, winter and spring, adjustments will be made to the Full Load rating to reflect the unit's capability at expected seasonal ambient temperatures.

Section 4.2.6 – Peak Load Capacity (Cp): The Peak Load capacity of demonstrating generating units shall be the additional amount of generation obtained by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. The Peak Load capacity shall be based on such unit's demonstrated capability during hours when the unit demonstrates peak load capability during the months of June through August, adjusted for temporary identifiable deratings.

Section 4.2.7 – Conventional (Ch) and Pumped Storage (Cpsh) Hydro Capacity: For purposes of the IIC, hydro capability is the average simulated generation during eight (8)

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consecutive hours occurring on five (5) consecutive weekdays using the average water inflows from historical data. The simulation process utilizes maximum (full) gate setting and best (most efficient) gate setting to determine the capability of the hydro facilities. The capability for the months June-August is the summer maximum gate simulated rating. For the months December-May, the capability is the winter maximum gate simulated rating. The capability of the months September-November is the summer best gate simulated rating. To the extent that an OPERATING COMPANY can demonstrate that a hydro facility can actually achieve the maximum gate rating during the fall months, the capability of such hydro facility will be the maximum gate rating.

Section 4.2.8 – Active Demand Side Options – Equivalent Capacity (DSO): The equivalent capacity of each active demand side option for each month of the calendar year is determined from the following formula:

DSO = [(Cv x ICE) / (1 -(%TL/100))] x A

Where:

DSO = Demand side option equivalent capacity.

Cv = Contracted value.

ICE = Incremental capacity equivalent factor.

%TL = Six (6) percent incremental transmission losses.

A = Availability Factor.

The Incremental Capacity Equivalent Factor is a measure of the effect of a demand side option on generating system reliability. The Availability Factor is a measure of the probability of an active demand side option being available at the time it is needed.

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Section 4.2.9 – Reserved Contract Purchases and Sales (RPS): Reserved contract purchases and sales for any month include all contracted capacity purchases from and sales to OTHERS for which there are underlying reserves.

Section 4.2.10 – Purchased Resource Capacity (PRC): Purchased resource capacity includes all purchased capacity for which an underlying generating resource is identified and may represent any type of capacity (e.g., combined cycle).

Section 4.3 – Determination of Peak Hour Load Responsibility of Each OPERATING COMPANY (L): The monthly peak hour load responsibility of each OPERATING COMPANY is determined by the following formula:

L = L' x La/100

Where:

L' = Monthly ten (10) highest hour average load of the integrated electric system.

La = Monthly average percent contribution of each OPERATING COMPANY's ten (10) highest hour average loads to the sum of those loads for all OPERATING COMPANIES for the most recent three-year period.

Section 4.4 – Recognition of Resource Additions or Deletions: For additions or deletions of capacity resources for the coming year, an adjustment will be made in the capability resources of the appropriate OPERATING COMPANY based upon the actual date of the addition or deletion (e.g., commercial operation, retirement, purchase, or sale); provided, however, that the adjustment will not be made in a month earlier than that originally established by the Operating Committee pursuant to the coordinated planning process. If the actual date is on or before the 15th day of the month, the capacity adjustment begins in that month. If the actual date is beyond the 15th day of the month, the capacity adjustment begins in the following month.

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Section 4.5 – Capacity Outside of the Coordinated Planning Process: If an OPERATING COMPANY has capacity that was not established by the Operating Committee as part of the coordinated planning process, such capacity will not be included as capacity available to the OPERATING COMPANY (pursuant to Section 4.2 of this Manual) for reserve sharing purposes ("unrecognized capacity"). Notwithstanding the foregoing, if an OPERATING COMPANY's monthly capacity/load ratio, as determined by comparing its available capacity (pursuant to Section 4.2 of this Manual) with its load responsibility (pursuant to Section 4.3 of this Manual), is less than the comparable ratio for the aggregate system (excluding the load responsibility and available capacity of the subject OPERATING COMPANY), then unrecognized capacity (up to an amount that will make these ratios comparable) will be designated as capacity available to that OPERATING COMPANY for that month.

ARTICLE V

RATE FOR MONTHLY RESERVE SHARING CAPACITY FOR EACH OPERATING COMPANY

Section 5.1 – Provision for Monthly Capacity Rate for Reserve Sharing: This article of the Manual establishes the formula rate for deriving the monthly reserve sharing capacity charge for each OPERATING COMPANY based on its most recently installed peaking facilities (or equivalent purchased resources) available for year-round operation or scheduling. OPERATING COMPANIES that have not installed or purchased such facilities or resources within the last five (5) years will utilize the weighted average rate of all the OPERATING COMPANIES that have installed or purchased such facilities or resources. In the event none of the OPERATING COMPANIES have installed or purchased such facilities or resources within the last five (5) years, the rate of the last facility or resource installed or purchased by any of them will be

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utilized for all OPERATING COMPANIES. The monthly reserve sharing capacity charges are utilized in the determination of payments to the Pool by the OPERATING COMPANIES purchasing capacity during the month and receipts from the Pool by the OPERATING COMPANIES selling capacity during the month. Each OPERATING COMPANY that sells reserve sharing capacity to the Pool will receive a payment based on the product of the amount of net capacity sales (CS) times that OPERATING COMPANY's monthly capacity rate. Each deficit OPERATING COMPANY will make payments to the Pool based on the product of the amount of net reserve sharing capacity purchased (CP) times the weighted average cost of such capacity sold to the Pool during the month. The monthly reserve sharing capacity rate of each OPERATING COMPANY for each month of the Contract Year is shown on Informational Schedule No. 3. Such rates will be revised in accordance with this Manual and the IIC in subsequent contract years.

Section 5.2 – Derivation of Monthly Capacity Costs of Each OPERATING COMPANY: The derivation of the monthly capacity costs of each OPERATING COMPANY, as used for purposes of the reserve sharing capacity rate, is based on one of the following: (i) the capacity cost of the most recently added peaking facility; (ii) the capacity cost of the most recent equivalent purchased resource; or (iii) the weighted system average of the capacity costs of the most recently added peaking facilities or equivalent purchased resources.

The monthly reserve sharing capacity rate of each OPERATING COMPANY for an installed peaking facility under subpart (i) will be determined by the following formula:

$$R1 = (I \times LFCC/100/C1) \times MCWF$$

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Where:

R1	=	Monthly charges for peaking facility ($/kW-Month).
I	=	Gross investment in peaking facility ($).
LFCC	=	16.3%, levelized fixed capacity charge.
C1	=	Peaking facility's rated production capability (kW), as determined by Section 4.2 of this Manual.
MCWF	=	Monthly Capacity Worth Factor for the applicable month.

The AGENT may periodically re-evaluate the monthly capacity worth factors based upon evaluations of system reliability. The governing MCWFs will be included in the Informational Schedules submitted in accordance with ARTICLE VI of the IIC.

For purposes of subpart (ii), the monthly reserve sharing capacity rate of each OPERATING COMPANY for an equivalent purchased resource will be the annual capacity rate ($/kW-Year) paid for such resource, multiplied by the applicable MCWF.

For purposes of subpart (iii), the monthly reserve sharing capacity rate will be the weighted system average of the costs of the most recently added peaking facilities (as determined for purposes of subpart (i)) or equivalent purchased resources (as determined for purposes of subpart (ii)), multiplied by the applicable MCWF.

Section 5.3 – Monthly Reserve Sharing Capacity Rate To Be Adjusted For Production Resource Change: If a peaking facility or an equivalent purchased resource of an OPERATING COMPANY is placed in commercial operation or available for scheduling by the 15th day of the month established by the Operating Committee as part of the coordinated planning process, the

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budgeted investment cost or annual capacity rate will be used in the determination of the monthly reserve sharing capacity rate for such OPERATING COMPANY for that and subsequent months of the calendar year. If the facility or resource is not placed in commercial operation or available for scheduling by the 15th day of such month, the cost basis established under Section 5.2, as used to derive the monthly reserve sharing capacity rate for the previous month, will remain in effect until the month in which the facility or resource is in commercial operation or available for scheduling on or before the 15th day.

ARTICLE VI

RATE FOR TIE-LINE LOAD CONTROL AND FREQUENCY REGULATION BY HYDRO FACILITIES

Section 6.1 – Provision for Hydro Regulation Energy Losses: Because of energy losses from hydro regulation, the OPERATING COMPANIES supplying this service are deprived of hydro energy. To distribute equitably this loss of energy among the OPERATING COMPANIES in accordance with size of loads regulated and to compensate the OPERATING COMPANIES for regulating services rendered, adjustments in billing determinations are necessary. Hydro energy losses actually incurred by regulating OPERATING COMPANIES during each day are replaced by the Pool at zero cost, and the AGENT allocates such energy losses to all OPERATING COMPANIES in accordance with Peak-Period Load Ratios. Energy lost during high-flow periods is replaced during the period in which such losses occur, and energy lost from poorer efficiencies during normal and low-flow periods is replaced during the 14-hour peak period since hydro energy so lost could have been retained in storage and generated during this period.

Section 6.2 – Provision for Increases in Cost Due to Hydro Regulation: Payments are made to hydro regulating OPERATING COMPANIES for each hour of such regulation for the increase

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in operating and maintenance expenditures for governor mechanisms and water turbine parts, and these expenses are allocated to all OPERATING COMPANIES in accordance with Peak-Period Load Ratios. Such payments are calculated using actual expenses incurred through the last calendar year available, adjusted to current-year dollars, for the cost of labor, engineering and supervision, and materials and supplies in the following FERC Accounts: 544-10, Generator and Exciters; 544-20, Hydraulic Turbines and Settings; 544-40, Governors and Control Apparatus; and 544-50, Powerhouse Remote Control Equipment. The basis for hourly payments is the difference in the average hourly costs for regulating plants and non-regulating plants, expressed in the following formula:

Hourly Charge	=	[MCW - (MCWO/HWO) x MCWH]/HOR
Where:		
MCW	=	Summation of costs for regulating plants.
MCWO	=	Summation of costs for non-regulating plants.
HWO	=	Summation of hours for non-regulating plants.
MCWH	=	Summation of hours for regulating plants.
HOR	=	Summation of hours in the regulating mode for regulating plants.

The regulating OPERATING COMPANIES shall supply the AGENT an hourly statement of energy losses incurred in providing hydro regulating services. Such statement should include sufficient detail to permit review and verification by the AGENT.

Section 6.3 – Regulation by Pumped Storage Hydro Projects: It is understood that pumped storage hydro projects owned by the OPERATING COMPANIES may also be used for regulation of the integrated electric system. In such event, the hourly charge for such regulation will be the same charge derived under the formula contained in Section 6.2 hereof.

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Section 6.4 – Provision for Increases in Cost Due to Hydro Scheduling: Because the use of hydro resources for tie-line load control and frequency regulation does not allow the hydro energy to be scheduled in the most cost effective manner, less economic gains are achieved than would have been if the hydro energy had been used to displace only the highest cost other energy sources. The difference in actual displacement costs represents the value of the lost economic opportunity by the owning OPERATING COMPANY by such use of hydro energy, or the costs of providing higher cost energy. The AGENT shall allocate such costs to all the OPERATING COMPANIES in accordance with Peak-Period Load Ratios.

[END OF MANUAL]

Southern Company

Determination of Annual Capacity Rate

January 1, 2024 - December 31, 2024

Reference: Manual, Article V

Rate Basis:	Alabama Purchased Resource	Georgia Purchased Resource	Mississippi Purchased Resource	Southern Power Purchased Resource
1. Net Production Capacity (kW)	17,104	21,462	3,446	7,988
2. Gross Investment in Peaking Facilities (I)				
3. Levelized Fixed Capacity Charge (LFCC)				
4. Annual Charge ($ per kW year)	$ 73.200000 (a)	$ 73.200000 (b)	$ 73.200000 (d)	$ 73.200000 (e)

Notes:
(a) Cost of Peaking Resources Purchased by Alabama Power Company
(b) Cost of Peaking Resources Purchased by Georgia Power Company
(d) Cost of Peaking Resources Purchased by Mississippi Power Company
(e) Cost of Peaking Resources Purchased by Southern Power Company

MONTHLY CAPACITY CHARGES
FOR RESERVE SHARING PURPOSES
($/KW-MO)

	Monthly Capacity Worth Factors	Alabama	Georgia	Mississippi	Southern Power
January - December 2024		***73.200000***	***73.200000***	***73.200000***	***73.200000***
January	0.50	36.600000	36.600000	36.600000	36.600000
February	0.10	7.320000	7.320000	7.320000	7.320000
March	0.01	0.732000	0.732000	0.732000	0.732000
April	0.01	0.732000	0.732000	0.732000	0.732000
May	0.01	0.732000	0.732000	0.732000	0.732000
June	0.04	2.928000	2.928000	2.928000	2.928000
July	0.10	7.320000	7.320000	7.320000	7.320000
August	0.10	7.320000	7.320000	7.320000	7.320000
September	0.01	0.732000	0.732000	0.732000	0.732000
October	0.01	0.732000	0.732000	0.732000	0.732000
November	0.01	0.732000	0.732000	0.732000	0.732000
December	0.10	7.320000	7.320000	7.320000	7.320000

MONTHLY LOAD CAPACITY COMPARISON

MW PURCHASE OR (SALE)

	ALABAMA	GEORGIA	MISSISSIPPI	SOUTHERN POWER
January	-	-	-	-
February	(147.097)	(0.189)	147.285	-
March	(191.939)	-	191.939	-
April	-	(344.113)	656.885	(312.772)
May	-	(267.072)	467.201	(200.128)
June	(36.803)	(36.429)	81.308	(8.077)
July	-	-	-	-
August	-	-	-	-
September	-	(98.067)	135.351	(37.284)
October	-	-	172.337	(172.337)
November	-	-	-	-
December	-	-	-	-
Total 2024	**(375.838)**	**(745.870)**	**1,852.306**	**(730.598)**

DOLLAR PAYMENTS OR (RECEIPTS)

	ALABAMA	GEORGIA	MISSISSIPPI	SOUTHERN POWER
January	$ -	$ -	$ -	$ -
February	$ (1,076,747)	$ (1,381)	$ 1,078,128	$ -
March	$ (140,499)	$ -	$ 140,499	$ -
April	$ -	$ (251,891)	$ 480,840	$ (228,949)
May	$ -	$ (195,497)	$ 341,991	$ (146,494)
June	$ (107,758)	$ (106,663)	$ 238,069	$ (23,648)
July	$ -	$ -	$ -	$ -
August	$ -	$ -	$ -	$ -
September	$ -	$ (71,785)	$ 99,077	$ (27,292)
October	$ -	$ -	$ 126,151	$ (126,151)
November	$ -	$ -	$ -	$ -
December	$ -	$ -	$ -	$ -
Total 2024	**$ (1,325,004)**	**$ (627,217)**	**$ 2,504,755**	**$ (552,534)**

( ) Indicates Sales to Pool

BY MR. JONES:

Q Mr. Pollock, you also prepared a trade secret version of your testimony that was filed with the Commission on the same date?

A Yes.

Q And other than the redactions in that testimony, is it identical to the redacted public disclosure version?

A Yes.

MR. JONES: Mr. Chairman, I ask the witness' trade secret version of his testimony be marked as GAM Exhibit 1.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GAM Exhibit 1.)

BY MR. JONES:

Q And, Mr. Pollock, you also prepared three exhibits labeled in your testimony as Exhibits JP-1, -2, and -3; correct?

A Yes.

Q And any changes you need to make to those exhibits?

A No.

MR. JONES: And, Mr. Chairman, I'd ask that those three exhibits be marked Exhibits --

GAM Exhibits 2, 3, and 4.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as GAM Exhibits 2, 3.)

BY MR. JONES:

Q And, Mr. Pollock, have you prepared a summary of your testimony?

A I have.

MR. JONES: Mr. Chairman, with your permission, I would like the witness to give a summary.

CHAIRMAN SHAW: Yes, sir. Go ahead, Mr. Pollock.

MR. POLLOCK: Good morning, Commissioners. Georgia Association of Manufacturers shares and understands the concerns about both the sudden change and unprecedented amount of load growth that Georgia Power is now experiencing and projecting. However, Georgia Power is not alone in experiencing accelerated load growth.

Due to the influx of data centers, battery and electrical vehicle manufacturing, and related industries, the Southeast as a whole is experiencing rapid load growth. Thereby, necessitating a more rapid increase in capacity resources. Georgia Power affiliate Alabama Power Company, Duke Energy

Carolinas, Duke Energy Progress are all experiencing accelerated load growth and, as a consequence, they are seeking to accelerate planned capacity additions.

While these circumstances can pose a risk of over-committing to new resources, some of the proposed new capacity resources, particularly the purchase power agreements with Mississippi Power and Santa Rosa, are much lower in cost than Georgia Power's current system resources, which now includes Vogtle 3 and will soon include Vogtle 4.

Keep in mind that rates are determined by dividing Georgia Power's costs -- costs by sales. If sales grow faster than costs, rates will go down. Similarly, if Georgia Power adds or retains more lower-cost resources to meet growing demand, this too will place downward pressure on rates. On the other hand, adding more expensive capacity resources, such as the proposed solar and battery storage project, will place upward pressure on rates.

Now, given the extraordinary circumstances -- excuse me -- surrounding this IRP Update, Georgia Power requests for deferred accounting and additional sums should not be approved even though

similar proposals have been adopted in the past, including recently in the 2022 IRP.

Unlike in the past, the proposed PPA capacity payments are much less than the incremental revenues from load growth projected in 2024 and 2025. And that's before taking into account any further capacity sales, which the company is currently negotiating.

Further, the earnings band approved in the 2022 rate case and past history demonstrate that Georgia Power has more than ample earnings headroom to fully expense the purchase power capacity costs without harming its financial integrity. Even if the company were to expense 275 million a year -- a year for new resources, it would not reduce its earned ROE below the 10.5 percent midpoint approved in the rate case.

Deferred accounting should only be used when it is necessary to prevent material harm to the utility's financial integrity, or to prevent rate shock. Neither circumstance is present in this -- in this case. And, accordingly, the Commission should reject the deferred accounting proposals.

As others have already testified, the conditions required for awarding an additional sum

are not present in this case. The company already has an incentive to procure additional capacity. Given that neither purchase power agreement were procured competitively and that the company will experience higher and not lower revenues, and that accelerating capacity additions pose more risks on customers, and that a capacity payment to the Mississippi Power PPA is higher than the reserve sharing purchases under the Southern Company Intercompany Interchange Contract, for these reasons the proposed additional sum should be rejected.

Finally, the Georgia Association of Manufacturers appreciates the fact that Georgia Power is providing more opportunities for customers to provide the needed capacity. While we believe that the DCL, DCO, and CL schedules have merit, we have serious concerns with the lack of transparent pricing, which, when coupled with the proposed terms and conditions, could unnecessarily stifle participation. However, we believe that our issues and concerns can be resolved with further discussions with Georgia Power and interested parties.

And that concludes my summary.

MR. JONES: Thank you, Mr. Pollock.

Mr. Chairman, the witness is available for questions from the Commission and cross-examination.

CHAIRMAN SHAW: Thank you, Mr. Jones.

Commissioners, any questions for Mr. Pollock?

COMMISSIONER PRIDEMORE: I do, Mr. Chairman.

CHAIRMAN SHAW: Go ahead.

COMMISSIONER PRIDEMORE: Hi, Mr. Pollock.

MR. POLLOCK: Good morning.

COMMISSIONER PRIDEMORE: I just would like for you to unpack a little bit more for us on page 4 of your prefiled testimony. The Mississippi -- Mississippi Power PPA is -- it is -- of course, those units in that -- those assets are part of the IIC. I appreciate the fact that you recognize the importance of the IIC.

But knowing that the Mississippi Commission was going to retire those units, though, they would no longer be part of the IIC. So why do you speak against on -- like I think I found -- you start your argument to me on line 13 and go to line 20.

Why -- explain to me why you disagree with the PPA approach.

MR. POLLOCK: So the reason that I'm recommending or have made the position I've taken on the -- on the PPA is the fact that the Southern

Companies for many years, even since before I started in this business a long time ago, has been planned on a coordinated basis. And utilities all support each other in joint planning.

Now, it's true that the Mississippi Commission saw that Mississippi Power had excess capacity. They said: We want you to propose a plan to retire this capacity or demonstrate that there's an alternative or a reason to keep this capacity going.

And that was a plan that was implemented in 2021. As you know, when a -- when a utility, you know, implements an integrated resource plan, it's a plan. It's not an action necessarily.

And if circumstances were to change that says the reverse, the load growth now grow -- growing, instead of being flat, that can change a plan that had been previously approved by that Commission.

Clearly this -- this capacity was surplus to Mississippi Power's needs. It's being -- it was being sold into the IIC anyway to serve the other companies. That mechanism, I think, could have still been used, provided that the Southern Company, assuming they continue their joint planning and resources, recognize: We don't want you to retire those units yet because, you know, the rest of the

system is growing and we need the capacity.

So I think given -- given that premise and given the fact that the companies are -- are joined at the hip in planning, you know, I think that there's at least a reasonable likelihood those units would remain and -- and are going to remain online because of the need.

COMMISSIONER PRIDEMORE: Well, maybe I'll wait until Georgia Power comes up for cross and ask the same question. Because it seems to me that -- I know the Georgia Association of Manufacturers and your members -- what you're looking for is system reliability.

And so if the Mississippi Commission was going to sunset those units, PPA to me seems to be the logical route to go because it does guarantee service to a Georgia manufacturer if they need reliable service.

MR. POLLOCK: And I totally understand the argument. I mean, it is an alternative, you know. And, really, my observation is more of: Well, look at what they're paying versus what they would have paid under the IIC. And -- and why are they paying more for one than the other?

COMMISSIONER PRIDEMORE: Okay. They can pick

this up when they come in.

MR. POLLOCK: Thank you.

COMMISSIONER PRIDEMORE: Thank you, Mr. Pollock.

MR. POLLOCK: Sure.

CHAIRMAN SHAW: Any other commission -- questions from Commissioners?

(No response.)

CHAIRMAN SHAW: Mr. Pollock, on -- when you talk about the additional sum also on page 3, talk me through why you are recommending that -- that they the company gets zero additional sum, instead of a -- just a smaller amount due to the way this is structured. I'm just talking about the Mississippi Power and the Santa Rosa PPAs.

MR. POLLOCK: Yeah. So as I -- yeah. So I think the circumstances surrounding additional sum really aren't present in this case, you know. And the reason for having an additional sum is that, you know, if the utility provides -- deploys additional resources to meet growing demand. And in the process of that deployment, either through demand-side responses, which don't -- don't require any rate base additions, or through purchase power agreements, which, again, don't provide any

rate-based agreements or additions, the additional sum is essentially providing financial compensation for the fact that the company is not going to be earning, you know, return on those assets.

Well, that's not really an issue here because the company is growing, which means that the company is going to be earning a return on all of its assets. And -- and the other criteria is lost revenues.

Well, yeah, if you sell less energy through energy efficiency, you're losing revenues. So there's an incentive for the company to -- you know, you're giving the company incentive to do energy efficiency because that -- that additional sum helps offset the loss in revenues that they've experienced by selling less.

We're not talking about selling less energy in this case. We're talking about selling a lot more energy in this case. And so revenues are going to grow.

So you really don't have the circumstances that -- that really necessitate, I think, an additional sum. Now, if you want to award something lower than -- than what they're asking for, that's, of course, your -- your prerogative.

CHAIRMAN SHAW: Okay. This -- this would probably be a better question for Mr. Jones, but I -- you know, we are actually -- it's been -- we -- we've talked about this a lot. About the fact that the -- almost right at 80 percent of the reason why we're here yesterday and today, and January and all the way through April dealing with this case is because of data centers.

And I would assume that many of these data centers are members of Georgia Association of Manufacturers. Would that be --

MR. POLLOCK: I -- I think there might be a few.

MR. JONES: There are a couple of companies that have.

CHAIRMAN SHAW: So I guess what I -- my question would be: When you were working on this docket and planning your testimony and preparing everything, how did -- did that factor in at all; that -- that equation between many of these being members of GAM and --

MR. POLLOCK: Well, that's --

MR. STPHAO: -- how it's impacting the whole reason we're here?

MR. POLLOCK: Yeah. that's -- that's, of

course, an excellent question. I mean, we're not privy to what their growth plans are. So I have no idea, no knowledge of what any of the GAM members are doing, in terms of future expansions.

But, as you know, we're all into -- you know, the two mantras that -- if I could characterize the two mantras of GAM: Electricity needs to be reliable and affordable. And so whatever it takes to accomplish reliability and affordability, I think, is consistent with the principles that -- that GAM members will support.

CHAIRMAN SHAW: Okay. Commissioners, any other questions before we move on?

(No response.)

CHAIRMAN SHAW: All right. We'll start with the -- going down the list for cross. Starting with Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: No questions.

Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone Renewable Energy.

MR. GALLOWAY: No questions, Mr. Chairman.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

And I -- I saw y'all come in.

MS. BROWN: No questions, Mr. Chairman.

CHAIRMAN SHAW: Okay. No questions.

Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND.

(No response.)

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions, Mr. Chairman.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

Mr. Baker, notice I'm still talking a little faster than my normal South Georgia dialect.

MR. BAKER: I've got two questions today, so, yeah, I'll -- I'll speed it up here.

CROSS-EXAMINATION

BY MR. BAKER:

Q Good morning, Commissioners. Good morning, Mr. Pollock.

A Good morning, Mr. Baker.

Q A couple of my questions have already been addressed so I'm going to cut my cross down.

First question: Do you agree with staff's position that any amount of an additional sum should be included in the company's earnings?

A In other words, should the deferrals be expen-- or the costs be expensed?

Q Yes.

MR. THOMAS: I'm -- excuse me. I'm going to object. First of all, friendly cross.

And, also, this is outside the scope of Mr. Pollock's testimony.

CHAIRMAN SHAW: Mr. Baker, let's -- let's refrain from anything that could be considered friendly cross.

MR. BAKER: Well, I was just taking advantage of Mr. Pollock's expertise in this area and his --

CHAIRMAN SHAW: Well, if you want to rephrase

the question a little bit and maybe make it a little more pointed, I will allow it.

MR. BAKER: I'll try one more time and see if I can get it a little bit more focused.

BY MR. BAKER:

Q Should any costs the company incurs -- or should any revenue the company receives be included in their earnings for calculation -- for calculation -- revenue calculation purposes?

A Are we talking about specifically the -- the purchase power agreements?

Q Just generically.

A Generically. I mean, generally speaking, all sources of revenues are -- are reviewed when you examine a utility's overall earnings. I think the additional sum has been an exception to that rule, however.

Q Okay. Thank you.

Turning to page 19 of your testimony, would your statement that even if certain plants are found to be marginally economic under certain specific circumstances, this finding alone is not sufficient reason to irrevocably commit to retiring these resources?

Does this also apply to the Gaston and Scherer units in Georgia?

A Yes, it does. It's a very similar circumstance

where you've identified in a previous IRP that certain units are marginally economic and you're going to give them another round to determine whether or not -- before you make an irrevocable decision to retire those units, make sure that they are no longer economic and, importantly, no longer needed.

Q Okay.

A Because circumstances have a way of changing, as -- as we now see.

MR. BAKER: Okay. Thank you, Mr. Pollock.

Thank you, Mr. Chairman.

CHAIRMAN SHAW: All right. Thank you, Mr. Baker.

Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

(No response.)

CHAIRMAN SHAW: Department of Defense.

MR. McNUTT: No questions, Mr. Chairman.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions, Mr. Chairman.

CHAIRMAN SHAW: All right. Georgia Power Company.

MR. MARZO: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. MARZO:

Q Good morning, Mr. Pollock.

A Mr. Marzo, how are you?

Q Doing good. Doing good.

I just have a few questions for you this morning related to your testimony.

Now, it's fair to say that you agree that the company is facing extraordinary circumstances of accelerating load growth and increased capacity need; is that correct?

A Yes.

Q And you testify all around the country. And is it fair to say that Georgia is one of many states seeing this unprecedented acceleration of load growth?

A That's true. It's -- it's even beyond the southeast. We're seeing more and more utilities having to ramp up their capacity back positions.

Q Thank you, Mr. Pollock.

And if I could direct you to your Exhibit JP-1, which is now GAM-2.

A Okay.

Q And this is an article, I believe, that you have cited from S&P where it talks about unprecedented

load growth in North Carolina. And if I could point you to the middle of page 1, am I correct that it says that Duke Energy identified this unprecedented economic growth in its carbon plan filed and reiterated acceleration of that growth in January 31st of this year?

A Yes.

Q Now, the filing discussed there is for Duke North Carolina. And that's in the company's carbon plan; correct?

A Correct.

Q And it stated in this article: Duke is proposing to meet this accelerated need with a variety of natural gas, renewable, and small modular reactors; is that correct?

A Yes.

Q Okay. And, similarly, if I were to flip over that exhibit to page 2, the article discusses that Duke Energy in South Carolina is proposing to build natural gas plants to meet this unprecedented need; is that correct?

A Yes.

Q Now, are you aware that TVA, as well, has announced that it's building 3800 megawatts of new generation by 2028?

A I'm aware that they are on a building cycle at

this point. I don't recall the amount, but they are -- they are definitely accelerating their capacity expansions.

Q Do you know whether the 3800 megawatts includes gas resources, along with various combinations of renewables and batteries?

A I'm pretty certain it does include gas.

Q Okay. And am I -- am I correct that Georgia Association of Manufacturers -- it's important to GAM that Georgia remain competitive with these other states that are addressing this economic development need?

A Yes.

Q Okay. And, Mr. Pollock, you also talked about how load growth can have a positive impact on customers, in terms of load growth materializing and putting downward pressure on rates.

Am I correct, do you agree that when load growth does materialize, it can reduce downward pressure on customers' rates?

A Yes.

Q Okay. And you have reviewed the company's analysis in DEA 3-6?

A Yes, I have.

Q Okay. And that's -- that really is the analysis that depicts the company's showing of if their

plan's adopted and the load comes as expected, there's a downward pressure on rates; correct?

A That's right. And -- excuse me -- I would comment that that analysis is also pretty conservative because it's using a lower load forecast to quantify the additional revenues associated with load growth than the load growth that would occur if the capacity of -- the full -- full amount of -- full suite of resources that the company is planning to install were -- you know, were indeed installed to meet the higher -- much higher growth. So I would believe that -- I believe that analysis is pretty conservative.

Q Okay. Thank you, Mr. Pollock.

Now, I want to ask you a few questions about deferrals. And before we leave this topic, although I know that GAM is not recommending approval of deferrals in this case, can we agree that the depiction in DEA 3-6 shows the impact of including additional sum and deferrals in the downward pressure on rates calculation?

A Yes, it does.

Q Okay. Now, can we agree that it's in the Commission's discretion to approve deferrals?

A Yes.

Q Okay. And can we agree that Georgia Commission in rate cases makes determinations of what is deferred

cost or prudently incurred in the time and the recovery of deferrals?

A Correct. In rate cases that's -- that's usually when that determination is made.

Q Okay. So a deferral made today, the Commission still gets to look at the prudency of costs in the rate case; correct?

A Or they -- or they can decide that the cost should have been deferred in the rate case.

Q Okay. Are you aware that the company has committed to take several actions to mitigate deferrals?

A Yes. And -- and I think that's -- those actions to basically resell that capacity, I think, is -- you know, provides a good motivation for the company to be successful in that. Because to the extent that the company can remarket that capacity and make revenues associated with offsetting the costs, the need for a deferral is much less -- less great.

Q Okay. And I heard you -- moving on to the DER and DER tariffs, I heard you -- in your summary earlier probably you eliminated a number of my questions.

It's GAM's position that they support generally the concepts of the DER and DER tariffs; is that correct?

A Yes. We believe customers can provide a lot of the solution to -- to any kind of, you know, accelerated

capacity needs. And that -- that should be an area that should be given a lot of analysis.

Q And I know the changes that you are proposing are largely driven to attain more specificity regarding terms; is that correct?

A Yes. Because customers need to know what the risks and benefits are going to look like. And the tariffs as written now really don't provide that information.

Q But can we agree that in developing tariff language there is often a balance between specificity and having flexibility, but, in the end, the goal is to make the offering attractive to customers?

A That -- that should be the goal, yes.

Q Okay.

VICE-CHAIRMAN ECHOLS: Let me interrupt and ask a question about some of GAM -- GAM's members. I know I was visiting with Gerdau steel and Arglass, one in Cartersville, one in Valdosta. They both expressed an interest in doing some behind-the-meter solar, but it wasn't on the property. It was going to be across a road. It was going to violate one of our -- one of our rules.

Are you -- are you seeing more -- not just members of GAM, but, you know, industrials around

the country, want to, you know, do more behind-the-meter to, you know, curtail their usage of -- of utility-supplied power?

MR. POLLOCK: I've -- I've seen that customers are willing to do that, but I think they're also starting to see a good synergy in being able to bring, you know, projects to the utility and -- and try to sleeve some of the energy. Basically, take the project, have the company, you know, buy power from the project and resell that power directly to the customer as a way of -- excuse me -- as a way of trying to meet their sustainability goals. That -- that we're seeing more of -- interest in that -- that type of proposal.

VICE-CHAIRMAN ECHOLS: And your recommendations, you know, for Georgia in specific, what -- what do you think we need to do to be more friendly towards that?

What -- what policy changes do we need to make?

MR. POLLOCK: Well, I think that -- first of all, I think that offering a broader suite of tariffs like the company is proposing, I think, is a really good start. And -- and I think increasing the transparency and balance terms and conditions in the rates that we just -- were just talking about, I

think, will really help and not -- not try to inhibit customer participation.

I think an underused resource is demand response. And I think the company could benefit a lot more by having more demand response. Gerdau, for example, I know is very much into demand response in many of its other jurisdictions because that's a way that they can utilize the flexibility of their load and it -- and take advantage of the better economics.

And as you know, steel making is a commodity business. And, you know, electricity costs are a significant operating cost in that. So anything that they can do usefully that helps the utility that also helps lower the cost is, of course, going to increase the longevity of that particular facility.

VICE-CHAIRMAN ECHOLS: Thank you.

MR. MARZO: Thank you, Commissioner.

BY MR. MARZO:

Q Mr. Pollock, one last question here. I mean, would you agree with me that GAM and the company have been able to work together constructively in prior cases to address issues around tariff language and new programs?

A Yes.

Q Okay. I want to ask you a couple of follow-up questions to Commissioner Pridemore's questions around the IIC.

Are you aware that each opco is required to bring their own resources to meet their load?

A That's the -- that's the concept is that -- that, you know, over the long term, the -- the notion is is that each utility, each operating company, should stand on its own.

Q Okay. And are you aware that each opco may sell any excess megawatts into the market if it's in the best interest of its customers?

A Market you mean outside of Southern Company?

Q Outside of the --

A Yes. That --

Q Yeah.

A That's a -- that's an avenue, yes.

Q And do you understand that MPC was remarketing its resources when Georgia Power approached them?

A I would assume that they were -- they would have tried to, yes.

Q And would you expect in this case the Georgia Public Service Commission, if there was an uneconomic Georgia Power resource or a better market opportunity for

that resource, that the Georgia Commission would order Georgia Power to sell it to the pool?

A Well, they wouldn't have to order it to sell it to the pool, but they would certainly order the company or persuade the company that it -- that it should try to remarket that capacity as a way of offsetting the economics.

Q Okay. To get the best value?

A Yes. In creating the best value for the capacity.

Q And if -- if that happened to be an off-system, out of the pool type of transaction, then you -- you'd expect the Commission to -- to be in favor of that; correct?

A Yes.

MR. MARZO: Okay. All right. Thank you, Mr. Pollock. I appreciate your testimony this morning.

MR. POLLOCK: Thank you.

MR. MARZO: Thank you, Mr. Chairman.

CHAIRMAN SHAW: Thank you.

Mr. Jones, redirect.

MR. JONES: I just have one question on redirect.

//

REDIRECT EXAMINATION

BY MR. JONES:

Q Mr. Pollock, you remember the questions about deferrals and whether to address them in an IRP or in a rate case; correct?

A Yes.

Q But if -- if the Commission were to grant regulatory deferrals and then deal with them later in a rate case, wouldn't there be -- would there be a presumption of recovery once the deferral had been granted?

A Clearly. If the Commission says, We're going to allow these deferrals, these costs to be deferred, then, I mean, the company is going to record that deferral on its books. And that creates an expectation that the company will recover all the costs that the Commission said they could defer. So it -- it kind of forecloses any kind of re-examination of that issue in the rate case.

MR. JONES: Okay. Mr. Chairman, that's all I had on redirect.

CHAIRMAN SHAW: All right. Thank you, Mr. Jones. Do you have anything else?

MR. JONES: I don't. I just -- we can leave the witness up there all day, but I -- I'll ask that

he --

CHAIRMAN SHAW: No, let's not do that.

MR. JONES: I would enjoy it, but I will -- I'll ask that he be excused. And I will ask that my exhibits be moved into evidence.

CHAIRMAN SHAW: So marked.

(GAM Exhibits 1, 2, 3, 4 were admitted into evidence.)

CHAIRMAN SHAW: Mr. Pollock, good to see you again. Thank you for being with us. You're -- you can be excused.

MR. POLLOCK: As always, thank you guys for your time and attention.

CHAIRMAN SHAW: Thank you.

All right. We're going to -- here's what we're going to do. We're going to kind of go back through the list and stop where we get to the next -- let's see here.

Are there any other groups that have shown up since we did the original appearance list call?

MR. HUBBARD: Yes. Georgia Center for Energy Solutions.

CHAIRMAN SHAW: Okay.

MS. SCOTT: Georgia WAND.

CHAIRMAN SHAW: Georgia WAND.

All right. And I saw Coalition for Local Governments.

MR. GALLOWAY: Mr. Chairman, I missed the original --

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: Heelstone, yes, sir.

CHAIRMAN SHAW: All right.

All right. Georgia Center for Energy Solutions, do you have a -- do you want to go ahead and bring your panel up?

I don't want to get started with public witnesses before 9:30, but I don't want to stop where we're at.

MR. SHERRIER: Good morning, Chairman, Commissioners.

Will you please raise your right hand.

Thereupon,

PETER HUBBARD,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. SHERRIER:

Q Please state your name for the record and could you spell your last name for the court reporter.

A Peter Hubbard, H-u-b-b-a-r-d.

Q And by whom are you -- are you employed?

A Georgia Center for Energy Solutions.

Q And on whose behalf are you testifying?

A The same.

Q On February 15th of this year, did you prefile or cause to be prefiled 35 pages of direct testimony in question-and-answer format in Docket 55378?

A Yes.

Q Mr. Hubbard, do you have any corrections or changes to your prefiled direct testimony or attachments at this time?

A I do. On page 23, line 17, I would like to strike twice "the" and replace it with "a higher rate than."

Q Other than those changes, if I were to ask you the same questions that appear in your prefiled testimony at the hearing today under oath, would your answers be the same?

A Yes.

MR. SHERRIER: Mr. Chairman, incorporating the changes Mr. Hubbard has made on the stand, I move to have Mr. Hubbard's prefiled direct testimony entered into the record as if given orally from the stand.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Peter Hubbard follows:)

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's 2023	**)**	
Integrated Resource Plan Update	**)**	
And Application for Certification	**)**	
Of Plant Yates Units 8-10	**)**	
	)	**Docket No. 55378**
	)	
	)	
	)	
	)	

Direct Testimony of
Peter Hubbard
Georgia Center for Energy Solutions

February 15, 2024

Direct Testimony of Peter Hubbard
on the Georgia Power Company 2023 Integrated Resource Plan Update

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

A. My name is Peter Hubbard. I am a Clean Energy Advocate with the Georgia Center for Energy Solutions (GCES). My business address is 55 Leslie Street SE, Atlanta, Georgia 30317.

Q. PLEASE DESCRIBE YOUR ORGANIZATION.

A. GCES seeks to develop an economic and regulatory framework to transition Georgia's electric, transportation, buildings, and agriculture sectors to a 100% clean energy (zero-carbon) future in an equitable, reliable, resilient, sustainable, rapid, and economically efficient manner and in furtherance of the public benefit.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. My professional experience is in renewable project development and energy management consulting focused on electric utility Integrated Resource Plan (IRP), organized power markets in North America, global gas market analysis, commodity price projections, stochastic risk analysis, scenario development, capacity expansion modeling, and production cost modeling. I have 15 years of professional experience in the energy sector.

Q. MR. HUBBARD, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. I have previously filed direct testimony and given an oral summary of my direct testimony before the Georgia Public Service Commission ("Commission") related to the Georgia Power Company (GPC or the Company) 2019 Integrated Resource Plan in Docket #42310 and again in the GPC 2022 IRP and Application for Certification of 2,356 MW of gas-fired Power Purchase Agreements (Docket #44160).

Q. **ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am testifying on behalf of the Georgia Center for Energy Solutions.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of this direct testimony is to demonstrate how GPC is using flawed analysis in its application before the Commission to certify the Yates CTs, resulting in an unjust cost shift onto residential ratepayers in particular and an imprudent plan to build new gas-fired generating assets. These new gas plants are at risk of becoming stranded assets whose costs will be further shifted onto residential ratepayers as regulatory assets. I will provide examples of GPC acting in ways that result in fewer choices in the open market. And I will provide pragmatic solutions to help GPC meet the acute near-term capacity shortage due to load growth without building new gas-fired units at Plant Yates.

Q. WHAT CAN WE LEARN FROM GEORGIA POWER COMPANY EXPANSION PLANS IN THIS 2023 IRP UPDATE, PARTICULARLY THOSE CASES WITH UNPROVEN CARBON CAPTURE?

A. In Document Filing #216658, Supplemental Filing Errata dated 12-7-2023, GPC provides only six (6) capacity expansion plans out of the 14 portfolios evaluated in the 2022 IRP. Three of these capacity expansion plans (MG0, LG0, HG0) include a $0 CO2 price while varying the wholesale price of gas, which significantly favors selection of gas-fired resources by shifting costs onto GPC customers. As a result, these three portfolios heavily select 8 to 11 GWs of new gas-fired capacity by 2036. These same three portfolios include 1 to 2 GWs of brand new nuclear beginning in 2035, which is impossible for several reasons.[1] In

[1] NuScale was the top contender for a First-Of-A-Kind Small Modular Reactor to achieve commercial status until it withdrew its project in November 2023. NuScale had planned to develop a six-reactor 462 MW project in Utah with a COD in 2030, but partners began to pull out of the project as estimated costs rose from $58/MWh to $89/MWh. Compare this cost to the GA PSC Commission estimate for Vogtle Units

the next two capacity expansion plans (MG20, MG50), GPC clings to its gas-fired capacity by conjuring up Carbon Capture and Sequestration (CCS). GPC only has to look to their affiliate in Mississippi Power Company and the ruinous disaster that was the Kemper Project to understand that CCS is not a commercial technology with too many failures to count. But we could ask Southern Company, who manages and operates the National Carbon Capture Center south of Birmingham, Alabama. Their website notes they've spent 150,000 testing hours with no commercial CCS project, but there is a DOE funded report[2] that states, "*Our models indicate that our technology can meet the DOE cost targets for carbon capture* ***by 2035****. The technology is flexible to multiple applications including post-combustion carbon capture from industrial sources or direct air capture."* GPC is proposing 4 to 8 GWs of gas-fired combined cycle capacity w/ CCS in 2034. In its response to STF-PIA-10-8 question, "Has the Company evaluated the cost of installing carbon sequestration and storage, hydrogen conversion, or gas dual firing or conversion at any of its existing fossil plants (coal or gas-fired)?" GPC responds, "*Georgia Power has not evaluated the cost of installing carbon sequestration and storage, hydrogen conversion, or gas fuel firing or conversion at any of the Company's existing fossil plants (coal or gas-fired). However, at the direction of counsel, in 2021, Southern Company Services conducted a system level pre-screening analysis related to the installation of carbon sequestration and storage at fossil plants across the system. This is a confidential technical and legal analysis.*" Be that as it may, CCS is not commercial. Then in its response to STF-PIA-10-9 question, "*Has the Company evaluated the cost of installing carbon sequestration and storage, hydrogen conversion, or gas dual firing or conversion at any of its newly proposed fossil plants?"* GPC responds, "*The Company has proposed to construct Plant Yates*

3&4 at $150/MWh. In addition, a COD of 2035 is unrealistic given the 15-year experience at Plant Vogtle. https://www.eenews.net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/

[2] Precision Combustion, Inc., "High-Efficiency Post Combustion Carbon Capture System National Carbon Capture Center Contractor Report," DOE Award Number: DE-SC0017221, issued 2023

Units 8-10 as a new fossil generation resource and submitted the air permit application to the Georgia Environmental Protection Division on December 8, 2023. As a part of the control technology evaluation required in the air permit application, the Company evaluated the feasibility of installing carbon capture and sequestration ("CCS") or low-greenhouse gas ("GHG") hydrogen co-firing for Plant Yates Units 8-10. Although these technologies are not demonstrated nor technically feasible for implementation on simple cycle combustion turbines, the Company nonetheless included an assessment of possible costs using generic and publicly available information. In this evaluation, there were still certain costs that could not be quantified, and no site-specific engineering was completed. ***The control technology evaluation concluded that even the partial costs for CCS or low-GHG hydrogen co-firing are unreasonable for Plant Yates Units 8-10.***" This is GPC itself saying that the Yates CTs will never see CCS technology bolted on, not now, not ever. The Yates CTs are guaranteed to become stranded assets in a rapidly decarbonizing world.

Q. IS GEORGIA POWER COMPANY PROVIDING STRAIGHTFORWARD ANALYSIS OF ITS LOAD GROWTH PROJECTIONS?

A. In STF-DEA-1-5, GPC states that, "G*eorgia Power selected a P95 load value in response to the unprecedented pace of economic development in the state of Georgia and because the Company has seen more increases in large projects interested in the state over the last several months than decreases. The P95 value establishes an upper limit for potential large load outcomes, offering a heightened level of load realization that is expected to benefit all customers and additional capacity resources to accommodate potential load increases in the ongoing economic development pipeline. Considering the uncertainty surrounding future growth, the Company opted for the P95 load value to ensure sufficient capacity to meet the anticipated loads and continue to support economic development in*

Georgia and to benefit all customers." This allows GPC to exaggerate the load growth, helping to justify the capital cost of building new gas-fired generation.

Q. HOW DOES GEORGIA POWER CO. CONSISTENTLY UNDERESTIMATE THE COST OF NATURAL GAS FUEL? A. GPC has a long history of consistently underpricing fuel costs, favoring gas capacity and leaving ratepayers exposed to volatile commodity markets. Back in 2007 GPC said, "*Since the approval of the 2004 IRP, fuel costs are significantly higher. Fuel commodity prices have increased from previous estimates.*"[3] In 2010, GPC said, "*Since the approval of the 2007 IRP, fuel costs have experienced significant volatility. Fuel commodity prices increased to record prices in the summer of 2008 and subsequently declined significantly in 2009. This price volatility highlights the need for fuel diversity to protect customers from fuel price fluctuation.*"[4] In 2013, GPC said, "*The IRP planning process overseen by the Commission has created a versatile fleet that can respond effectively to swings in gas and coal prices, with new nuclear providing low cost energy and greater fuel cost stability than fossil fuels.*"[5] GPC expressed grave concern about the cost of the EPA MATS rule in its interim 2011 IRP Update, but in 2013 was able to eliminate significant uncertainty and select a MATS compliance plan that, "*equates to a savings of several hundred million dollars for customers.*"[6] In its 2016 IRP, GPC moved from MATS to the newest grave concern over the EPA's Clean Power Plan that result in nearly $1.4 billion in higher costs and to compensate GPC for retiring its fossil-fired units.[7] In 2016 with significant Vogtle

[3] Docket #24505, Georgia Power's 2007 Application for Approval of an Integrated Resource Plan, page 1-5

[4] Docket #31081, Georgia Power's 2010 Integrated Resource Plan Main Document, pages 1-7 and 1-8

[5] Docket #36498, Georgia Power's 2013 Application for Approval of an Integrated Resource Plan, page 1-10

[6] Docket #36498, Georgia Power's 2013 Application for Approval of an Integrated Resource Plan, page 1-4

[7] Georgia Power Company: "Using the EPA's assumptions, in 2016-2017 alone, the CPP would, for Georgia Power, result in $830 million in incremental costs related to increased production costs and an insufficient reserve margin, $70 million in additional transmission projects, $485 million to compensate for impacts to

construction delays and cost overruns, GPC continued, "*It is important that nuclear continue to be evaluated as a possible resource option for the future. With the reality of carbon regulation, the Company must continue to be proactive in its consideration of future nuclear as a viable baseload option.*" GPC sought $175 million to pursue even more nuclear power in Stewart County. GPC says, "*Energy efficiency and renewable resources cannot provide a reliable and economic supply of electricity to customers without other resources in place* [note: this is verifiably false]." GPC adds, "***Adding only natural gas-fired resources would result in an over-reliance on a fuel with a history of volatility and which is subject to potential future cost increases driven by regulation, changing market conditions and other factors.***"[8] By 2022, gas-fired generation was back in favor with 2,356 MWs of gas PPAs approved. Now, in 2024, GPC is seeking certification of the Yates CTs. GPC consistently underestimates the cost of fuel in its planning by selecting moderate fuel costs with no environmental compliance costs where external emissions and economic and public health costs remains outside of the analysis, leading to favorable treatment of gas-fired resources.

Q. HOW HAS GEORGIA POWER COMPANY MANIPULATED THE IRP PROCESS IN ITS FAVOR?

A. GPC has a long history of changing the rules of its IRP process to obtain the company's preferred portfolio, but not what is in the public interest. In 2007 GPC asked, "*that the requirement to conduct RFPs be waived in years where the IRP Mix Study identifies baseload nuclear or coal capacity as the most cost effective resource. The 2007 IRP Mix Study selected nuclear as the most cost effective resource in the 2015 and 2016 timeframe. Because the Company is still uncertain as to when next generation nuclear will be available* ***the Company has taken a***

the fuels program and the retirement of over 4,000 MW of fossil-fired units with a current value of over $3.7 billion." Docket #40161, page 1-5

[8] Docket #40161, Georgia Power's 2016 Application for Approval of an Integrated Resource Plan, page 6-77

conservative approach by listing the first new nuclear unit in 2016."[9] The Commission ordered GPC to issue an RFP for capacity and energy resources identified in its 2007 IRP (Docket #25036), which resulted in three PPAs for 1,800 MW of gas-fired facilities, most of which is still under contract today.

Q. HOW IS GEORGIA POWER COMPANY FAILING TO ACCOUNT FOR TAX CREDIT OPPORTUNITIES FROM THE INFLATION REDUCTION ACT?

A. In its response to STF-JKA-2-19-f, GPC states, "*Both the Company's economic analysis and Resource Mix Study assume BESS resources would utilize the ITC. Likewise, both evaluations assume solar resources would utilize the PTC. The economic analysis does not assume domestic content or energy community benefits at commercial operation for the proposed projects given the chosen locations and likely source of materials for construction. However, the BESS augmentations are expected to receive bonus credits for domestic content. The Resource Mix Study assumes either energy community or domestic content benefits will be available for generic renewable or BESS additions. Therefore, the Resource Mix Study assumes those Inflation Reduction Act ("IRA") benefits.*" The problem is that GPC is undercounting the IRA benefits, using only a 40% tax credit for generic renewables or BESS additions when 50% is expected for utility scale solar and storage projects. It is possible for distribution level solar and storage projects to achieve even higher percentages of a project's cost in ITC and other federal benefits provided by the IRA. Moreover, GPC is suppressing the development of new solar and storage resources by not committing to a retirement date of 2028 for its coal units, which would unlock the 10% Energy Community tax credit at critical sites like in and around Plant Bowen, where GPC stated they had critical transmission issues. Plant Bowen is facing significant new capital costs to meet the proposed 2023 ELG Rule, which is a risk GPC is not accounting

[9] Docket #24505, Georgia Power's 2007 Application for Approval of an Integrated Resource Plan, page 1-8

for appropriately. When GPC says, "*The Company remains optimistic about the potential of the IRA to reduce the cost of new renewables for customers,*" they mean they will slow-walk solar and storage deployment for as long as possible.

Q. COULD GPC IDENTIFY SHORT-TERM SOLUTIONS FROM AMONG THE RECENT RFI RESPONDENTS?

A. In STF-DEA-9-2, which notes that GPC stated, "T*here is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027,*" we learn that more than 2,700 MW of resources responded to the RFI and are expected to be available by the end of 2027. The RFI included: Standalone BESS with grid charging capability; BESS with a Renewable Resource with grid charging capability; and gas-fired generation. However, GPC concluded from this RFI that there were no existing resources available for the need years addressed in this IRP. GPC is able to and should tap this pool of resources to address the acute short-term capacity shortage. I urge the Commission to require GPC to allow each of these RFI respondents, and all newcomers, to provide unsolicited proposals that will be assessed from an interconnection standpoint in accordance with FERC Order 2023.[10]

Q. HOW HAS GEORGIAPOWER COMPANY DEMONSTRATED ANTI-COMPETITIVE BEHAVIOR?

A. GPC has a long history of anti-competitive behavior. In particular, GPC intentionally makes it difficult to develop cheap, clean, firm new generation resources in Georgia by obscuring and changing the calculation of system Avoided Cost, which is the cost GPC avoids by not producing for itself an equivalent amount of energy and capacity. PURPA requires electric utilities to purchase the electric energy and capacity made available by these generators at

[10] https://www.ferc.gov/explainer-interconnection-final-rule

just and reasonable rates. However, independent power producers have had difficulty selling energy and capacity to GPC, whether as a PURPA qualifying facility or when trying to secure a Power Purchase Agreement. Last month, a major developer of renewable capacity and energy resources filed a petition before this Commission in Docket #4822 that states, "***At a time when Georgia Power acknowledges its urgent need for new generation capacity, [this developer] urges the Commission to remove unlawful barriers blocking the development of 420 MW of new, clean, affordable power generation that [this developer] stands ready to build and operate.***" This developer has significant solar and storage capacity it could bring online to help meet the acute short-term capacity shortage, but for GPC standing in the way. In the 2022 IRP and again in the 2023 IRP Update, the Incremental Capacity Equivalent (ICE) Factor showed utility scale solar with a 10% winter and 35% summer capacity value (rooftop solar is 5% and 25%, respectively). Solar has non-zero capacity value at all times, yet solar received a 0% capacity credit in the GPC capacity RFP.

When GPC initiated conversations in the marketplace seeking available capacity (see response to STF-JKA-2-19), GPC had, "*initial exploratory conversations in early August 2023 regarding Georgia Power's potential acquisition of additional ownership interests in an existing generation asset within the Southern Company footprint. Following initial discussions and through September 2023, the Company began its due diligence on the assets, scope, risks, and applicable regulatory requirements for the potential acquisition. Between early October 2023 and end of November 2023, the parties engaged in active negotiations regarding the terms and conditions for the proposed asset purchase agreement. However, on November 30, 2023, the parties agreed to suspend negotiations and not move forward with the transaction at this time. As stated in the direct testimony filed on December 4, 2023, the Company is no longer pursuing the potential acquisition of additional ownership interests in an existing generation asset within the Southern Company footprint.*" This was an opportunity that GPC

passed, likely based on faulty assumptions and possible anti-competitive practice, that could have helped to mitigate the acute near-term capacity shortage.

In its response to STF-PIA-9-11 "*What cost threshold would the proposed 200 MW of BESS co-located with 200 MW of new solar facility be held to? Would avoided cost be an appropriate threshold? If so, what avoided scenario (MGO, etc.)? If not, please explain why. Would bids from a recent or future renewable with BESS RFP be an appropriate threshold? If not, please explain why,"* GPC states, "*traditional avoided cost threshold is inappropriate for meeting an identified capacity need. The objective is to meet the identified need at the lowest incremental cost to customers given the capacity options available to the Company at the time. Bids from past or future RFPs do not represent capacity options that are currently available to meet the identified capacity need addressed in the 2023 IRP Update and would therefore be an inappropriate cost threshold as well.*" GPC was completely unsuccessful in its attempt to reach agreement with the bidders of 2023/2024 RFP, reportedly eliminating offers for 1,030 MW of renewable resources that did not pass the economic hurdle of artificially-low Avoided Cost parameter, which has since been relaxed into a best cost analysis in the latest RFP but it was too little, too late to salvage GPC's failing to procure more than half the solar and storage capacity they are required procure from the 2019 IRP, which could have helped to solve this acute near-term capacity shortage. GPC says twice in direct testimony[11] that "*time is of the essence*," but that only applies to building new gas capacity, not to renewable procurements required by the Commission.

Q. CAN YOU PROVIDE ADDITIONAL EXAMPLES OF GPC BEHAVIOR THAT YOU CONSIDER TO BE ANTI-COMPETITIVE.

[11] Document Filing #216591, Direct Testimony, page 24 line 14, page 31 line 9

A. The uncertainty and unfairness of GPC's calculation of Avoided Cost is a major impediment to the development of solar and storage resources in Georgia. By stripping out capacity revenues, by stripping out environmental compliance costs for coal ash into a separate rider, by stripping out nuclear construction costs into another separate rider, and so on, the leftover revenue ascribed to the cost avoided to produce a kWh of energy is not enough to make any project pencil without subsidies. Avoided Cost is difficult to finance in the best of circumstances, but near impossible with GPC's anticompetitive treatment of Avoided Cost.

In its response to STF-GS-1-8, GPC states, "*The Company is proposing a new Curtailable Load program, which will compensate customers for curtailing load during periods of extreme supply and demand conditions. The customer payment will be directly linked to the capacity value provided by the potential demand reduction.*" Why is GPC allowed to discriminate against generators who will receive zero capacity revenue in the Avoided Cost they use to price their PPA price offers, even though these generators will add physical generation capacity to the grid, whereas the newly proposed Curtailable Load program will provide capacity revenues for removing demand. The physical implications for transmission capacity behave similarly and should be treated similarly from a commercial standpoint. This is a way that GPC exhibits anticompetitive business practices.

Q. WHAT ARE THE REASONS THE MG0 CASE IS NOT AN APPROPRIATE REFERECE CASE ON WHICH TO BASE A PREFERRED PORTFOLIO?

A. The 2023 IRP Update cannot use the MG0 results because there is now a non-zero GHG emissions cost called the methane emissions charge beginning in 2024.[12] Any analysis based on a $0 GHG emissions cost is built on flawed, outdated assumptions that are not consistent with current regulatory reality. GPC has once

[12] https://crsreports.congress.gov/product/pdf/R/R47206

again chosen MG0 as its primary case, allowing GPC to ignore the 3 million tons per year of GHG emissions[13] that the Yates CTs will create, year after year with zero environmental compliance cost assigned, leading to the selection of the Yates CTs.

Q. PLEASE DESCRIBE THE RISK TO GPC CUSTOMERS FROM NEW GAS-FIRED GENERATION SUPPLY, INCLUDING STRANDED ASSET RISK, AND PROVIDE EXAMPLES.

A. GPC's plan to build new gas-fired generation capacity creates a broad range of risks of financial impairment for these assets in the near-term and long-term, likely shortening their useful life and putting the assets at risk to retire before project debt is fully amortized. These stranded assets costs are typically passed onto customers as regulatory assets, with little accountability for the utility who took the imprudent decision to build new gas capacity. The multiple financial risks to gas-fired resources are derivative of the regulatory risk, climate risk, fuel price volatility risk, and correlated fuel scarcity risk that all fossil gas resources face today, all of which are risks that are increasing over time. Moreover, these are risks that solar and storage projects do not face.

GPC says they are evaluating emissions abatement technologies for gas-fired CC and CT units such as Carbon Capture and Sequestration (CCS) and hydrogen in order to preserve the future optionality of new gas-fired generation in the face of increasing regulatory and economic pressure. However, it is likely that any retrofitting of gas-fired generating units with carbon emissions control technology like CCS or to co-fire hydrogen will be prohibitively costly to implement, leading to assets at risk of becoming financially stranded and forced to cease operations while still holding debt. This is because CCS is pre-commercial, risky, and a poor choice for abatement technology for the foreseeable future.

[13] See Document Filing #217280, Application for Certification of Yates 8-10, Table 3-3

Several new-build gas-fired generation projects that have been cancelled in favor of battery storage help to further exemplify the risk to TVA. Recently in Q4 2023, Competitive Power Ventures cancelled plans for its 657 MW gas-fired Keasley project in New Jersey[14], and Invenergy cancelled its 639 MW gas-fired Allegheny project in Pennsylvania[15], citing unfavorable economics compared to alternatives like battery storage. Global Energy Monitor reported[16] that in the first half of 2023, plans for 68 gas-fired power projects around the world were cancelled in favor of battery storage, due to unfavorable economics, uncertainty over revenues, fewer expected run hours, etc. These investment decisions align with analysis published by the Rocky Mountain Institute in December 2022 showing that more than 90% of proposed gas plants are outcompeted by cheaper renewable energy, thanks in large part to the IRA[17].

Specifically in this proceeding, GPC appears to use a 40-year book life for accounting purposes. The Yates CTs simply will not be able to recover the plant capital costs, let alone the $79.2 million in transmission improvements required by the Yates CTs[18], which will lead to a stranded asset costs that GPC will request be put into a regulatory asset and added to the rate base together with the original unamortized capital costs from the unpaid for Yates CTs and any additional environmental compliance costs. At a minimum, any gas-fired capacity must be 100% hydrogen-capable, which is currently commercially available from multiple OEMs, in order to preserve future optionality and avoid assets that are guaranteed

[14] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/competitive-power-ventures-pulls-plug-on-657-mw-gas-plant-in-new-jersey-77841585

[15] https://webcache.googleusercontent.com/search?q=cache:iZai_Cx0ETMJ:https://www.post-gazette.com/business/powersource/2023/11/14/invenergy-natural-gas-powerplant-allegheny-energy-center-cancelled/stories/202311130131&hl=en&gl=us

[16] https://www.reuters.com/business/energy/giant-batteries-drain-economics-gas-power-plants-2023-11-21/

[17] https://rmi.org/business-case-for-new-gas-is-shrinking/

[18] STF-DEA-4-1, Table 2

to become stranded. But H_2 is not a silver bullet[19] and represents significant moral hazard for GPC and its affiliates. The Southern Natural Gas Pipeline that delivers fuel to power plants in the Southeast is 50% owned by Southern Company. There is affiliate incentive and profit directly tied to the transport of gas to new-build gas-fired power plants. Southern Company spent $2.27 billion in 2015 on a gas pipeline, which now sells gas to GPC-owned gas-fired power plants. GPC-affiliate company Southern Company Services then provides specialized services, at cost, to Southern Company to market gas to affiliate-owned gas-fired power plants, costing $762 million in 2022 for their expertise in fuel supply services. These intimate commercial arrangements among affiliates and subsidiaries deserve greater regulatory scrutiny.

Q: PLEASE DESCRIBE THE RISK TO GPC FROM RISING FUEL COSTS AND PRICE VOLATILITY.

A: The US natural gas market is experiencing a long-term structural shift towards increased linkage to global markets due primarily to Liquefied Natural Gas (LNG) exports. The US became the top LNG exporting country last year[20] and as much as 30% of US natural gas production will be exported to markets primarily in Asia and Europe by 2030, doubling the percentage of current exports[21]. These LNG exports together with rising pipeline exports to Mexico and Canada will put upward pressure on the cost of natural gas that GPC must purchase for its gas-fired generation fleet. Increasing LNG and pipeline exports will more closely bind the US to the whiplash fluctuations of global markets and extreme weather events, adding to the inherent price volatility of commodities like natural gas. GPC has stated previously that the volatility of natural gas prices becomes a greater risk as gas-fired generation becomes a larger portion of its portfolio. This risk takes a

[19] https://www.canarymedia.com/articles/hydrogen/should-power-plants-burn-clean-hydrogen-to-make-electricity

[20] https://www.eia.gov/todayinenergy/detail.php?id=60582

[21] https://www.eia.gov/todayinenergy/detail.php?id=60944 and other sources

back seat to GPC's proposed plan to build new gas-fired capacity, which will certainly result in greater gas reliance and vulnerability to volatile fossil gas prices. Since GPC passes its fuel costs directly to customers, it is GPC's customers who are forced to bear this unlimited upside risk. This risk was borne out in 2022 when the annual average wholesale natural gas price in the United States was $6.45/MMBtu—or more than double the annual average of the prior 12 years—and GPC fuel costs skyrocketed as a direct result. Moreover, passing fuel costs onto customers invites moral hazard, which is discussed at length by the Southern Alliance for Clean Energy's expert witness Ron Binz before the South Carolina Public Service Commission, "*From the utility's perspective, operating a natural gas plant is not risky because there is no way the utility will collect less than its reasonable and prudently incurred cost for fuel, no matter how much the price changes.*"[22]

Q: IS GEORGIA POWER COMPANY PRUDENTLY ACCOUNTING FOR THE MANY RISKS THAT COME WITH INCREASED GAS-FIRED CAPACITY?

A: GPC is not accounting for the risk of more gas-fired capacity. Currently GPC relies heavily on thermal power plants; adding more gas capacity concentrates and increases the risk. During extreme weather events, which are becoming more common, thermal power plants can see their summer net dependable capacity reduced by 7% or more during period of high summer heat. Thermal plants may experience frozen equipment, involuntary interruptions to natural gas transport, and other winter-related causes for failure to dispatch reliably. Natural gas fuel supply issues are implicated in each of the last five major North American load shed events 2011-2022.

[22] https://cleanenergy.org/wp-content/uploads/South-Carolina-Fuel-Cost-Proceeding-Testimony-for-SACE-Upstate-Forever-SC-Coastal-Conservation-League.pdf

Q. DID GEORGIA POWER COMPANY FOLLOW ANY OF THE RECOMMENDATIONS IN YOUR DIRECT TESTIMONY IN THE 2019 IRP AND 2022 IRP?

A. In my 2019 direct testimony I made several recommendations: triple solar procurements to 3,000 MW; publish a distribution hosting capacity map; accurately model solar and storage as a dispatchable resource; and commit to a clearly articulated roadmap for 100 percent zero carbon system by 2050. The Commission stipulated in 2019 to more than double the GPC-proposed solar capacity. However, GPC only minimally complied with this requirement by issuing its second utility-scale solar RFP 10 days before the 2022 IRP was filed.[23] It went on to fail entirely and zero MWs of solar and storage were procured, to the best of my knowledge. This demonstrates an inability to execute on required obligations in a timely manner and a lack of respect for the Commission's stipulation. In my 2022 direct testimony, I pointed out the many ways in which GPC was steering the outcome of its IRP analysis toward its preferred outcome, providing credible analysis both from me and other experts. I demonstrated with GPC-provided analysis that they were increasing risk by decreasing fuel diversity with 2,356 MW new gas PPAs lasting up to 15 years. GPC failed to address any of the concerns raised and dismissed the direct testimony stating falsely that I did not bring any analysis. In this 2023 IRP Update and in its procurements, GPC continues to unjustly undervalue solar and storage and suppress wholesale market offerings with failed RFPs. GPC has yet to provide a credible plan to reach the 2050 Net Zero Carbon target set by Southern Company, despite GPC modelling out to 2056. GPC is now proposing to build new gas-fired power plants at high risk of cost shift onto GPC residential customers in particular and with no commercial prospects for carbon capture and sequestration.

[23] https://gpcrenew23.accionpower.com/_gpcrenew_2101/calendar.asp

Q. PLEASE PROVIDE A LIST OF PRAGMATIC SOLUTIONS TO THE ACUTE SHORT-TERM CAPACITY SHORTAGE THAT GPC SAYS IS URGENT.

Commissioner Echols said he felt the 2023 IRP update has been rushed and that GPC has not looked at all options to address the acute short-term capacity shortage caused by load growth, and I agree. He said we need creative solutions to meet the extraordinary energy and capacity needs requested by GPC in this 2023 IRP Update. Several options have been suggested, such as exploring Jacksonville Electric Authority's percentage ownership of Vogtle Units 3&4 as noted by SACE. GPC appears to be exploring solar plus storage microgrids with key federal partners in Georgia, which should be expanded to all customers with just and reasonable DER-enabling tariffs. GPC should explore energy and capacity wheeled from MISO into the SOCO tight pool as well as grid enhancing technologies. GPC should target BESS and hybrid projects in the SOCO interconnection queue that have already completed their interconnection studies and can be brought online relatively soon, assigning those projects their correct value when clearly GPC's Avoided Cost calculation is failing to adapt to market conditions. GPC should allow solar and storage projects to be evaluated correctly in the capacity expansion plan, whereas currently they are being modeled in Aurora incorrectly by GPC.

GPC does a disservice to this Commission and to ratepayers by omitting key information from this 2023 IRP Update. For example, this 2023 IRP Update does not review the benefits of residential rooftop customers and their contribution to capacity requirements and system reliability. This 2023 IRP Update omits the fact that there are over 40,800 MWs of solar photovoltaic, standalone storage, and hybrid solar+storage projects currently in the Southern Company Interconnection Queue, and that a substantial percentage of this dispatchable renewable capacity could be brought online in Georgia more quickly if GPC found a need to move

quickly. This 2023 IRP Update fails to acknowledge the tremendous benefit and cost savings to ratepayers that would come from sharing capacity resources with neighboring Balancing Authorities, whether bilaterally or through an organized wholesale capacity market.

Nevertheless, there are many solutions to the acute short-term capacity shortage caused by load growth. These solutions include, but are not limited to, the following **Solutions:**

There are 420 MW AC of solar that are ready to be built by one developer as of last month, but this capacity and energy cannot advance due to "unlawful barriers blocking development" imposed by Georgia Power Company (see Docket #4822). A policy of enabling DERs will lessen the cost and burden of rapid load growth in Georgia by allowing GPC's customers to invest their own money in local, distributed generation that reduces system requirements for both capacity and energy. There is now a large body of evidence to support the safe and reliable operation of bulk electric systems with a large penetration of renewables, including at the distribution level as in California. Other utility IRPs like the TVA IRP that shows Rapid DER Adoption is the least cost and best performing portfolio across five strategies in terms of Present Value of Revenue Requirements (PVRR), lowest total resource cost, least risk-benefit ratio, least risk exposure, lowest CO2 emissions, lowest CO2 intensity, lowest water consumption, lowest waste, and lowest land use, with a favorable flexibility turn down factor and with positive contributions to local employment. Should GPC engineers or management have any questions about managing the increase of intermittent renewables, they can be addressed in collaboration with the US Department of Energy and its national laboratories who offer technical assistance and operational experience.

In response to STF-PIA-3-5, GPC acknowledges that the Thermostat DR program shows a positive Total Resource Cost based on kW demand savings, and this despite lower Avoided Costs that hurt DSM measures. GPC is artificially limiting this program to 50,000 customers or well under 2% of residential customers, when it could expand the program to 2.7 million residential customers. This is a missed opportunity and an example of a concrete action this Commission can authorize to address the acute near-term capacity shortage.

In its response to STF-JKA-6-5, GPC states, "*Yes, the Company could consider an agreement outside of a RFP process for the potential new or planned projects.*" The Commission should require GPC to entertain unsolicited proposals received outside of announced RFPs and RFIs, which would be subject the same rigorous scrutiny for interconnection and other requirements without being burdened by GPC's onerous and time-intensive RFP and RFI solicitation process.
In Document Filing #216375 in Docket #44160, GPC gives its 2023 Q3 figures for Community Solar, which look pitifully small if accurate. GPC reports 0.04% of its residential customers are participating in the Community Solar offering. Clearly, this failure is on GPC's program design, whereas by contrast we have multiple examples of successful Community Solar programs flourishing across the United States.

The Intercompany Interchange Contract (IIC) provides for coordinated planning between the Operating Companies and for the sharing of surpluses and deficits of capacity. GPC could rely on the reserve sharing provision of the IIC, utilizing its affiliates' capacity surplus in Winter of 2026 to eliminate the GPC capacity deficit. See Hearing Request 1-3 for more context. Beginning in Winter of 2027, GPC notes that its need with planning reserve sharing would be slightly less due to another affiliate having a small amount of capacity surplus for Winter of 2027 through Winter of 2040. This capacity is available to Georgia Power customers

through reserve sharing and could, with Commission authorization, be used as a long-term capacity resource to serve the acute near-term capacity shortage.

Grid-Enhancing Technologies are technologies that are commercially available today, are low cost, and increase power grid transmission capacity by 30% or more to directly enable the existing grid to accommodate more renewable energy projects. Examples include Ambient Adjusted Rating devices that measure the power lines temperature, current, and angle in real-time. It allows utilities to implement hourly ratings that change based on the projected ambient temperature every hour instead of just summer and winter ratings and comply with FERC Order 881 as required by 2025. While this docket is focused on supply side resources with a passing glance toward demand side management, there is a direct impact on the cost of the Transmission Planning Study (Docket #25981). In its response to STF-GS-1-7 "*Has the Company evaluated whether the transmission upgrades identified in the Transmission Screening Analysis could be reduced, deferred, or eliminated with the deployment of grid-enhancing technologies including dynamic line ratings, topology optimization, power flow control devices, and similar solutions?*" GPC has not yet filed an update to its transmission planning study in Docket #44160 as of the intervenor testimony filing deadline, but they did respond, "*Due to the timing of the transmission constraints, the most appropriate projects were developed.*" Note that the PIA staff and intervenors asked if grid-enhancing technologies had been considered in the last IRP, and GPC demurred then as well as now. When asked if GPC is considering grid-enhancing technologies, the answer was no, they are considering reconductoring, redispatch, and rebuild but not dynamic line ratings and other grid-enhancing technologies. GPC will not pursue this low cost, commercially available suite of technology solutions known as grid-enhancing technologies that can help to solve the near-term capacity and energy shortfall unless the Commission requires it in this proceeding.

GPC did not discuss in its 2023 IRP Update main document or direct testimony that Plant Franklin is an existing resource that has 712+ MW of winter capacity resources in the short-term capacity need years, which did not participate in the GPC 2022-2028 Capacity RFP and which is owned by GPC's affiliate Alabama Power Company. [24] This existing gas resource was not considered, leading in part to the selection of new gas builds at Plant Yates. Any claim that PPAs are less reliable than GPC-owned assets, which limits PPAs to 30% of load, is much less of a concern than meeting load growth with available assets. Also, many PPAs are with GPC affiliates, raising concerns more about reliability with GPC affiliates and less about the contract structure of a PPA that can be rewritten to fully mitigate any perceived risk.

A program like Hawaii Electric Company (HECO) and their highly successful Battery Bonus program should be the model in Georgia. As noted, Battery Bonus is simple: the utility pays a cash incentive and provides bill credits for customers to add energy storage (a battery) to a new or existing rooftop solar system. All customers receive an $850/kW payment for the battery in exchange for a10-year commitment of capacity that is discharged from the battery for 2 hours during the evening peak. The popular Battery Bonus incentive in Hawaii quickly reached the cap of 3% of total firm capacity, demonstrating a rapid and proven solution to the acute near-term capacity shortage.

In its response to STF-DEA-4-9 GPC states that, "*No, the Company did not evaluate the potential of localized battery storage solutions to mitigate peak loads in the transmission screens filed in the 2023 IRP Update on October 27, 2023.*" GPC must consider localized utility-scale BESS specifically and DERs in general to mitigate transmission screens in the 2023 IRP Update. GPC must look at other hybrid solar and storage configurations including AC-coupled BESS that charge

[24] See DR STF-PIA-6-14-attachment

from the grid, rather than the BESS that GPC says will only charge from solar and not from the grid.

GPC can capture an additional 10% investment tax credit by retiring coal plants and siting new solar and storage facilities in the resulting Energy Communities. By keeping these coal plants running when they are currently uneconomic ***and*** not retiring them, they are putting significant upward pressure on electricity rates.

The US Department of Defense (DOD) is an important ***existing*** customer of GPC and is very supportive of hydrogen gas; they may be willing to pay the premium in order to meet their 2030 decarbonization goals. GPC must listen to its existing customers and work toward meeting their needs, or they will see their customers go to the market as the GSA and DOD are doing to procure 100% clean energy by 2030 for all federal facilities in the wholesale PJM market covering 13 states.[25]

The Commission can exercise its authority and obligation under O.C.G.A. § 46-3A-2 to determine that the GPC 2023 IRP Update fails to demonstrate the economic, environmental, and other benefits to the state and to customers of the utilities associated with the pooling of power, facilities that operate on alternative sources of energy, and energy efficiency; and ordering an independent, objective third-party consulting firm to prepare a new IRP that follows the law.

Q. GIVE AN EXAMPLE OF GEORGIA POWER COMPANY GIVING ASSURANCE OF NO RATE IMPACT WHILE PROVIDING NO SUPPORTING EVIDENCE AND THE RESULTING IMPACT TO CUSTOMER RATES.

[25] https://www.axios.com/2024/02/09/big-federal-purchase-carbon-electricity

A. In its response to STF-DEA-3-6 that asks, "*Provide a forecast of upcoming price increases as a result of the inclusion of Plant Vogtle Units 3 and 4 into rate base as well as the new load acquisitions necessary to serve major new load growth,*" GPC states, "*Plant Vogtle Units 3 and 4…will result in an increase of…$8.95 per month for a typical residential customer…All else being equal, the Company expects that the projected revenues associated with incremental load from known new customer projects, which necessitate the additional capacity requested in the 2023 IRP Update, will fully offset the costs of those resources requested in the 2023 IRP Update and put downward pressure on overall retail rates.*" GPC said the same thing about Vogtle in 2007 and they are still including nuclear in this very IRP Update. Here, in the very same response, GPC exclaims that rates are increasing now, but it won't happen again this time, although it just happened last time. GPC is not held accountable to broken promises.[26] When there is some claw back of revenues, it is much smaller than the increase in unearned revenue GPC receives.[27] Moreover, that still leaves GPC with increased profits from a now-higher authorized ROE that carries well into the future. The result is residential customers' electricity bills climbing at twice the rate of inflation since 2007.

Q. DOES GEORGIA POWER COMPANY'S TRACK RECORD GIVE CONFIDENCE THAT THERE WILL BE NO UPWARD PRESSURE ON RATES?

A. GPC's response to STF-LA-1-11 provides no confidence based on its poor track record of management and its history of flawed analysis favoring gas-fired capacity. GPC maintains its testimony that "***all else being equal, considering the expected load growth and cost of the solutions proposed in this 2023 IRP***

[26] For example, GPC has not accounted anywhere for the risible results from the first full year of its participation on the Southeastern Energy Exchange Market (SEEM). Total first year benefits were only $3.3 million whereas up to $46 million in first year benefits were promised.

[27] The Commission and Staff often point to the $3.5B saved as a result of prudency review in the Vogtle monitoring case. What is not mentioned is that GPC still walks away with $3.4B more in profit than was approved at the time of the Vogtle certification (CPCN) plus GPC receives $3.5B to cover finance costs.

Update, the Company does not expect customer rates to increase." It repeats this again in response to STF-LA-1-16, "*The costs associated with the incremental capacity requested in the 2023 IRP Update, including requests for regulatory asset treatment for certain costs, as well as the retail revenues from the additional load growth that is necessitating the need for this incremental capacity, will impact future rate adjustments for retail customers. Based on the Company's preliminary estimates, all else being equal, the revenues from the additional load growth are expected to exceed the costs of the incremental capacity and put downward pressure on retail rates.*" The risk of authorizing new gas capacity in 2024 is squarely at odds with prudent IRP practice and puts the overwhelming share of risk on the shoulders of GPC customers, not GPC management or corporate shareholders.

Q. WHY ARE THE GEORGIA POWER COMPANY-PROPOSED DER TARIFFS INSUFFICIENT TO ADDRESS THE SHORT-TERM CAPACITY SHORTAGE?

A. In STF-LA-1-10, the data request focuses on Distributed Energy Resource ("DER"). As it relates to tariff DCL-1, on page 43 (lines 1-5) of the Company Direct Testimony, the panel states: "*The participating customer's payment will be calculated as the total cost of the asset less 75% of the net present system value over the life of the asset. This structure (1) ensures all customers will see a benefit based on the discounted system value credited, (2) mitigates the bad debt risk to non-participants, and (3) ensures that participating customers receive resilience benefits.*" The data request is for information on how the discounted system value is derived. In its response to STF-LA-1-10, GPC states, "*The discounted system value was determined using a shared savings model similar to that used to determine DSM incentive levels. We believe the 75% will ensure participating customers receive sufficient incentive to participate in the program while delivering value to non-participating customers. The Company did not*

estimate any bad debt risk associated with the program. Customers will be required to pay for their portion of the asset upfront or over a period of up to 5 years in accordance with the Company's credit policy. At all times the Company will own the asset and the ability to realize the capacity and energy value it provides to the system. Resilience benefits are the ability of the participating customer to continue receiving electric service during a local outage. The value of this resiliency is customer, asset, and location specific. The participating customer will need to quantify the resiliency benefit for their operation. During a local outage, the Company will provide resilience service to the participating customers through the on-site DER. The DER will be monitored at the Company's Operations Center. In addition, the Company will provide preventative maintenance to ensure the DER is appropriately maintained and capable of responding for system or resiliency benefit." This is an overly bureaucratic, complicated, and burdensome DER program that is not likely to be successful, as proposed by GPC. Alternatively, a program like Hawaii Electric Company (HECO) and their highly successful Battery Bonus program[28] should be the model in Georgia. Battery Bonus is simple: the utility pays a cash incentive and provides bill credits for customers to add energy storage (a battery) to a new or existing rooftop solar system. All customers receive an $850/kW payment for the battery in exchange for a10-year commitment of capacity that is discharged from the battery for 2 hours during the evening peak. The popular Battery Bonus incentive quickly reached the cap of 3% of total firm capacity, demonstrating a rapid and proven solution to the acute near-term capacity shortage.

Q. HOW CAN DISTRIBUTED ENERGY RESOURCES HELP TO ADDRESS THE ACUTE SHORT-TERM CAPACITY SHORTAGE CAUSED BY LOAD GROWTH?

[28] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/battery-bonus

A. In a technical brief from the Lawrence Berkeley National Laboratory,[29] they find that an increasing number of states are requiring regulated utilities to file plans that identify distribution system needs, including DERs that can avoid or defer certain types of traditional utility investments cost-effectively. Price-based demand response (DR) is an underutilized resource that could substantially contribute to load flexibility and long-term planning for Georgia's bulk power and distribution systems. "*Table 7 reports the LCOC for price-based DR. Values for TOU rates range from $7/kW-year to $100/kW-year, with the latter being close to the CONE in most areas in the country.* ***This indicates that even the high end of the TOU cost range is most likely cost-effective compared to deploying new generation capacity — especially since CONE does not reflect the incremental cost of transmission.*** *The high-end values are driven by customer marketing and acquisition costs. Unfortunately, the IRPs we studied provided no detail on what these costs entail and why some utilities assume values substantially higher than others do. We compared the LCOC across utilities and rates and determined that load reduction assumptions are the main driver for LCOC. Higher load reduction assumptions typically result in lower costs. Low implementation costs also drive LCOC down.*"

Table 7. Levelized cost of capacity by customer class and rate

Utility ID	Res-TOU	C&I-TOU	Res-CPP	C&I-CPP	Res-VPP	C&I-RTP
1	$80-$100/kW-yr				$33-$59/kW-yr	
2			-$3 to -$8/kW-yr	$81-$86/kW-yr		
3				$22/kW-yr		
4	$16/kW-yr				$10/kW-yr	$8/kW-yr
5	$7/kW-yr	$14 $18/kW-yr				
6	$14-$36/kW-yr	$6-$8/kW-yr				
7				$71/kW-yr		

[29] Lawrence Berkeley National Laboratory, "The use of price-based demand response as a resource in electricity system planning," Juan Pablo Carvallo and Lisa Schwartz, November 2023, see page 13, https://emp.lbl.gov/publications/use-price-based-demand-response

Q. IS GEORGIA POWER COMPANY MARKETING AND OUTREACH FOR DER OPPORTUNITIES SUFFICIENT?

A. In response to STF-PIA-8-4 about whether GPC has coordinated with any Data Center customers to understand how the customer will coordinate rooftop PV and BESS to serve as a resource during periods of peak demand, GPC states, "*As with any new large load customers interested in selecting Georgia Power to provide their electric service, the Company discusses with potential customers the various programs available for Distributed Energy Resource ("DER") assets that can be used as a system resource. In addition, the Company often discusses the benefits and eligibility criteria for potential new large load customers to participate in one or more of Georgia Power's customer renewable programs, such as the Clean and Renewable Energy Subscription ("CARES") Program, the Flex Renewable Energy Credit ("REC") Program, the Retail REC Retirement ("R3") Program, or other renewable program solutions as outlined on Georgia Power's website. For transmission planning purposes, the Company must consider the peak demand of the future load in its analysis.*" GPC's proposed customer-sited DER tariffs are inadequate to garner sufficient interest, and we cannot rely on GPC's lack of analysis, given the critical urgency they express to meet load growth in Georgia.

Q. IN WHOSE INTERESTS IS GEORGIA POWER COMPANY ACTING PRINCIPALLY?

A. GPC is putting its corporate parent shareholders' interests over the interests of Georgia residential customers primarily. In this 2023 IRP Update, GPC proposes a plan that includes 1,400 MWs of new construction gas-fired combustion turbines. There is no consideration of how gas CTs are compatible with the 2050 Net Zero Carbon Target or discussion of the recent $2 billion Fuel Cost Recovery-26 surcharge for natural gas (Docket #44902). There is no mention that new-build gas CTs will enrich GPC's affiliates—all of whom are wholly owned by GPC corporate parent Southern Company save

one—including Southern Power Company, Southern Company Services, Southern Natural Gas Company, and Southern Wholesale Energy, at the significant expense of GPCS ratepaying customers (to their detriment), given lower-cost alternatives that are not being considered in this 2023 IRP Update but are being provided in this testimony as cost effective and pragmatic solutions.

Q. GIVE AN EXAMPLE OF UNDERWHELMING EFFORT FROM GEORGIA POWER COMPANY.

A. GPC has a long history of doing the bare minimum. For example, GPC proposed the Power Credit program in 2007 and by 2019 there were 12 participants out of 2.7 million residential customers. In STF-JKA-6-2, there is a data point on Dispatchable Demand Side Options (DSO) where GPC notes it only assumes 148 MW of DER Customer Programs by 2028, followed by a question of what GPC could do to accelerate the growth of these programs if it would help meet reserve margin requirements? GPC responds saying, "*the Company has developed the two new DER programs (DCO & DCL), both of which should help to accelerate adoption of dispatchable DER. Deploying a DERMS platform will further enable the growth of dispatchable DSOs.*" This disinterest and very low target for Dispatchable DSO is insufficient to the level of alarm that GPC has raised in this 2023 IRP Update regarding the near-term acute capacity shortage.

Q. HOW IS GEORGIA POWER COMPANY REPRESENTING THE NEW-BUILD YATES CTS TO THE COMMISSION?

In the direct testimony page 40 lines 12-17, GPC states, "*To support the timely development of these units, the Company has advanced a reservation fee to the consortium to provide for the procurement of long lead time equipment and required services. These steps help ensure the proposed CT units can be developed in the timeframe needed to support the Company's capacity needs identified in the 2023 IRP Update.*" In STF-LA-1-9-d, the data request is to

"*explain fully and in detail how CT-related development costs that the Company proposes to incur could become not useful or transferable to other projects?*" In its response to STF-LA-1-9 regarding CTs, GPC states, "*Projected amounts of regulatory assets that could occur for CT-related development costs including those associated with the reservation fee that end up not being useful cannot be determined at this time. The Company will take all reasonable steps to recover expenditures and/or maintain the usefulness of equipment and services received.*" GPC is presenting the Yates CTs to the Commission as pre-selected, having already signed a precedent agreement for gas pipeline service possibly from its own pipeline affiliate and also contracted for engineering services with a major EPC contractor and also began procurement with a major turbine OEM, already signed and in effect as of last month, and also signed a Payment for Ecosystem Services agreement for the Yates CTs, and initiated LGIP applications for interconnection request (IR) for the Yates CTs (IC-1166, IC-1167, IC-1168), and even held the IR scoping meeting for Yates CTs six months ago in August 2023, with all this done before the Commission is allowed to review and approve these sunk costs because GPC analysis tells us there is no other choice than the gas-fired Yates CTs.

Moreover, in its response to STF-JKA-2-22, GPC states that, "*construction of the three units will be substantially completed in 32, 37, and 40 months, respectively, assuming a final decision for the 2023 IRP Update is obtained in April 2024.*" The Commission should ask whether the EPC Agreement that GPC executed in January 2024—ahead of Commission review and approval—has a mechanism to deal with current procurement lead times of 38 months for 230 kV breakers, which is the voltage at which the Yates CTs will interconnect to the grid. These 230 kV breakers are in high demand due to offshore wind project projects and utility stockpiling for critical reliability concerns.

Finally, note that in response to STF-JKA-2-2 supplemental filing, GPC states, "*Due to one of the proposed CTs expecting to achieve commercial operation in 2027, rather than 2026, approximately 200 MW of Other BESS were advanced to 2026 to fulfill the resulting projected capacity need for the winter of 2026/2027.*" This demonstrates that GPC can advance the timeline of BESS resources ***if it wants to***, but it chooses not to in favor of gas-fired resources.

Q. WILL INTERIM ERIS CAPACITY LIMIT THE YATES CTS FROM HELPING TO ADDRESS THE ACUTE NEAR-TERM ENERGY SHORTAGE?

A. In response to STF-GS-2-2, GPC states, "the Company plans to designate all 1,350 MW of proposed Plant Yates combustion turbines, and the facility will be limited to 600 MW of firm output until all identified transmission improvements are in-service by summer 2028. The requested energy resource interconnection service (ERIS) does not contribute to or increase the likelihood of transmission constraints or curtailments." GPC then states in STF-GS-2-1 that, "neither ERIS nor NRIS convey any delivery rights or grant any form of firm or non-firm transmission service." But that is only part of the definition in the Open Access Transmission Tariff.[30] GPC leaves out the critical part that ERIS makes one "eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System ***on an as available basis***." The solution GPC proposes to address load growth is to build

[30] Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

the three Yates CTs, even though GPC admits in STF-GS-2-2 that they would only contribute 600 MW to the short-term capacity need identified in this IRP Update, reaching full firm output three years later than needed. The requested service of ERIS will in fact throttle the Yates CTs from helping to address the acute short-term capacity shortage caused by load growth. GPC has stated that BESS resources can be brought online more quickly than gas. Indeed, BESS would have been selected far more often if given fair treatment in GPC's analysis.

Table 3-3. Proposed CT Units: Annual Potential Emissions for Each Fuel

	Potential Emission Rates (Three CTs)[1][2]				
Pollutant	Normal Operation (tpy)	With Startup and Shutdown (tpy)	Normal Operation (tpy)	With Startup and Shutdown (tpy)	Potential to Emit (tpy)
	Natural Gas		Distillate Oil		
NO_X	218.1	293.0	403.5	**504.8**	504.8
CO	190.9	946.2	245.4	**3,013.8**	3,013.8
VOC	61.1	301.9	56.2	**1,041.2**	1,041.2
TSP	37.9	43.6	192.8	**251.0**	251.0
PM_{10} / $PM_{2.5}$	130.3	131.3	264.6	**316.4**	316.4
SO_2	30.4	29.6	28.8	27.4	30.4
H_2SO_4	46.6	45.4	44.0	42.0	46.6
Lead	0.01	0.01	**0.26**	0.25	0.26
GHG (CO_2e)	2,585,053	2,516,687	3,060,060	2,917,477	3,060,060

(1) See **Appendix C** for detailed calculations.
(2) See **Section 6.1.2** for detailed discussion of startup and shutdown emissions.

The flaws in the MG0 case mean all related studies like the transmission study update—which depends on accurate generation dispatch—will be flawed immediately upon delivery by GPC in two weeks. GPC confirms yet another flaw in its response to STF-DEA-8-7 by stating, "*Battery charging studies were not performed as part of the transmission screens filed in the initial IRP Update filing and transmission supplemental filing.*"

Q. ARE BATTERIES BENEFICIAL TO THE GRID?

A. In response to STF-JKA-5-10-b, GPC states, "*Generic BESS resources may be able to provide multiple use cases subject to the availability of transmission and general system conditions. The proposed BESS facilities can provide energy arbitrage benefits and capacity value benefits. During real time operations, the BESS may also be able to provide operating reserve benefits and similar benefits during periods when the adjacent solar resources are not utilizing the interconnection capacity. The Company's economic analysis for BESS resources conservatively assumed only energy arbitrage and capacity value benefits.*" However, when GPC reduces the value stack for BESS to only energy and capacity, this unfairly limits what a BESS is able to provide. GPC now has years of experience with BESS on its system; there are no insurmountable technical barriers to deployment.

Q. WHAT DOES GEORGIA POWER COMPANY SAY ABOUT BATTERY STORAGE AS A SOLUTION TO ITS CAPACITY SHORTAGE?

A. GPC testified (Direct Testimony, p.37 lines 9-11) that, *"The time to construct BESS is shorter than other types of generation and, therefore, can be more quickly deployed…*" GPC also acknowledged that BESS provide tremendous benefits and value to the grid. However, GPC is proposing that the vast majority of the 6,600 MWs requested will come from fossil generation that will become stranded assets well before the end of their useful life, saddling ratepayers with avoidable debt. Note that half of the load requests are outside the service territory of GPC, per responses to STF-DEA-3-6.

Furthermore, in its response to STF-JKA-4-13-b, GPC states, "T*he Company is confident that the BESS will serve as a reliable and economical solution for the anticipated capacity needs…BESS technology is being demonstrated as a reliable generation option across the world. CAISO and Electric Reliability Council of Texas ("ERCOT") have over 10.4 GW of BESS in operation with another 75 GW*

planned. The ease of installation of BESS, compared to alternative technologies will allow the technology to scale at an unprecedented pace...The Company will utilize tier 1 suppliers for its BESS projects that have a proven track record and a portfolio of gigawatt hours of battery storage deployed. Initial performance testing of the battery will ensure the battery meets required performance standards...With the passing of the IRA, and the significant advancement in battery technology, the economic and reliability proposition for BESS has never been greater for customers." BESS can be deployed more quickly than gas-fired resources, even on brownfield sites.

Q. WHY IS IT IMPRUDENT TO APPROVE THE CERTIFICATION OF YATES 8-10?

A. GPC is presenting the Yates CTs as pre-selected, having already signed a precedent agreement for gas pipeline service possibly from its own pipeline affiliate and also contracted for engineering services with a major EPC contractor and also began procurement with a major turbine OEM, already signed and in effect as of last month, and also signed a Payment for Ecosystem Services agreement for the Yates CTs, and initiated an LGIP application for interconnection request for the Yates CTs, and even held the interconnection scoping meeting for Yates CTs six months ago in August 2023, with all this done before the Commission is allowed to review and approve these sunk costs because GPC analysis tells us there is no other choice than the gas-fired Yates CTs. It is noted that GPC has not deigned fit to respond to the comment: "*It is noted that O.C.G.A § 46-3A-3 lists "Actions prohibited without a certificate of public convenience and necessity" and this includes "enter[ing] into a long-term purchase of electric power" and would infer prohibition of the further step of re-marketing a contracted PPA for two (2) years prior to capacity need. GPC is presenting the PPAs with Mississippi Power Company and Santa Rosa Energy Center LLC as pre-selected and only seeking Commission review after entering*

into the contracts." It is further noted that one day before intervenor testimony is due, GPC sought favorable treatment for imprudently incurred gas development costs in its supplemental update to STF-LA-1-23 stating, "*The Company is requesting regulatory asset treatment for development costs not useful or transferable to other projects in the event the Company's request to develop three simple cycle combustion turbines (CTs) at Plant Yates is denied. The estimated maximum regulatory asset amount, if the project is denied, would equal REDACTED of projected development costs and a REDACTED cancellation cost.*" Note that GPC has a history of pre-selecting projects and poor analysis. GPC was pre-planning for Vogtle Unites 3&4 well before the 2007 IRP, "*Georgia Power Company is actively pursuing the option for deploying advanced nuclear generation at the existing Vogtle plant site. The Company filed an Early Site Permit (ESP) application with the Nuclear Regulatory Commission (NRC) in August of 2006 and anticipates filing an application for a Combined Construction Operating License (COL) in 2008.*"[31] GPC went on to say, "Because of the long lead times and licensing requirements for nuclear plants, Georgia Power must continue to invest to maintain nuclear as a viable option for new base-load capacity. ***If the company does not continue to invest in these initiatives, nuclear will not be a viable option in the 2015/2016 timeframe, and Georgia's citizens will be denied an option that could potentially result in significant savings.***"

Q. PLEASE PROVIDE A CONCLUDING SUMMARY OF YOUR DIRECT TESTIMONY.

A. In my direct testimony, I demonstrate how GPC is using flawed analysis in its application before the Commission to certify the Yates CTs, resulting in an unjust cost shift onto residential ratepayers in particular and an imprudent plan to build new gas-fired generating assets. These new gas plants are at risk of becoming stranded assets whose costs will be further shifted onto residential ratepayers as

[31] Docket #24505, Georgia Power's 2007 Application for Approval of an Integrated Resource Plan, page 6-5

regulatory assets. I also provide many examples of GPC acting anticompetitively in ways that results in fewer choices in the open market. And I provide practical solutions to help GPC meet the acute near-term capacity shortage due to load growth. I urge the Commission to reject this *ex post facto* Yates CT application due to its flawed 2023 IRP Update analysis and pre-determined outcomes, and to require GPC remove its own barriers to high-value solar and storage projects that are ubiquitous in its modeling, operations, contracting, and planning practices.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

VERIFICATION

The undersigned, Peter Hubbard, affirms on this 15th of February, 2024 under the penalties of perjury that the answers in the foregoing Direct Testimony in Georgia Power Company's 2023 Integrated Resource Plan Update and Application for Certification of Plant Yates Units 8-10 (Docket #55378) before the Georgia Public Service Commission are true to the best of his knowledge, information, and belief.

Peter Hubbard 2-15-24

Peter Hubbard

Georgia Center for Energy Solutions

On 2/15/24, Peter Hubbard personally appeared before me and presented a valid GADL as proof of identity.

Chandler Daniel Notary.

My notarial commission expires 12/5/26.

CHANDLER DANIEL NOTARY PUBLIC DEKALB COUNTY, GA Exp: 12/05/2026

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing Direct Testimony on behalf of the Georgia Center for Energy Solutions in Georgia Power Company's 2023 Integrated Resource Plan Update and Application for Certification of Plant Yates Units 8-10 (Docket #55378) upon all parties listed below via electronic service and addressed as follows:

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This 15th day of February 2024.

2-15-24

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On 2/15/24, Peter Hubbard personally appeared before me and presented a valid GADL as proof of identity.

Chandler D. Notary.
My commission expires 12/5/26.

CHANDLER DANIEL NOTARY PUBLIC Exp. 12/05/2026 DEKALB COUNTY, GA

BY MR. SHERRIER:

Q Mr. Hubbard, did you prepare a summary of your testimony?

A I did.

MR. SHERRIER: Mr. Chairman, with your permission, I'd like to ask Mr. Hubbard to read his summary.

CHAIRMAN SHAW: Okay. Go ahead.

MR. HUBBARD: Thank you very much, Commissioners and Chairman for your time and for your careful scrutiny of this 2023 IRP Update.

My name is Peter Hubbard and I'm an expert in IRPs and in power project development. I have an answer to almost every good question that you have raised in this hearing, Commissioners. But in my testimony I demonstrate using Georgia Power Company's words and analysis that if this imprudent plan to build the Yates CTs is approved, it will result in an unjust cost shift onto ratepayers, especially residential customers.

Why? It's because the risk is heavily asymmetric. If staff is wrong, then Georgia Power Company doesn't make as much profit. If the company is wrong, customers foot the bill.

New gas plants are today more expensive to

build and operate than battery-and-storage projects. The Yates CTs are at high risk of becoming stranded assets, meaning they suffer premature write-downs and those reliabilities are converted to regulatory assets and cost-shifted onto residential ratepayers and other customers.

This is exactly what Georgia Power Company is proposing to do right now with its late appeal to this Commission to treat the imprudent costs for developing the Yates CTs as regulatory assets should they not be approved.

To be clear, Georgia Power Company only saw fit to put these imprudent and unjustified costs for the Yates CTs' development before this Commission for authorization only after it had spent $250 million.

In my testimony I provide several examples of how Georgia Power Company behaves in ways that are anticompetitive, that result in fewer choices in the market, and thus higher prices for ratepayers. I demonstrate how Georgia Power Company manipulates the IRP process to their desired outcome, as they have in IRPs going back to at least 2007, as I've reviewed.

And, finally, and importantly, I provide practical and low-cost solutions to help Georgia

Power Company and this Commission to meet load growth without building new gas-fired plants -- units at -- at Plant Yates.

I give many specific examples. But first I'd like to just tic through a few of the reasons why this IRP, like many others, has been manipulated to arrive at Georgia Power Company's preferred outcome.

Number one, carbon capture. This IRP assumes carbon capture will not only be commercially viable, but up to 8000 megawatts could be installed and operating on their system ten years from now. This is not grounded in reality this assumption.

From their own testimony, they say all these -- quote: Although these technologies are not demonstrated, nor technically feasible for implementation on simple cycle combustion turbines, the company never -- nonetheless included an assessment of possible costs, end quote.

They then go on to say that carbon capture is unreasonable for Plant Yates Units 8 and 10. That will leave these units exposed to emissions compliance costs at higher risk and be at higher risk of becoming stranded assets.

Number two, emissions costs. This IRP assumes that there is a zero cost today for using fossil

gas, an emissions charge related to fossil gas. This is not reality, once again. There is already a methane emissions charge resulting from the Inflation Reduction Act that is in place in 2024 that adds $900 a ton, growing to $1,500 a ton in two years. So this assumption is one of the flaws in the IRP.

Number three, load growth. This has already been covered in detail, but I would just note that Mr. Marzo has mentioned a number of times that this is unprecedented load growth. If you look at staff DEA-3-12, you will see going back to the 2007, 2010, 2013 IRP that the load growth predicted today -- predicted then is higher than what they are predicting right now.

I have a demonstrative exhibit. That's a tough thing to take in. I didn't have time to submit it. Happy to leave that with you.

Number four, the expensive cost of gas. Georgia Power Company said just a few IRP cycles ago, quote: Adding only natural gas-fired resources would result in an overreliance on a fuel with a history of volatility and which is subject to potential future cost increases driven by regulation, changing market conditions, and other

factors, end quote. They went on to then lock in 2400 megawatts of gas and now nearly 1600 megawatts of gas in this IRP.

Number five, the Inflation Reduction Act is heavily undervalued in this IRP. A number of other witnesses have talked to that. I don't need to go into it.

I will just say that they are undercounting how much can be unlocked, especially if we retire Plant Bowen and Plant Scherer. That opens up energy community and economic development in those areas with that 10 percent bonus tax credit.

The PPA from Mississippi Power is scraping the bottom of the barrel. That's the shorthand way to say that.

And, number seven, the Yates CTs. Georgia Power Company has already spent $250 million without any approval from this Commission. They've already signed a precedent agreement for gas pipeline service, possibly from its own pipeline affiliate, and also contracted for engineering services with a major EPC contractor, and also began procurement with a major turbine OEM already signed and in effect as of last month, or two months ago now. And also signed a payment for ecosystem services

agreement for the Yates CTs and initiated interconnection applications for the Yates CTs and has already held the scoping meeting for these. All of this before asking for your permission.

All of these actions and costs were made imprudently before allowing your review. So those are some of the flaws. There's many more in the testimony --

VICE-CHAIRMAN ECHOLS: Actually, I mean, everything changed in 1991 regarding that. I mean, before '91, that's how they did business; right?

And they would come to this Commission and -- you know, and seek recovery and, you know, the Commission wasn't obligated to give it. Now, you know, if we -- if we certify it, you know, we are obligated to give it, assuming it's prudent.

So they're -- you know, they're doing this, you know, at their own -- you know, at their own peril possibly. But maybe not, depending on what the Commissioners decide.

So I think it's a risk -- it's a risk they're taking, but I don't -- you know, I don't really see it as -- you know, as something where they're, you know, breaking the law, or, you know, as -- as drastic as you're -- as you're describing it.

MR. HUBBARD: I wish I had the official code of Georgia as annotated in front of me to give you that. I put it in my application for leave to intervene.

I think you're right, as well, there. It does say -- and this was specifically about the PPAs. They need to be approved before that's come. And maybe that's happened. I -- I'm not aware of that. And it is a risk.

But what I'm saying is that Georgia Power Company -- setting aside the law, they're presenting this as a fait accompli. It's a -- as a done and dusted deal. The money is invested. This is the path that we have to go down and the alternatives just don't make sense.

They haven't investigated the alternatives. That's, I think, what's been mentioned many times by other intervenors here and expert witnesses.

So it is a risk, but my understanding is that they need to come to you for authorization. And I haven't seen that done yet. $250 million in the hole and they're already asking for that to be treated as a regulatory asset, shifted onto ratepayers if this isn't deemed prudent.

VICE-CHAIRMAN ECHOLS: I mean, the -- you know,

one of the Scherer units was going to Florida because of -- because this Commission didn't give them recovery on it. So they sold it somewhere else. And for the life of the unit, it went to Florida.

So, I mean, it's -- you know, they have options if we don't -- you know, if we don't do this. But I mean --

MR. HUBBARD: I --

VICE-CHAIRMAN ECHOLS: Clearly that's why we're here to discuss it. And I guess they felt like time was of the essence and so they -- they made a calculated decision. And we'll see -- see what our Commission decides.

MR. HUBBARD: I do agree there is a breathless urgency and exigency to their request. It's why we're all here today expending our time and energy on an IRP that didn't need to take place.

But let me just get to the solutions, if I may, just very briefly. I know this has gone on for a moment.

The battlefield is littered with the carnage of Georgia Power Company's anti-competitiveness. So last month -- sorry, two months ago now, in January, a developer of renewable capacity and energy

resources filed a petition before this Commission saying, quote: At a time when Georgia Power Company acknowledges its urgent need for new generation capacity, this developer urges the Commission to remove unlawful barriers blocking the development of 420 megawatts of new, clean, affordable power generation that this developer stands ready to build and operate, unquote.

There's also the failed negotiations from acquiring an additional ownership interest in existing generation asset within the Southern Company footprint. There's also the failed 1030 megawatts from the 2023-'24 RFP that this Commission mandated the company go out and acquire after the 2019 IRP and they failed to do so.

I understand changing market conditions. I'm happy to answer questions about that.

The battery bonus program, I want to spend just a tiny moment on that. That is a demand-resource option that is implemented in numerous places. You'll hear another expert witness talk about it.

But at Hawaii Electric Company what they do is they pay customers who have solar or would like to put solar in their house to install the battery. And they pay them for that and then the company can

pull on that battery for two hours -- a two-hour commitment during peak for 10 years. And that has shaved off 3 percent of peak load in Hawaii's that -- and that balancing area. That's a solution that could be implemented right now.

The thermostat DR program is a great program and should be expanded far beyond 25,000.

Grid enhancing technologies. There are so many solutions on the table that Georgia Power is simply not considering by using one base case with flawed assumptions to come to the conclusions that they were looking for.

So, in conclusion, Georgia Power Company is gaslighting the public, gaslighting its customers, and gaslighting this Commission into thinking that gas-fired power plants are the answer to their failure to see load growth less than two years into the future, which is why we are all here.

I'll leave it there and happy to answer any questions you may have.

CHAIRMAN SHAW: Mr. Sherrier.

MR. SHERRIER: He's -- he's available for questions and cross.

CHAIRMAN SHAW: Any questions from Commissioners?

COMMISSIONER PRIDEMORE: I do. I do.

MR. HUBBARD: Too poor to hire a lawyer.

CHAIRMAN SHAW: Go ahead.

COMMISSIONER PRIDEMORE: I do.

Have you made a copy of your member roster available to this Commission, Mr. Hubbard?

MR. HUBBARD: No, I have not.

COMMISSIONER PRIDEMORE: Why not?

MR. HUBBARD: I'm happy to do so. I just haven't been requested.

COMMISSIONER PRIDEMORE: For the record, who are your members?

MR. HUBBARD: I'm happy to share that with you.

COMMISSIONER PRIDEMORE: You cannot share them today with us?

MR. HUBBARD: No, I cannot.

COMMISSIONER PRIDEMORE: How many members do you have?

MR. HUBBARD: Twenty-six.

COMMISSIONER PRIDEMORE: Okay. And you don't know who they are?

MR. HUBBARD: I do know who they are. I need to ask their permission if I can reveal their names.

I'm happy to do so under an NDA, if you would like.

COMMISSIONER PRIDEMORE: So you're testifying here for people that wish to be confidential --

MR. HUBBARD: Yes.

COMMISSIONER PRIDEMORE: -- and not transparent --

MR. HUBBARD: Yes.

COMMISSIONER PRIDEMORE: -- about whom they are?

MR. HUBBARD: Yes.

COMMISSIONER PRIDEMORE: Hmm. Okay. Why would this Commission give credence to people that don't want to state who they are and what they want from government?

MR. HUBBARD: Because I'm representing them and representing the 2.3 million residential customers who I have not seen have representation. And here's why. Residential --

COMMISSIONER PRIDEMORE: Mr. Hubbard, I'm going to stop you right there. The five members of this Commission are elected by the voters of Georgia and we're their representation, first.

Second, Mr. Chairman, I want to make it a hearing request that Mr. Hubbard provide to this Commission the list of his 26 members.

And if he cannot for confidential reasons, then

I -- we need a legal definition as to why he cannot.

CHAIRMAN SHAW: Very well.

COMMISSIONER PRIDEMORE: You mentioned in your prefiled testimony that you have 15 years' experience in IRP planning and in energy markets. But, yet, you do not list who your previous employers are or how you got said experience.

How did you get that experience?

MR. HUBBARD: I've worked for a number of years at -- let's see. I'm happy to provide that resume as an exhibit.

It's been provided in past IRPs. That's why I didn't provide it this time. I'm happy to also submit it as an exhibit.

But to answer your question, Siemens, Energy Business Advisory, AFRY Management Consulting. And -- and I also have private experience as a developer, as well.

COMMISSIONER PRIDEMORE: Okay. So you worked for Siemens?

MR. HUBBARD: Yes.

COMMISSIONER PRIDEMORE: Okay. All right. Good. Very good.

Well, thank you for being here. Appreciate that.

MR. HUBBARD: Thank you.

CHAIRMAN SHAW: Any other questions?

(No response.)

CHAIRMAN SHAW: Mr. Hubbard, I'll -- I'm going to let you -- I'm going to excuse you, but you'll remain under oath and we'll -- we'll pick back up. We'll begin cross.

But we're going to stop right there and we're going to just move on to our public witness and comment period this morning. I will remind everyone that -- you have the sheet, Sallie?

Just want to remind everyone, we are kind of on a time crunch today. So we're going to try our best to stick to our three-minute rule. Let's see how many we've got.

MS. TURNER: Sixteen.

CHAIRMAN SHAW: I don't -- I don't think we've got -- we don't have as many as yesterday. So I don't think we'll have to waive the one-hour rule today, but we're going to go down the list and -- and begin that.

So, first of all, I'd just like to thank everyone for taking the time to come down to the Commission or come up to the Commission this morning, especially on this rainy day. And we -- we

value your comments and we appreciate each and every one of them.

And we also value the -- I don't even know how to put a number on it. But hundreds and thousands of letters that we've received and public comments that are provided in writing. And I've -- I just had a couple that I wanted to highlight because I had a couple of letters in the last -- or we had a couple of letters just recently from a couple of retired generals that are very -- that have close ties to Robins Air Force Base in support of the battery energy storage system proposals in the docket. So I just wanted to acknowledge those, as well.

We're going to start. When I call your name, I'm going to call your name and then I'll go ahead and call the name of the person that's on deck so that you'll be ready. And we'll go ahead and get started.

Craig -- and if I pronounce a name wrong, please -- please just restate your name when you get up there because some of these are hard to -- harder to read.

Craig Hofmeister. And next is Marianne Celano, Celano.

Good morning.

MR. HOFMEISTER: Good morning. Well, my name is Craig Hofmeister. I'm a physician and live in DeKalb County. You're holding a hearing for proposed increase fossil fuel use by 30 percent. I'm gravely concerned about this from the perspective of a cancer doctor. The burning fossil fuels is not safe because it leads to climate change, air pollution, and exposure to carcinogens, which increase your risk for cancer.

I work at Emory University focused on patients with leukemia, lymphoma, myeloma. I'm a member of Georgia Clinicians for Climate Action.

None of you will ever want to be patients in my clinic. My patients more often than not present with fractures, anemia and kidney failure from multiple myeloma. Their lives have taken an unexpected hard turn and they expect to die of their cancer. Preventing the suffering is important and you all can do your part right now by decreasing, rather than increasing, fossil fuel use.

Let me tell you how fossil fuel use creates carcinogens. Even after coal mines are retired, waste from prior coal use continues to poison the state. Georgia utilities operate 24 federally

regulated coal ash ponds and landfills located predominantly close to low-income communities and communities of color, containing nearly 87 million cubic yards of toxic waste. At all but one of these Georgia plants, the groundwater is contaminated above federal and state safe standards.

Current and future fossil use consumption brought to the state via methane gas-filled pipelines lead to environmental pollution, including air and water contamination, which are known risk factors for cancer. Air pollution includes particulate matter, nitrogen oxide, sulfur dioxide, for which long-term exposure increases the risk of lung cancer, one of the leading causes of cancer death in the state of Georgia. Leakage or spills from pipelines and the use of benzene contaminate groundwater and increase the risk of leukemia.

Finally, workers in the fossil fuel industry are exposed to benzene and polycyclic aromatic hydrocarbons, which can increase the risk of lung cancer, mesothelioma, and leukemia.

You might respond that we should only be considering the health of Georgians and ignore the consequences of fossil fuel extraction in other states. This callous view ignores the doubling of

the risk of leukemia for children that near -- that live near unconventional oil and gas development wells.

I just visited an area along the Mississippi River between Baton Rouge and New Orleans where there's a high concentration of petrochemical plants releasing pollutants into the air and water. While I was there, the water didn't taste right, the air didn't smell right, and the fire from industrial combustion was visible for miles. And the rate of cancer is so high that the area has been dubbed "Cancer Alley."

I'm shocked as a cancer doctor we would even consider new fossil fuel infrastructure because we know that the extraction and burning of fossil fuels contributes to preventable cancer diagnoses. Cancer is, in fact, the second leading cause of death in Georgia. And pollution and contamination from the fossil fuel industry increases the cancer risk for all of this in the room. The only safe prescription for health of all Georgians is clean renewable energy.

Sorry I'm over time. Thank you.

CHAIRMAN SHAW: Oh, you're fine. Thank you, Doctor.

All right. Marianne Celano. And up next is Anne Mellinger-Birdsong.

MS. CELANO: Good morning, Commissioners.

CHAIRMAN SHAW: Good morning.

COMMISSIONER PRIDEMORE: Good morning.

MS. CELANO: My name is Dr. Marianne Celano. I am a DeKalb County resident and a board-certified couple and family psychologist.

I primarily work with kids and families who struggle, kids who struggle with anxiety and behavior problems, and a few of my patients have brought up their worries about climate change. Many have shared their fears about climate-related disasters, such as intense storms or heat waves.

In fact, research shows that many kids worry about climate change, perceive the future as frightening, and see -- and feel betrayed by what they perceive to be inadequate government response. Children will bear more of the burdens of a warming climate and for a longer time than adults.

And climate change is on the news. Kids hear about it more and more and they have questions. But how -- will climate change affect us? How will it affect animals? If scientists and leaders have known about climate change for a long time, why

haven't the adults done what it takes to prevent the planet from heating up?

It is because of these questions that I decided to write a picture book about climate change for young children with my friend Marietta Collins, who works at Morehouse School of Medicine.

"Something Happened to Our Planet" features a child who's worried about the climate crisis, but doesn't know what to do about it. After talking with her family, she and her friends come up with some ideas, such as planting trees and getting their school to switch from styrofoam disposable lunch trays to reusable lunch trays.

We wrote the story to provide a positive narrative for how children can channel their climate anxiety into collective action. We want both children and adults to do this, to channel their anxiety this way. After all, research shows that active coping, particularly with the support of others, fosters hope for kids and adults with climate anxiety.

In our readers note at the back, we also encourage adults to take collective action to push for clean energy infrastructure at the federal, state, and community level. That is why I'm here

today.

I am just one healthcare provider, but I now have a platform. We read this book to hundreds of kids in schools across Georgia. We're going to do it again this spring. We're reading it in churches, synagogues, book festivals, my coauthor's sorority events. I now have a platform and I intend to use it.

Georgia Power should not prolong or increase our dependence on fossil fuels. As elected PSC members, I urge you to consider Georgia's most vulnerable members, its children. The only safe prescription for health of all Georgians is clean renewable energy.

Thank you.

CHAIRMAN SHAW: Thank you, Doctor. Anne Mellinger-Birdsong, followed by John Duke.

Good morning.

MS. MELLINGER-BIRDSONG: Good morning. My name is Anne Mellinger-Birdsong. I'm a pediatrician and I live in DeKalb County. Methane, also called natural gas, is a fossil fuel and it is known to release many air pollutants and greenhouse gases into the air, some of which are known carcinogens. The pollutants include nitrogen dioxide, ozone,

sulfur dioxide, and particulate matter and VOCs or volatile organic compounds.

Children's health is more affected by air pollution because they are still growing, their organs, especially their lungs, are still developing, and because they breathe more air for their size than adults. Eighty percent of our lungs form after birth.

Children who grow up with more air pollution have 10 to 12 percent smaller lung volume and are more likely to develop asthma. Children with asthma who breathe more air pollution are more likely to have asthma attacks and to need more asthma medicine.

Children who live near fracking sites have double the rate of childhood leukemia. When we use methane gas, we are affecting the health of children who live near the wellheads. Gas pipelines explode, killing people and burning houses. And gas pipelines and compressants -- compressor stations leak methane and carcinogenic air pollution into the air.

I'm also talking about coal. Coal has significant effects on children's health. When coal plants close, there are 20 to 25 percent fewer

preterm births in communities close to the coal plant. When coal plants close, there are 66 percent fewer two-years-olds with developmental delay in communities close to the coal plant. Children who live near coal plants have higher rates of ADHD, anxiety, and social problems.

The PSC needs to think again about what is safe. Is it just that the electrical wires don't fall down or cause fires or explosion?

Is a power source that causes developmental delay, asthma attacks, damaged lung growth, and leukemia safe?

Can we live with ourselves knowing that we are causing this amount of harm to children?

In summary, this IRP request to build more methane gas units and continuing to use coal power plants is not financially wise and it hurts the health of children in Georgia and in other states. Burning coal, gas, oil, and biomass is not safe for Georgians. The only safe prescription for health of Georgians is clean renewable energy.

Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

John Duke, followed by Claire Wilkinson.

Good to see you again, Mr. Duke.

MR. DUKE: All right. Thank you.

First of all, I want to say that I care about each of you on the PSC and that none of this is personal. It is pure hubris to build more fossil fuel infrastructure as though you don't see the elephant in the room.

Let me give you the definition of hubris: Dangerous overconfidence and complacency. These 2050 goals of going to clean energy don't mean anything in practicality. It is just green washing to continue the delay -- the transition away from fossil fuels. It is a retreat from your position because denial of the calamity that humanity faces can no longer be denied.

I'm pretty sure your staff knows all of this and what I'm about to say. They already know the cheapest ways to make electricity. The price of solar panels and batteries continue to fall. For example, batteries will go below a hundred dollars per kilowatt hour and then the dam will break, so to speak.

Texas already has 3.2 gigawatts of battery capacity and are adding 2500 megawatts per year of the equivalency of two Vogtle nuclear reactors per year. It saved their ass during the heat wave last

summer.

Here's a quote from the Wall Street Journal: In Texas, which saw ten power demand records this summer, batteries have helped narrowly evade rolling outages.

Here is reporting from the state of South Australia: South Australia is again showing global leadership in the energy transition, bringing its net 100 percent renewables capacity target forward from 2030 to 202- -- 2027. And this is just the beginning. The state's transmission company ElectraNet says it's receiving unprecedented interest in new demand driven by electrification, new and expanding mining operations, industrial loads, desalination facilities, and energy-intensive operations, such as data centers.

Batteries react faster to peak demand on the grid than any other type of power plant. While natural gas plants can react subhourly, batteries can react on a subminimum basis.

But the answer to variability, however, is not just batteries. It is a system solution, a combination of demand flexibility. Have you thought about implementing variable pricing so that you send the proper signal when demand is high?

Interconnections, overbuilding solar and wind is still cheaper than anything else.

I just want to say, in finality, that just know that we will continue to build the political wheel. Please do not get left behind. The calvary is coming.

The world is transitioning away from digging stuff out of the ground and setting it on fire. And the vast majority of us speaking here are on the right side of history.

Thank you.

CHAIRMAN SHAW: Thank you, Mr. Duke.

Claire Wilkinson, followed by Jack Alperstein.

Good morning.

MS. WILKINSON: Good morning. My name is Claire Wilkinson and I'm currently a master's in public health student studying global epidemiology and pursuing a certificate in climate and health. Here I've gained some insights into how environmental changes intersect with a complex web of ecological and social factors that ultimately impact health outcomes and disease transmission.

I also live in DeKalb County and am deeply concerned about the proposed increase in the burning of fossil fuels due to its negative health effects

on all people. It's been well established that healthy air results in fewer premature babies, fewer asthma attacks, heart attacks, strokes, better mental health, and less dementia.

While the benefits of healthy air are undeniable, it's essential to recognize that ongoing increases in greenhouse gas emissions are undermining these gains. Studies have revealed links between higher exposure to air contaminants due to these emissions and cognitive impairments, with reported effects ranging from impaired neurocognitive development in infancy and childhood to higher rates of cognitive decline and dementia later on in life.

Over a lifetime, these deficits in human capital accrue through over-educational attainment, wages, and productivity, posing significant barriers to societal progress in health, education and economic prosperity. In fact, there have been several recent studies that have shown how worker productivity is also harmed by air pollution and outdoor conditions.

Take, for instance, Georgia Power, which relies on over 700 line workers. Outdoor workers are subject to health problems from these outdoor air

pollution, which has been shown to reduce work output and increase work absences.

Thus, building new power sources that produce pollution not only jeopardizes the health of these essential workers, but also increases Georgia Power's labor costs due to decreased productivity and increased absenteeism. This productivity loss is not included in the levelized cost of energy, so it makes gas even more expensive.

In the grand scheme of things, we find ourselves weighing short-term gains in profit against the enduring generational losses and profound impact on human lives. Overall, the burning of coal, gas, oil, and biomass is not safe for Georgians. The only safe prescription for the health of all Georgians is clean renewable energy.

Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

Jack Alperstein, followed by Bob James.

Good morning.

MR. ALPERSTEIN: Good morning. My name is Jack Alperstein and I live in DeKalb County. I'm also a master's in public health student at Emory University studying environmental health, epidemiology, and climate change. I understand your

job as Public Service Commissioners is to ensure that safe, affordable, and reliable electricity is provided to Georgia residents. I also focus on keeping Georgians safe.

The burning of coal, methane gas, oil, and biomass releases greenhouse gases into our atmosphere. This traps heat inside our planet and warms our world, raising the temperature of the air. The National Oceanic and Atmospheric Administration confirms that a warmer atmosphere can hold more water vapor. And an atmosphere with more water vapor can make more precipitation.

A hotter earth means a wetter one, not a drier one. This is the situation for much of the middle and higher latitudes of earth, which puts Georgia in this wetter zone. This can lead to more severe weather events, hurricanes, and big rain events, which are becoming more frequent and intense.

Yesterday, Westside Atlanta residents filed a lawsuit against the City of Atlanta over sewage and flooding concerns from poorly maintained sewer and stormwater infrastructure. The rains from September 14th, 2023, flooded a historically black neighborhood, as it often does, during an unusually heavy downpour.

This comes 14 years after the catastrophic Atlanta flood of 2009 and the many yearly flooding events for members of Westside Atlanta. I use this -- I use this example to highlight unnecessary hardship from climate change on historically black communities already burdened from the burning of fossil fuels living in areas of high air and soil pollution.

As a response to the lawsuit, a city spokesperson said the city has invested more than $2 billion already in sewer system improvements in an attempt to mitigate a preventable problem. This cost is in addition to insurance price hikes to these residents.

Injuries or fatalities during these events can often be due to drowning. Emergency room visits for gastroenteritis and other infectious waterborne pathogens spike due to the disruption of sewage and water infrastructure and impacts on sanitation and hygiene. This will only add high healthcare costs that could be prevented.

Wouldn't it be cheaper, cleaner, and safer for Georgia residents if we didn't burn fossil fuels that created this problem to begin with?

The elderly, pregnant mothers, and children are

more vulnerable to the -- these gastroenteri- -- intestinal diseases. Their immune systems are compromised, overburdened, or not fully formed in the case of children. Perhaps the Commissioners would be interested in working with Emory's epidemiologists to estimate the disability adjusted life years from the burning of fossil fuels.

The burning of coal, methane, gas, oil, and biomass is not safe for Georgians. The only safe prescription for the health of all Georgians is clean and renewable energy.

Thank you very much.

CHAIRMAN SHAW: Thank you, sir.

VICE-CHAIRMAN ECHOLS: I have a -- I have a question for you. And I'm --

MR. ALPERSTEIN: Sure.

VICE-CHAIRMAN ECHOLS: I'm not being a smart aleck here --

MR. ALPERSTEIN: Sure.

VICE-CHAIRMAN ECHOLS: -- because I love what Emory's done with the solar on the parking decks. And they've appeared here before and seeking a microgrid and they've -- they've done a number of phenomenal projects. I've spoken on that -- on that campus.

MR. ALPERSTEIN: Sure.

VICE-CHAIRMAN ECHOLS: Have you reached out to the administration about their diesel generators behind the hospital, behind all the buildings?

Have you pursued maybe having them take a more --

MR. ALPERSTEIN: Uh-huh.

VICE-CHAIRMAN ECHOLS: -- sustainable option? Because right there under your nose are the generators. They fire them up once a week.

MR. ALPERSTEIN: Sure.

VICE-CHAIRMAN ECHOLS: You're -- you're aware of that?

MR. ALPERSTEIN: We're aware that the healthcare industry as a whole, beyond Emory, and -- is a very wasteful industry. This is not something that me as a public health student is -- am addressing. But I would be happy to reach out to the Emory University hospital and -- and look into that for you.

VICE-CHAIRMAN ECHOLS: Great. Thank you.

MR. ALPERSTEIN: Thank you very much.

CHAIRMAN SHAW: All right. Mr. Bob James, followed by Ronald Dean.

MR. JAMES: Yeah. I'm going to be as brief as

I can. I was here yesterday and you got a thrust of my message about we're not alone.

And I want to express my appreciation to you for allowing me to speak again, as also your support, especially for the Inflation Reduction Act opportunities.

And as I was listening yesterday to the PSC technicians, I was very impressed with the incredible detail that they were saying is needed from Georgia Power. And I would like to add a little bit of a different kind of perspective to this and that's the stewardship role we all have to play, in terms of not just caring for our environment, but for the people in it, which doesn't just include our own limited space.

We need to encourage our -- our voters to consider everybody else on the planet. This is a very important thing and I hope that the -- that the member -- that you will support what the PSC technicians are recommending.

And I look forward to some improvement in the future. So thank you.

CHAIRMAN SHAW: Thank you, Mr. James.

Ronald Dean, followed by Jerry Tokars.

Good morning.

MR. DEAN: Good morning, Mr. Chairman and members of the Commission. Thank you for the opportunity to speak this morning.

My name is Ronnie Dean. I am the president and CEO of SGMC Health. We're an independent, nonprofit, regional referral center based in Valdosta, Georgia. We serve Lowndes, Berrien, and Lanier Counties, operate four hospital campuses, long-term care facilities, a myriad of services, and serve 15 counties in South Georgia.

Through the pandemic, we had the privilege of taking care of Georgians from 49 counties where they could not either be served because of capacity issues or capability issues. We are a large economic engine for South Georgia. We generate a $1 billion economic impact, 3,100 employees or direct contract employees, and spin off 10,000 jobs.

As the leading healthcare provider in the state of Georgia, SGMC Health recognizes the critical importance of addressing the growing energy demands to sustain the extraordinary economic growth our state has experienced. The need for immediate action to provide augmented energy production, coupled with a comprehensive long-term plan is paramount to support the continued prosperity of our

communities. And more important and maybe as important, I should say, the resilience and vital infrastructure of particularly healthcare facilitates.

Georgia's economic growth has resulted in substantial increase in energy consumption. The escalating demand for energy underscores the urgent need for investments in energy infrastructure and production capabilities. Simply put, failure to address these needs risks compromising the reliability and stability of Georgia's electrical grid, posing significant challenges to essential services, including healthcare.

Hospitals, clinics, and medical centers rely heavily on constant, reliable energy to supply power to the life-saving equipment, maintain critical functions, and ensure the safety and well-being of patients. And having experienced the direct impact of Hurricane Idalia and existing on five backup diesel power generators for a period of up to five days, it is -- access to uninterrupted energy cannot be underscored when it comes to taking care of patients, which is the only reason we exist.

In conclusion, I urge policymakers, industry stakeholders, community leaders to prioritize

immediate action to address Georgia's evolving energy needs by investing in robust energy infrastructure and implementing forward-looking strategies. We can safeguard the resilience of healthcare facilities and uphold our commitment to Georgians.

I want to thank you for all you do. You serve a valued purpose in the life of Georgians. And I appreciate the opportunity to address you this morning.

CHAIRMAN SHAW: Thank you, Mr. Dean. Thank you for taking the time to come all the way up from Valdosta. I certainly know that drive a little bit, too.

But I just want to thank you. I've got an uncle that's -- that's sitting in your hospital right now that's been there quite a bit lately. And he's been there a lot -- a while on this visit and all he can talk about is the world-class care that he's receiving from everybody there. It's amazing. So thank you.

And to those that are representing Emory, when you think about battery -- I mean, backup generation, when my daddy was laying there in the heart failure center in -- on April 19th and 20th of

2015, the last thing we were worried about was that back -- that diesel backup. I can promise you, we were just trying to make sure he could get that oxygen.

MR. DEAN: Sure.

CHAIRMAN SHAW: Thank you.

Yes, sir.

MR. TOKARS: Good morning. My name is Jerry Tokars. I'm a resident of Atlanta, Georgia. I'd like to thank you for the opportunity to speak today.

There's a long list of harmful effects, including health and economic losses, of global warming. To minimize these harmful effects, I support the gradual transition to net zero greenhouse gas emissions by 2050.

Net zero by 2050 is both a national goal and has been supported by the Southern Company. Looking at their website, they say: Net zero transition. Southern Company is taking action to meet our goal of net zero green gas emissions by 2050.

Currently, I understand that about 60 percent of power in Georgia is generated from natural gas, coal, and oil. To get from 60 percent, where we are now, to zero by 2050, we will need to reduce fossil

fuels use by about 2.5 percent each year.

We can thank the PSC and the Georgia Power Corporation for moving us in the right direction as Plant Vogtle now contributes substantially to carbon-free electricity. However, if the Georgia Power proposal is approved, power generated by polluting fossil fuels will increase, rather than decrease. This will move us in the wrong direction and put Georgians at increased risk.

Instead, we should supply all new energy needs from clean renewable, carbon-free sources, mostly solar and wind. The PSC should reject the Georgia Power proposal, reevaluate the need for increased power, and ensure that -- that clean energy is used to meet any and all future increased needs. If we need more electrons, let's make them clean electrons.

Thank you for your attention.

CHAIRMAN SHAW: Thank you, Mr. Tokars.

Next is Melisa Griffin, followed by John Shackleton.

MS. GRIFFIN: Good morning, everybody. My name is Melisa Griffin. I have lived in the State of Georgia since 2016 and I currently live in East Cobb. I am a software engineer, but I'm not here to

talk about data centers because no one wants to talk about that.

I am here to speak as a concerned mother. I'm sorry. I'm nervous. You have already heard from multiple physicians about the health effects that fossil fuels can have on the health of children. I have a two-year-old son and I know every mother worries about the health of their child.

I'm sorry.

I believe that we have a responsibility to him and all children to make a world with clean air and safe water. We are at a tipping point of guaranteeing a healthy world for our kids. We must transition away from fossil fuels for this to happen.

I do not care that Georgia Power failed to forecast correctly. It's not a reason to threaten the future of all children. Building more oil and gas plants and not retiring coal plants is not a solution.

We have a chance to make sure Georgia is a healthy and safe place for people to raise families. I cannot personally offer solutions to what -- you know, the load that Georgia Power has said they will need. But I know there are a lot of smart people in

this room and a lot of smart people at Georgia Power that can figure it out.

Please demand that Georgia Power do what is right for the people in this state. I appreciate everybody listening to me.

Sorry for having emotions. Thank you.

CHAIRMAN SHAW: You're fine. Thank you.

John Shackleton, followed by Nancy Jo Kirk.

Good morning.

MR. SHACKLETON: Good morning. My name is John Shackleton. I'm back with a few more words to encourage further efforts to evaluate Georgia Power's requests in Docket 55378.

My passion is learning about climate change, its issues and solutions, and educating others. My wife and I recently purchased a plug-in hybrid vehicle and hope that it will soon be powered by renewable energy and not fossil fuels.

The United States is one of the highest per capita greenhouse emissions in the world. We as an individual state in the country have a moral obligation to change from business as usual, including recognizing that clean energy is cheaper.

Americans are typically shortsighted. Government is called upon to provide direction and

solutions. Social Security evolved because we weren't willing to save for our future. Members of the Public Service Commission are entrusted with our energy future because the public is not knowledgeable enough to make the best choices for themselves.

We hear about all the noble goals from government entities -- entities and corporations about carbon neutrality by 2040, 2050. Much of this is public -- public relations and greenwashing to placate criticisms. Those in power are kicking the can down the road.

Our reality is what we're doing right now and in the immediate future. We see a preview of the games being played in Georgia Power's recent proposal, which features mostly fossil fuels. In my opinion, carbon capture is a fantasy perpetuated by fossil fuel companies to perpetuate their business.

I was encouraged to hear some of the comments yesterday which indicated willingness of the PSC to request more from Georgia Power about their real needs to try to take advantage of the incentives/credits available from the federal government to allow more residential solar that reduces Georgia Power's electric responsibilities.

Educating consumers about tax-favored heat pumps and other energy-saving devices would allow Georgia Power to reduce its electricity increase requests.

Furthermore, most large tech corporations who are demanding electricity for their data centers are on the forefront of striving for smaller carbon footprints and could be encouraged to put solar on their data centers with proper guidance.

The truth is that predictions of our warming planet are coming true and then some. Heat, flooding, drought and other climate phenomena are setting monthly and yearly records. That's before some of the tipping points that could accelerate -- that would accelerate global hotting would kick in.

Decisive and prudent action is called for. That is what Georgians expect of you, our leaders of the PSC. I thank you for making them.

CHAIRMAN SHAW: Thank you. Good to see you again.

Nancy Jo Kirk, followed by Jonathan Roberts.

MS. KIRK: Good morning. My name is Nancy Jo Kirk --

CHAIRMAN SHAW: Good morning.

MS. KIRK: -- and I have been a resident of Cobb County for nearly 60 years. And I -- I retired

from Kennesaw State University in 2021, where I was a senior lecturer in the department of chemistry and biochemistry.

I'm asking you to please deny the request by Georgia Power to substantially increase the supply of electric power generated by fossil fuels. All scientific evidence shows that we must reduce carbon dioxide in the atmosphere. We have only to look at the past and scientifically projected future effects of climate change to -- in the State of Georgia to see why this request must be denied. The lives of Georgians, the economy of the state, and the health of the environment depend on your decision.

It's official. 2023 was the planet's warmest year on record.

You can see why when I taught, I didn't need a microphone. Sorry.

Heat kills. One study, as an example, shows that agricultural workers and construction workers are 35 times and 13 times more likely to die from heat than workers in other industries. Excess heat exacerbates the negative health effects of pollution, which is why we cannot continue to supply Georgia's energy needs using coal and gas.

Pollution kills. In 2023, thick smoke flowing

south from the Canadian wildfires for months decreased the quality of air in Georgia. There is a direct link from climate change to the extraordinary size of these fires.

Georgia lost 80 to 90 percent of its peach crop due to extreme fluctuations in temperature just a year ago. I am a home gardener with blueberries and my home crop has decreased significantly in recent years because of these fluctuations in temperature during flowering, which makes me, and I'm sure you, reason to be sympathetic with professional growers.

Rising sea levels will progressively inundate the coast. The result is decreased property values and increased flood insurance. Plus, we inland citizens play -- pay much of the remediation efforts through our taxes. This is bad for our economy.

I believe the correct response to the request by Georgia Power is to, one, insist on an independent commission to reevaluate the energy needs. Two, require all increased energy be supplied by clean, renewable sources. And, three, follow standard bidding procedures in selecting these sources.

Thank you very much.

CHAIRMAN SHAW: Thank you, ma'am.

Jonathan Roberts, followed by Clare McCarthy.

MR. ROBERTS: Good morning.

CHAIRMAN SHAW: Good morning.

MR. ROBERTS: Thank you for your time.

My name is Jonathan Roberts. I'm an employee of Sultage. We're an independent power producer, develop solar projects, own and operate about 500 megawatt.

I'm here on behalf on the Solar Energy Industries Association. I know some of you, have met in the past, and thank you for your time this morning.

I'm an engineer, a father, and a developer of storage and renewable projects. SEIA asked me to deliver a few remarks. I'll be brief.

The Commission should direct Georgia Power & Light to move away from fossil fuels and meet the new and tremendously growing demand with a diverse mix of renewable energy, including solar, energy storage, wind, hydro. With these resources working together, Georgia Power can meet customer needs affordably in our state and perhaps without the need of PPAs from uneconomic coal plants from Mississippi or, you know, the situation from the -- the PPA in Florida.

Renewable energy is reliable, very low cost. And with the mix of resources, including solar-plus-storage, Georgia Power can meet customer needs around the clock. Already solar and wind are cost competitive with new fossil fuels as demonstrated in IRPs across the country before multiple PSCs.

Already solar and wind are cost competitive and federal support makes renewable energy even more affordable and brings investment to the great State of Georgia. Adding more renewable energy to the mix of Georgia is good for business. With renewables, we don't need to rely on expensive out of-state fuel like from Mississippi and Florida.

Solar can already support a vast number of 5,000 well-paying jobs that are coming to Georgia. I myself moved here from the Chicago area with my family to -- to work in the industry here and have been developing projects here and other states.

With strong leadership from this Commission and foresight to the future, that number can grow. And renewable energy is abundant, creates jobs locally. It creates investment opportunities for the great State of Georgia as we see data centers and companies, like module manufacturers and battery

companies, car companies and so forth all setting up shop here. This is something that those industries want to see, as well, when they're setting up shop to support their operations, whether it's onsite generation or for the general mix of -- of the portfolio that they're looking for. Renewable energy is abundant and it creates jobs.

If we continue to build fossil fuels or prop up uneconomic plants out of state, such as the 750 megawatt from the Mississippi PPA that, you know, the Mississippi Public Service Commission said was uneconomic and ordered its retirement, it risks our future because of climate change. We all know it's real. It's an existential threat. And it's just a long-range plan and Georgia Power must move away from polluting and dangerous fossil fuels and reconsider their IRP.

Georgia Power did not consider the full potential of a mixed portfolio of renewables to meet -- and storage to meet customer needs. And the Commission should require Georgia Power for far more renewable and storage in its mix.

Thank you for your time.

CHAIRMAN SHAW: Thank you, sir.

Clare McCarthy, followed by Lisa Coronado.

MS. McCARTHY: Good morning, Commissioners. My name is Clare McCarthy and I am a graduate student at Emory University. And I've lived in Atlanta for the past several years.

Over my years at Emory, I have sought to learn about my university's energy consumption. I have been told by Emory staff that a huge barrier to Emory is renewable energy and that zero emissions goal is our energy provider itself.

We do face a few on-campus challenges. But even if every single one of those was addressed, we would still be hindered by our provider as about 20 percent of our emissions come from purchased power.

Other schools in other parts of the country can work towards achieving that zero emissions with the support of renewable energy offerings from their energy provider, but schools in Georgia do not have that luxury. It doesn't seem fair that Georgia Power holds so much influence over dictating whether we meet our goals with the demand for renewables from Emory and -- as well as other companies in Georgia is very strong.

But moving away from the Emory situation, I see this current moment as a potential turning point

that could lead us down two different paths. Option one, Georgia Power's request is approved. Fossil -- fossil fuel energy use is expanded in Georgia. Southern Company's net zero transition goal of 2050 becomes immensely more difficult to meet.

Yesterday and today we've been hearing a lot about how fossil fuels and climate change harm human health. To reemphasize, the expansion of fossil fuels exacerbates warming temperatures and air pollutants. This can significantly impact people, like Georgia's farmers, who will be forced to work in increasingly hot temperatures.

Not only does fossil fuel-driven climate change have health impacts, but economic impacts. For instance, agricultural production is already degrading in areas of the country due to flooding and temperature change. And, logistically, fossil fuels are a finite resources. If we choose this option one, we choose to rely on a source of energy that will inevitably run out.

Option two -- I'll be brief -- Georgia Power's request is not approved. Georgia Power decides instead to ramp up renewable production. In this scenario, Georgians experience a cleaner environment and improved physical and mental health compared to

option one. And some of the economic losses of climate change are averted. And our state decides to rely on sources of energy that literally do not run out.

The decision of which path our state pursues is yours. Sure, we can argue that we'll be fine if we continue business as usual for the next few years but that seems not only shortsighted, but selfish. You don't know me, but think of one other young person who is important in your life who will be alive 50 years from now. Do they deserve the same quality of life as you have enjoyed?

Commissioners, the future of our state is in your hands and I truly, truly hope that you will not take this decision lightly.

Thank you.

CHAIRMAN SHAW: Thank you.

Lisa Coronado, followed by -- well, I've got Melisa Griffin on here again, unless there's two.

MS. GRIFFIN: That was an accident. I'm sorry.

CHAIRMAN SHAW: Okay.

All right. Hey, good morning.

MS. CORONADO: Good morning. My name is Lisa Coronado and I'm a resident of DeKalb County.

There is a central question before you right

now: Is it acceptable for Georgia Power to greatly increase its reliance on fossil fuels?

On one side you have a long list of intervening parties saying no. They have data to back their reasoning, strong economic arguments, and they pose alternatives for energy sourcing. You have also heard from dozens of public speakers also saying no.

Physicians and public experts have presented on how fossil fuel use has led to premature deaths, increased asthma and cancer, debilitating anxiety, and more. Students have pointed to the worldwide scientific community's urgent call to rapidly phase down on fossil fuels now to prevent reaching a level of warming that will lead to more frequent and increasingly more devastating extreme weather events.

And on the other side you have Georgia Power, who along -- and Southern Company, who, along with other utilities and fossil fuel companies, has for decades spent vast amounts of money to try to discredit climate scientists and science, even though they knew the arguments were sound. Companies whose main motive is profit for their shareholders and whose actions have brought us to this perilous moment we are in today.

Georgia Power is arguing that they need to increase their fossil fuel energy sourcing now not to keep the lights on, but in order to compete for new customers. It comes down to the five of you and your decision will have state and national and international repercussions.

Grant Georgia Power's request and cities and counties across Georgia won't be able to meet their clean energy goals because the electricity from their monopoly provider will continue to come from dirty, polluting sources. You will set a dangerous precedent for other utility regulators to follow.

If Duke and TVA are also given permission from their regulators to increase their fossil fuel energy sourcing this year, then critical 2035 national greenhouse gas reduction targets for the utility sector would basically be out of reach in 2024. Failing to reach these goals, the U.S. would lose its opportunity to be a world leader. We would lose our ability to influence other countries to take critical climate action.

You are in positions of incredible power and opportunity and responsibility. You really could be super heroes, taking action and setting an example for others to follow that would help those living

now and all future generations. Or you will be recognized as five people who were in the right place at the right time but chose not to take critical action.

Given the enormous climate implications of your decision and the concerns that your constituents have been expressing about this for years, there really should be a climate scientist or a liaison on the PSA -- PSC staff. Since there is not, I have reached out to the Union of Concerned Scientists. They have four scientists well known and respected for their understanding of the climate science and their ability to communicate it, standing by to talk with you. I will pass on their bios and contact info.

Please reach out to them. Please act now. Later really is too late.

CHAIRMAN SHAW: Henry Slack. Good to see you again.

And that's -- that's the end of the list that I have. But if there's anyone else that's come in after the sign-up, we'll -- we'll allow.

MR. SLACK: Yeah. Thank you so much. And it's a pleasure to address y'all again. I will be brief.

First, I just wanted to mention something I

didn't say yesterday. My church installed solar panels on the roof. It's a terrible roof. It faces the wrong direction, too steep an angle, all kinds of things. And, yet, we're getting a 7 percent return on that investment.

This is money we sometimes -- you know, we've stuck it in a safe account and, you know, got 2 percent, 1 1/2 percent over the past few years. So this is -- this is wonderful. And I encourage any and all of you, get your churches, nonprofits, cities, counties to be installing solar because it is a great investment. And I know some of you agree with that.

But someone suggested yesterday that: Well, they may install these, but they won't use these much. And my wife reminded me of my brother's child. Great kid, daddy still pays the bill, and the kid says he wants a Hummer. Yeah, gasoline powered, of course. And he has an unprecedented need for it. A lot of friends out of state.

And -- and my brother says: Well, I don't think he'll drive it that much. And, you know, sometimes -- sometimes it's hard to argue.

But in terms of unprecedented things, just a reminder, Dallas, Texas, was at 95 degrees

Fahrenheit this week, which is very much unprecedented.

So what I'd love for y'all to do is to postpone Georgia Power. Because your excellent staff yesterday gave some wonderful comments on how -- how the -- their request was a little deficient in some matters. And give them the chance to come up with more models and more things so they can answer some of your staff's requests.

That's all. Thank you.

CHAIRMAN SHAW: Thank you.

Were there any others that came in after the sign-up sheet was completed that want to comment before we move forward with the rest of the hearing?

(No response.)

CHAIRMAN SHAW: Okay. Hearing none, thank you again to everyone that took the time to come here today and provide your comments. We appreciate each and every one of them.

I'm -- we're going -- we're going to just kind of take a couple-minute break here long enough to get the room set back up and allow those that -- that did want to choose to -- to head out to do so.

So thank you all again.

(A recess was held from 10:21 a.m. until 10:29 a.m.)

CHAIRMAN SHAW: Okay. We'll go ahead and get started again.

Mr. Hubbard, I'll remind you you're -- you're under oath, though. So thank you for coming back to the witness stand.

Commissioners have asked questions, so we'll move forward with cross, starting with the Georgia Public Service Commission.

MR. THOMAS: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. THOMAS:

Q Mr. Hubbard, O.C.G.A. 46-2-59(e) says: The Commission or hearing officer shall permit only the following persons to intervene: A person who demonstrates a legal property or other interest in the proceeding. In determining whether to prevent -- permit intervention, the hearing officer may consider whether the purpose -- person's interest is adequately represented by other parties and whether the intervention will unduly delay the proceeding or prejudice the rights of other parties, which means part of this Commission is required to consider is whether to allow an intervention is -- is whether that group demonstrates that legal property or other interest in the proceeding and whether those interests are adequately represented by other

parties.

How can the Commission make that type of determination if it doesn't even know who a party's representing?

A I told you that I represent the 2.3 million residential customers that have been getting short shrift, along with the confidential members that I mentioned.

Q Okay. So you -- you represent 26 members and the Commission doesn't know what their interest in the proceeding is; is that correct?

A Their interest is what I'm telling you it is. It's -- it aligns with the 2.3 million residential customers who are not receiving a fair hearing. And that's demonstrated by how rates have gone since the 2007 IRP for residential customers particularly.

That's the concern and that's what I'm here to represent. I don't see that representation. And that's been borne out by the rate increases that have taken place.

Q But just to be clear -- yes or no -- you represent 26 parties. We don't know who they are or what their interest is; is that correct?

A You don't know who they are. I do.

MR. THOMAS: No further questions.

CHAIRMAN SHAW: All right. Thank you.

Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions, Mr. Chairman.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Coalition of Local Government.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

CROSS-EXAMINATION

BY MR. BAKER:

Q Hey, good morning, Mr. Hubbard. Two clarification questions.

Referring to page 11 of your testimony, what can be done to eliminate the uncertainty and unfairness of GPC's calculation of avoided costs, so solar, and storage resources have a level playing field to compete in Georgia?

A Well, there is a -- excuse me -- there's a number of things that are stripped out of the avoided costs. I would say first and foremost are capacity prices.

There's always a future need for capacity. It's always in the future four or five years down the road. That seems to be stripped out of avoided cost.

I would also just argue the -- the artificially low gas prices that are put into that forecast of avoided costs. There's a number of other things that could be done to level the playing field with respect to avoided costs, but those are two of the largest.

Q Okay. All right. And at -- referring to page 17 of your testimony -- prefiled testimony, what do you mean when you stated the GPC should allow solar and storage projects to be evaluated correctly in the capacity expansion plan; whereas, currently they are being modeled in Aurora incorrectly?

Page 17, line 18.

A Sure. Yeah. This is -- I focused on this quite a bit in my 2022 testimony, the IRP there. And I guess what I would say is, you know, I haven't looked at this too closely. In the past I looked at it closely.

But allowing -- so I'm speaking a little bit off the cuff. But 300-megawatt blocks, for example, of capacity being allowed at a time, sure, that's convenient for the modeling and it's done because of the computational, you know, requirements of doing this modeling. Although, they've only really done, it looks like, one case, you know. Or at least used one case -- sorry. They reduced the number of cases that they used. You know, so that's one thing that I would point to.

It's a difficult question to answer because I haven't dived into the Aurora modeling in this IRP. I have not filed to look at the -- the trade secret information. So I haven't had access to their models.

I think that's been a bit of a common refrain,

in fact, is that there isn't enough information to determine. Or the modeling hasn't, you know, been very forthright with respect to that kind of information.

So there's a number of things in the Aurora modeling that I think I could point to. Just off the top of my head, as well, you know, there's -- there's something like two dozen different models that are used. And so the data is being ported back and forth between them and there's all kinds of errors that can be introduced there.

So those are two minor examples. I think there's many more that simply were dismissed by Georgia Power Company in my testimony two years ago, saying I simply didn't provide analysis. There are many examples.

Q Okay. That's -- that's all you remember?

A That's all I remember.

MR. BAKER: Okay. Thank you very much.

MR. HUBBARD: Thank you.

CHAIRMAN SHAW: Thank you.

Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

MR. MAHAN: No questions.

CHAIRMAN SHAW: Department of Defense.

Department of Defense.

(No response.)

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: No questions.

CHAIRMAN SHAW: Any redirect?

(No response.)

CHAIRMAN SHAW: All right. Mr. Hubbard, thank you. You can --

MR. HUBBARD: Thank you.

CHAIRMAN SHAW: You can be excused.

MR. HUBBARD: Thank you very much, Commissioners.

CHAIRMAN SHAW: All right. Georgia Coalition of Local Governments, you can call up your panel.

MS. BROWN: Mr. Chair, with your permission, SCLC will be swearing in our witness.

CHAIRMAN SHAW: Oh, okay. No problem.

MS. WHITFIELD: And just to clarify, Commissioners, we are helping swear in a handful of witnesses today for intervenors who don't have counsel.

CHAIRMAN SHAW: Thank you for doing that.

MS. WHITFIELD: Gentlemen, could you please raise your right hand.

Thereupon,

BLAKE RICHETTA,
ANDREW POSNER,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. WHITFIELD:

Q Could you each state your name for the record.

A (Witness Posner) Andy Posner.

A (Witness Richetta) Blake Richetta.

Q And by whom are you testifying -- or for whom are you testifying today?

A (Witness Posner) Capital Good Fund on behalf of the Georgia Coalition of Local Governments. Sorry.

Q And, Mr. Posner, by whom are you employed?

A (Witness Posner) Capital Good Fund.

Q And, Mr. Richetta, by whom are you employed?

A (Witness Richetta) Sonnen.

Q Okay. On February 15th of this year, did you prefile or cause to be prefiled a trade secret and a public --

MS. WHITFIELD: Or did they enter trade secret?

MS. BROWN: Just public.

BY MS. WHITFIELD:

Q Did you cause -- I'm sorry.

Did you prefile or cause to be prefiled a public disclosure version of 25 pages of direct testimony in question-and-answer format in Docket 55378?

A (Witness Posner) Yes.

A (Witness Richetta) Yes.

Q Do you have any corrections or changes to your prefiled direct testimony at this time?

A (Witness Posner) I do not.

A (Witness Richetta) No.

Q If you were to be asked the same questions that appear in your prefiled testimony today under oath, would your answers be the same?

A (Witness Posner) Yes.

Q (Witness Richetta) Yes.

MS. WHITFIELD: Chair, I move to have the public disclosure version of Mr. Posner and Mr. Richetta's prefiled testimony entered into the record as if given orally from the stand.

CHAIRMAN SHAW: So marked.

Gentlemen, have a seat.

(Whereupon, the prefiled direct testimony of Andrew Posner and Blake Richetta follows:)

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's 2023	**)**	**Docket No. 55378**
Integrated Resource Plan Update	**)**	

DIRECT TESTIMONY OF BLAKE F. RICHETTA AND ANDREW V. POSNER

IN SUPPORT OF

THE GEORGIA COALITION OF LOCAL GOVERNMENTS

February 15, 2024

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES AND BUSINESS ADDRESSES.

A. My name is Blake Richetta, and I am the Chairman and CEO of sonnen, Inc. - Americas. My business address is 1578 Litton Dr, Stone Mountain, GA 30083.

A. My name is Andrew "Andy" Posner, and I am the Founder and CEO of the Capital Good Fund. My business address is 333 Smith Street Providence, RI 02908.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. We are testifying on behalf of the Georgia Coalition of Local Governments.

Q. MR. RICHETTA, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I began my career as a Sales Manager at Lutron Electronics, a leading manufacturer of energy-saving light, shade, and temperature controls. For the first eight years of my career, I was responsible for building the go-to-market strategy and business model for RadioRA, a lighting control system for residential applications. Over the next six years of my career, I assumed a National Sales Manager role focused on developing sales channels, installer programs, and training programs for a successor product, the RadioRA2.

After leaving Lutron in 2016, I joined Tesla as a North American Power Wall sales manager, where I worked for 9 months before becoming the Vice President of Sales for sonnen's US subsidiary. I was in this role for a short time before being promoted to Senior Vice President, then Chairman and CEO about two years later.

In my tenure at sonnen, I have become a recognized pioneer of the residential behind-the-meter energy storage based Virtual Power Plant business model in the United States. Under my leadership, sonnen co-developed the "2019 Utility Project

of the Year" Soleil Lofts apartment community VPP in Herriman Utah (12.6 MWh) with the Wasatch Group and Rocky Mountain Power. Following Soleil, sonnen worked under the leadership of Rocky Mountain Power to develop the national "Peak Load Management Association" award-winning Wattsmart residential and commercial Distributed Battery Grid Management System, currently deployed throughout Utah and Southern Idaho. Wattsmart and Soleil Lofts provide the electric grid with >31MWh of residential and C&I stored energy reservoir – including sonnen and non-sonnen batteries, firmly dispatchable under the direct control of RMP, yielding a full stack of grid services on a daily basis.

Some of my most recent accomplishments include launching the sonnenConnect California VPP, as well as becoming a founding member of the Consumer Battery Energy Sharing or "CBES" VPP program with LUMA in Puerto Rico. In California, sonnenConnect presents a legitimate solution to California's NEM3, featuring the deployment of sonnen's patented Optimized TOU Algorithm for proactive bill management services, as well as activating four CAISO and non-CAISO based grid service levers.

I have also led sonnen to co-develop other notable solar + battery master planned communities alongside innovative home builders, including DOE award-winning Mandalay Homes in Arizona, Residential LEED Platinum+ Pearl Homes in Florida, and recently, Living Community pioneer Thrive Collaborative in Michigan.

Finally, in the wake of Hurricane Maria, I led the sonnen organization alongside Pura Energia, while founding the 501(C)(3) del Sol Foundation for Energy Security, to build nine microgrids that provide lifesaving services for disadvantaged communities across the island of Puerto Rico.

I hold master's and bachelor's degrees in business administration from Pennsylvania Western University in Edinboro.

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

A. No I have not.

Q. MR. POSNER, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I founded Capital Good Fund, a nonprofit, U.S. Treasury certified Community Development Financial Institution (CDFI) in 2009 while getting my master's degree in environmental studies at Brown University. I wrote my thesis on the potential to use financial services—loans, leases, financial coaching, other banking products—to create economic opportunity for underserved families and communities while also addressing environmental issues such as air pollution and climate change. Capital Good Fund's mission is to create pathways out of poverty and advance an inclusive green economy through financial services.

In my 15 years as Founder and CEO, Capital Good Fund has supported more than 16,000 families and financed more than $42 million in loans and solar leases across eleven states, including Georgia. Roughly 2/3 of our clients are people of color, and 83.5% of our clients qualify as low-income (80% of Area Median Income or below). Our financial products fall into three categories—clean energy, immigration, and small dollar consumer loans that offer a low-interest alternative to credit cards and payday loans. These offerings come with industry-leading rates and are offered without consideration of a consumer's credit score. We also offer a robust financial coaching program.

Capital Good Fund first began offering clean energy loans in partnership with utilities in Rhode Island and Massachusetts through their "HEAT Loan" program. This program allows customers to make a wide variety of approved energy efficiency improvements—in particular heat pumps and insulation—and pay for them using a no interest loan, thanks to an interest buydown from the HEAT Loan

program. We were selected as the only non-bank participating lender, primarily to reach the Low- and Moderate-Income ("LMI") market which had previously been underserved. Through this program, we have originated 1,150 loans for $14.7 million, with a 99.4% cumulative repayment rate.

Beginning in 2021, we launched our DoubleGreen Solar loan program to help LMI customers in Rhode Island, Massachusetts, and Texas access low-cost, long-term financing for rooftop solar and battery storage. Since then, we have originated 147 Solar loans for $6.86 million, with a 100% repayment rate and no delinquencies.

In late September 2023, we once again expanded our clean energy offerings with the launch of the Georgia BRIGHT solar leasing program here in Georgia. This program is structured to help families earning under $100,000 per year install solar and or / battery-storage at no upfront cost and save money on their electricity bills from day one. Already, more than two dozen households have closed leases, and our pipeline is growing daily as we add new community partners to the effort through our Solar Education and Outreach Program. We have also launched a variation of Georgia BRIGHT for nonprofits, which currently has a pipeline of one megawatt of scoped facilities, which we hope to turn into signed SEPAs in the coming months.

In addition to my master's degree, I hold a bachelor's degree in Spanish Language and Culture from California State University, Northridge.

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

A. No, I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of the panel's testimony is to introduce the Commission to the concept of a virtual power plant (VPP) and to demonstrate the value that a VPP can provide

as a quick-to-deploy, low-cost resource for meeting the growing capacity needs identified in this docket. Our testimony will outline the proven track record of VPPs in other states and countries and the wide range of services that these resources can provide. Moreover, our testimony will speak to the ancillary benefits of VPPs, including resiliency, energy savings, and local economic development, among others. Finally, our testimony will outline the different programs and federal funding opportunities that are available to ensure sufficient customer interest in distributed energy resources to support a successful VPP.

Q. MR. RICHETTA, PLEASE TELL US ABOUT YOUR ORGANIZATION

A. sonnen Inc. USA is a nationally renowned VPP based energy storage and software company, based in Stone Mountain, Georgia. Our parent company is the sonnenGroup, which was founded in Wildpoldsried Bavaria Germany in 2008. We are a global leader in energy storage and virtual power plant solutions, with more than 180,000 batteries installed worldwide and virtual power plants operating on three continents.

sonnen's value proposition and trajectory as a company are best understood in the context of Germany's ambitious and rapid clean energy transition, or "Energiewende." At the time of sonnen's founding, energy storage was basically still a research concept. Solar energy could only be consumed when it was produced or fed into the grid, and there was no demand from customers or grid operators for a different approach. In April 2001, the German Bundestag passed the Erneuerbare-Energien-Gasetz (EEG), providing a Feed-in-Tariff of effectively 200% of the retail price of electricity for injecting a kWh of solar energy into the grid from a rooftop solar array. This incentive structure led Germany to have one of the world's largest penetrations of solar energy, but it also presented several significant grid management challenges.

Our first battery, the sonnenBatterie, was a visionary solution to this problem before it emerged. At first, our home battery system was simply a means for maximizing

self-consumption and minimizing exports. However, we soon realized that in order to realize our vision of bringing safe, clean energy to everyone, we had to organize those resources on a larger scale to provide dynamic grid services. This journey began with small, distribution scale operations in retail energy markets through our sonnenCommunity and sonnenFlat offerings, which maximized solar self-consumption on a community scale, but our ambitions soon grew to offering an even larger range of services.

In 2017, we began a pilot with the German transmission grid to provide grid services using digitally networked sonnenBatteries. This early sonnenVPP was used to balance out frequency fluctuations and stabilize the grid, proving that VPPs could provide the same services as centralized, physical power plants. By 2018, the sonnenVPP was approved as a participant in the national power market. Today, this original VPP has eclipsed 250 MWh and is on track to reach 1 GWh in the next few years, making it the largest residential VPP in Europe. Now, we have VPPs operating in 5 countries, including the United States, and we are working to launch one in the United Kingdom very soon. Moreover, we are actively working to expand our battery manufacturing operations to meet the growing demand driven by our VPP business, particularly here in the United States.

Q. WHAT IS A VIRTUAL POWER PLANT?

A. The fundamental components of a VPP are 1) behind-the-meter ("BTM") distributed energy resources or "DERs" and 2) software which enables behind-the-meter DERs to be controlled and networked with other similar devices in order to bring aggregated value to the larger energy system. Presently, these DERs fall into three broad categories: 1) renewable energy generators, predominantly rooftop solar; 2) battery energy storage systems; and 3) intelligent, digitalized loads, such as smart thermostats, electric vehicles and their charging equipment, and grid interactive water heaters, among others. Virtual power plants can provide a wide range of grid services, including capacity, energy, frequency response, demand

response, and spinning and non-spinning reserves. Virtual power plants can also support load shifting or act as load sinks, absorbing excess renewable energy that would normally be curtailed.

Q. HOW DO VIRTUAL POWER PLANTS WORK?

A. For many utilities, customer-sited resources are largely unmanaged. Rooftop solar injects energy into the grid when it is produced, at roughly the same time that all other rooftop, community-scale, and utility-scale solar facilities are producing and injecting into the grid. Customers run their air conditioners or heat pumps essentially whenever they want to, trusting that there will always be enough electricity to achieve and maintain their desired temperature.

In some limited cases, such as cases of customers with EVs or customers with rooftop solar paired with storage, rate structures might exist to encourage customers to charge at a certain time or to store their excess generation and consume it during system peaks, but these price signals are static and are not responsive to current conditions. These rate structures also do nothing to coordinate resources, so that—for example—excess solar generation from one household can "pre-cool" the next house over ahead of the afternoon peak.

Virtual power plants take these unmanaged and largely uncontrolled generation systems, storage resources, and loads and orchestrate them to achieve grid harmonization and balance on a dynamic basis, in response to real time conditions. Resources are grouped into thoughtful, purposeful energy networks that can interact as a single firm dispatchable grid asset with the greater distribution system to provide specific "grid services." All of this is made possible by powerful VPP software that can remotely monitor and control compatible technologies via a simple internet connection.

Q. HOW MUCH CAPACITY CAN VIRTUAL POWER PLANTS PROVIDE?

A. The beauty of virtual power plants is that they are highly scalable and modular. The maximum capacity of a virtual power plant is limited only by the technical, economic, and achievable potential of the distributed energy resources that it dispatches.

For perspective, our WattSmart virtual power plant in Utah currently includes more than 20 MW of capacity, but our goal is to reach 40 MW by the end of 2024 and to continue to scale from there to 100 MW and beyond in the 2030s.

Q. HOW QUICKLY COULD A VIRTUAL POWER PLANT BE DEPLOYED?

A. At this point, there are several off-the-shelf software products and control systems that can integrate with a utility's energy management system in a matter of months. For example, for the WattSmart program, we utilized 100% in house sonnen VPP software, which we were able to integrate into Rocky Mountain Power's grid management system (OSI's Monarch System) in less than six months. It took an additional 6 months to add an IEEE2030.5 server to allow our VPP software to control non-sonnen batteries. In other words, even if some degree of customization is needed, a full-scale, brand-agnostic program can be rolled out in roughly a year, and certainly less than two years. More so than the platform integration, the driving factors for the timeline are the regulatory process, which was very supportive in Utah, and the speed with which new resources can be installed, interconnected, and enrolled.

Q. WHERE ARE VIRTUAL POWER PLANTS BEING USED?

A. Virtual power plants are in use around the world, but they are particularly prevalent in Europe, Australia, North America, and Asia. Here in the United States, utilities and independent aggregators are operating virtual power plants in Utah, Vermont, New York, Hawaii, California, Texas, and in the ISO-NE market, just to name a few, and plans are in motion to deploy a VPP in the Carolinas. At a sub-utility scale, there are several examples of apartment buildings or planned communities that are

operating as virtual power plants, including projects that sonnen has supported in Arizona, Florida, and Michigan.

Q. WHERE HAS SONNEN DEPLOYED VIRTUAL POWER PLANTS?

A. sonnen's first VPP in the United States was developed in 2017 at Mandalay Homes in Arizona, a planned development that is expected to grow to more than 2,900 homes through 2040. This project, which received the US Department of Energy Grand Award for Grid-Interactive Efficient Building Innovation in 2021, consists of homes equipped with rooftop solar, battery storage, energy efficiency, and advanced cloud-based control algorithms that respond to price signals within a unique time of use rate.

Our next big project in the United States was the WattSmart Batteries program, which we launched in Utah with Rocky Mountain Power in 2019. This project began at Soleil Lofts, a 600-unit apartment complex that is home to a first of its kind, utility controlled Virtual Power Plant consisting of 4.5 MW of dispatchable capacity with a 12.6 MWh energy reservoir. From the beginning, Rocky Mountain Power dispatched this VPP on a daily basis, delivering genuine value to the grid. Since then, the WattSmart Batteries program has opened to all customers in Rocky Mountain Power's footprint across Utah and Idaho, where it continues to provide daily services in terms of frequency regulation, load shaping, and peak shaving.

In the past couple of years, we have launched VPPs in California and Puerto Rico, and efforts are underway to launch VPPs in NYISO and ISO-NE. We are also supporting VPPs at additional planned communities, like Pearl Homes' Hunter's Point development in Florida and Veridian at the County Farm in Ann Arbor Michigan, which is being built by the Thrive Collaborative.

Q. PLEASE DESCRIBE THE WATTSMART PROGRAM.

A. The WattSmart Batteries program is a fully operational (i.e. non-pilot) distributed battery grid management program that is directly dispatched by the utility on a daily basis. This program is first-of-its-kind in the USA and offers a wide and growing range of grid services, including non-wires alternatives for local load pocket decongestion and T&D deferral; demand response; capacity planning; energy; frequency response; mitigation of the "duck curve" effect; individual and system-level resiliency; and spinning and non-spinning reserves. In the near future, the utility hopes to explore using the batteries for reverse demand response, using the batteries as load sinks during times of low grid demand and high excess generation.

Under this program, participants receive upfront and ongoing incentives for purchasing batteries that the utility can access to support the grid. The initial commitment is four years, with the opportunity to continue after that in exchange for a larger participation incentive.

Q. WHAT BATTERIES ARE ELIGIBLE TO PARTICIPATE IN THE WATTSMART PROGRAM?

A. Right now, the WattSmart program is open to six battery models from four manufacturers—sonnen, Solar Edge, Fortress, and Torus. Rocky Mountain Power is actively engaging other battery manufacturers in hopes of expanding this list.

Participation is open to any batteries that meet the following requirements:

- Ability to integrate with Rocky Mountain Power's distributed battery grid management program, including 30 second interval data.
- Utility grade batteries with a minimum of 4 kW / 10 kWh.
- Minimum of 10-year battery warranty.
- Minimum of 7,500 battery cycle life to accommodate daily load cycling.
- Ability to charge/discharge multiple times a day.
- Full dispatch control by PacifiCorp to meet the needs of the program.

- Proper UL or equivalent safety certifications for residential and commercial applications.

Additional requirements must be met in terms of telemetry and communications protocols.

Q. WHAT INCENTIVES DO CUSTOMERS RECEIVE FOR PARTICIPATING IN THE WATTSMART PROGRAM?

A. The Wattsmart Program offers customers an upfront incentive of $400 per kW of storage capacity for a four-year commitment. Larger incentives of $600 per kW are available to households that currently have photovoltaic systems and commercial customers.

In addition to the upfront incentive, participants receive an ongoing incentive of $15 per kW in years 2, 3, and 4. This ongoing incentive rises to $50 per kW beginning in year 5. Participants who had batteries prior to the program begin at the $50 per kW incentive.

Q. WHEN THE UTILITY DISPATCHES A CUSTOMER'S BATTERY, IS THAT ENERGY EXPORTED TO THE GRID OR CONSUMED BY THE CUSTOMER?

A. When Rocky Mountain Power dispatches a battery, it serves the customer's energy needs first before exporting to the grid. This ensures customers receive the full financial benefit of having solar and having a battery in terms of reducing their energy bills.

As noted earlier, Rocky Mountain Power is planning to eventually use customer batteries to absorb excess solar energy that would otherwise be curtailed as a form of reverse demand response. When this occurs, that energy will be exported directly to this grid, since it was not produced by the customer.

Q. MANY CUSTOMERS USE BATTERY STORAGE FOR ENERGY ARBITRAGE UNDER A TIME OF USE RATE. DOES THE WATTSMART PROGRAM PREVENT CUSTOMERS FROM DOING THIS?

A. The Wattsmart Program includes daily load cycling as a feature. Batteries charge during solar producing hours from connected rooftop solar systems and discharge when energy prices are highest and solar is unavailable. For customers on a time of use rate, this automatic process is functionally and financially equivalent to customer-initiated arbitrage. For customers on a standard residential rate, this is the equivalent of optimizing your battery to maximize self-consumption.

As noted in the prior question, the batteries will eventually be used to absorb excess energy from utility scale solar or wind facilities that would otherwise be curtailed. In that case, customers will not receive the arbitrage benefit for the energy they did not produce. However, this will not prevent customers from realizing significant financial benefits from the battery program through the upfront and ongoing participation incentives, as well as available tax credits and the savings they will receive through self-consumption of the energy they generate.

Q. WHAT PERCENTAGE OF THE BATTERY CAPACITY CAN ROCKY MOUNTAIN POWER USE?

A. The agreement allows for up to 90%. In practice, grid conditions rarely require that level of discharge.

Q. DOES ROCKY MOUNTAIN POWER DISPATCH THE BATTERY IF WEATHER CONDITIONS ARE EXPECTED TO BE POOR?

A. No. As you would expect, utilities have access to some of the best meteorological data available. If the utility expects severe weather that could cause outages, they do not dispatch customer batteries and reserve the full capacity for the use of the customer. The same is true for planned outages for maintenance.

Q. WHAT IS YOUR UNDERSTANDING OF THE CUSTOMER RESPONSE TO THE WATTSMART PROGRAM?

A. The customer response has been very positive. As of January 2024, more than 3,300 customers were involved in the program, and enrollment has only accelerated with time as more battery brands have been approved for the program and as more solar contractors have grown to understand and promote the rebate offering.

For context, full retail net metering ended in Utah in 2017 and was replaced with a net billing structure that credits exported generation at a much lower wholesale rate. The WattSmart program offers customers an accessible pathway to getting essentially the full retail value for their generation, plus the added bonus of backup power. Many customers have also expressed a sense of pride in being part of the solution for using locally produced, clean energy in a way that helps keep Rocky Mountain Power's rates among the lowest in the country.

Q. WHAT IS YOUR UNDERSTANDING OF THE UTILITY RESPONSE TO THE WATTSMART PROGRAM?

A. Rocky Mountain Power has truly embraced this program. Shortly after rolling out this concept at Soleil Lofts Apartments, Rocky Mountain Power petitioned its regulators to adopt the program as a permanent offering across its Utah and Idaho service territories. Their commitment to the program is evident in continued innovations, including incorporation of additional battery brands and models, deep partnership with the solar industry and other trade allies, and ongoing evaluation of increasingly innovative use cases, like localized distribution investment deferrals.

Rocky Mountain Power has cited several reasons for promoting and expanding the program, including:

- The ability to keep rates low by maximizing use of solar energy

- Avoiding operational problems from unmanaged rooftop solar, including minimizing ramping requirements and alleviating congestion
- Providing a path forward for the solar industry after net metering
- The wide range of use cases
- The positive response from customers
- The responsiveness and flexibility of the battery technology

Already, other utilities are taking notice. Rocky Mountain Power recently hosted a summit that was attended by representatives from Duke Energy, Arizona Public Service, and other utilities that were looking to replicate their success in their territories. Rocky Mountain Power will also have representation at a wide variety of industry conferences, including NARUC's 2024 Winter Policy Summit and DistribuTECH International.

Q. BESIDES INCENTIVES, WHAT OTHER COSTS DID ROCKY MOUNTAIN POWER INCUR IN ROLLING OUT THIS PROGRAM?

A. Non-incentive costs included program administration, marketing, and software. These costs were estimated to be $226,000 for program year 2022, or just over 12% of the total program cost.[1] Critically, Rocky Mountain Power did not need to invest in a Distributed Energy Resource Management System (DERMS) for this program.

Q. HOW DOES THE WATTSMART PROGRAM PERFORM DURING THE WINTER?

A. In cold temperatures, all batteries experience some degradation in their performance. The chemical reactions in the battery slow, so batteries' ability to accept a charge and reach full capacity decrease. However, these challenges can be mitigated with thoughtful siting. I will note that sonnen batteries, which use a lithium iron phosphate chemistry, are specifically engineered to be safe for indoor

[1] https://pscdocs.utah.gov/electric/20docs/20035T07/315314RedactedTariff9-3-2020.pdf

use, so it is possible to prevent any temperature-related performance degradation through indoor siting. This is the case at our Soleil Lofts project, but even locating the battery in an unconditioned garage offers some advantages relative to a fully outdoor installation.

Another consideration in winter is that there isn't as much solar generation overall, which could make it harder to fill the battery from connected solar alone. This has not been a significant problem in Utah, since net metering encouraged customers to size solar arrays to cover their entire annual usage, but even here in Georgia where systems tend to be smaller, a partially full battery can still be useful. As noted earlier, Rocky Mountain Power rarely discharges batteries to the 10% reserve limit. Plus, the batteries can grid charge using excess solar or wind energy from utility scale systems if needed.

Q. THE WATTSMART PROGRAM IS ONLY FOCUSED ON BATTERIES AT THIS STAGE. DO OTHER SONNEN VPPS IN THE UNITED STATES INCLUDE OTHER RESOURCES?

A. At this stage, our U.S. VPPs are only focused on batteries. Many of our utility partners already had demand response programs for thermostats and other controllable loads when we initiated our battery programs, so there was no need or desire to control those technologies with our VPP product. However, our European VPPs tend to have a much wider array of products than just batteries, so we certainly have the capability to support a multi-technology VPP.

Q. WHAT BENEFITS WOULD RESULT FROM DEPLOYING A VIRTUAL POWER PLANT AS PART OF THIS PROCEEDING?

A. A virtual power plant would offer several advantages. From an operational perspective, VPPs can be deployed quickly and at a low cost. They provide a pathway to greatly increasing integration and use of zero carbon, locally produced energy with no fuel cost. They offer a wide range of use cases, including the

potential to defer distribution and transmission system upgrades that can be a barrier to connecting lowest cost energy with load.

From an economic development and stakeholder relations perspective, VPPs can offer a new business model to the solar industry and a mutually beneficial investment opportunity to aspiring rooftop solar customers. They can reduce energy burdens, increase resilience at the individual and system level, and support the many manufacturers who are operating in this state or desire to with a new market opportunity.

I would be remiss if I did not point out that despite having our headquarters in Georgia, we have done no projects here.

Q. MR. POSNER, PLEASE TELL US ABOUT YOUR ORGANIZATION.

A. Capital Good Fund is a nonprofit, U.S. Treasury-certified nonprofit Community Development Financial Institution (CDFI) that operates in eleven states, including Georgia. Since our founding in 2009, we have been offering inclusive financial products and financial coaching to low-income and disadvantaged communities, with a particular emphasis on communities of color and communities that speak English as a second language. We offer financial products across three key verticals—clean energy, immigration, and small dollar consumer loans.

CDFIs exist primarily to provide financial services to communities excluded from mainstream products from banks, credit unions, and other low-cost lenders. Lack of access to affordable loans, checking and savings accounts, and financial coaching has resulted in a $200 billion predatory loan industry nationwide, consisting of payday lenders, pawnshops, rent-to-own stores, auto-title lenders and other firms that charge high-double and even triple-digit interest rates. In other words, one of our many roles is to address market failures.

As the nation transitions to cleaner energy sources, an obvious market failure is the difficulty that lower-income families face in accessing rooftop solar and other forms of clean energy. This is particularly true here in Georgia, where there are few if any state incentives for rooftop solar, energy efficiency technologies, and battery storage.

Recognizing these challenges, Capital Good Fund teamed up with the cities in the Coalition of Local Governments to launch the Georgia BRIGHT program in the fall of 2023 and to pursue related federal funding opportunities.

Q. PLEASE TELL US ABOUT THE GEORGIA BRIGHT PROGRAM.

A. Georgia BRIGHT is a solar and storage leasing program that was specifically designed for households earning under $100,000 per year. The BRIGHT program is designed to offer households day one and ongoing energy savings, with all maintenance included for 25 years. This program was made possible through the Inflation Reduction Act, which made nonprofits eligible to receive the solar investment tax credit as a direct payment for the first time. This allows organizations like Capital Good Fund to claim the tax credit on behalf of residents who may not be able to claim the credit themselves due to insufficient tax appetite. Georgia BRIGHT also leverages bulk purchasing, monetization of renewable energy credits, additional tax credits (such as the low-income bonus credit and the Energy Community adder), and impact investments at a concessionary rate to offer participants the lowest possible lease payment and the greatest possible savings.

Currently, the BRIGHT program is available to income-qualified homeowners in Georgia who have a roof in good condition or space for a ground-mounted system. Approval is not based on credit score, but a holistic evaluation of a household's ability to repay the lease given the anticipated savings. For now, the program is operating as a pilot with enough capital to serve between 150 and 175 households, but the goal is to make the program a permanent offering with an even wider range

of eligibility (for example, expanding to serve renters) in the near future. We also wish to highlight that this is a first-of-its-kind program that we are proud to be piloting in Georgia.

Q. WHAT PERCENTAGE OF CUSTOMERS TO DATE HAVE OPTED FOR STORAGE?

A. As of February 13, 2024, more than 56% of leases have included storage. This is far above our initial expectations and would likely increase if additional incentives were to become available as part of a virtual power plant program. This uptake has been particularly noteworthy since, while a PV-only system can deliver at least 10% month-one bill savings, adding storage results in a "bill-swap", or even a slight bill increase. Customers have been opting for storage because of how much the value the benefit of resilience in the face of outages and the ability to up-size their solar system to offset more of their consumption. Were there an incentive of $400/kW of storage, all customers would realize day-one bill savings even with a battery, and uptake would undoubtedly be even higher, as some customers who wanted storage decided to maximize savings with a PV-only system.

Q. WHAT HAS BEEN THE AVERAGE INCOME OF PARTICIPATING CUSTOMERS?

A. The average annual household income of participating customers has been $70,705.94, with a low of $38,712 and a median of $67,080.

Q. IS THE BRIGHT PROGRAM ONLY AVAILABLE TO HOMEOWNERS?

A. No, we also offer a BRIGHT program for nonprofit organizations, like houses of worship, shelters, food pantries, local governments, and other community-serving organizations. In this case, it is not a lease but rather a Solar Energy Procurement Agreement, or SEPA.

In the future, we are excited to develop mechanisms to serve renters, small businesses, and any other groups facing barriers.

Q. IF A VIRTUAL POWER PLANT WERE APPROVED AS PART OF THIS PROCEEDING, HOW COULD CAPITAL GOOD FUND AND THE BRIGHT PROGRAM SUPPORT THOSE EFFORTS?

A. Capital Good Fund could support VPP deployment in several ways. First, we could support customer acquisition through our existing outreach around the BRIGHT program. In addition to the Coalition governments, our outreach is supported by a network of community organizations, such as Georgia Interfaith Power & Light, who receive a success fee for each lead they generate that results in a closed lease.

Second, we would contribute to a successful program by offering an affordable and accessible financing mechanism for solar and battery storage. In this period of high interest rates, most solar loan and lease products have interest rates, or effective interest rates, that make day one savings difficult, if not impossible. Moreover, most of these require high credit scores. By contrast, Capital Good Fund's approval process does not consider a participant's credit score, and the interest rate that is embedded in our lease is lower than the going rate for a 30-year mortgage. As discussed previously, more than half of the participants in the BRIGHT program have opted for storage, even though storage often comes at a modest premium. If incentives were available that would eliminate that premium and allow for savings, I feel quite confident in saying that nearly all of our participants would choose to include it.

Finally, Capital Good Fund would support a highly subscribed VPP program through our access to federal funding. As a CDFI, Capital Good Fund is eligible for and has pursued several federal funding opportunities, both as a lead applicant and as a subrecipient. The most notable of these is the Greenhouse Gas Reduction Fund Program, which includes three competitions—the National Clean Investment Fund, the Clean Communities Investment Accelerator, and the Solar for All program.

Decisions on all three competitions are due in March, and we are expecting to receive funding through all three programs, since we are involved in multiple applications for each program. These awards would greatly expand our pool of capital and allow us to offer even more favorable rates for our solar and storage products. Moreover, the Solar for All program should also provide critical resources for solar-enabling work, like roof replacements and electrical upgrades. Besides shading, this has been the biggest reason we have had to turn customers away from participating in BRIGHT.

Q. PLEASE DESCRIBE THE SOLAR FOR ALL PROGRAM

A. Solar for All is a $7 billion federal funding program that is being offered through the Environmental Protection Agency. Through this competition, the EPA will award up to 60 grants to states, territories, tribal governments, municipalities, and nonprofits to help low-income and disadvantaged communities access and benefit from solar energy.

Q. HOW LIKELY IS IT THAT GEORGIA WILL RECEIVE SOLAR FOR ALL FUNDING FOR PROJECTS IN GEORGIA POWER TERRITORY?

A. The EPA has indicated that sixty awards will be made, with the general intention of ensuring that each state and territory receives at least one award. Three of the four applications that proposed to do work in Georgia would make investments in Georgia Power territory, including applications by Capital Good Fund and the Georgia Environmental Finance Authority. We obviously can't know for sure which application the federal government will choose, but the guidance suggested that applications with a statewide focus would be viewed more favorably, so I think it is quite reasonable to assume that a significant amount of Solar for All funding will be spent in Georgia Power territory.

Q. WHAT WOULD BE THE SCALE OF THE SOLAR FOR ALL PROGRAM?

A. Statewide applications for the state of Georgia could be for up to $250 million, and both Capital Good Fund and GEFA requested this amount. By our modeling, this could result in more than 300 MW of solar and nearly 110 MWh of battery storage. However, I will caveat that this battery storage projection is likely an underestimate, since actual adoption rates for storage through the BRIGHT program have been more than double our original assumption and would be much higher with the addition of a VPP incentive.

Q. WHAT WOULD BE THE PERFORMANCE PERIOD?

A. Award notifications are expected in March of this year, and the funding is available for five years.

Q. WHAT STEPS COULD THE COMMISSION TAKE TO MAXIMIZE THE IMPACT OF THIS HISTORIC INVESTMENT?

A. The biggest thing that the Commission could do to maximize the impact of Solar for All funding would be to create a program structure, like a virtual power plant program, that would simultaneously help more customers access batteries and support grid stability by dispatching those batteries for grid services.

To put this in perspective, if the Commission were to adopt the $400/kW incentive for residential customers and the $600/kW incentive for commercial customers that Rocky Mountain Power offers through the WattSmart program, we would expect total storage deployment to increase by 10-15% relative to our projections, based solely on our ability to make the awarded capital go further. Specifically, between a VPP incentive and Solar for All Funding, we would expect to originate leases that include storage to 3,200 low-income households and 1,300 community facilities (nonprofits, houses of worship, schools, etc.) over five years, totaling 110 megawatt-hours of battery capacity. That value does not even consider the persuasive impact of the additional incentive in driving consumer interest.

Q. WHAT IMPACT WOULD THESE CHANGES HAVE ON LOWER INCOME HOUSEHOLDS?

A. Three impacts that are particularly important to my organization are reductions in energy burden; resilience; and job creation.

All of the households we serve are low or moderate income, and many of those households are burdened with energy bills in excess of $200/month. Solar, particularly with battery storage, is a critical tool for reducing these bills to a more manageable level. Any programs that can support our work to get these technologies into communities will have an amplifying effect. With Solar For All funding and a VPP incentive, we would expect households to save at least 20% on their electric bills in month one.

Another impact would be greater access to resilience. Our customer population has included seniors, individuals living with disabilities, and individuals with medical dependence on electricity. For each of these populations, backup power can have serious quality of life benefits, and in some cases even be a matter of life and death.

It is important to note as well that resilience can also have a financial impact—for most of the people involved in this proceeding, losing a refrigerator full of food to a power outage would be an inconvenience and a disappointment, but it would not prevent us from eating. However, for a family in need, losing a weeks' worth of groceries can take a family from having hot, nutritious meals to living on whatever shelf stable, processed alternatives they have on hand.

Finally, we prioritize working with smaller contractors, including woman- and minority-owned firms such as Be Smart Home Solutions and Better Tomorrow Solar. The BRIGHT program will create hundreds of good-paying local jobs in the coming years, and the addition of batteries to a system creates more revenue-generation opportunities for installers and other companies throughout the value chain.

Q. WHAT OTHER BENEFITS WOULD RESULT FROM THESE CHANGES?

A. There has been a lot of discussion in this proceeding about whether the massive load growth that is anticipated will ultimately raise costs for customers. A lot of this uncertainty depends on whether the projected loads actually materialize on time and at the level anticipated. By offering a modular solution to capacity expansion, VPPs offer a crucial safeguard against overbuilding or building too quickly, offering customers additional protection against price increases.

Moreover, investing in solar and storage is a future-proof investment. When restrictive climate regulations or carbon prices are ultimately put in place, as they are almost certain to be, solar and storage will be able to continue operating without interruption. Oil-, gas-, or coal-fired resources will not. At a minimum, these resources will require significant investments to become fully hydrogen capable or be retrofitted with carbon capture. At worst, they will become stranded assets that must be retired prematurely and replaced with alternative resources. And of course, solar plus storage does not result in the local air pollution or greenhouse gas emissions that stem from fossil fuel-based power generation, an issue of particular importance to lower-income ratepayers that tend to live in areas with worse air quality.

Q. WHAT ARE THE PANEL'S RECOMMENDATIONS FOR THE COMMISION?

A. Our panel has three key recommendations:

1. The Commission should direct Georgia Power to evaluate the Rocky Mountain Power program and similar program models and bring a VPP program proposal to the Commission for approval within 180 days of the conclusion of this proceeding. This proposal should include proposed upfront and participation incentives and their justifications, administrative cost estimates, estimated implementation timelines, and other relevant

information. This process should include opportunities for stakeholder input from parties to this docket.

2. The RNR tariff should be modified to eliminate system size limits for solar energy systems paired with storage. That is, residential customers should be allowed to have systems greater than 10 kW, and commercial customers should be allowed to have systems greater than the current limit of 125% of their peak demand or 250 kW. This change should be made to maximize the amount of solar energy and battery capacity that is available for utility control via the virtual power plant. Though not directly a concern for utility regulation, we must note that this more efficient use of rooftops, parking lots, and other previously developed or disturbed spaces will reduce the need to convert farm land and forested areas into large solar farms, which is an additional benefit for our environment, community character, and quality of life.

3. The Commission should direct Georgia Power to develop and file a plan for expediting interconnection and witness testing of customer-sited solar energy and battery storage systems to support maximum resource availability to meet the capacity needs identified in this docket. These costs should be addressed in the 2025 rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

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February 15, 2024

VIA ELECTRONIC DELIVERY

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

Re: Direct Testimony on Behalf of Georgia Interfaith Power & Light; Docket No. 55378

Dear Ms. Tanner:

Please find enclosed an electronic version of the following **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light** to be filed in Docket No. 55378.

Please also find enclosed an electronic version of the Trade Secret version of the Direct Testimony of Chelsea Hotaling on behalf of GIPL. Additionally, the testimony will be delivered to the Commission in hard copy, including a sealed envelope containing the Trade Secret version of Ms. Hotaling's testimony.

Respectfully submitted,

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Counsel for GIPL

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	
Georgia Power Company's 2023	)	**Docket No. 55378**
Integrated Resource Plan Update	)	
	)	
	)	

DIRECT TESTIMONY OF CHELSEA HOTALING
ON BEHALF OF GEORGIA INTERFAITH POWER & LIGHT

February 15, 2024

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I. INTRODUCTION

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

A: My name is Chelsea Hotaling. I am a Consultant at Energy Futures Group, located at 30 Court Street, Canton, New York, 13617.

Q: MS. HOTALING, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A: I have worked for seven years in electric utility regulation and related fields. I have reviewed dozens of integrated resource plans ("IRPs") and related filings by utilities in Arizona, Colorado, Kansas, Kentucky, Indiana, Iowa, Michigan, Minnesota, Missouri, Montana, New Mexico, Nova Scotia, Puerto Rico, and South Carolina. I have performed my own capacity expansion, production cost, and reliability modeling in numerous cases using multiple models including EnCompass, Aurora, PLEXOS, and the Strategic Energy & Risk Valuation Model ("SERVM").

I received a Bachelor's Degree in Accounting and Economics from Elmira College in 2011. I also received a Master of Business Administration Degree in 2012, a Master's Degree in Environmental Policy in 2019, and a Master's Degree in Data Analytics in 2020, from Clarkson University. My resume, included as **Exhibit CH-1,** provides additional detail regarding my professional and educational experience.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. No, I have not. I have filed testimony before the Public Service Commission of West Virginia, the Public Service Commission of South Carolina, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Iowa Utilities Board, and the Colorado Public Utilities Commission.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: I am testifying on behalf of Georgia Interfaith Power and Light ("GIPL").

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I was asked to review the assumptions and recommendations Georgia Power Company ("GPC" or "the Company") made related to its 2023 IRP Update,[1] with a focus on the load forecast, new resource assumptions, and Georgia Power's proposed pathway for meeting projected load growth.

Though I reviewed the entire filing, I focused on the resources needed to meet the projected load growth between now and the winter of 2028/2029.

Q: WHY DID YOU FOCUS ON MEETING ENERGY NEEDS BETWEEN NOW AND THE WINTER OF 2028/2029?

A: Georgia Power has indicated that the period of load that it is addressing in this IRP Update is narrow: today through the December 2028.[2] Georgia Power has repeatedly indicated that the All-Source and Battery Energy Storage System RFPs that were approved in the 2022 IRP would address capacity needs beginning in the winter of 2028/2029.

[1] On December 4, 2023, Georgia Power Company submitted and requested approval to procure several resources including: two Power Purchase Agreements ("PPAs"), up to 1,000 MW of battery energy storage systems ("BESS"), up to 1,400 MW from combustion turbine ("CT") resources, two new customer-sited distributed energy resource ("DER") programs, one new demand response program, an amendment to one existing demand response program. Georgia Power also asked for approval of the proposed Flex Capacity framework and transmission system improvements related to the resources requested in the Company's filing. Georgia Power 2023 Integrated Resource Plan Update ("IRP Update Main Document").

[2] Georgia Power 2023 IRP January 16, 2024 Hearing Transcript "Hearing Transcript" at 479:2-4.

II. SUMMARY OF RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: My recommendations are as follows:

1. Load Forecast

a. The Commission should only approve resources sufficient to meet the most likely load growth to occur, which has been identified by Georgia Power's modeling at the 50th percentile (or P50).

b. The Commission should direct Georgia Power to track specific data that will improve the accuracy of future forecasting for large-load customer growth.

2. Proposed Resources

a. The Yates CTs are not necessary to support Georgia Power's projected capacity needs between now and 2028, even if the Commission uses Georgia Power's extreme growth estimates (P95).

i. I recommend that the Commission defer consideration of the Yates CTs until the 2025 IRP, when it will have the benefit of a fulsome long-term planning process. In the alternative, the Commission should direct Georgia Power to expedite the upcoming all-source RFP to determine the economically optimal portfolio of resources to meet projected capacity needs.

ii. The Commission should not charge billpayers for the approximately $250 million in expenses that Georgia Power has identified as its development and cancellation costs if the Yates CTs are not approved.

b. Battery Energy Storage Solutions are sufficient to meet Georgia Power's capacity needs between now and 2028, and they can be competitively procured.

i. I recommend that the Commission direct Georgia Power to issue an expedited BESS RFP for at least 1,410 MW as soon as possible.

3. Flex Capacity

a. A flex capacity framework is unnecessary; it unnecessarily shifts the Company's risk-taking from its shareholders to its customers. The Commission should deny this request.

III. GEORGIA POWER'S LOAD FORECAST

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ABOUT GEORGIA POWER'S LOAD GROWTH.

A: Georgia Power has relied on a generally accepted statistical method to forecast new load growth coming to Georgia, but Georgia Power's interpretation of its own forecast unreasonably overestimates the pace of growth. Georgia Power relies on a load projection that its own statistical analysis suggests will be higher than actual demand 95% of the time. However, Georgia Power's statistical method also identified the capacity-needs that are **most likely** on an annual basis, and I recommend that the Commission plan to acquire resources to meet that probable need (identified as P50 or the 50th percentile).

Q: PLEASE BREAK THAT DOWN FOR ME. TO START, WHAT HAS CHANGED SINCE THE 2022 IRP THAT HAS RESULTED IN THIS NEW LOAD FORECAST DISCUSSION?

A: Georgia Power has reported a change to the load forecast that was modeled for the 2022 IRP as a result of large-load customers (that Georgia Power calls "economic development projects") responding to the economic growth and business opportunities in the state. This has resulted in a significant difference between the load growth projected in the 2022 IRP and Georgia Power's chosen load growth projections for this 2023 IRP Update. By December 2028, Georgia Power is now planning for 4,094 MW more than it projected during the 2022 IRP. Its own projections, however, suggest that 3,141 MW of growth through 2028 is most likely.

Winter Peak	GPC 2022 IRP Budget	GPC Most Likely Load Growth (P50)	GPC 2023 IRP Planning (P95)	Difference between 2022 IRP and 2023 Update (P50)	Difference between 2022 IRP and 2023 Update (P95)
2024	15,581	15,268	15,283	(313)	(298)
2025	15,636	15,796	15,947	160	312
2026	15,657	16,790	17,256	1,133	1,599
2027	15,673	18,163	18,928	2,490	3,255
2028	15,657	18,798	19,751	3,141	4,094
2029	15,757	19,390	20,551	3,633	4,793
2030	15,796	19,966	21,326	4,170	5,530
2031	15,957	20,408	21,880	4,451	5,923

Table 1. 2022 IRP Winter Peak Load Forecast Compared to 2023 IRP Update Forecast[3]

Q: GEORGIA POWER'S NEW LOAD FORECAST RELIES ON A NEW APPROACH TO FORECASTING. DO YOU AGREE THAT A NEW FORECASTING APPROACH IS NEEDED TO CAPTURE GEORGIA'S LARGE LOAD GROWTH?

A: Yes. Traditionally, Georgia Power uses linear regression to develop the baseline load forecast used in the IRP planning process. This methodology relies on traditional economic and demographic variables as drivers of energy use. Since these models are based on the historical trends for the different variables included in the model, it is challenging for the traditional forecast to be able to account for the large-load projects arising from the economic growth Georgia is experiencing. As a result, it is reasonable for Georgia Power to supplement its baseline forecasting approach with another methodology to try to forecast this distinctive rapid, large load growth.

Q: HOW DID GEORGIA POWER DEVELOP THE LOAD FORECAST MODEL THAT WAS USED IN THIS 2023 IRP UPDATE?

A: Since the load growth experienced by Georgia Power in the last two years is not captured in traditional load forecast models, Georgia Power's load forecast model[4] attempted to capture the uncertainty around several variables, including the probability of the "economic development projects" successfully coming online, the timing of the load coming online or experiencing delays, and the level at which load will materialize relative to what the customer initially indicated it would demand. Specifically, Georgia Power decided to

[3] Extrapolated from data provided in Georgia Power's response to STF-PIA-4-13 Attachment and DEA-1-5 Att. B.
[4] The load forecast model is referred to as the "Load Realization Model" in the workpapers provided by Georgia Power with this filing.

utilize the @RISK software which performs Monte Carlo simulations on variables specified by Georgia Power to try to capture the uncertainty related to the load growth.

Q: WHAT IS A MONTE CARLO SIMULATION AND WHY IS IT USED HERE?

A: A Monte Carlo simulation is a widely accepted statistical process that helps estimate the probability of uncertain events. In this case, the Monte Carlo simulation was designed by Georgia Power to estimate the probability (likelihood) that certain amounts of load will actually be demanded by large customers on its system.

Q: PLEASE DESCRIBE THE VARIABLES GEORGIA POWER USED IN ITS MONTE CARLO SIMULATION TO ESTIMATE THE UNCERTAINTY OF ITS FUTURE LARGE LOAD DEMAND.

A: The first variable in the model is what Georgia Power calls the probability of "Project Success," which represents a compilation of three separate inputs:

(1) Whether the project will be located in the state of Georgia (P1)

(2) Whether Georgia Power will be selected as the electric service provider for the project (P2)

(3) The success rate of the project after the contract is signed (P3)

Table 2 below shows an example of how these three inputs were set up in what Georgia Power calls the "Load Realization Model" to represent the different combinations that arise from the assumptions Georgia Power made for each of these three inputs. For P1, each project was assigned either a [redacted] or [redacted] value. For P2, each project was assigned a value of [redacted], [redacted], [redacted], or [redacted]. P3 is the success rate that Georgia Power has reported for its historical projects. Georgia Power has stated that it has a recent success rate of about [redacted] for projects coming online after a service contract is signed.[5] Overall Project Success is based on the product of P1 x P2 x P3. The product of these three factors is ultimately the input that is factored into the Monte Carlo simulations for the model.

[5] Georgia Power response to STF-DEA-1-13.

GA as State Selection (P1)	GPC as Provider (P2)	Project Reaching COD (P3)	Project Success (P1xP2xP3)
[redacted]			

Table 2. Project Success: Input Variables in the Load Realization Model

The value reported for the Project Success represents the percentage of times that the load will materialize in each simulation. For example, if a project has a success value reported at [redacted], that means that out of the 100,000 combinations that are drawn in the Monte Carlo simulation, the number of iterations in the model simulation where the announced load is included is based on the project success value, or [redacted].[6]

The other two variables included to capture uncertainty in the load forecast model include the probability that the announced load for the project will be different from the load that materializes (Metered vs. Announced Load) and the probability that the Commercial Operation Date ("COD") of the project will be delayed. Georgia Power assigned both of these variables a triangular distribution with a low, mid, and high value. Georgia Power has acknowledged that without historical data, the triangular distributions have been assigned to reflect what it considers the minimum, maximum, and most likely outcomes.[7] The value for each of the six potential customer segments is shown in **Table 3**.

[6] Georgia Power response to STF-DEA-1-16 subpart b.
[7] 2023 IRP Update Technical Appendix ("Technical Appendix") 7, TS-Load and Energy Forecast at 18.

	Minimum	Most Likely	Maximum
Cryptocurrency	[redacted]		
Datacenter			
Miscellaneous			
Warehouse			
Distribution			
Industrial (All Segments)			

Table 3. Metered vs. Announced Load: Triangular Distribution Values

Within the model, the metered vs. announced load variable is used to scale the announced load of the project according to the ramp-up schedule[8] that is also specified in the model. For example, the announced load for a project might be 300 MW, but there is some uncertainty around whether this full level of load will materialize, as it could be less than 300 MW. With regard to this uncertainty, Georgia Power stated, "… based on Georgia Power's experience, the load announced by a customer is only an estimate of its metered load, which can materialize at a lower level than that at the time of the customer's initial announcement."[9] The model will interpret this uncertainty by pulling from the low, mid, and high values that Georgia Power has specified for the customer segments. In the example I referenced above, if the project is at 300 MW of announced load, then that project will materialize as a percentage of that announced load in the Load Realization Model (i.e., if the simulation run picks a maximum value of 75%, the 300 MW load will appear as 225 MW in the outputs).

Table 4 below shows the triangular distribution values for Commercial Operation Date ("COD") delay. Based on the values specified by Georgia Power, this means that the maximum delay for any project in the model is [redacted] months and the most likely value is [redacted] months.

[8] The ramp-up schedule reflects that the entire load is typically not required on Day-1 of a project. For example, if a project has an announced load of 300 MW, it might expect to need 100 MW on Day-1 and then ramp up by 50 MW each year to reach the 300 MW announced load by 2027.
[9] Technical Appendix 7, TS Load and Energy Forecast at 16.

	Minimum	Most Likely	Maximum
Commercial Operation Date ("COD") Delay	[redacted]		

Table 4. COD Delay (Months): Triangular Distribution Values

Once the @RISK model performs 100,000 draws on these uncertain variables, the load for each potential project is added together to arrive at the portfolio level load projection each year that Georgia Power then includes as an adjustment to the baseline load forecast.

Q: DID GEORGIA POWER'S LOAD REALIZATION MODEL PROVIDE A SINGLE ESTIMATE FOR PROJECTED LOAD?

A: No. Georgia Power's Load Realization Model is based on 100,000 simulations, with each individual simulation representing a different estimate of potential load growth based on the assumptions that Georgia Power assigned to the uncertain variables. The 100,000 simulations are then combined to give a range of possible load growth and to show how likely it is for each load projected to actually occur.

As a matter of statistics, the most likely load growth scenario is the data point in the middle, where 50% of the scenarios project more growth and 50% of the scenarios project less growth. This data point is referred to as P50, or the 50th percentile. Similarly, probabilities can be assigned to all the other data points as well. P05 (the 5th percentile) and P95 (the 95th percentile) describe load forecasts where just 5% of the scenarios run are lower or higher than that amount of load. In other words, scenarios smaller than P05 or larger than P95 are very unlikely to occur.

Q: DID GEORGIA POWER ALSO PROVIDE THE RESULTS OF THE 50TH PERCENTILE?

A: Yes. In addition to the total winter load forecasts shown in Table 1, Georgia Power provided the new large-load-only P50 forecast in response to a discovery request from Public Interest Advocacy ("PIA") Staff.[10] **Table 5** below shows a comparison between the 95th and 50th percentiles resulting from Georgia Power's Load Realization Model for new large-load projects. In year 2026, the 95th percentile load level indicates that 95% of

[10] Georgia Power response to TS-STF-DEA-1-5 Attachment A.

potential load outcomes are less than [redacted] MW and only 5% of the possible load outcomes are higher than [redacted] MW.

Year	P95	P50
2023	[redacted]	
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		

Table 5. Comparison of the P95 and P50 Load Forecasts[11]

Q. HOW DID GEORGIA POWER DECIDE WHICH PART OF THE LOAD REALIZATION MODEL'S LOAD GROWTH RANGE TO USE?

A: Georgia Power chose to plan for P95: That means that Georgia Power is planning for bigger load growth than its own simulation says it needs 95% of the time.[12] Said another way, Georgia Power is planning for more load growth than its model says will be needed in 95,000 out of the 100,000 simulations run.[13]

Georgia Power provided many explanations for choosing the high-end of possible load (P95) in its testimony:

- "[P95] was chosen because it supports the ask that we have in front of this Commission."[14]

[11] Technical Appendix 7, TS Load and Energy Forecast Table 1.5.2.3-1 at 20 and Georgia Power response to TS-STF-DEA-1-5 Attachment A.
[12] Technical Appendix 7, Load and Energy Forecast at 3. As Georgia Power stated, "[…] P95 indicates a load level where 95% of all potential combinations fall at or below this level, and 5% of the load combinations fall above it."
[13] Hearing Transcript at 378:4-8.
[14] Hearing Transcript at 378:21-23.

- "[P95] accommodates for the rapid growth that we have seen throughout 2023 where different sensitivities that we did were doubled a couple of times throughout the year."[15]
- "[P95] accommodates for the current capacity market conditions."[16]
- "[T]hat higher load level was chosen because that's what we expect the State's load growth to be. . . . [W]e continue to see load growth outrunning the forecast."[17]
- "From a statistical perspective, yes, I agree that the P50 level represents the median of the range of all potential outcomes. But for the purposes of this IRP, we're picking a higher-level degree to represent the increases in the load that we have seen throughout 2023 and because it's a better level to plan . . . for our resources."[18]
- "[T]here's a lot more risk on the upper side than the lower side."[19]

Q: IS IT REASONABLE TO USE THE P95 FORECAST FOR THIS IRP UPDATE?

A: No. It is not reasonable to plan for a load scenario that is at or higher than 95% of modeling scenarios for this IRP Update.

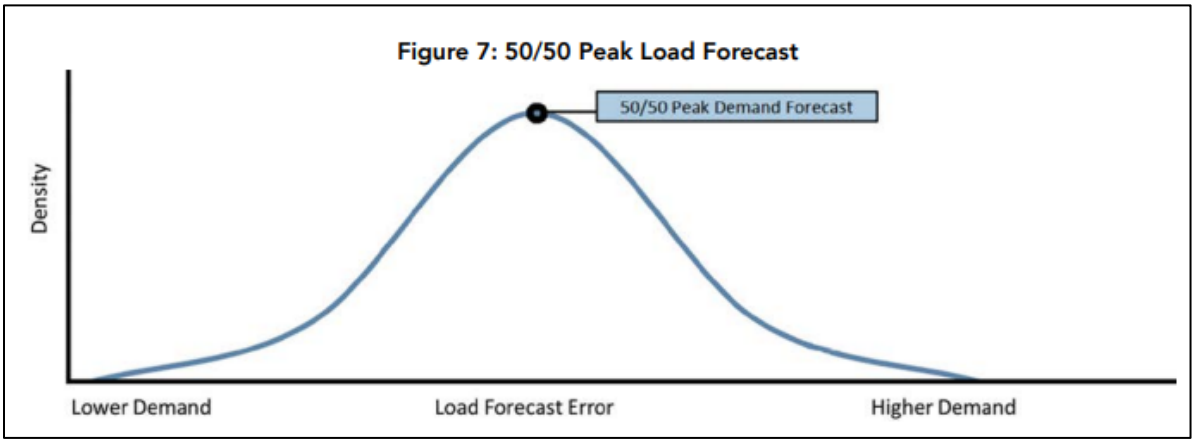
Q: WHY IS IT UNREASONABLE TO USE THE P95 FORECAST FOR THIS IRP UPDATE?

A: Georgia Power should base planning on the 50th percentile (P50) for a few reasons:

First, load forecasts that utilities use as inputs for capacity expansion models are typically 50/50 forecasts, which means there is a 50% chance of an over-forecast (meaning the forecast is higher than actual needs) and a 50% chance of an under-forecast (meaning the forecast is lower than actual needs), as reflected in the below image.[20] (Notably, for the

[15] Hearing Transcript at 378:23-379:1.
[16] Hearing Transcript at 379:1-2.
[17] Hearing Transcript at 379:3-8.
[18] Hearing Transcript at 382:20-383:1.
[19] Hearing Transcript at 379:8-9.
[20] NARUC, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms, November 2023, at 18. Retrieved at: 0CC6285D-A813-1819-5337-BC750CD704E3 (naruc.org)

Southern Company System, load forecasting erred on the side of over-forecasting every year between 2000-2017.[21])



The same idea applies here: The 50th percentile is the median of the load level in the model. Intuitively, using P50 is logical, because it uses the modeling for the very purpose for which the model was developed: To estimate the most likely outcome. Here, Georgia Power used a Monte Carlo simulation to make an informed projection about how demand will grow in Georgia. The 50th percentile reflects a balance between demand that may or may not materialize.

Second, I agree with Georgia Power's written testimony that it is reasonable to "plan for a probable amount of customer choice load and avoid overestimating load additions that could add unnecessary capacity to the electric system."[22] **The 95th percentile, used by Georgia Power, will be an overestimation 95% of the time.** As a matter of basic statistics, **the 50th percentile is the amount of load that is more likely to occur than not—or, is probable.**

Third, Georgia Power's Target Reserve Margin ("TRM") already accounts for the risks inherent in load forecasting. Georgia Power has one of the largest winter reserve margins among its Southern peers.[23] And Georgia Power's TRM explicitly accounts for load

[21] IRP Update Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Table 1-3.
[22] Georgia Power Direct Testimony at 19:20-22.
[23] Hearing Transcript at 501:11-16; *see also, e.g.*, Hearing Transcript at 502:1-3; 2023 Long-Term Reliability Assessment December 2023, North American Electric Reliability Corporation, at 83&91; 2023 Resource Adequacy

forecasting error.[24] In addition, as I will discuss in more detail in the next section, Georgia Power plans for a higher reserve margin than utilities typically plan for, which is a loss of load expectation ("LOLE") of one day in ten years or 0.1 days per year. In the 2022 IRP TRM Study, the minimum reserve margin for Georgia Power was found to be 20%, but Georgia Power took additional steps to evaluate the economics and risk components for a reserve margin higher than 20%.

Fourth, I disagree with Georgia Power's oral testimony which suggested that using the 95th percentile of growth is justified by either "rapid load growth" or by the observations that load growth is "outrunning the forecast." **To the contrary, rapid load growth is exactly what this model is designed to capture, using probabilities assigned by Georgia Power**.

The model incorporates estimates of the likelihood of each project's overall success. As I discussed earlier in my testimony, the project success variable is based on the probabilities chosen by Georgia Power for (1) the project selecting Georgia as the state to locate in, (2) the project selecting Georgia Power as the electric service provider, and (3) the likelihood of projects materializing after a contract has been signed. Table 1 provided the unique project success values contained in Georgia Power's Load Realization Model based on the input assumptions for each project. **Table 6** below shows the total announced load contained within the Load Realization Model based on the probability of Project Success. The model interprets the Project Success value as the percentage of iterations where the project will be considered a success, and the announced load will be included in the model and reflected in the resulting total level of load for Georgia Power. This shows that the announced loads with lower levels of project success are being considered in the Load Realization Model and the announced load of these lower probability of success projects are being factored into the load model.

Study for Duke Energy Carolinas & Duke Energy Progress (Reserve margins below 21%), Astrape Consulting, at 3; 2023 Virginia Electric and Power Company, Integrated Resource Plan 2023 at 59 (Reserve margins below 15%).
[24] IRP Update Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Figure III.1 at 13.

Project Success	Announced Load
[redacted]	

Table 6. Announced Load Based on Project Success

Fifth, I have seen no support for Georgia Power's oral testimony that there is "a lot more risk from the upper side than the lower side."[25] Risk is frequently considered as part of system planning, but in this case, the risk of overbuilding the system versus the risk of underbuilding has a very different dynamic than typical risk-benefit assessments of load growth. In large part, that is because **Georgia Power's projected load is largely from customers that it is not obligated to serve.**

If Georgia Power adds capacity to meet the projections of P50, there is an equal chance that Georgia Power will overbuild as underbuild. If Georgia Power overbuilds (meaning load demand ends up being lower than P50), existing customers will incur unnecessary costs for that additional capacity. As summarized succinctly by Georgia Power, "If we're wrong [about load growth], that would not be beneficial for customers."[26] If Georgia Power underbuilds (meaning load demand ends up being significantly higher than P50), then Georgia Power may need to forego or delay entering into customer choice contracts, which could lead large-load customers to choose a different Georgia electricity provider or choose not to locate in Georgia at all.

Table 7 below shows the announced load across different industry segments and whether that load would be located within Georgia Power's service territory or outside of the service territory. Out of all the announced load included in the Load Realization Model, over half (about [redacted]) is outside of the service territory and would fall under customer choice.

[25] Hearing Transcript at 379: 8-9.
[26] Hearing Transcript at 485:21-22.

	Announced Load (MW)		
Segment	Inside Service Territory	Outside Service Territory	Total
[redacted]			

Table 7. Announced Load (MW) Contained in the Load Realization Model[27]

Q: WHAT RECOMMENDATIONS DO YOU HAVE RELATED TO GEORGIA POWER'S LOAD FORECAST MODEL?

A: First, I recommend that Georgia Power plan for the load growth that its analysis estimates is most likely to occur: the 50th percentile of the load level forecasted for new customers by its Monte Carlo simulation (P50).

Second, I recommend that Georgia Power track specific datapoints relied upon in this new large-load forecasting process to inform future forecasting for large-load customers. To the extent that Georgia Power is not already doing so, I recommend that Georgia Power track (and report) data including:

a) the date first contacted by the customer,

b) the date when selections are made (the selection of Georgia as the state to locate in and the selection of Georgia Power as the electric service provider),

c) the announced load from the customer,

d) dates when any changes were made to the customer's announced load and whether that has an impact on the anticipated ramp-up schedule,

e) date the customer was connected and the first month of service,

[27] Georgia Power response to STF-DEA-6-3.

f) the actual connected load, and

g) the actual load ramp-up over time.

Based on some of the responses Georgia Power provided in discovery,[28] it appears that the Company may be tracking this information now, but if the Company is not, all of these data points are critical to help inform the decisions about what values to include for the uncertain variables in the Load Realization Model.

IV. GEORGIA POWER'S NEED FOR NEW RESOURCES

A. Georgia Power's Winter Capacity Position

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ABOUT ALTERNATIVE OPTIONS TO FULFILL GEORGIA POWER'S CAPACITY NEEDS.

A: Georgia Power does not need the proposed Yates CTs to fulfill its capacity needs in advance of the BESS and all-source RFPs designed to serve winter 2028 and beyond. Instead, approximately 1,410 MW of BESS resources, which have been identified by Aurora as the economically optimal investments, are sufficient to meet Georgia Power's near-term capacity needs under the P50 scenario. **Even if the Commission plans to meet Georgia Power's high-end 95th percentile load estimate, Plant Yates is still not necessary to meet Georgia Power's capacity needs.** Instead, a combination of BESS resources and PPAs in 2027 and 2028 could meet these needs.

Q: HOW DID YOU EVALUATE ALTERNATIVES TO GEORGIA POWER'S PROPOSED RESOURCE MIX?

A: I reviewed Georgia Power's resource mix study and the results of Georgia Power's Request for Information for capacity to the market. I also evaluated Georgia Power's winter capacity position under both the P50 and P95 load forecasts developed by Georgia Power. Then I determined which resources identified as "economically optimal" by Aurora could fulfill Georgia Power's capacity needs. I prioritized non-thermal resources, which is also consistent with the resource selection by Aurora in the time frame at issue in this IRP Update.

[28] Georgia Power response to STF-PIA-7-10.

Q: PLEASE DESCRIBE THE RESOURCE MIX STUDY RESULTS THAT YOU REVIEWED.

A: I reviewed Georgia Power's use of the Aurora model as part of its resource mix study. The Aurora modeling process identifies the economically optimal resources to meet the load growth identified by Georgia Power (P95) in order to minimize total system costs. Candidate resources are offered for selection in the model, and Aurora will select the optimal build of new resources. Georgia Power made updates to the cost assumptions for the new generic resources that were modeled for the 2022 IRP.

Q: WHICH RESOURCES DID THE AURORA MODELING IDENTIFY AS ECONOMICALLY OPTIMAL TO MEET GEORGIA POWER'S P95 LOAD BETWEEN 2024 and 2028?

A: Aurora identified the Mississippi Power PPA (for 2027 and 2028 only), solar, batteries, and 300 MW of CTs as economically optimal to meet the P95 needs identified by Georgia Power between now and 2028. **Table 8** below shows the annual incremental new resources selected in the Aurora capacity expansion modeling for the "MG0-Base GPC" run. The four-hour BESS additions between 2027 and 2028 total 1,580 MW. These resources would be incremental to the 500 MW BESS (and all-source RFP) that was ordered from the 2022 IRP, which Georgia Power assumes will be powering the grid by the end of 2028.[29]

Year	CT with SCR	MPC PPA	Solar	Battery 4-Hour
2024				
2025				
2026				
2027		750		900
2028	300		750	780

Table 8. Aurora Modeling Annual New Resource Additions (MW)[30]

Q: HOW DOES THE AURORA MODELING ALIGN WITH THE PROJECTS THAT RESPONDED TO THE REQUEST FOR INFORMATION ("RFI") ISSUED BY GEORGIA POWER?

[29] Georgia Power response to STF-JKA-3-16 indicates that the 500 MW ESS from the 2022 IRP was modeled in Aurora as the resource "O3_2022_IRP_ESS". *See also*, IRP Update Main Document at 15.
[30] Georgia Power workpaper named "PD Capacity Expansion Plans Supplemental – Errata", worksheet named "MG0 (GPC Only)".

A: Georgia Power received RFI bids for about 3,000 MW of capacity from BESS resources for 2026, 2027, and 2028.[31] About half of those resources (approximately 1,400 MW) are already planned to be available before the end of 2028.[32] Georgia Power's graphics and **Table 9** below summarize the bids received by Georgia Power. Table 9 shows the total annual nameplate capacity from the BESS and renewable plus BESS bids that Georgia Power received in response to the RFI. [33]

Resource Types	Exisiting Project	New Project	Planned Project	Not Provided	Grand Total
ESS Other (Flywheel, CO2, etc.)		4		1	5
ESS Standalone		6	7	1	14
Nuclear Energy		1			1
Solar + Storage		4	9		13
Solar Only	4				4
Thermal	4				4
Grand Total	8	15	16	2	41

[34]

Breakdown of Resource Types		
Capacity Resource Type	# of Responses	Sum of Capacity (MW)
ESS Other	4	769
BESS Standalone	13	2,695
BESS + solar	12	1,680
Solar Only (not applicable)[3]	5	1,228
Thermal (CC / CT)	2	1,243
Nuclear Energy	1	280
Total	**37**	**6,667**

[35]

	2026	2027	2028	2029	2030
BESS	[redacted]				
Renew+BESS					
Total					

Table 9. Summary of Standalone BESS and Renewable+BESS Projects (Nameplate MW)[36]

[31] Hearing Transcript at 354:10-16.
[32] Georgia Power response to TS STF-PIA-9-13, Attachment A at 1 (determined not to be Trade Secret by email exchange with Georgia Power counsel).
[33] [redacted] of standalone and renewable plus BESS resources were bid in without a specified online date.
[34] Georgia Power response to TS STF-PIA-9-13 Attachment B.
[35] Georgia Power response to TS STF-PIA-0-13 Attachment A.
[36] Based on information provided in the workpaper named "TS_ResponseDataScrubbed_ForRFISummary".

Q: PLEASE DESCRIBE GEORGIA POWER'S CAPACITY NEEDS BEFORE THE END OF 2028.

A: **Table 10** below shows Georgia Power's capacity position relative to a winter TRM of 24.43% for 2024-2026 and 25% starting in 2027 under the P50 load forecast. This capacity position look also evaluates the system with and without consideration of the additional capacity from the Mississippi Power and Santa Rosa PPAs. Table 10 shows the level of capacity that would be needed to meet the winter TRM without consideration for the Mississippi Power or Santa Rosa PPAs.

(P50 – No PPAs)	2024	2025	2026	2027	2028
Peak Demand	15,268	15,796	16,790	18,163	18,798
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	**30.9%**	**34.2%**	**26.8%**	**19.9%**	**17.5%**
Capacity Needed				918	1,410
Reserve Margin	**30.9%**	**34.2%**	**26.8%**	**25.0%**	**25.0%**

Table 10. Georgia Power Winter Capacity Position Under P50 and No PPAs

(P50 – PPAs Included)	2024	2025	2026	2027	2028
Peak Demand	15,268	15,796	16,790	18,163	18,798
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	30.9%	34.2%	26.8%	19.9%	17.5%
Add Proposed PPAs:					
MPC PPA	750	750	750	750	750
MPC PPA Sale	-500	-500			
Santa Rosa PPA		230	230	230	230
Total Existing & PPA Capacity	**20,230**	**21,676**	**22,276**	**22,765**	**23,068**
Reserve Margin	**32.50%**	**37.22%**	**32.67%**	**25.34%**	**22.71%**
Capacity Needed					430
Reserve Margin	**32.50%**	**37.22%**	**32.67%**	**25.34%**	**25.00%**

Table 11. Georgia Power Winter Capacity Position Under P50 and the PPAs

Table 11 shows that when the PPAs are included under the P50 load forecast, the capacity need for Georgia Power starts in 2028 at 430 MW. This is in comparison to the 2,400 MW worth of supply side capacity that Georgia Power is requesting.

I also evaluated the winter capacity position for Georgia Power under the P95 load forecast as shown in **Table 12** below. I calculated the level of capacity that Georgia Power would

need to arrive at the winter TRM: Under the P95 forecast, after accounting for the PPAs, Georgia Power needs 895 MW in 2027 and 1,621 MW in 2028.

(P95 – PPAs Included)	2024	2025	2026	2027	2028
Peak Demand	15,283	15,947	17,256	18,928	19,751
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	30.7%	32.9%	23.4%	15.1%	11.8%
Add Proposed PPAs:					
MPC PPA	750	750	750	750	750
MPC PPA Sale	-500	-500			
Santa Rosa PPA		230	230	230	230
Total Existing & PPA Capacity	**20,230**	**21,676**	**22,276**	**22,765**	**23,068**
Reserve Margin	**32.37%**	**35.92%**	**29.09%**	**20.27%**	**16.79%**
Capacity Needed				895	1,621
Reserve Margin	**32.37%**	**35.92%**	**29.09%**	**25.00%**	**25.00%**

Table 12. Georgia Power Winter Capacity Position Under P95 Load

B. Georgia Power's Winter Target Reserve Margin

Q: PLEASE SUMMARIZE WHAT CONCLUSIONS YOU DREW ABOUT GEORGIA POWER'S RESERVE MARGIN AND HOW IT MAY IMPACT GEORGIA POWER'S CAPACITY NEEDS?

A: Georgia Power has a higher-than-typical reserve margin, because it plans for reliability (as is typical) and then adds additional reserve margin based on economic analysis. However, in the time since the reserve margin study was completed, the primary input for the economic analysis (the cost of CTs) has changed significantly. As a result, it is likely that Georgia Power is relying on a higher planning reserve margin than could be justified if it reevaluated its economic analysis today. These outdated assumptions could lead to Georgia Power overbuilding by approximately 1,185 MW of winter capacity in 2028. Considered another way, updates to Georgia Power's reserve margin study could result in Georgia Power not needing any new capacity beyond what is provided by the PPAs before 2028, even under the P95 growth assumptions.

Q: WHAT TARGET RESERVE MARGIN ("TRM") HAS GEORGIA POWER USED IN ITS CALCULATION OF THE COMPANY'S CAPACITY POSITION?

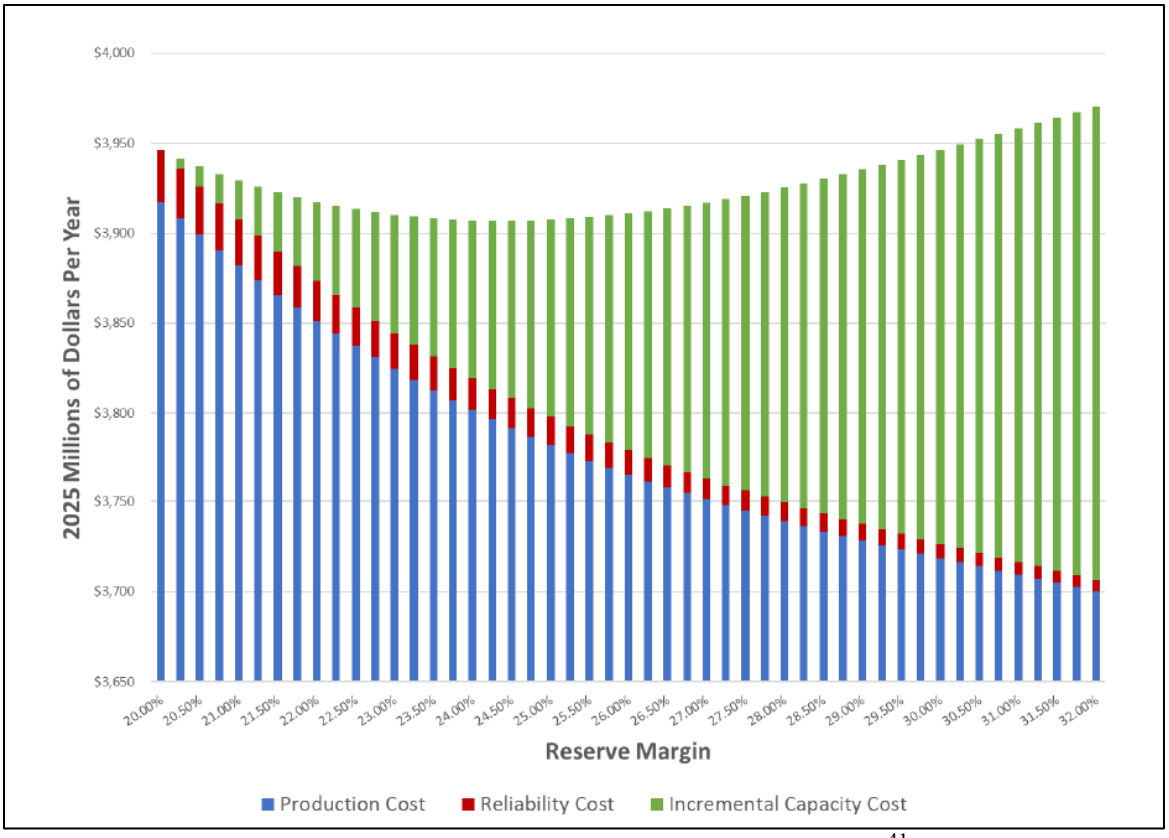
A: Georgia Power used the winter TRMs that were determined from the SERVM modeling performed for the 2022 IRP, which were 25.50% for 2024-2026 and a 26% starting in 2027

for the Southern Company System.[37] Georgia Power did not rerun its TRM study, but it did update the TRM for the 2023 IRP Update to account for updated diversity factors that are applied to the Southern Company System TRM. This means that the TRM for Georgia Power for this 2023 IRP Update is 24.43% for the short-term (2024-2026) and 25% for the long-term (starting in 2027) after accounting for this diversity factor.[38]

Q: HOW DID GEORGIA POWER DEVELOP ITS TRM FOR THE 2022 IRP?

A: Georgia Power used the SERVM model, which evaluates the ability of a system's resources to meet load across thousands of iterations that include varying assumptions around weather, the load forecast error, and generator forced outages. In many cases, utilities will develop a reserve margin based on meeting the industry standard metric of one loss of load expectation ("LOLE") in ten years or 0.1 events per year. To develop Georgia Power's TRM, Georgia Power takes any additional step to evaluate the expected costs of maintaining reserve capacity, production costs, and reliability costs to determine the economic optimum reserve margin ("EORM"). This evaluation considers the tradeoff between the costs of additional generating capacity on the system versus the improvement in resource adequacy from having those additional generating resources. Georgia Power evaluated the EORM by comparing the production[39] and reliability[40] costs, as determined by the SERVM model, to the incremental capacity cost of new generation over several different winter planning reserve margin levels (ranging from 20% to 32%) to find the point where the sum of the production costs, reliability costs, and incremental capacity costs is minimized. The image below shows the winter EORM from the TRM Study.

[37] Georgia Power response to Staff JKA-6-1 subpart d.
[38] Georgia Power response to Staff JKA-6-1 subpart d. These diversity factors are reflected in calculation E contained in the capacity position calculations provided in Georgia Power's response to STF-JKA-2-2 Attachment B.
[39] Production costs include the cost of generation (such as fuel and variable O&M) and costs of market purchases.
[40] Reliability costs include the cost of expected unserved energy, emergency market purchases, and the cost to call demand response resources.



Winter EORM U-Curve from the TRM Study[41]

In its 2022 IRP analysis, Georgia Power found this point to be 24.25%,[42] but included an additional step to calculate the potential to mitigate high-cost outcomes using the Value at Risk ("VaR") metric. After also evaluating the VaR metric, Georgia Power increased the EORM from 24.25% to a 26% risk-adjusted EORM.

Q: IN THE TRM STUDY DEVELOPED FOR THE 2022 IRP, WHAT RESOURCE DID GEORGIA POWER USE AS ITS REFERENCE FOR THE INCREMENTAL CAPACITY COST OF NEW GENERATION?

A: Georgia Power used the cost of a combustion turbine ("CT") for the incremental capacity cost of new generation in the determination of the EORM. As Georgia Power stated in the TRM Study:

[41] Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Figure III.1 at 38.
[42] *Id.*

> *For the type of analysis performed in this study, where the objective is to balance the cost of the incremental capacity with the reliability benefits achieved by that capacity addition, it is necessary that the capacity considered represents a true reliability addition, as opposed to an addition for both reliability and energy economics. As such, simple-cycle CT technologies are the appropriate resources to be utilized for the evaluation. Therefore, the cost associated with advancing a CT one year is the cost of capacity used in the analysis. This cost is also known as the "economic carrying cost" or one-year deferral cost associated with that resource.*[43]

Q: CAN THE COST OF NEW GENERATION HAVE AN IMPACT ON THE RESULTING EORM?

A: Yes. It is an essential input into that analysis. Therefore, it is possible that changes in the cost assumption for the capacity of the new generation could impact the EORM. If the capacity price of the new generation is lower, then there will be an economic case for a higher EORM. However, if the capacity price of the new generation is higher, this would have the opposite effect and the EORM will be lower.

Q: DO YOU KNOW WHAT COSTS GEORGIA POWER USED FOR NEW GENERATION IN THE 2022 TRM STUDY?

A: I am not sure what capital costs were used to develop the economic carrying costs of the CTs in the TRM Study developed for the 2022 IRP, because I do not have access to the inputs Georgia Power used to calculate the carrying costs. Given the timing of the TRM study and its development as an input into the Aurora modeling performed for the 2022 IRP, it is likely that the cost was similar or the same as what was modeled by Georgia Power in the resource mix study that was a part of the 2022 IRP.

Q: HOW DO THE COSTS COMPARE BETWEEN THE CTS THAT GEORGIA POWER MODELED IN THE 2022 IRP AND THIS 2023 IRP UDPATE?

A: **Table 13** below shows the capital, fixed operations and maintenance ("O&M"), and variable O&M costs that Georgia Power modeled for CTs in the 2022 IRP and the 2023 IRP Update. The capital cost for CTs in the 2023 IRP Update increased [redacted] from the 2022 IRP.

[43] *Id.* at 29 – 30.

	2022 IRP	2023 IRP
Overnight Costs ($/kW)	[redacted]	
Fixed O&M ($/kW-yr)		
Variable O&M ($/MWh)		
Maintenance Capital ($/kW-yr)		

Table 13. 2022 and 2023 IRP Cost Comparison for CT with SCR[44]

Q: IS IT POSSIBLE THAT THE TRM CALCULATED BY GEORGIA POWER WILL BE DIFFERENT WHEN THE TRM STUDY IS UPDATED?

A: Given the magnitude of the increase in the capital costs of the CTs between the 2022 IRP and the 2023 IRP, it is possible that when Georgia Power performs an updated TRM study the EORM may not be the same as what was calculated in the TRM Study, and it could possibly be lower. Georgia Power reported that sensitivities were performed on the capital cost of the incremental capacity generation as part of the 2022 TRM Study, but the table with those results was redacted. As a result, I am unable to compare the capital costs from the 2023 IRP Update to the costs evaluated in the sensitivity analysis in the TRM Study.

Q: WHAT IMPACT COULD THIS HAVE ON GEORGIA POWER'S CAPACITY POSITION?

A: The TRM Study performed for the 2022 IRP showed that at a LOLE of 0.1 days per year, or the minimum threshold to have adequate reliability for the system, the resulting winter TRM is 20%. **If the TRM Study was reevaluated with a higher capital cost for the CTs, it is possible that the EORM would fall down to the 20% minimum needed** to meet the LOLE standard. If there is a decrease to the TRM then Georgia Power would not need as much additional capacity as it claims in the 2023 IRP Update.

Q: DOES A LOWER TRM MEAN THAT THERE WILL BE A HIGHER PROBABILITY OF LOSS OF LOAD?

A: It is true that there is a tradeoff between resource adequacy and costs. However, the 20% winter TRM still meets industry standard LOLE. A reduction in the TRM does not mean that Georgia Power customers would have to accept a less reliable electric supply than is available from other U.S. utilities. To provide context for this difference in capacity, under

[44] Georgia Power response to TS-STF-JKA-2-14 Attachment D.

the load forecast proposed by Georgia Power for this IRP Update, the difference between a 26% TRM and a 20% TRM is approximately 1,185 MW of winter capacity in 2028.

Q: DID YOU EVALUATE HOW A CHANGE IN THE TRM COULD IMPACT GEORGIA POWER'S CAPACITY NEEDS?

A: Yes. I also looked at Georgia Power's winter capacity position under P95 load with consideration of the difference in capacity between Georgia Power continuing to have its current winter TRM and if the winter TRM was the minimum threshold to meet the LOLE standard, which Georgia Power found to be at a reserve margin of 20%. **Table 14** shows that if one uses a 20% reserve margin and the P95 load forecast and accounts for the proposed Mississippi Power and Santa Rosa PPAs, Georgia Power has enough capacity to meet the 20% reserve margin until 2028, when the shortfall is about 633 MW.

	2024	2025	2026	2027	2028
Surplus (Shortfall) for 20% TRM	1,891	2,539	1,569	52	-633

Table 14. Georgia Power Winter Capacity Surplus (Shortfall) Under P95 Load Forecast and a 20% Reserve Margin (MW)

C. Georgia Power's Procurement of Resources

Q: PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS RELATED TO GEORGIA POWER'S PROCUREMENT OF RESOURCES.

A: I recommend that the Commission direct Georgia Power to immediately begin an expedited competitive procurement process for BESS resources. As described above, I do not believe that the Yates CTs are necessary to meet Georgia Power's capacity needs at issue in this IRP Update. So I recommend that the Commission defer consideration of the necessity of the Yates CTs until the full IRP process in 2025. Alternatively, if the Commission is inclined to approve purchasing additional capacity, I recommend the Commission direct Georgia Power to immediately begin an expedited all-source RFP process, so that the CTs can be tested against the market.

Q: CAN YOU DETERMINE HOW THE RESOURCES CHOSEN BY GEORGIA POWER IN THIS FILING COMPARE TO THE PRICES FOR SIMILAR RESOURCES IN THE MARKET?

A: No. The resources chosen by Georgia Power were not selected as a result of an RFP process, and it is unknown how these projects compare on an economic basis to the pool of projects that should be considered as resource options.

Q: CAN YOU EXPLAIN WHAT YOU MEAN WHEN YOU SAY "POOL OF PROJECTS"?

A: Yes. There are several potential projects that could be determined to be economic through an RFP process, including the projects chosen by Georgia Power in this filing, the projects that bid into the RFI issued by Georgia Power, projects that are in the interconnection queue and might have entered the queue after RFI responses were due, or possibly even projects that did not respond to the RFI but may respond to an RFP, since an RFP sends a stronger signal to potential respondents on the intention of the utility to procure capacity. In addition, as part of this filing, Georgia Power has revealed that it is evaluating additional BESS projects at the site of existing company owned or PPA solar facilities; those projects could also hypothetically respond to an RFP.[45]

Q: DO YOU HAVE ANY REASON TO BELIEVE THAT AN RFP PROCESS MAY YIELD A LOWER COST PORTFOLIO OF RESOURCES?

A: I do believe that an RFP process is the best way to ensure that the most cost effective portfolio of resources are pursued to meet capacity needs As part of my work on IRPs and certificates of public convenience and necessity ("CPCN") cases across many different jurisdictions, I have had the opportunity to participate in RFP stakeholder meetings and review RFP bid information. In some cases, utilities have conducted RFPs ahead of performing capacity expansion modeling to determine the bids to pursue and in other cases, utilities have pursued RFPs following the commencement of an IRP. In both cases, I have been able to review bid information, subject to a nondisclosure agreement. As a result, I cannot share specific values due to the confidential nature of the information, but I can say that I have seen a trend of differences in price points between PPAs and owned resources. These differences indicate there is a price premium for utility-owned resources.

Q: WHAT RECOMMENDATIONS DO YOU HAVE SPECIFIC TO THE BESS PROJECTS (INCLUDING BESS + RENEWABLE PROJECTS) THAT GEORGIA POWER HAS REQUESTED APPROVAL OF?

A: I recommend that the Commission direct Georgia Power to issue a BESS RFP as soon as possible on an expedited basis. Under the most likely load growth scenario, Georgia Power will have more than enough capacity to meet its load and a 26% reserve margin through

[45] Georgia Power response to STF-PIA-4-16 subpart d.

2026. An RFP should be issued to buy 1,410 MW of BESS resources to be deployed in 2027 and 2028. Based on the RFI results, there are at least 1,400 BESS resources that currently plan to be available by 2027 and 2028. And by issuing an expedited RFP, the projects proposed by Georgia Power could be tested against the market's ability to provide similar resources. This will ensure that the portfolio of resources selected to meet projected capacity needs will be based on an economic comparison of projects.

Q: WHAT CONCLUSIONS HAVE YOU DRAWN CONCERNING THE PLANT YATES CTS?

A: First, as described above, the CTs are not necessary to meet Georgia Power's most likely load requirements during the time frame at issue here (2024-2028).

Second, it is not reasonable for customers to buy a 45-year, 1,400 MW resource to meet the 300 MW need identified by Georgia Power's own modeling. The Aurora modeling performed as part of the resource mix study indicated that CTs were not selected as economically optimal until 2028, and the level of CTs selected in 2028 (300 MW) is substantially less than the capacity of the proposed Plant Yates CTs (1,400 MW).

Third, there is incomplete information about alternative options that could be pursued by Georgia Power. It is not clear if Georgia Power considered or evaluated the potential to site battery storage resources at the Plant Yates facility. Georgia Power's discovery responses have indicated that analysis around evaluating the potential to add BESS was related to existing PPA and company owned solar facilities. Georgia Power's testimony in this case indicated that transmission screens were only performed for resources proposed in this 2023 IRP Update (not for all possible resources outside of what Georgia Power proposed in this filing).[46] There are potential cost and transmission tradeoffs between adding CTs instead of BESS at the Plant Yates site. Adding BESS at Plant Yates would allow the project to qualify for the 10% energy community tax credit bonus under the Inflation Reduction Act since Yates' coal units were retired in 2015. This means that any BESS added at the site would qualify for an investment tax credit ("ITC") of 40%. It is also unclear if adding BESS at the Yates facility would require the same transmission upgrades

[46] Georgia Power Direct Testimony at 52.

that are needed to facilitate the addition of the proposed Yates CTs.[47] Without being able to compare the costs of the proposed Yates CTs to a BESS alternative, it is not possible to know if a strategy to build CTs instead of BESS is foregoing potential cost savings.

Q: WHAT RECOMMENDATION DO YOU HAVE FOR THE YATES CTS PROPOSED BY GEORGIA POWER IN THIS FILING?

A: The Commission should defer consideration of the need for the Yates CTs until the 2025 IRP, which is a process designed to plan for a longer time-horizon than this abbreviated IRP Update, and which will include comprehensive transmission, economic, and environmental planning. In addition, as described above, the Commission will have the benefit of additional historical information about the behavior of the new large load coming to Georgia and will also have the benefit of a new reserve margin study using the most up-to-date economic information.

In the alternative, if the Commission believes additional capacity is necessary, I recommend that the Commission direct Georgia Power to expedite the upcoming all-source RFP, which would allow Georgia Power to bid in the Yates CTs against alternative resources, such as the thermal resources proposed in Georgia Power's RFI responses and company-owned and market-driven solar and battery projects.

Q: DO YOU HAVE ANY RECOMMENDATIONS RELATED TO LANGUAGE THAT SHOULD BE INCLUDED IN THE RFP?

A: Yes. Georgia Power should include language within an all-source RFP that expressly solicits BESS project proposals at the Plant Yates facility to take advantage of the energy community bonus that would increase the ITC for those projects.

In one of its recent RFPs, Indiana Michigan Power Company ("I&M") allowed for similar projects to be proposed for its portion of the Rockport Plant site, which I&M plans to retire. I&M included this language[48] in the RFP:

[47] In response to STF-GS-1-1 Georgia Power indicated that BESS was not studied as an option to reduce, defer, or eliminate transmission upgrades needed to facilitate the delivery of power for the proposed CTs at Plant Yates.
[48] The ownership requirement as stated in the RFP language is specific to the requirements that would have to be followed for projects to reuse the injection point when the Rockport unit retires and would not be a requirement for any new projects sited at the Yates facility since the transmission service required for the Plant Yates 1-5 was not preserved after the units retired on April 15, 2015 (Georgia Power response to STF-JKA-2-25 subpart d related to the transmission service for Plant Yates 1-5).

A portion of the retiring Rockport Plant site will be available for bidders to propose Combustion Turbine (CT) generation projects as well as Energy Storage projects for participation in the RFP; no other technologies will be considered at this time for the Rockport site. I&M will offer the Rockport injection point to offsite projects of any generation type, however, such proposals will need to demonstrate site control that does not introduce an unacceptable level of risk and uncertainty with respect to execution, schedule, and cost. Additionally, such projects must demonstrate compliance with all aspects of the RFP. Bids on the Rockport site or proposing to use the Rockport injection point will be limited to PSAs only; PPAs will not be considered.[49]

Q: WHAT ARE SOME OF THE COSTS ASSOCIATED WITH THE YATES CT PROJECT?

A: The estimated in-service capital cost for the CTs is $[redacted];[50]

The transmission related costs for the Yates CTs are approximately $80,000,000.[51]

On February 14, Georgia Power supplemented its document responses and indicated that it estimated that by the end of this docket (in April 2024), if the CTs are not approved Georgia Power would still request recovery from customers of **approximately $250 million, which consists of approximately 70% development costs (already incurred) and 30% cancellation costs**.[52] (A large portion of the project development costs include [redacted].)

[49] 2023 I&M All-Source RFP at 5. Retrieved from https://imallsourcerfp.com/wp-content/uploads/2023/04/2023-IM-All-Source-RFP-3-31-23.pdf
[50] Technical Appendix 6 – "TS Technical Information Supporting the Proposal to Develop up to 1400 MW of CTs."
[51] Georgia Power response to TS-STF-DEA-4-1 Attachment.
[52] Georgia Power response to TS-STF-LA-1-23 Supplemental (Georgia Power agreed by e-mail that approximations of these figures are not Trade Secret information).
[53] Georgia Power response to TS-JKA-2-29 Attachment A at 3.

Q: IF THE COMMISSION ADOPTS YOUR RECOMMENDATION AND DEFERS CONSIDERATION OF THE PLANT YATES CTS UNTIL 2025, DO YOU AGREE WITH GEORGIA POWER'S RECOMMENDATION THAT ITS CUSTOMERS SHOULD PAY FOR THE MONEY IT HAS ALREADY SPENT ON THE CTS?

A: If the Plant Yates CTs are not approved, then Georgia Power plans to request recovery of approximately a quarter of a billion dollars.[54] I disagree with Georgia Power's request to charge existing billpayers for these expenses. Georgia Power opted to make decisions related to the proposed Plant Yates CTs outside of an economic procurement process through an RFP and it is unknown how the economics of the Plant Yates CTs compare to other resource alternatives.

V. FLEX CAPACITY FRAMEWORK AND OWNERSHIP REQUIREMENT

Q: WHAT IS THE "FLEX CAPACITY" FRAMEWORK THAT GEORGIA POWER IS REQUESTING APPROVAL OF IN THIS FILING?

A: In this filing Georgia Power is asking for approval of a "Flex Capacity" framework which would allow the Company to seek approval for additional capacity before the 2025 IRP if an updated load forecast results in projections of additional capacity needs. If an update to the load forecast presented in this filing results in a 500 MW or greater capacity, then Georgia Power would be able to recover the costs of activities related to bringing new capacity resources online. As stated in the Company's filing:

> *The Flex Capacity framework would authorize Georgia Power to undertake and recover the cost for preliminary development activities in connection with the development, operation, and ownership of new capacity resources. Additionally, the Company would be authorized to continue to explore PPA or acquisition options that could be presented for Commission approval and certification prior to the filing of the Company's 2025 IRP and recover any incremental cost incurred for this effort.*[55]

Q: DO YOU HAVE A RECOMMENDATION FOR GEORGIA POWER'S REQUEST TO RECEIVE APPROVAL FOR THE FLEX CAPACITY FRAMEWORK?

A: The Commission should deny this request. This request is unnecessary. Even if the unfathomable circumstance arose whereby the Commission denied **all** of Georgia Power's

[54] Georgia Power response to TS-STF-LA-1-23 Supplemental.
[55] Georgia Power Direct Testimony at 50 - 51.

new chosen resources **and** the statistically unlikely 95% load growth actually materialized, Georgia Power still would not need any new resources until 2026 (when it would still have enough capacity to meet its projected need plus a 23% reserve margin). Furthermore, the Flex Capacity framework authorization related to "undertake and recover the cost" concerns me given actions that Georgia Power has taken related to the proposed Plant Yates CTs and the significant costs (approximately $250 million) that could be billed to customers for their development costs prior to Commission approval. The Flex Capacity framework as proposed by Georgia Power could result in ratepayers being put in a similar situation in the future where they bear the risk of Georgia Power's expenses spent on generation resources that may not be needed to serve an expanded customer base.

VI. CONCLUSION

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	**Docket No. 55378**
2023 Integrated Resource Plan Update	)	

EXHIBIT CH-1

Chelsea Hotaling Consultant

ENERGY FUTURES GROUP

Professional Summary

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such as IRP analyses and has critiqued IRP modeling performed using Aurora, PLEXOS, PowerSimm, and System Optimizer. Chelsea has also conducted capacity expansion, production cost, and reliability modeling using the Aurora, PLEXOS, and SERVM models. Chelsea has experience working with numerous software programs including Python, R, and Stata.

Education

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2011

Experience

2021-present: Consultant, Energy Futures Group, Hinesburg, VT

2020-2021: Senior Analyst, Energy Futures Group, Hinesburg, VT

2019-2020: Analyst, Energy Futures Group, Hinesburg, VT

2018-2019: Intern, Sommer Energy, Canton, NY

2016-2019: Research Assistant, Clarkson University, Potsdam, NY

Selected Projects

- The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Performed SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP (2023). Performed EnCompass and SERVM modeling to evaluate a clean energy replacement portfolio as an alternative to the preferred plan presented in Santee Cooper's 2023 IRP (2023).

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- The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar. Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP. (2022 to 2023)
- GridLab. Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to 2023)
- Sierra Club. Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Appalachian Citizens' Law Center, and Mountain Association. Reviewed and provided comments on Kentucky Power's 2023 Integrated Resource Plan. (2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association. Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)
- The Department of Attorney General and Sierra Club. Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)
- The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar. Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)
- Colorado Office of the Utility Consumer Advocate. Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)
- Minnesota Center for Environmental Advocacy. Evaluation of Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to present) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)
- Earthjustice. Evaluation of PREPA's request for proposals for temporary emergency generation. (May 2020) Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- The Council for the New Energy Economics. Reviewed and provided comments on Evergy's 2023 IRP Annual Update. (2023) Reviewed and provided comments on Evergy's 2022 IRP Annual Update. (2022) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- EfficiencyOne. Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)

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- Southern Alliance for Clean Energy. Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)
- Washington Electric Cooperative. Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)
- Coalition for Clean Affordable Energy. Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)
- Citizens Action Coalition of Indiana. Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs (April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs. (December 2019)
- Institute for Energy Economics and Financial Analysis (IEEFA). Evaluation of National Grid's long-term natural gas capacity report. (March 2020) Evaluation of the Puerto Rico Energy Commission's proposed wheeling regulation. (March 2019) Co-author for the report Retail Choice Will Not Bring Down Puerto Rico's High Electricity Rates. (August 2018) Evaluation of the Puerto Rico Energy Commission's proposed microgrid rules. (February 2018)

Publications

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. Energy Policy, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. Energy Policy, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. Environmental Hazards, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine, edited by Alex Q. Huang and Wencong Su. Elsevier.

Chelsea Hotaling Consultant

Expert Testimony

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief,* on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. *In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC,* on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. *In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC,* on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. *Application for a Determination of Ratemaking Principle*, on behalf of Environmental Intervenors.

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief,* on behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*, on behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

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CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light** was filed with the Public Service Commission in Docket No. 55378 by electronic delivery on the 15th of February, 2024. An electronic copy of same was served upon all parties listed below by electronic mail as follows:

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MS. WHITFIELD: And, Mr. Chair, on behalf of the Governments, I ask that the gentlemen be allowed to share their summary of their testimony.

CHAIRMAN SHAW: Very well.

You may proceed.

MR. RICHETTA: Hello. Good morning, Mr. Chairman and Commissioners.

CHAIRMAN SHAW: Good morning.

MR. RICHETTA: Today I'm here on behalf of the Georgia Coalition of Local Governments to provide an overview of an established energy resource that can be adopted as either an alternative or a complement to the resources that are being evaluated in this case. This resource, the virtual power plant, represents a clean, modular, and affordable option for meeting load growth on the accelerated time frame that rapid economic development requires.

Virtual power plants are networks of distributed energy resources that can be dispatched as a single aggregated unit, or as a multitude of locationally specific clusters, in order to perform authentic grid services for the energy system. Ultimately, the virtual power plant should be viewed as a grid-balancing mechanism, enabled by both smooth, dispatchable, clean energy generation that

is harnessed and harmonized with the needs of the grid by way of an energy storage system, paired with flexible resources and highly responsive load shapes.

The virtual power plant can provide a wide range of grid services, including becoming a non-wired alternative to distribution system infrastructure investments, demand response during peak periods of peak load and system congestion, capacity planning or resource adequacy, energy products targeting peaking load power plant mitigation, frequency response, mitigation of the duck-curve effect, nonspinning reserves, voltage support, reverse demand response, and backup power system resiliency.

Virtual power plants can include three broad categories of resources -- generation resources like rooftop solar, energy storage resources like batteries, and controllable loads like EV chargers and smart thermostats. However, it is important to note that generation resources that are intermittent and non-dispatchable fail to meet our definition of a virtual power plant node; hence, the need for an energy storage technology.

My testimony will focus primarily on rooftop

solar and battery storage as resources that, when paired together under the control of a battery energy storage system, are uniquely poised to scale at the pace and magnitude that changing energy demands require. That said, this should not be construed as a recommendation against adoption -- adopting a VPP with greater resource diversity outside of solar and batteries.

For your information, Sonnen, Inc. is a nationally renowned energy storage and virtual power plant software company based in Stone Mountain, Georgia. Our parent company is the sonnenGroup, which was founded in Wildpoldsried, Bavaria, Germany, in 2008. We currently have more than 180,000 batteries installed worldwide and virtual power plants operating in five countries across three continents, including the largest residential virtual power plant in Europe, based in Germany, at more than 250 megawatt-hours of energy storage capacity, and the largest direct utility-dispatched residential storage-based VPP in the United States, dispatching multiple grid services on a daily basis, known as Wattsmart, with vertically integrated utility in Rocky Mountain Power in Utah.

The Wattsmart solar and battery VPP has more

than 3,300 customers enrolled in Utah today, representing more than 41 megawatt-hours of clean, dispatchable energy, and greater than 20 megawatts of capacity. Through the Wattsmart program, residential and commercial customers receive upfront and ongoing incentives from Rocky Mountain Power to purchase a battery that can be dispatched by the utility in response to grid needs.

The key distinguishing feature of the Wattsmart program, which we are proud of, are the frequency of dispatches every day, the depth of the grid services value stack being dispatched, which is up to eight grid services per day at this point, and the direct nature of the utility dispatch without the use of aggregator DERMs in the middle.

While some VPP programs focus primarily on infrequent periods of grid stress -- not that there's anything wrong with that -- the Wattsmart program is dispatched daily, sometimes two to four times per day, for a multiple of grid services. In addition to the following -- to following a daily cycle of absorbing excess solar energy during the day to be consumed in the evening, the batteries are available to provide other grid services, automatically dispatched by the utility's grid

management system based on real-time needs, OSI's Monarch system, including demand response, frequency response, and additional ancillary services.

In this way, the Wattsmart program has found a critical balance, we believe, between the interests of the utility, program participants, and nonparticipants. The utility receives a flexible and dispatchable resource that mitigates challenges from uncontrolled solar; participants receive a pathway to a return on investment for distributed solar, with the added bonus of backup power; and nonparticipants enjoy lower energy bills through avoided or reduced investment in capacity resources that are used only a fraction of the time, solar without batteries.

The benefits of a VPP are even more significant in a proceeding like this one, where time is of the essence but the exact pace and magnitude of load growth is uncertain. While many utility-scale resources are modular, in increments of tens or hundreds of megawatts, virtual power plants allow modularity down to the kilowatt or kilowatt-hour level. Moreover, instead of having lead times measured in many years, the architecture for a virtual power plant can be rolled out in a matter of

months, and resources can be added in a matter of weeks.

With new federal tax credits for battery storage, restored federal tax credits for distributed solar, and more federal funding than ever for clean energy projects, there is no shortage of customer interest in the resources that make up a VPP.

My colleague, Mr. Posner, will now speak to several programs that are currently in place on -- or on the horizon here in Georgia that are expected to result in exponential growth in the distributed solar and storage industry, as well as trends he is seeing towards greater customer interest in storage.

Andy.

MR. POSNER: Thank you, Blake. Good morning, Mr. Chairman and Commissioners.

I'm -- this is my first time testifying before the Commission. I'm very honored to do so.

As Mr. Richetta mentioned, the purpose of my testimony is to outline trends in the clean energy industry that are driving greater customer interest in the solar and storage technologies that would be critical to the success of a VPP.

My name is Andy Posner again. I'm the founder

and CEO of Capital Good Fund. We are a U.S. Treasury-certified Community Development Financial Institution, or CDFI. We are based in Rhode Island, but we include -- offer inclusive financial services in eleven states, including Georgia.

In September of last year, we launched the Georgia BRIGHT program, which is one of the first solar leasing programs where a nonprofit is the lessor. And we chose Georgia for the pilot, despite, or perhaps because it's a difficult market for solar, but we see a lot of opportunity for impact through this model.

So under this program, we're doing solar and storage leasing for low-income homeowners, specifically those earning less than 100,000. Low to moderate income, I should say. As well as solar energy purchase agreements for mission-aligned entities.

The program offers customers solar at no upfront cost, with monthly lease payments that are structured to allow for day one energy savings. Customers can also add battery storage to their lease, though this typically results in payments that are roughly equivalent to, or even slightly higher than, expected savings.

In fact, when we first developed the program, we expected about 20 percent of customers to offer storage. Though we're still in the early stages of the pilot, almost two-thirds have opted for storage thus far, even though, like I said, sometimes that has resulted in a slight increase in their bill.

And we believe that's because customers value the security of having backup power, as well as being protected against future electricity price increases.

If this Commission were to implement a virtual power plant program like the Wattsmart batteries program, I am very confident that nearly all customers would pursue storage. There are several reasons for this confidence. As I discuss in my written testimony, the Inflation Reduction Act of 2022 made programs like Georgia BRIGHT possible by restoring the solar tax credit to 30 percent, creating a 30 percent tax credit for standalone storage, creating adders for projects in energy communities and low-income communities, and allowing tax-exempt entities, like us, as well as governments and other entities to receive the credits as a direct payment.

These changes, particularly the so-called

direct pay provision, make it easier than ever for local governments, churches, nonprofits, and others to pursue solar either for themselves or on behalf of disadvantaged communities.

In addition to these structural changes, there are several federal funding opportunities on the horizon that will greatly accelerate investment in solar and storage. Most notably is the EPA Solar for All program, which will bring up to 250 million to the state to deploy solar in disadvantaged communities and will be announced any day and we're eagerly awaiting the announcements.

Several parties, including the members of the Coalition of Local Governments, applied for this funding for Georgia, which will allow us to serve tens of thousands of households over the next five years.

Based on these factors, our panel offers three key recommendations: First, the Commission should direct Georgia Power to evaluate the Rocky Mountain Power program and similar program models and bring a VPP program proposal to the Commission for approval within 180 days of the conclusion of this proceeding. The proposal should include proposed upfront and participation incentives and their

justifications, administrative cost estimates, estimated implementation timelines, and other relevant information. This process should include opportunities for stakeholder input from parties to the docket.

Second, the RNR tariff should be modified to eliminate system size limits for solar energy systems paired with storage. In other words, residential customers should be allowed to have systems greater than 10 kilowatts, and commercial customers should be allowed to have systems greater than the current limit of 125 percent of their peak demand or 250 kilowatts. This change should be made to maximize the amount of solar energy and battery capacity that's available for utility control via the virtual power plant.

Finally, the Commission should direct Georgia Power to develop and file a plan for expediting interconnection and witness testing of -- testing of customer-sited solar energy and storage systems to support maximum resource availability to meet the capacity needs identified in the docket.

I'll conclude by stressing that these recommendations should be adopted in this proceeding and not reserved until the 2025 IRP. To take full

advantage of the Solar for All funding that is coming this year, we need to have amplifying structures like a VPP in place as those programs are being designed and rolled out. Acting now on future-proof investments like solar and storage is critical to protecting ratepayers against stranded assets, volatile fossil fuel prices, and the risks of overbuilding or building too quickly.

Thank you for your attention and I look -- we look forward to taking questions.

CHAIRMAN SHAW: All right.

MS. BROWN: Mr. Chair, this panel is now available for questions from Commissioners and cross-examination.

CHAIRMAN SHAW: Okay. Thank you.

You mentioned in your summary -- and, you know, I'm on the residential side cap at 10 and then 250 on the commercial side. You -- you mentioned that those should be raised, but what -- what limit are you recommending?

MR. POSNER: I don't know that we're recommending a limit per se. It's just that currently we kind of have to undersize systems. And if you add batteries, you know, that allows you to have a larger system to make full use of the solar

and to fully charge a battery.

I don't know that we've recommended a particular size -- cap.

CHAIRMAN SHAW: Okay. But in your experience, I mean, what do you think on an -- on an average residential system what that number would need to be to avoid what you're referring to?

MR. POSNER: It's difficult to say. Because for low-income customers, it's smaller because they typically have smaller homes. But one of the things we want to make clear is that, you know, we're talking about doing 13 -- 3,200 low-income installations for residential and 1,300 community facilities. But this program would benefit moderate to middle to upper middle income families, or even upper income, many of whom could use 15-, 20-, 25-kilowatt systems.

I live in Los Angeles. I have a 16-kilowatt system paired with a 26-kilowatt-hour battery. My house is fully electrified and that isn't even enough to fully meet my needs. I just ran out of roof space.

So I don't know. I -- if it's okay, I could take it under advisement and come back with a recommendation. I don't want to speak too

off-the-cuff. But that's the thinking behind it.

CHAIRMAN SHAW: So your -- your response would be the same on the commercial side, too, on a -- on a proposed number?

MR. POSNER: Even more so on the commercial side.

CHAIRMAN SHAW: Okay.

MR. RICHETTA: I'd like to add on to it -- the answer. So if the concern that we're probably bringing up here is the general system constraints and the energy system in general and why these caps are in place in the first place, okay, first, let's talk about specifying what we're referring to.

Are we referring to kilowatt power peak of a solar array? Are we referring to the power from the energy storage system in kilowatts? Are we referring to the energy reservoir in the battery or kilowatt-hours? These, of course, are three entirely separate things.

Now, as it pertains to the system limitations, I just want to point out from a technical perspective, which, of course, batteries is my -- are my expertise. So from an electrochemical perspective, a battery is not a load. A battery is actually electrochemical storage.

And why this is a critical piece of information is Rocky Mountain Power went through quite an experience, quite a journey on this topic until they started to -- and I welcome Rocky Mountain Power to come speak with you guys, as well. I know they would be interested in it.

But in learning something that had already been adopted in the European Union, which is that -- in much of the European Union, okay, we can't just add a battery's power capacity to load because it doesn't make any sense. It's not a load, especially if the utility controls it.

Okay. Well, solar is a generator. And if that generation cannot be harnessed by the electrochemical storage and is, therefore, going to inject into the grid intermittently, then, of course, you have very real reasons to be concerned with size of the system.

But if your solar is generally sized appropriately for load and the size of the energy reservoir of the battery, then you have little to no need to be concerned about unfettered intermittent injection and -- especially if Georgia Power is controlling it. And you don't have to be concerned about: Okay. Is this going to be a load --

additional load, the battery itself?

Hopefully I could -- I can go into a lot more detail, but hopefully that gives you some more things to think about, as far as these caps. Because the caps can be changed to be appropriate with the science of the actual system.

CHAIRMAN SHAW: All right. Commissioners.

VICE-CHAIRMAN ECHOLS: Hey, thanks for being here. Georgia Power, you know, they -- they want to add batteries to, you know, all the -- the big solar that we have. So I think, in principle, they really like this concept because it's helping our winter peak. You're charging them the day before and you're dumping them in the morning when we've got that peak. And then, you know, the -- you know, the problem is averted.

So what you're talking about is just scaling it down; right? Just taking this same model that they like and just doing it on a home-by-home, business-by-business basis; right?

Is it generally the same concept?

MR. RICHETTA: Yeah. I'd say that, technically speaking, there is -- there are very nice additional benefits to having energy storage nodes that are at the end of the distribution system, adjacent to the

customer load. And that decentralized version of a battery network or swarm breathing has some benefits around grid infrastructure management, feeder management, and -- I won't say congestion, but at least the possibility of a very utilized grid.

And that is fundamentally different in some cases than energy storage systems that are very large that are upstream that are utility-scale, front-of-the-meter. So there's nothing wrong with utility-scale front-of-the-meter batteries that are fantastic, but it's slightly different use case from a grid management perspective than the distributed tiny batteries at the end of the distribution.

But, in general, what you're saying is completely true. It's just, I guess, it is -- well, you used the right word. It's a different flavor and it is a flavor that can add enormous value and provide some other benefits, like backup power for people.

And, also, I guess, the final piece, if I was speaking for Rocky Mountain Power, which I'm not, the idea that folks -- some folks really would like solar in their homes and this makes it so that this asset can be controlled and be turned into a real asset for the grid and not into something that could

actually cause rates to increase and stress on the load.

VICE-CHAIRMAN ECHOLS: You mentioned congested circuits or whatever. I mean, could it be that this is more valuable in certain places than others?

And that maybe we could send a price signal or some kind of a higher rebate to -- to that group? Have you ever seen that done where a specific -- specific geographical locale on the grid got something and maybe others didn't?

And does that cause people to be envious or upset or confused when -- when you do something like that?

MR. RICHETTA: I mean, the entire virtual power plant mechanisms around the world, what I could say is in general that -- although, that -- that is a really neat idea and people like it at first and they approach it, sometimes it ends up being difficult to implement and confusing to folks. And you end up having these weird -- at least when I benchmark what happened in Germany and Italy, it -- it ends up being this weird thing where certain groups of people think they're being cheated out of -- it's -- anyway. But, you're right, that this would scientifically be accurate that you could --

and economically connect a price signal to a specific locale.

What we saw in Utah was: Look, here's the deal. We want to scale this thing and really work on learning what this thing can actually do for the grid. And once we scale it and iterate on it, we will go ahead and see what the locational value is in certain markets or certain feeders and execute on specific programs for subprograms.

In other words, there's a program for the state for all people. The same program no matter where you live in Rocky Mountain Power. It's easy. You sign up, you get your check, boom.

Then we start seeing the solar contractors in the industry who are driven by Rocky Mountain Power to sell in certain areas. And then all of a sudden you have more density in certain local pockets and load pockets and then Rocky Mountain Power starts to play with that cluster. So the customer doesn't know that they're even in a more valuable place.

But, anyway, that's my answer.

MR. POSNER: If I may briefly, I -- I live in a fire zone. And so Southern California Edison offered me an additional incentive for adding my storage because, obviously, we're more prone to

outages where I live.

VICE-CHAIRMAN ECHOLS: What additional incentive did they offer you?

MR. POSNER: It was about $5,000 for a 26-kilowatt-hour system.

VICE-CHAIRMAN ECHOLS: Was it a rebate? Utility rebate?

MR. POSNER: Yes, it was --

VICE-CHAIRMAN ECHOLS: So you showed your receipt and you got that?

Did you also get a tax credit?

MR. POSNER: I did. At the time it was a 26 percent tax credit, but I -- I did get one, yes.

VICE-CHAIRMAN ECHOLS: What was your net cost by the time you got all that money?

MR. POSNER: It was a whole --

CHAIRMAN SHAW: Under -- under 10,000?

MR. POSNER: Probably a little bit more than that. Like 12.

VICE-CHAIRMAN ECHOLS: Let me ask you about the limits. Is there any -- is there any safety concern for, you know, upping these limits?

I know when we set these limits, or approved these limits, batteries weren't really a thing back then; right? So now it has kind of changed the math

on it; right?

So -- but is there a safety concern about -- about the limits?

MR. RICHETTA: Yeah, for sure. So, again, just to -- I'm a proud American, but I can benchmark Europe a lot because I work for a European company.

You know, the reality is we went through this journey a long -- much earlier. The energy storage market became very prevalent in Germany in 2009, which was kind of ancient history back here for that. And so we have this huge amount of history -- not huge, but -- regarding this type of thing.

Electrochemically speaking, of course, battery thermal runaway is something that should be understood and should be embraced as a -- a topic to be concerned about. And what has happened both in Europe and in the U.S. is that really good standards have started to be put in place.

All batteries are not the same. Even within the lithium family, batteries are not the same as it pertains to their chemical -- electrochemical properties for thermal runaway between anode, cathode, and electrolyte.

And what that basically boils down to is this: As an example, if you're talking about a cathode

that is lithium nickel manganese cobalt oxide, or nickel cobalt aluminum, these -- and the specific way that a battery is built for an electric car, you can have thermal runaway very easily with that cell.

If you're talking about a lithium iron phosphate cell or the cathodes that are in phosphate and the anhydrous graphite, this is a completely different type of thing. And UL 9540A has really done a nice job for -- I think for our country at defining: If you pass these standards, your battery is clearly safe.

And there's a bunch of parameters around what that means and how it can be installed. So one thing I'd say is I think the data is very clear. It is my personal opinion that having a broad brushstroke over all batteries, which, with all due respect, for instance, happened in New York City where they were very sensitive, but there was no sense around: Well, is this battery safe or not? Well, it's just a battery. So, no.

In markets where safety standards have been set and UL 9540A has been embraced, what you find is no change to safety. In fact, it's just as safe as having no battery.

As it pertains to solar arrays, I won't speak

to that because that's not my expertise. But from the battery perspective, hopefully that gives you some point. Bottom line is use -- use 9540A, put a standard in place, and batteries work very nicely.

VICE-CHAIRMAN ECHOLS: Yeah. Another reason for the Commission and the utility to be involved in approving these things.

MR. RICHETTA: Yep.

VICE-CHAIRMAN ECHOLS: I mean, my colleague was wishing for a battery expert yesterday. I think -- I think we have one here today.

I mean, I learned about battery safety at our car auction; right? Because we were constantly jump -- jumping off junk cars; right?

MR. RICHETTA: Uh-huh.

VICE-CHAIRMAN ECHOLS: And you put -- you know, on a lead acid battery, you hook it up wrong, it blows up in your face and you have acid, you know, all over you.

MR. RICHETTA: That's nasty.

VICE-CHAIRMAN ECHOLS: Yeah. That was -- you know, that was something in my -- you know, at 11 when I was out there driving that little Jeep and, you know, pulling vehicles through, my -- my dad made sure I --

MR. RICHETTA: It stayed in your mind; right?

VICE-CHAIRMAN ECHOLS: -- understood that.

Last question. I mentioned yesterday about the Green Mountain model of leasing their batteries. They've been doing that for five or six years, maybe more, versus the Rocky Mountain Power.

Why do you think the Rocky Mountain Power model is -- is superior to the utility -- it seems like if we let the utility, you know, have a role in this and they -- they own the batteries and they were -- you know, they were benefiting from it, that -- that it would be -- you know, they're setting it up. They've got the visibility.

It seems like the safety concerns regarding the thermal runaway would be taken care of. It just seems like having the utility handle it would provide for an overall better experience.

Am I wrong there?

MR. RICHETTA: No, not that you're wrong. It's a different philosophy. I can give you the pros and cons from what I can see.

I mean, certainly one of the issues Rocky Mountain Power had is they want scalability and they wanted to move quickly. And the scalability of having people own their own device or have financing

for their own device seemed to be a very scalable model.

Is it scalable and Green Mountain Power is doing it? I'm not saying it's not. Rocky Mountain Power's program is much larger now than theirs in a shorter period. But that's okay. It's not to say one's faster or one's better or anything.

Having the utility own it and making it part of their infrastructure investment and their -- even rate basing that investment and things of this nature, it seems like that's a very interesting place.

So the question is: Is that -- is that -- to me, is it fast enough? Is it scalable enough? And do you have any issues with the consumer?

Now, a lot of consumers are probably going to say: No. That sounds good. Put -- utility can own a battery at my house, that's fine.

But then there's a lot of people who we know are going to take issue with that. And, of course, with Wattsmart it doesn't matter.

Now, if Bill Comeau from Rocky Mountain Power were here, which he's not -- but if he was, he -- he would probably say something to the sense of: Also, it is much lower cost for Rocky Mountain Power to

give people incentives to spend their own money than to spend utility money.

And so they've done a cost analysis that shows: Wow. You make this workable for consumers and -- and they don't have to spend the money on it.

And so -- but the -- but the points you made were also salient.

VICE-CHAIRMAN ECHOLS: All right.

MR. RICHETTA: Which are -- yeah.

VICE-CHAIRMAN ECHOLS: Okay.

MR. POSNER: In our -- if I may add, in our modeling, the incentive we propose would make the difference between storage being a bill swap or slight bill increase and it saving money for everybody. And so I think from my vantage point, you kind of unlock the market with that upfront incentive and let customers and private installers just go nuts and install -- I mean, there's what, seven -- 11,000 rooftop arrays now. A lot of them don't have storage. I bet most of those folks would add it with this incentive, not to mention new -- new customers.

VICE-CHAIRMAN ECHOLS: Thank you so much.

MR. POSNER: Yeah.

CHAIRMAN SHAW: Any other questions from the

bench?

(No response.)

CHAIRMAN SHAW: All right. Georgia Public Service Commission.

CROSS-EXAMINATION

BY MR. THOMAS:

Q Hey, good morning. On page 5, line 13 of your testimony, you stated that you have more than two dozen households enrolled in the Georgia BRIGHT solar leasing program.

Do you know what percentage of those enrollees are Georgia -- Georgia Power customers?

A (Witness Posner) Roughly two-thirds. I could get the exact number, of course.

Q Okay. And have you contacted Georgia Power about your virtual power plant proposal?

And if so, what -- what was their response?

A (Witness Posner) I haven't myself contacted them about it, no. I don't know if the Coalition has.

MR. THOMAS: Okay. That's all the questions I have.

CHAIRMAN SHAW: Okay. Thank you, Mr. Thomas.

Going down the list, Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers

Association.

MR. DUNBAR: No questions.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

MR. COX: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. McNUTT: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: We don't have any questions for this panel today.

CHAIRMAN SHAW: Redirect.

MS. BROWN: Can I clarify a Commissioner question?

CHAIRMAN SHAW: I'll allow it.

CROSS-EXAMINATION

BY MS. BROWN:

Q Good afternoon, Panel. Or I guess it's still morning. It feels like afternoon.

Chairman Shaw was asking a question about the size limits for solar. Mr. Posner, in your experience, do you see that sometimes solar arrays don't use the full

roof space that's available because of economic incentives?

A (Witness Posner) Correct. Due to the avoided cost and lack in the metering, we're always undersizing systems, utilizing far less than we would be able to otherwise.

Q And in the Georgia BRIGHT program, has it typically been the case that systems equipped with storage have been larger solar arrays, as well?

A (Witness Posner) That's correct. The average system without storage is about 4 to 5 kilowatts, and with storage is 8 to 10.

Q Okay. And Commissioner Echols asked a question, Mr. Richetta, about locational value. Specifically, if the utility had a transmission or distribution congestion issue, could the utility market a virtual power plant program more aggressively in that area to mitigate that need?

A (Witness Richetta) Yeah, of course. And I guess that's an add-on to his earlier question that the value of this should be very much for Georgia Power, the whole energy system, and the consumer.

Q And one final question on that. Commissioner Echols asked about the value of letting the utility have a role. Can you speak to the level of control that Rocky

Mountain Power has over the batteries in Wattsmart?

A (Witness Richetta) Well, good question. An enormous amount of control. I mean, they are dispatching a -- this battery network multiple times a day for an entire suite of grid services.

They have all kinds of value models of what they've been able to defer, what energy costs, what peaking power plant mitigation they've done duck-curve mitigation. And this was all based on batteries that people own throughout the state that they have paid to have that ability to control.

MS. BROWN: Wonderful. Thank you so much.

I ask that the direct testimony be moved into the record and the witnesses be excused.

CHAIRMAN SHAW: So marked.

Gentlemen, thank y'all for your time. You can be excused.

The next panel to be called up will be that of Georgia Interfaith Power & Light.

I'll let you call your panel, Ms. Whitfield, and swear them in.

MS. WHITFIELD: Georgia Interfaith Power & Light calls Chelsea Hotaling to the stand.

And if Mr. Sherrier may pass out our demonstrative?

CHAIRMAN SHAW: Sure.

MS. WHITFIELD: Ms. Hotaling, if you could please raise your right hand.

CHELSEA HOTALING,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. WHITFIELD:

Q Please state your full name for the record and spell your last name for the court reporter's benefit, please.

A My name is Chelsea Hotaling. The last name is spelled H-o-t-a-l-i-n-g.

Q And by whom are you employed, Ms. Hotaling?

A Energy Futures Group.

Q And on whose behalf are you testifying today?

A Georgia Interfaith Power & Light.

Q On February 15th of this year, did you prefile or cause to be prefiled both a trade secret and a public disclosure version of 31 pages of direct testimony in question-and-answer format in Docket 55378?

A I did.

Q Did you also cause to be prefiled along with your testimony an attachment, your CV?

A I did.

Q Ms. Hotaling, do you have any corrections or

changes to your prefiled direct testimony or attachments at this time?

A I do not.

Q If I were to ask you the same questions that appear in your prefiled testimony at the hearing today under oath, would your answers be the same?

A Yes, they would.

MS. WHITFIELD: Chairman, I move to have the public disclosure version of Ms. Hotaling's direct prefiled testimony entered into the record as if given orally from the stand.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled public disclosure direct testimony of Chelsea Hotaling follows:)

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February 15, 2024

VIA ELECTRONIC DELIVERY

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

Re: Direct Testimony on Behalf of Georgia Interfaith Power & Light; Docket No. 55378

Dear Ms. Tanner:

Please find enclosed an electronic version of the following **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light** to be filed in Docket No. 55378.

Please also find enclosed an electronic version of the Trade Secret version of the Direct Testimony of Chelsea Hotaling on behalf of GIPL. Additionally, the testimony will be delivered to the Commission in hard copy, including a sealed envelope containing the Trade Secret version of Ms. Hotaling's testimony.

Respectfully submitted,

Jennifer Whitfield
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Counsel for GIPL

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	
Georgia Power Company's 2023	)	**Docket No. 55378**
Integrated Resource Plan Update	)	
	)	
	)	

DIRECT TESTIMONY OF CHELSEA HOTALING
ON BEHALF OF GEORGIA INTERFAITH POWER & LIGHT

February 15, 2024

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I. INTRODUCTION

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

A: My name is Chelsea Hotaling. I am a Consultant at Energy Futures Group, located at 30 Court Street, Canton, New York, 13617.

Q: MS. HOTALING, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A: I have worked for seven years in electric utility regulation and related fields. I have reviewed dozens of integrated resource plans ("IRPs") and related filings by utilities in Arizona, Colorado, Kansas, Kentucky, Indiana, Iowa, Michigan, Minnesota, Missouri, Montana, New Mexico, Nova Scotia, Puerto Rico, and South Carolina. I have performed my own capacity expansion, production cost, and reliability modeling in numerous cases using multiple models including EnCompass, Aurora, PLEXOS, and the Strategic Energy & Risk Valuation Model ("SERVM").

I received a Bachelor's Degree in Accounting and Economics from Elmira College in 2011. I also received a Master of Business Administration Degree in 2012, a Master's Degree in Environmental Policy in 2019, and a Master's Degree in Data Analytics in 2020, from Clarkson University. My resume, included as **Exhibit CH-1,** provides additional detail regarding my professional and educational experience.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. No, I have not. I have filed testimony before the Public Service Commission of West Virginia, the Public Service Commission of South Carolina, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Iowa Utilities Board, and the Colorado Public Utilities Commission.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: I am testifying on behalf of Georgia Interfaith Power and Light ("GIPL").

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I was asked to review the assumptions and recommendations Georgia Power Company ("GPC" or "the Company") made related to its 2023 IRP Update,[1] with a focus on the load forecast, new resource assumptions, and Georgia Power's proposed pathway for meeting projected load growth.

Though I reviewed the entire filing, I focused on the resources needed to meet the projected load growth between now and the winter of 2028/2029.

Q: WHY DID YOU FOCUS ON MEETING ENERGY NEEDS BETWEEN NOW AND THE WINTER OF 2028/2029?

A: Georgia Power has indicated that the period of load that it is addressing in this IRP Update is narrow: today through the December 2028.[2] Georgia Power has repeatedly indicated that the All-Source and Battery Energy Storage System RFPs that were approved in the 2022 IRP would address capacity needs beginning in the winter of 2028/2029.

[1] On December 4, 2023, Georgia Power Company submitted and requested approval to procure several resources including: two Power Purchase Agreements ("PPAs"), up to 1,000 MW of battery energy storage systems ("BESS"), up to 1,400 MW from combustion turbine ("CT") resources, two new customer-sited distributed energy resource ("DER") programs, one new demand response program, an amendment to one existing demand response program. Georgia Power also asked for approval of the proposed Flex Capacity framework and transmission system improvements related to the resources requested in the Company's filing. Georgia Power 2023 Integrated Resource Plan Update ("IRP Update Main Document").

[2] Georgia Power 2023 IRP January 16, 2024 Hearing Transcript "Hearing Transcript" at 479:2-4.

II. SUMMARY OF RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: My recommendations are as follows:

1. Load Forecast

a. The Commission should only approve resources sufficient to meet the most likely load growth to occur, which has been identified by Georgia Power's modeling at the 50th percentile (or P50).

b. The Commission should direct Georgia Power to track specific data that will improve the accuracy of future forecasting for large-load customer growth.

2. Proposed Resources

a. The Yates CTs are not necessary to support Georgia Power's projected capacity needs between now and 2028, even if the Commission uses Georgia Power's extreme growth estimates (P95).

i. I recommend that the Commission defer consideration of the Yates CTs until the 2025 IRP, when it will have the benefit of a fulsome long-term planning process. In the alternative, the Commission should direct Georgia Power to expedite the upcoming all-source RFP to determine the economically optimal portfolio of resources to meet projected capacity needs.

ii. The Commission should not charge billpayers for the approximately $250 million in expenses that Georgia Power has identified as its development and cancellation costs if the Yates CTs are not approved.

b. Battery Energy Storage Solutions are sufficient to meet Georgia Power's capacity needs between now and 2028, and they can be competitively procured.

i. I recommend that the Commission direct Georgia Power to issue an expedited BESS RFP for at least 1,410 MW as soon as possible.

3. Flex Capacity

a. A flex capacity framework is unnecessary; it unnecessarily shifts the Company's risk-taking from its shareholders to its customers. The Commission should deny this request.

III. GEORGIA POWER'S LOAD FORECAST

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ABOUT GEORGIA POWER'S LOAD GROWTH.

A: Georgia Power has relied on a generally accepted statistical method to forecast new load growth coming to Georgia, but Georgia Power's interpretation of its own forecast unreasonably overestimates the pace of growth. Georgia Power relies on a load projection that its own statistical analysis suggests will be higher than actual demand 95% of the time. However, Georgia Power's statistical method also identified the capacity-needs that are **most likely** on an annual basis, and I recommend that the Commission plan to acquire resources to meet that probable need (identified as P50 or the 50th percentile).

Q: PLEASE BREAK THAT DOWN FOR ME. TO START, WHAT HAS CHANGED SINCE THE 2022 IRP THAT HAS RESULTED IN THIS NEW LOAD FORECAST DISCUSSION?

A: Georgia Power has reported a change to the load forecast that was modeled for the 2022 IRP as a result of large-load customers (that Georgia Power calls "economic development projects") responding to the economic growth and business opportunities in the state. This has resulted in a significant difference between the load growth projected in the 2022 IRP and Georgia Power's chosen load growth projections for this 2023 IRP Update. By December 2028, Georgia Power is now planning for 4,094 MW more than it projected during the 2022 IRP. Its own projections, however, suggest that 3,141 MW of growth through 2028 is most likely.

Winter Peak	GPC 2022 IRP Budget	GPC Most Likely Load Growth (P50)	GPC 2023 IRP Planning (P95)	Difference between 2022 IRP and 2023 Update (P50)	Difference between 2022 IRP and 2023 Update (P95)
2024	15,581	15,268	15,283	(313)	(298)
2025	15,636	15,796	15,947	160	312
2026	15,657	16,790	17,256	1,133	1,599
2027	15,673	18,163	18,928	2,490	3,255
2028	15,657	18,798	19,751	3,141	4,094
2029	15,757	19,390	20,551	3,633	4,793
2030	15,796	19,966	21,326	4,170	5,530
2031	15,957	20,408	21,880	4,451	5,923

Table 1. 2022 IRP Winter Peak Load Forecast Compared to 2023 IRP Update Forecast[3]

Q: GEORGIA POWER'S NEW LOAD FORECAST RELIES ON A NEW APPROACH TO FORECASTING. DO YOU AGREE THAT A NEW FORECASTING APPROACH IS NEEDED TO CAPTURE GEORGIA'S LARGE LOAD GROWTH?

A: Yes. Traditionally, Georgia Power uses linear regression to develop the baseline load forecast used in the IRP planning process. This methodology relies on traditional economic and demographic variables as drivers of energy use. Since these models are based on the historical trends for the different variables included in the model, it is challenging for the traditional forecast to be able to account for the large-load projects arising from the economic growth Georgia is experiencing. As a result, it is reasonable for Georgia Power to supplement its baseline forecasting approach with another methodology to try to forecast this distinctive rapid, large load growth.

Q: HOW DID GEORGIA POWER DEVELOP THE LOAD FORECAST MODEL THAT WAS USED IN THIS 2023 IRP UPDATE?

A: Since the load growth experienced by Georgia Power in the last two years is not captured in traditional load forecast models, Georgia Power's load forecast model[4] attempted to capture the uncertainty around several variables, including the probability of the "economic development projects" successfully coming online, the timing of the load coming online or experiencing delays, and the level at which load will materialize relative to what the customer initially indicated it would demand. Specifically, Georgia Power decided to

[3] Extrapolated from data provided in Georgia Power's response to STF-PIA-4-13 Attachment and DEA-1-5 Att. B.
[4] The load forecast model is referred to as the "Load Realization Model" in the workpapers provided by Georgia Power with this filing.

utilize the @RISK software which performs Monte Carlo simulations on variables specified by Georgia Power to try to capture the uncertainty related to the load growth.

Q: WHAT IS A MONTE CARLO SIMULATION AND WHY IS IT USED HERE?

A: A Monte Carlo simulation is a widely accepted statistical process that helps estimate the probability of uncertain events. In this case, the Monte Carlo simulation was designed by Georgia Power to estimate the probability (likelihood) that certain amounts of load will actually be demanded by large customers on its system.

Q: PLEASE DESCRIBE THE VARIABLES GEORGIA POWER USED IN ITS MONTE CARLO SIMULATION TO ESTIMATE THE UNCERTAINTY OF ITS FUTURE LARGE LOAD DEMAND.

A: The first variable in the model is what Georgia Power calls the probability of "Project Success," which represents a compilation of three separate inputs:

(1) Whether the project will be located in the state of Georgia (P1)

(2) Whether Georgia Power will be selected as the electric service provider for the project (P2)

(3) The success rate of the project after the contract is signed (P3)

Table 2 below shows an example of how these three inputs were set up in what Georgia Power calls the "Load Realization Model" to represent the different combinations that arise from the assumptions Georgia Power made for each of these three inputs. For P1, each project was assigned either a [redacted] or [redacted] value. For P2, each project was assigned a value of [redacted], [redacted], [redacted], or [redacted]. P3 is the success rate that Georgia Power has reported for its historical projects. Georgia Power has stated that it has a recent success rate of about [redacted] for projects coming online after a service contract is signed.[5] Overall Project Success is based on the product of P1 x P2 x P3. The product of these three factors is ultimately the input that is factored into the Monte Carlo simulations for the model.

[5] Georgia Power response to STF-DEA-1-13.

GA as State Selection (P1)	GPC as Provider (P2)	Project Reaching COD (P3)	Project Success (P1xP2xP3)
[redacted]			

Table 2. Project Success: Input Variables in the Load Realization Model

The value reported for the Project Success represents the percentage of times that the load will materialize in each simulation. For example, if a project has a success value reported at [redacted], that means that out of the 100,000 combinations that are drawn in the Monte Carlo simulation, the number of iterations in the model simulation where the announced load is included is based on the project success value, or [redacted].[6]

The other two variables included to capture uncertainty in the load forecast model include the probability that the announced load for the project will be different from the load that materializes (Metered vs. Announced Load) and the probability that the Commercial Operation Date ("COD") of the project will be delayed. Georgia Power assigned both of these variables a triangular distribution with a low, mid, and high value. Georgia Power has acknowledged that without historical data, the triangular distributions have been assigned to reflect what it considers the minimum, maximum, and most likely outcomes.[7] The value for each of the six potential customer segments is shown in **Table 3**.

[6] Georgia Power response to STF-DEA-1-16 subpart b.
[7] 2023 IRP Update Technical Appendix ("Technical Appendix") 7, TS-Load and Energy Forecast at 18.

	Minimum	Most Likely	Maximum
Cryptocurrency	[redacted]		
Datacenter			
Miscellaneous			
Warehouse			
Distribution			
Industrial (All Segments)			

Table 3. Metered vs. Announced Load: Triangular Distribution Values

Within the model, the metered vs. announced load variable is used to scale the announced load of the project according to the ramp-up schedule[8] that is also specified in the model. For example, the announced load for a project might be 300 MW, but there is some uncertainty around whether this full level of load will materialize, as it could be less than 300 MW. With regard to this uncertainty, Georgia Power stated, "… based on Georgia Power's experience, the load announced by a customer is only an estimate of its metered load, which can materialize at a lower level than that at the time of the customer's initial announcement."[9] The model will interpret this uncertainty by pulling from the low, mid, and high values that Georgia Power has specified for the customer segments. In the example I referenced above, if the project is at 300 MW of announced load, then that project will materialize as a percentage of that announced load in the Load Realization Model (i.e., if the simulation run picks a maximum value of 75%, the 300 MW load will appear as 225 MW in the outputs).

Table 4 below shows the triangular distribution values for Commercial Operation Date ("COD") delay. Based on the values specified by Georgia Power, this means that the maximum delay for any project in the model is [redacted] months and the most likely value is [redacted] months.

[8] The ramp-up schedule reflects that the entire load is typically not required on Day-1 of a project. For example, if a project has an announced load of 300 MW, it might expect to need 100 MW on Day-1 and then ramp up by 50 MW each year to reach the 300 MW announced load by 2027.
[9] Technical Appendix 7, TS Load and Energy Forecast at 16.

	Minimum	Most Likely	Maximum
Commercial Operation Date ("COD") Delay	[redacted]		

Table 4. COD Delay (Months): Triangular Distribution Values

Once the @RISK model performs 100,000 draws on these uncertain variables, the load for each potential project is added together to arrive at the portfolio level load projection each year that Georgia Power then includes as an adjustment to the baseline load forecast.

Q: DID GEORGIA POWER'S LOAD REALIZATION MODEL PROVIDE A SINGLE ESTIMATE FOR PROJECTED LOAD?

A: No. Georgia Power's Load Realization Model is based on 100,000 simulations, with each individual simulation representing a different estimate of potential load growth based on the assumptions that Georgia Power assigned to the uncertain variables. The 100,000 simulations are then combined to give a range of possible load growth and to show how likely it is for each load projected to actually occur.

As a matter of statistics, the most likely load growth scenario is the data point in the middle, where 50% of the scenarios project more growth and 50% of the scenarios project less growth. This data point is referred to as P50, or the 50th percentile. Similarly, probabilities can be assigned to all the other data points as well. P05 (the 5th percentile) and P95 (the 95th percentile) describe load forecasts where just 5% of the scenarios run are lower or higher than that amount of load. In other words, scenarios smaller than P05 or larger than P95 are very unlikely to occur.

Q: DID GEORGIA POWER ALSO PROVIDE THE RESULTS OF THE 50TH PERCENTILE?

A: Yes. In addition to the total winter load forecasts shown in Table 1, Georgia Power provided the new large-load-only P50 forecast in response to a discovery request from Public Interest Advocacy ("PIA") Staff.[10] **Table 5** below shows a comparison between the 95th and 50th percentiles resulting from Georgia Power's Load Realization Model for new large-load projects. In year 2026, the 95th percentile load level indicates that 95% of

[10] Georgia Power response to TS-STF-DEA-1-5 Attachment A.

potential load outcomes are less than [redacted] MW and only 5% of the possible load outcomes are higher than [redacted] MW.

Year	P95	P50
2023	[redacted]	
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		

Table 5. Comparison of the P95 and P50 Load Forecasts[11]

Q. HOW DID GEORGIA POWER DECIDE WHICH PART OF THE LOAD REALIZATION MODEL'S LOAD GROWTH RANGE TO USE?

A: Georgia Power chose to plan for P95: That means that Georgia Power is planning for bigger load growth than its own simulation says it needs 95% of the time.[12] Said another way, Georgia Power is planning for more load growth than its model says will be needed in 95,000 out of the 100,000 simulations run.[13]

Georgia Power provided many explanations for choosing the high-end of possible load (P95) in its testimony:

- "[P95] was chosen because it supports the ask that we have in front of this Commission."[14]

[11] Technical Appendix 7, TS Load and Energy Forecast Table 1.5.2.3-1 at 20 and Georgia Power response to TS-STF-DEA-1-5 Attachment A.
[12] Technical Appendix 7, Load and Energy Forecast at 3. As Georgia Power stated, "[…] P95 indicates a load level where 95% of all potential combinations fall at or below this level, and 5% of the load combinations fall above it."
[13] Hearing Transcript at 378:4-8.
[14] Hearing Transcript at 378:21-23.

- "[P95] accommodates for the rapid growth that we have seen throughout 2023 where different sensitivities that we did were doubled a couple of times throughout the year."[15]
- "[P95] accommodates for the current capacity market conditions."[16]
- "[T]hat higher load level was chosen because that's what we expect the State's load growth to be. . . . [W]e continue to see load growth outrunning the forecast."[17]
- "From a statistical perspective, yes, I agree that the P50 level represents the median of the range of all potential outcomes. But for the purposes of this IRP, we're picking a higher-level degree to represent the increases in the load that we have seen throughout 2023 and because it's a better level to plan . . . for our resources."[18]
- "[T]here's a lot more risk on the upper side than the lower side."[19]

Q: IS IT REASONABLE TO USE THE P95 FORECAST FOR THIS IRP UPDATE?

A: No. It is not reasonable to plan for a load scenario that is at or higher than 95% of modeling scenarios for this IRP Update.

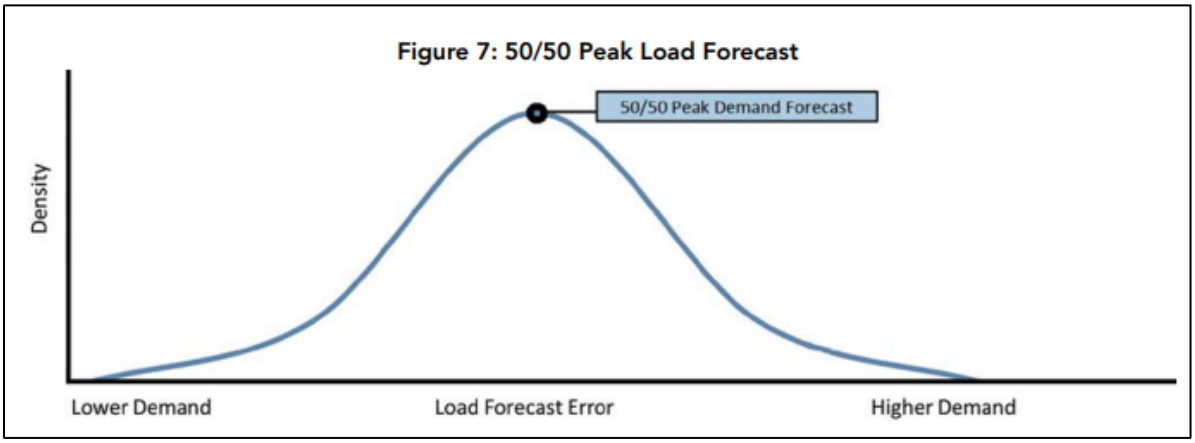
Q: WHY IS IT UNREASONABLE TO USE THE P95 FORECAST FOR THIS IRP UPDATE?

A: Georgia Power should base planning on the 50th percentile (P50) for a few reasons:

First, load forecasts that utilities use as inputs for capacity expansion models are typically 50/50 forecasts, which means there is a 50% chance of an over-forecast (meaning the forecast is higher than actual needs) and a 50% chance of an under-forecast (meaning the forecast is lower than actual needs), as reflected in the below image.[20] (Notably, for the

[15] Hearing Transcript at 378:23-379:1.
[16] Hearing Transcript at 379:1-2.
[17] Hearing Transcript at 379:3-8.
[18] Hearing Transcript at 382:20-383:1.
[19] Hearing Transcript at 379:8-9.
[20] NARUC, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms, November 2023, at 18. Retrieved at: 0CC6285D-A813-1819-5337-BC750CD704E3 (naruc.org)

Southern Company System, load forecasting erred on the side of over-forecasting every year between 2000-2017.[21])



The same idea applies here: The 50th percentile is the median of the load level in the model. Intuitively, using P50 is logical, because it uses the modeling for the very purpose for which the model was developed: To estimate the most likely outcome. Here, Georgia Power used a Monte Carlo simulation to make an informed projection about how demand will grow in Georgia. The 50th percentile reflects a balance between demand that may or may not materialize.

Second, I agree with Georgia Power's written testimony that it is reasonable to "plan for a probable amount of customer choice load and avoid overestimating load additions that could add unnecessary capacity to the electric system."[22] **The 95th percentile, used by Georgia Power, will be an overestimation 95% of the time.** As a matter of basic statistics, **the 50th percentile is the amount of load that is more likely to occur than not—or, is probable.**

Third, Georgia Power's Target Reserve Margin ("TRM") already accounts for the risks inherent in load forecasting. Georgia Power has one of the largest winter reserve margins among its Southern peers.[23] And Georgia Power's TRM explicitly accounts for load

[21] IRP Update Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Table 1-3.
[22] Georgia Power Direct Testimony at 19:20-22.
[23] Hearing Transcript at 501:11-16; *see also, e.g.*, Hearing Transcript at 502:1-3; 2023 Long-Term Reliability Assessment December 2023, North American Electric Reliability Corporation, at 83&91; 2023 Resource Adequacy

forecasting error.[24] In addition, as I will discuss in more detail in the next section, Georgia Power plans for a higher reserve margin than utilities typically plan for, which is a loss of load expectation ("LOLE") of one day in ten years or 0.1 days per year. In the 2022 IRP TRM Study, the minimum reserve margin for Georgia Power was found to be 20%, but Georgia Power took additional steps to evaluate the economics and risk components for a reserve margin higher than 20%.

Fourth, I disagree with Georgia Power's oral testimony which suggested that using the 95th percentile of growth is justified by either "rapid load growth" or by the observations that load growth is "outrunning the forecast." **To the contrary, rapid load growth is exactly what this model is designed to capture, using probabilities assigned by Georgia Power**.

The model incorporates estimates of the likelihood of each project's overall success. As I discussed earlier in my testimony, the project success variable is based on the probabilities chosen by Georgia Power for (1) the project selecting Georgia as the state to locate in, (2) the project selecting Georgia Power as the electric service provider, and (3) the likelihood of projects materializing after a contract has been signed. Table 1 provided the unique project success values contained in Georgia Power's Load Realization Model based on the input assumptions for each project. **Table 6** below shows the total announced load contained within the Load Realization Model based on the probability of Project Success. The model interprets the Project Success value as the percentage of iterations where the project will be considered a success, and the announced load will be included in the model and reflected in the resulting total level of load for Georgia Power. This shows that the announced loads with lower levels of project success are being considered in the Load Realization Model and the announced load of these lower probability of success projects are being factored into the load model.

Study for Duke Energy Carolinas & Duke Energy Progress (Reserve margins below 21%), Astrape Consulting, at 3; 2023 Virginia Electric and Power Company, Integrated Resource Plan 2023 at 59 (Reserve margins below 15%).
[24] IRP Update Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Figure III.1 at 13.

Project Success	Announced Load
[redacted]	

Table 6. Announced Load Based on Project Success

Fifth, I have seen no support for Georgia Power's oral testimony that there is "a lot more risk from the upper side than the lower side."[25] Risk is frequently considered as part of system planning, but in this case, the risk of overbuilding the system versus the risk of underbuilding has a very different dynamic than typical risk-benefit assessments of load growth. In large part, that is because **Georgia Power's projected load is largely from customers that it is not obligated to serve.**

If Georgia Power adds capacity to meet the projections of P50, there is an equal chance that Georgia Power will overbuild as underbuild. If Georgia Power overbuilds (meaning load demand ends up being lower than P50), existing customers will incur unnecessary costs for that additional capacity. As summarized succinctly by Georgia Power, "If we're wrong [about load growth], that would not be beneficial for customers."[26] If Georgia Power underbuilds (meaning load demand ends up being significantly higher than P50), then Georgia Power may need to forego or delay entering into customer choice contracts, which could lead large-load customers to choose a different Georgia electricity provider or choose not to locate in Georgia at all.

Table 7 below shows the announced load across different industry segments and whether that load would be located within Georgia Power's service territory or outside of the service territory. Out of all the announced load included in the Load Realization Model, over half (about [redacted]) is outside of the service territory and would fall under customer choice.

[25] Hearing Transcript at 379: 8-9.
[26] Hearing Transcript at 485:21-22.

	Announced Load (MW)		
Segment	**Inside Service Territory**	**Outside Service Territory**	**Total**
[redacted]			

Table 7. Announced Load (MW) Contained in the Load Realization Model[27]

Q: WHAT RECOMMENDATIONS DO YOU HAVE RELATED TO GEORGIA POWER'S LOAD FORECAST MODEL?

A: First, I recommend that Georgia Power plan for the load growth that its analysis estimates is most likely to occur: the 50th percentile of the load level forecasted for new customers by its Monte Carlo simulation (P50).

Second, I recommend that Georgia Power track specific datapoints relied upon in this new large-load forecasting process to inform future forecasting for large-load customers. To the extent that Georgia Power is not already doing so, I recommend that Georgia Power track (and report) data including:

a) the date first contacted by the customer,

b) the date when selections are made (the selection of Georgia as the state to locate in and the selection of Georgia Power as the electric service provider),

c) the announced load from the customer,

d) dates when any changes were made to the customer's announced load and whether that has an impact on the anticipated ramp-up schedule,

e) date the customer was connected and the first month of service,

[27] Georgia Power response to STF-DEA-6-3.

f) the actual connected load, and

g) the actual load ramp-up over time.

Based on some of the responses Georgia Power provided in discovery,[28] it appears that the Company may be tracking this information now, but if the Company is not, all of these data points are critical to help inform the decisions about what values to include for the uncertain variables in the Load Realization Model.

IV. GEORGIA POWER'S NEED FOR NEW RESOURCES

A. Georgia Power's Winter Capacity Position

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ABOUT ALTERNATIVE OPTIONS TO FULFILL GEORGIA POWER'S CAPACITY NEEDS.

A: Georgia Power does not need the proposed Yates CTs to fulfill its capacity needs in advance of the BESS and all-source RFPs designed to serve winter 2028 and beyond. Instead, approximately 1,410 MW of BESS resources, which have been identified by Aurora as the economically optimal investments, are sufficient to meet Georgia Power's near-term capacity needs under the P50 scenario. **Even if the Commission plans to meet Georgia Power's high-end 95th percentile load estimate, Plant Yates is still not necessary to meet Georgia Power's capacity needs.** Instead, a combination of BESS resources and PPAs in 2027 and 2028 could meet these needs.

Q: HOW DID YOU EVALUATE ALTERNATIVES TO GEORGIA POWER'S PROPOSED RESOURCE MIX?

A: I reviewed Georgia Power's resource mix study and the results of Georgia Power's Request for Information for capacity to the market. I also evaluated Georgia Power's winter capacity position under both the P50 and P95 load forecasts developed by Georgia Power. Then I determined which resources identified as "economically optimal" by Aurora could fulfill Georgia Power's capacity needs. I prioritized non-thermal resources, which is also consistent with the resource selection by Aurora in the time frame at issue in this IRP Update.

[28] Georgia Power response to STF-PIA-7-10.

Q: PLEASE DESCRIBE THE RESOURCE MIX STUDY RESULTS THAT YOU REVIEWED.

A: I reviewed Georgia Power's use of the Aurora model as part of its resource mix study. The Aurora modeling process identifies the economically optimal resources to meet the load growth identified by Georgia Power (P95) in order to minimize total system costs. Candidate resources are offered for selection in the model, and Aurora will select the optimal build of new resources. Georgia Power made updates to the cost assumptions for the new generic resources that were modeled for the 2022 IRP.

Q: WHICH RESOURCES DID THE AURORA MODELING IDENTIFY AS ECONOMICALLY OPTIMAL TO MEET GEORGIA POWER'S P95 LOAD BETWEEN 2024 and 2028?

A: Aurora identified the Mississippi Power PPA (for 2027 and 2028 only), solar, batteries, and 300 MW of CTs as economically optimal to meet the P95 needs identified by Georgia Power between now and 2028. **Table 8** below shows the annual incremental new resources selected in the Aurora capacity expansion modeling for the "MG0-Base GPC" run. The four-hour BESS additions between 2027 and 2028 total 1,580 MW. These resources would be incremental to the 500 MW BESS (and all-source RFP) that was ordered from the 2022 IRP, which Georgia Power assumes will be powering the grid by the end of 2028.[29]

Year	CT with SCR	MPC PPA	Solar	Battery 4-Hour
2024				
2025				
2026				
2027		750		900
2028	300		750	780

Table 8. Aurora Modeling Annual New Resource Additions (MW)[30]

Q: HOW DOES THE AURORA MODELING ALIGN WITH THE PROJECTS THAT RESPONDED TO THE REQUEST FOR INFORMATION ("RFI") ISSUED BY GEORGIA POWER?

[29] Georgia Power response to STF-JKA-3-16 indicates that the 500 MW ESS from the 2022 IRP was modeled in Aurora as the resource "O3_2022_IRP_ESS". *See also*, IRP Update Main Document at 15.
[30] Georgia Power workpaper named "PD Capacity Expansion Plans Supplemental – Errata", worksheet named "MG0 (GPC Only)".

A: Georgia Power received RFI bids for about 3,000 MW of capacity from BESS resources for 2026, 2027, and 2028.[31] About half of those resources (approximately 1,400 MW) are already planned to be available before the end of 2028.[32] Georgia Power's graphics and **Table 9** below summarize the bids received by Georgia Power. Table 9 shows the total annual nameplate capacity from the BESS and renewable plus BESS bids that Georgia Power received in response to the RFI. [33]

Resource Types	Exisiting Project	New Project	Planned Project	Not Provided	Grand Total
ESS Other (Flywheel, CO2, etc.)		4		1	5
ESS Standalone		6	7	1	14
Nuclear Energy		1			1
Solar + Storage		4	9		13
Solar Only	4				4
Thermal	4				4
Grand Total	8	15	16	2	41

[34]

Breakdown of Resource Types		
Capacity Resource Type	# of Responses	Sum of Capacity (MW)
ESS Other	4	769
BESS Standalone	13	2,695
BESS + solar	12	1,680
Solar Only (not applicable)[3]	5	1,228
Thermal (CC / CT)	2	1,243
Nuclear Energy	1	280
Total	**37**	**6,667**

[35]

	2026	2027	2028	2029	2030
BESS	[redacted]				
Renew+BESS					
Total					

Table 9. Summary of Standalone BESS and Renewable+BESS Projects (Nameplate MW)[36]

[31] Hearing Transcript at 354:10-16.
[32] Georgia Power response to TS STF-PIA-9-13, Attachment A at 1 (determined not to be Trade Secret by email exchange with Georgia Power counsel).
[33] [redacted] of standalone and renewable plus BESS resources were bid in without a specified online date.
[34] Georgia Power response to TS STF-PIA-9-13 Attachment B.
[35] Georgia Power response to TS STF-PIA-0-13 Attachment A.
[36] Based on information provided in the workpaper named "TS_ResponseDataScrubbed_ForRFISummary".

Q: PLEASE DESCRIBE GEORGIA POWER'S CAPACITY NEEDS BEFORE THE END OF 2028.

A: **Table 10** below shows Georgia Power's capacity position relative to a winter TRM of 24.43% for 2024-2026 and 25% starting in 2027 under the P50 load forecast. This capacity position look also evaluates the system with and without consideration of the additional capacity from the Mississippi Power and Santa Rosa PPAs. Table 10 shows the level of capacity that would be needed to meet the winter TRM without consideration for the Mississippi Power or Santa Rosa PPAs.

(P50 – No PPAs)	2024	2025	2026	2027	2028
Peak Demand	15,268	15,796	16,790	18,163	18,798
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	**30.9%**	**34.2%**	**26.8%**	**19.9%**	**17.5%**
Capacity Needed				918	1,410
Reserve Margin	**30.9%**	**34.2%**	**26.8%**	**25.0%**	**25.0%**

Table 10. Georgia Power Winter Capacity Position Under P50 and No PPAs

(P50 – PPAs Included)	2024	2025	2026	2027	2028
Peak Demand	15,268	15,796	16,790	18,163	18,798
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	30.9%	34.2%	26.8%	19.9%	17.5%
Add Proposed PPAs:					
MPC PPA	750	750	750	750	750
MPC PPA Sale	-500	-500			
Santa Rosa PPA		230	230	230	230
Total Existing & PPA Capacity	**20,230**	**21,676**	**22,276**	**22,765**	**23,068**
Reserve Margin	**32.50%**	**37.22%**	**32.67%**	**25.34%**	**22.71%**
Capacity Needed					430
Reserve Margin	**32.50%**	**37.22%**	**32.67%**	**25.34%**	**25.00%**

Table 11. Georgia Power Winter Capacity Position Under P50 and the PPAs

Table 11 shows that when the PPAs are included under the P50 load forecast, the capacity need for Georgia Power starts in 2028 at 430 MW. This is in comparison to the 2,400 MW worth of supply side capacity that Georgia Power is requesting.

I also evaluated the winter capacity position for Georgia Power under the P95 load forecast as shown in **Table 12** below. I calculated the level of capacity that Georgia Power would

need to arrive at the winter TRM: Under the P95 forecast, after accounting for the PPAs, Georgia Power needs 895 MW in 2027 and 1,621 MW in 2028.

(P95 – PPAs Included)	2024	2025	2026	2027	2028
Peak Demand	15,283	15,947	17,256	18,928	19,751
Total Existing Capacity	19,980	21,196	21,296	21,785	22,088
Reserve Margin	30.7%	32.9%	23.4%	15.1%	11.8%
Add Proposed PPAs:					
MPC PPA	750	750	750	750	750
MPC PPA Sale	-500	-500			
Santa Rosa PPA		230	230	230	230
Total Existing & PPA Capacity	**20,230**	**21,676**	**22,276**	**22,765**	**23,068**
Reserve Margin	**32.37%**	**35.92%**	**29.09%**	**20.27%**	**16.79%**
Capacity Needed				895	1,621
Reserve Margin	**32.37%**	**35.92%**	**29.09%**	**25.00%**	**25.00%**

Table 12. Georgia Power Winter Capacity Position Under P95 Load

B. Georgia Power's Winter Target Reserve Margin

Q: PLEASE SUMMARIZE WHAT CONCLUSIONS YOU DREW ABOUT GEORGIA POWER'S RESERVE MARGIN AND HOW IT MAY IMPACT GEORGIA POWER'S CAPACITY NEEDS?

A: Georgia Power has a higher-than-typical reserve margin, because it plans for reliability (as is typical) and then adds additional reserve margin based on economic analysis. However, in the time since the reserve margin study was completed, the primary input for the economic analysis (the cost of CTs) has changed significantly. As a result, it is likely that Georgia Power is relying on a higher planning reserve margin than could be justified if it reevaluated its economic analysis today. These outdated assumptions could lead to Georgia Power overbuilding by approximately 1,185 MW of winter capacity in 2028. Considered another way, updates to Georgia Power's reserve margin study could result in Georgia Power not needing any new capacity beyond what is provided by the PPAs before 2028, even under the P95 growth assumptions.

Q: WHAT TARGET RESERVE MARGIN ("TRM") HAS GEORGIA POWER USED IN ITS CALCULATION OF THE COMPANY'S CAPACITY POSITION?

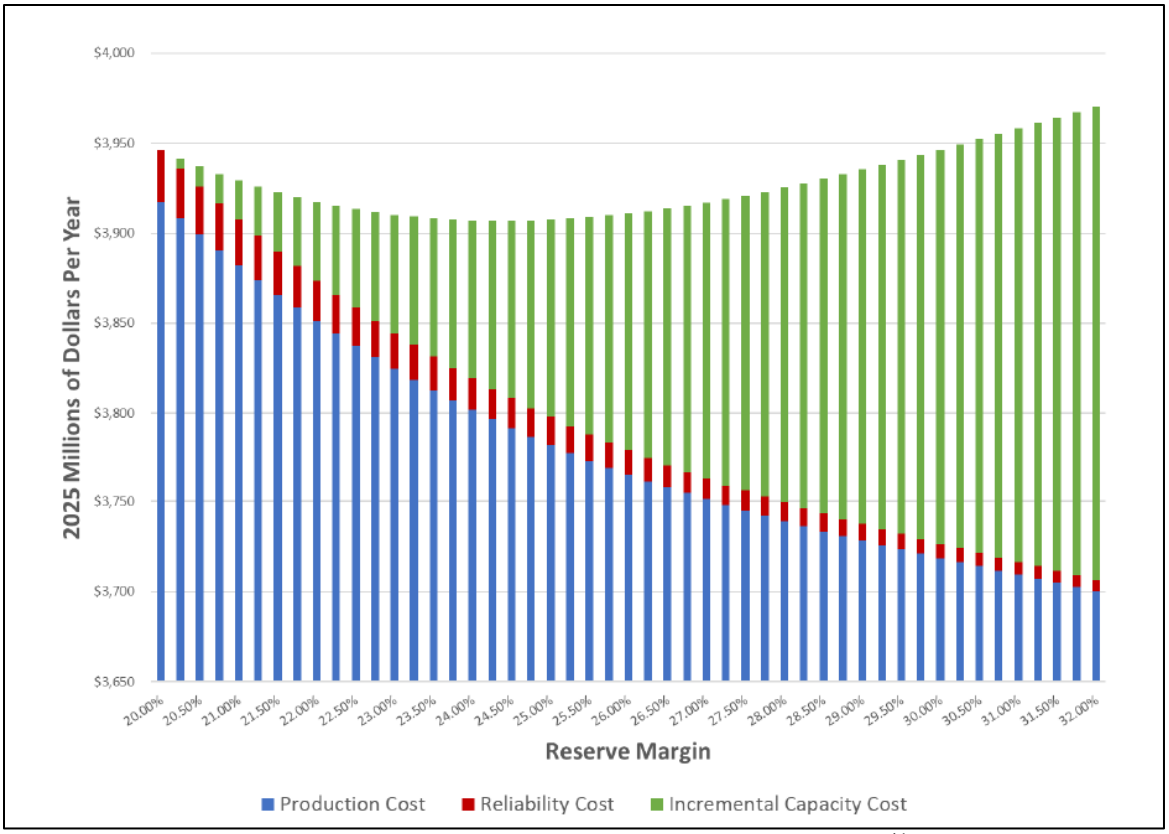
A: Georgia Power used the winter TRMs that were determined from the SERVM modeling performed for the 2022 IRP, which were 25.50% for 2024-2026 and a 26% starting in 2027

for the Southern Company System.[37] Georgia Power did not rerun its TRM study, but it did update the TRM for the 2023 IRP Update to account for updated diversity factors that are applied to the Southern Company System TRM. This means that the TRM for Georgia Power for this 2023 IRP Update is 24.43% for the short-term (2024-2026) and 25% for the long-term (starting in 2027) after accounting for this diversity factor.[38]

Q: HOW DID GEORGIA POWER DEVELOP ITS TRM FOR THE 2022 IRP?

A: Georgia Power used the SERVM model, which evaluates the ability of a system's resources to meet load across thousands of iterations that include varying assumptions around weather, the load forecast error, and generator forced outages. In many cases, utilities will develop a reserve margin based on meeting the industry standard metric of one loss of load expectation ("LOLE") in ten years or 0.1 events per year. To develop Georgia Power's TRM, Georgia Power takes any additional step to evaluate the expected costs of maintaining reserve capacity, production costs, and reliability costs to determine the economic optimum reserve margin ("EORM"). This evaluation considers the tradeoff between the costs of additional generating capacity on the system versus the improvement in resource adequacy from having those additional generating resources. Georgia Power evaluated the EORM by comparing the production[39] and reliability[40] costs, as determined by the SERVM model, to the incremental capacity cost of new generation over several different winter planning reserve margin levels (ranging from 20% to 32%) to find the point where the sum of the production costs, reliability costs, and incremental capacity costs is minimized. The image below shows the winter EORM from the TRM Study.

[37] Georgia Power response to Staff JKA-6-1 subpart d.
[38] Georgia Power response to Staff JKA-6-1 subpart d. These diversity factors are reflected in calculation E contained in the capacity position calculations provided in Georgia Power's response to STF-JKA-2-2 Attachment B.
[39] Production costs include the cost of generation (such as fuel and variable O&M) and costs of market purchases.
[40] Reliability costs include the cost of expected unserved energy, emergency market purchases, and the cost to call demand response resources.



Winter EORM U-Curve from the TRM Study[41]

In its 2022 IRP analysis, Georgia Power found this point to be 24.25%,[42] but included an additional step to calculate the potential to mitigate high-cost outcomes using the Value at Risk ("VaR") metric. After also evaluating the VaR metric, Georgia Power increased the EORM from 24.25% to a 26% risk-adjusted EORM.

Q: IN THE TRM STUDY DEVELOPED FOR THE 2022 IRP, WHAT RESOURCE DID GEORGIA POWER USE AS ITS REFERENCE FOR THE INCREMENTAL CAPACITY COST OF NEW GENERATION?

A: Georgia Power used the cost of a combustion turbine ("CT") for the incremental capacity cost of new generation in the determination of the EORM. As Georgia Power stated in the TRM Study:

[41] Technical Appendix Volume 1, Southern Company, *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, January 2022 (Public version) Figure III.1 at 38.
[42] *Id.*

> *For the type of analysis performed in this study, where the objective is to balance the cost of the incremental capacity with the reliability benefits achieved by that capacity addition, it is necessary that the capacity considered represents a true reliability addition, as opposed to an addition for both reliability and energy economics. As such, simple-cycle CT technologies are the appropriate resources to be utilized for the evaluation. Therefore, the cost associated with advancing a CT one year is the cost of capacity used in the analysis. This cost is also known as the "economic carrying cost" or one-year deferral cost associated with that resource.*[43]

Q: CAN THE COST OF NEW GENERATION HAVE AN IMPACT ON THE RESULTING EORM?

A: Yes. It is an essential input into that analysis. Therefore, it is possible that changes in the cost assumption for the capacity of the new generation could impact the EORM. If the capacity price of the new generation is lower, then there will be an economic case for a higher EORM. However, if the capacity price of the new generation is higher, this would have the opposite effect and the EORM will be lower.

Q: DO YOU KNOW WHAT COSTS GEORGIA POWER USED FOR NEW GENERATION IN THE 2022 TRM STUDY?

A: I am not sure what capital costs were used to develop the economic carrying costs of the CTs in the TRM Study developed for the 2022 IRP, because I do not have access to the inputs Georgia Power used to calculate the carrying costs. Given the timing of the TRM study and its development as an input into the Aurora modeling performed for the 2022 IRP, it is likely that the cost was similar or the same as what was modeled by Georgia Power in the resource mix study that was a part of the 2022 IRP.

Q: HOW DO THE COSTS COMPARE BETWEEN THE CTS THAT GEORGIA POWER MODELED IN THE 2022 IRP AND THIS 2023 IRP UDPATE?

A: **Table 13** below shows the capital, fixed operations and maintenance ("O&M"), and variable O&M costs that Georgia Power modeled for CTs in the 2022 IRP and the 2023 IRP Update. The capital cost for CTs in the 2023 IRP Update increased [redacted] from the 2022 IRP.

[43] *Id.* at 29 – 30.

	2022 IRP	2023 IRP
Overnight Costs ($/kW)	[redacted]	
Fixed O&M ($/kW-yr)		
Variable O&M ($/MWh)		
Maintenance Capital ($/kW-yr)		

Table 13. 2022 and 2023 IRP Cost Comparison for CT with SCR[44]

Q: IS IT POSSIBLE THAT THE TRM CALCULATED BY GEORGIA POWER WILL BE DIFFERENT WHEN THE TRM STUDY IS UPDATED?

A: Given the magnitude of the increase in the capital costs of the CTs between the 2022 IRP and the 2023 IRP, it is possible that when Georgia Power performs an updated TRM study the EORM may not be the same as what was calculated in the TRM Study, and it could possibly be lower. Georgia Power reported that sensitivities were performed on the capital cost of the incremental capacity generation as part of the 2022 TRM Study, but the table with those results was redacted. As a result, I am unable to compare the capital costs from the 2023 IRP Update to the costs evaluated in the sensitivity analysis in the TRM Study.

Q: WHAT IMPACT COULD THIS HAVE ON GEORGIA POWER'S CAPACITY POSITION?

A: The TRM Study performed for the 2022 IRP showed that at a LOLE of 0.1 days per year, or the minimum threshold to have adequate reliability for the system, the resulting winter TRM is 20%. **If the TRM Study was reevaluated with a higher capital cost for the CTs, it is possible that the EORM would fall down to the 20% minimum needed** to meet the LOLE standard. If there is a decrease to the TRM then Georgia Power would not need as much additional capacity as it claims in the 2023 IRP Update.

Q: DOES A LOWER TRM MEAN THAT THERE WILL BE A HIGHER PROBABILITY OF LOSS OF LOAD?

A: It is true that there is a tradeoff between resource adequacy and costs. However, the 20% winter TRM still meets industry standard LOLE. A reduction in the TRM does not mean that Georgia Power customers would have to accept a less reliable electric supply than is available from other U.S. utilities. To provide context for this difference in capacity, under

[44] Georgia Power response to TS-STF-JKA-2-14 Attachment D.

the load forecast proposed by Georgia Power for this IRP Update, the difference between a 26% TRM and a 20% TRM is approximately 1,185 MW of winter capacity in 2028.

Q: DID YOU EVALUATE HOW A CHANGE IN THE TRM COULD IMPACT GEORGIA POWER'S CAPACITY NEEDS?

A: Yes. I also looked at Georgia Power's winter capacity position under P95 load with consideration of the difference in capacity between Georgia Power continuing to have its current winter TRM and if the winter TRM was the minimum threshold to meet the LOLE standard, which Georgia Power found to be at a reserve margin of 20%. **Table 14** shows that if one uses a 20% reserve margin and the P95 load forecast and accounts for the proposed Mississippi Power and Santa Rosa PPAs, Georgia Power has enough capacity to meet the 20% reserve margin until 2028, when the shortfall is about 633 MW.

	2024	2025	2026	2027	2028
Surplus (Shortfall) for 20% TRM	1,891	2,539	1,569	52	-633

Table 14. Georgia Power Winter Capacity Surplus (Shortfall) Under P95 Load Forecast and a 20% Reserve Margin (MW)

C. Georgia Power's Procurement of Resources

Q: PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS RELATED TO GEORGIA POWER'S PROCUREMENT OF RESOURCES.

A: I recommend that the Commission direct Georgia Power to immediately begin an expedited competitive procurement process for BESS resources. As described above, I do not believe that the Yates CTs are necessary to meet Georgia Power's capacity needs at issue in this IRP Update. So I recommend that the Commission defer consideration of the necessity of the Yates CTs until the full IRP process in 2025. Alternatively, if the Commission is inclined to approve purchasing additional capacity, I recommend the Commission direct Georgia Power to immediately begin an expedited all-source RFP process, so that the CTs can be tested against the market.

Q: CAN YOU DETERMINE HOW THE RESOURCES CHOSEN BY GEORGIA POWER IN THIS FILING COMPARE TO THE PRICES FOR SIMILAR RESOURCES IN THE MARKET?

A: No. The resources chosen by Georgia Power were not selected as a result of an RFP process, and it is unknown how these projects compare on an economic basis to the pool of projects that should be considered as resource options.

Q: CAN YOU EXPLAIN WHAT YOU MEAN WHEN YOU SAY "POOL OF PROJECTS"?

A: Yes. There are several potential projects that could be determined to be economic through an RFP process, including the projects chosen by Georgia Power in this filing, the projects that bid into the RFI issued by Georgia Power, projects that are in the interconnection queue and might have entered the queue after RFI responses were due, or possibly even projects that did not respond to the RFI but may respond to an RFP, since an RFP sends a stronger signal to potential respondents on the intention of the utility to procure capacity. In addition, as part of this filing, Georgia Power has revealed that it is evaluating additional BESS projects at the site of existing company owned or PPA solar facilities; those projects could also hypothetically respond to an RFP.[45]

Q: DO YOU HAVE ANY REASON TO BELIEVE THAT AN RFP PROCESS MAY YIELD A LOWER COST PORTFOLIO OF RESOURCES?

A: I do believe that an RFP process is the best way to ensure that the most cost effective portfolio of resources are pursued to meet capacity needs As part of my work on IRPs and certificates of public convenience and necessity ("CPCN") cases across many different jurisdictions, I have had the opportunity to participate in RFP stakeholder meetings and review RFP bid information. In some cases, utilities have conducted RFPs ahead of performing capacity expansion modeling to determine the bids to pursue and in other cases, utilities have pursued RFPs following the commencement of an IRP. In both cases, I have been able to review bid information, subject to a nondisclosure agreement. As a result, I cannot share specific values due to the confidential nature of the information, but I can say that I have seen a trend of differences in price points between PPAs and owned resources. These differences indicate there is a price premium for utility-owned resources.

Q: WHAT RECOMMENDATIONS DO YOU HAVE SPECIFIC TO THE BESS PROJECTS (INCLUDING BESS + RENEWABLE PROJECTS) THAT GEORGIA POWER HAS REQUESTED APPROVAL OF?

A: I recommend that the Commission direct Georgia Power to issue a BESS RFP as soon as possible on an expedited basis. Under the most likely load growth scenario, Georgia Power will have more than enough capacity to meet its load and a 26% reserve margin through

[45] Georgia Power response to STF-PIA-4-16 subpart d.

2026. An RFP should be issued to buy 1,410 MW of BESS resources to be deployed in 2027 and 2028. Based on the RFI results, there are at least 1,400 BESS resources that currently plan to be available by 2027 and 2028. And by issuing an expedited RFP, the projects proposed by Georgia Power could be tested against the market's ability to provide similar resources. This will ensure that the portfolio of resources selected to meet projected capacity needs will be based on an economic comparison of projects.

Q: WHAT CONCLUSIONS HAVE YOU DRAWN CONCERNING THE PLANT YATES CTS?

A: First, as described above, the CTs are not necessary to meet Georgia Power's most likely load requirements during the time frame at issue here (2024-2028).

Second, it is not reasonable for customers to buy a 45-year, 1,400 MW resource to meet the 300 MW need identified by Georgia Power's own modeling. The Aurora modeling performed as part of the resource mix study indicated that CTs were not selected as economically optimal until 2028, and the level of CTs selected in 2028 (300 MW) is substantially less than the capacity of the proposed Plant Yates CTs (1,400 MW).

Third, there is incomplete information about alternative options that could be pursued by Georgia Power. It is not clear if Georgia Power considered or evaluated the potential to site battery storage resources at the Plant Yates facility. Georgia Power's discovery responses have indicated that analysis around evaluating the potential to add BESS was related to existing PPA and company owned solar facilities. Georgia Power's testimony in this case indicated that transmission screens were only performed for resources proposed in this 2023 IRP Update (not for all possible resources outside of what Georgia Power proposed in this filing).[46] There are potential cost and transmission tradeoffs between adding CTs instead of BESS at the Plant Yates site. Adding BESS at Plant Yates would allow the project to qualify for the 10% energy community tax credit bonus under the Inflation Reduction Act since Yates' coal units were retired in 2015. This means that any BESS added at the site would qualify for an investment tax credit ("ITC") of 40%. It is also unclear if adding BESS at the Yates facility would require the same transmission upgrades

[46] Georgia Power Direct Testimony at 52.

that are needed to facilitate the addition of the proposed Yates CTs.[47] Without being able to compare the costs of the proposed Yates CTs to a BESS alternative, it is not possible to know if a strategy to build CTs instead of BESS is foregoing potential cost savings.

Q: WHAT RECOMMENDATION DO YOU HAVE FOR THE YATES CTS PROPOSED BY GEORGIA POWER IN THIS FILING?

A: The Commission should defer consideration of the need for the Yates CTs until the 2025 IRP, which is a process designed to plan for a longer time-horizon than this abbreviated IRP Update, and which will include comprehensive transmission, economic, and environmental planning. In addition, as described above, the Commission will have the benefit of additional historical information about the behavior of the new large load coming to Georgia and will also have the benefit of a new reserve margin study using the most up-to-date economic information.

In the alternative, if the Commission believes additional capacity is necessary, I recommend that the Commission direct Georgia Power to expedite the upcoming all-source RFP, which would allow Georgia Power to bid in the Yates CTs against alternative resources, such as the thermal resources proposed in Georgia Power's RFI responses and company-owned and market-driven solar and battery projects.

Q: DO YOU HAVE ANY RECOMMENDATIONS RELATED TO LANGUAGE THAT SHOULD BE INCLUDED IN THE RFP?

A: Yes. Georgia Power should include language within an all-source RFP that expressly solicits BESS project proposals at the Plant Yates facility to take advantage of the energy community bonus that would increase the ITC for those projects.

In one of its recent RFPs, Indiana Michigan Power Company ("I&M") allowed for similar projects to be proposed for its portion of the Rockport Plant site, which I&M plans to retire. I&M included this language[48] in the RFP:

[47] In response to STF-GS-1-1 Georgia Power indicated that BESS was not studied as an option to reduce, defer, or eliminate transmission upgrades needed to facilitate the delivery of power for the proposed CTs at Plant Yates.
[48] The ownership requirement as stated in the RFP language is specific to the requirements that would have to be followed for projects to reuse the injection point when the Rockport unit retires and would not be a requirement for any new projects sited at the Yates facility since the transmission service required for the Plant Yates 1-5 was not preserved after the units retired on April 15, 2015 (Georgia Power response to STF-JKA-2-25 subpart d related to the transmission service for Plant Yates 1-5).

A portion of the retiring Rockport Plant site will be available for bidders to propose Combustion Turbine (CT) generation projects as well as Energy Storage projects for participation in the RFP; no other technologies will be considered at this time for the Rockport site. I&M will offer the Rockport injection point to offsite projects of any generation type, however, such proposals will need to demonstrate site control that does not introduce an unacceptable level of risk and uncertainty with respect to execution, schedule, and cost. Additionally, such projects must demonstrate compliance with all aspects of the RFP. Bids on the Rockport site or proposing to use the Rockport injection point will be limited to PSAs only; PPAs will not be considered.[49]

Q: WHAT ARE SOME OF THE COSTS ASSOCIATED WITH THE YATES CT PROJECT?

A: The estimated in-service capital cost for the CTs is $[redacted];[50]

The transmission related costs for the Yates CTs are approximately $80,000,000.[51]

On February 14, Georgia Power supplemented its document responses and indicated that it estimated that by the end of this docket (in April 2024), if the CTs are not approved Georgia Power would still request recovery from customers of **approximately $250 million, which consists of approximately 70% development costs (already incurred) and 30% cancellation costs**.[52] (A large portion of the project development costs include [redacted].)

[49] 2023 I&M All-Source RFP at 5. Retrieved from https://imallsourcerfp.com/wp-content/uploads/2023/04/2023-IM-All-Source-RFP-3-31-23.pdf
[50] Technical Appendix 6 – "TS Technical Information Supporting the Proposal to Develop up to 1400 MW of CTs."
[51] Georgia Power response to TS-STF-DEA-4-1 Attachment.
[52] Georgia Power response to TS-STF-LA-1-23 Supplemental (Georgia Power agreed by e-mail that approximations of these figures are not Trade Secret information).
[53] Georgia Power response to TS-JKA-2-29 Attachment A at 3.

Q: IF THE COMMISSION ADOPTS YOUR RECOMMENDATION AND DEFERS CONSIDERATION OF THE PLANT YATES CTS UNTIL 2025, DO YOU AGREE WITH GEORGIA POWER'S RECOMMENDATION THAT ITS CUSTOMERS SHOULD PAY FOR THE MONEY IT HAS ALREADY SPENT ON THE CTS?

A: If the Plant Yates CTs are not approved, then Georgia Power plans to request recovery of approximately a quarter of a billion dollars.[54] I disagree with Georgia Power's request to charge existing billpayers for these expenses. Georgia Power opted to make decisions related to the proposed Plant Yates CTs outside of an economic procurement process through an RFP and it is unknown how the economics of the Plant Yates CTs compare to other resource alternatives.

V. FLEX CAPACITY FRAMEWORK AND OWNERSHIP REQUIREMENT

Q: WHAT IS THE "FLEX CAPACITY" FRAMEWORK THAT GEORGIA POWER IS REQUESTING APPROVAL OF IN THIS FILING?

A: In this filing Georgia Power is asking for approval of a "Flex Capacity" framework which would allow the Company to seek approval for additional capacity before the 2025 IRP if an updated load forecast results in projections of additional capacity needs. If an update to the load forecast presented in this filing results in a 500 MW or greater capacity, then Georgia Power would be able to recover the costs of activities related to bringing new capacity resources online. As stated in the Company's filing:

> *The Flex Capacity framework would authorize Georgia Power to undertake and recover the cost for preliminary development activities in connection with the development, operation, and ownership of new capacity resources. Additionally, the Company would be authorized to continue to explore PPA or acquisition options that could be presented for Commission approval and certification prior to the filing of the Company's 2025 IRP and recover any incremental cost incurred for this effort.*[55]

Q: DO YOU HAVE A RECOMMENDATION FOR GEORGIA POWER'S REQUEST TO RECEIVE APPROVAL FOR THE FLEX CAPACITY FRAMEWORK?

A: The Commission should deny this request. This request is unnecessary. Even if the unfathomable circumstance arose whereby the Commission denied **all** of Georgia Power's

[54] Georgia Power response to TS-STF-LA-1-23 Supplemental.
[55] Georgia Power Direct Testimony at 50 - 51.

new chosen resources **and** the statistically unlikely 95% load growth actually materialized, Georgia Power still would not need any new resources until 2026 (when it would still have enough capacity to meet its projected need plus a 23% reserve margin). Furthermore, the Flex Capacity framework authorization related to "undertake and recover the cost" concerns me given actions that Georgia Power has taken related to the proposed Plant Yates CTs and the significant costs (approximately $250 million) that could be billed to customers for their development costs prior to Commission approval. The Flex Capacity framework as proposed by Georgia Power could result in ratepayers being put in a similar situation in the future where they bear the risk of Georgia Power's expenses spent on generation resources that may not be needed to serve an expanded customer base.

VI. CONCLUSION

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
	)	
Georgia Power Company's	**)**	**Docket No. 55378**
2023 Integrated Resource Plan Update	**)**	

EXHIBIT CH-1

Chelsea Hotaling Consultant

ENERGY FUTURES GROUP

Professional Summary

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such as IRP analyses and has critiqued IRP modeling performed using Aurora, PLEXOS, PowerSimm, and System Optimizer. Chelsea has also conducted capacity expansion, production cost, and reliability modeling using the Aurora, PLEXOS, and SERVM models. Chelsea has experience working with numerous software programs including Python, R, and Stata.

Education

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2011

Experience

2021-present: Consultant, Energy Futures Group, Hinesburg, VT

2020-2021: Senior Analyst, Energy Futures Group, Hinesburg, VT

2019-2020: Analyst, Energy Futures Group, Hinesburg, VT

2018-2019: Intern, Sommer Energy, Canton, NY

2016-2019: Research Assistant, Clarkson University, Potsdam, NY

Selected Projects

- The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Performed SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP (2023). Performed EnCompass and SERVM modeling to evaluate a clean energy replacement portfolio as an alternative to the preferred plan presented in Santee Cooper's 2023 IRP (2023).

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Chelsea Hotaling Consultant

ENERGY FUTURES GROUP

- The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar. Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP. (2022 to 2023)
- GridLab. Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to 2023)
- Sierra Club. Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Appalachian Citizens' Law Center, and Mountain Association. Reviewed and provided comments on Kentucky Power's 2023 Integrated Resource Plan. (2023)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association. Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)
- The Department of Attorney General and Sierra Club. Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)
- The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar. Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)
- Colorado Office of the Utility Consumer Advocate. Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)
- Minnesota Center for Environmental Advocacy. Evaluation of Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to present) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)
- Earthjustice. Evaluation of PREPA's request for proposals for temporary emergency generation. (May 2020) Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- The Council for the New Energy Economics. Reviewed and provided comments on Evergy's 2023 IRP Annual Update. (2023) Reviewed and provided comments on Evergy's 2022 IRP Annual Update. (2022) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- EfficiencyOne. Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)

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- Southern Alliance for Clean Energy. Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)
- Washington Electric Cooperative. Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)
- Coalition for Clean Affordable Energy. Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)
- Citizens Action Coalition of Indiana. Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs (April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs. (December 2019)
- Institute for Energy Economics and Financial Analysis (IEEFA). Evaluation of National Grid's long-term natural gas capacity report. (March 2020) Evaluation of the Puerto Rico Energy Commission's proposed wheeling regulation. (March 2019) Co-author for the report Retail Choice Will Not Bring Down Puerto Rico's High Electricity Rates. (August 2018) Evaluation of the Puerto Rico Energy Commission's proposed microgrid rules. (February 2018)

Publications

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. Energy Policy, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. Energy Policy, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. Environmental Hazards, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine, edited by Alex Q. Huang and Wencong Su. Elsevier.

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ENERGY FUTURES GROUP

Expert Testimony

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief,* on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. *In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC,* on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. *In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC,* on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. *Application for a Determination of Ratemaking Principle*, on behalf of Environmental Intervenors.

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief,* on behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*, on behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

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Chelsea Hotaling Consultant

Before the Public Utilities Commission of Colorado, Proceeding No. 21A-0141E. *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*, on behalf of the Colorado Office of the Utility Consumer Advocate.

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CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light** was filed with the Public Service Commission in Docket No. 55378 by electronic delivery on the 15th of February, 2024. An electronic copy of same was served upon all parties listed below by electronic mail as follows:

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MS. WHITFIELD: I further ask that the trade secret version of Ms. Hotaling's prefiled direct testimony be marked for identification as GIPL Exhibit 2.

CHAIRMAN SHAW: So -- so marked.

(The document referred to was marked for identification as GIPL Exhibit 2.)

MS. WHITFIELD: Finally, I would ask that the attachment to Ms. Hotaling's prefiled direct testimony be marked for identification as GIPL Exhibit 3.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GIPL Exhibit 3.)

BY MS. WHITFIELD:

Q Ms. Hotaling, did you prepare a summary of your testimony?

A I did.

Q Could you --

MS. WHITFIELD: Chairman, with your permission, I'd like to ask Ms. Hotaling to read her summary.

CHAIRMAN SHAW: Yes. Please proceed.

MS. HOTALING: Thank you.

Good morning, Commissioners. This is my first time testifying before you in Georgia and I am

presenting my testimony on behalf of Georgia Interfaith Power & Light.

My name is Chelsea Hotaling. I'm an electric utility consultant with Energy Futures Group. In this role, I have reviewed dozens of integrated resource plans and related filings by utilities across the country.

In this docket, I reviewed the assumptions and recommendations Georgia Power made related to its 2023 IRP Update, with a focus on the load forecast, new resource assumptions, and Georgia Power's proposed pathway for meeting projected load growth.

I'd like to offer three recommendations for the Commission. My first recommendation is about the load forecast. I recommend that the Commission only approve resources sufficient to meet the most likely need for capacity.

Georgia Power has relied on a generally accepted statistical method to forecast new load growth coming to Georgia, but Georgia Power's interpretation of its own forecast unreasonably overestimates the pace of growth. Georgia Power relies on a load projection that its own statistical analysis suggests will be higher than actual demand 95 percent of the time. However, Georgia Power's

statistical method also identified the capacity needs that are most likely on an annual basis. That data point is called P50.

Page 1 of the demonstrative handout you have in front of you includes two charts to help illustrate this recommendation. The first chart shows the different projected levels of growth.

Red is Georgia Power's current projection of growth called P95. Under that is blue, the projection of growth that Georgia Power modeled as most likely to occur, which is called P50.

Under that is green. This is staff's base case projection. Then yellow, that's staff's low-growth projection. And gray and black are Georgia Power's load growth projections in their 2023 budget and 2022 IRP budget, respectively.

As you can see, P50 is still an aggressive projection of growth, but it does not reflect growth as quickly or as severely as the data relied on by Georgia Power in this case.

The second chart on page 1 is Table 1 from my prefiled testimony. 2028 is highlighted here because that is the farthest date that Georgia Power is asking to plan for in this IRP. It shows the numerical differences between the last IRP's budget,

the most likely load growth today, which is P50, and the 95th percentile of growth relied on by Georgia Power.

My second set of recommendations is about alternative options to fulfill Georgia Power's capacity needs. Based on my review of Georgia Power's load and resource mix models, I have found that approximately 1400 megawatts of battery resources are sufficient to meet Georgia Power's capacity needs through 2028.

I recommend that the Commission direct Georgia Power to issue an expedited RFP for battery resources for at least 1410 megawatts as soon as possible. In my experience, the competitive RFP process yields the best value for billpayers.

I have concluded that the Yates combustion turbines are not necessary to support Georgia Power's capacity needs between now and 2028.

I recommend that the Commission defer consideration of the Yates CTs until the 2025 IRP, when it will have the benefit of a full long-term planning process, including transmission and environmental studies. The Commission will also have the benefit of additional data about this new load growth.

In the alternative, the Commission should direct Georgia Power to expedite the upcoming all-source RFP. Under no circumstance should the Commission charge customers for the costs of canceling Georgia Power's plants -- plans for Plant Yates, which Georgia Power has indicated could be up to a quarter of a billion dollars.

Page 2 of your demonstrative shows Table 8 from my testimony. This is an expert -- excerpt from Georgia Power's Aurora resource mix modeling. This table shows the resources that Georgia Power's analysis chose as the most economically optimal. This kind of modeling is just one factor in choosing the optimal resource mix. But it's an important one, and notably, this modeling, which was completed by Georgia Power, not me, does not support Georgia Power's requested investments in three combustion turbine units.

The last chart on your demonstrative shows Table 11 from my testimony. This table shows that under Georgia Power's most likely load growth scenario, Georgia Power doesn't need new capacity until 2027, at which point fewer than 1000 megawatts are needed to meet Georgia Power's requested reserve margin.

So that concludes my summary. Thank you.

MS. WHITFIELD: Mr. Chairman, Ms. Hotaling is now available to answer questions from the Commission and for cross-examination from the parties.

CHAIRMAN SHAW: Thank you, ma'am.

Commissioners, any questions for the panel?

(No response.)

CHAIRMAN SHAW: All right. We'll move down the line. Georgia Public Service Commission.

MS. DAVIS: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MS. DAVIS:

Q Good morning. I just have a one question for you.

On page 3, lines 25 through 26 of your testimony, you recommended a new battery-specific RFP be issued as soon as possible. You are aware, aren't you, that the Commission already directed Georgia Power to issue an RFP for 500 megawatts of storage in the 2022 IRP and that RFP is being drafted right now?

A I'm aware of that, yes.

Q Wouldn't it be quicker and more efficient simply to expand that existing process, rather than to start a second one from scratch?

A Yeah. It's -- it's possible. It could be whatever the best pathway is, whether that's initiating a new or expanding upon the existing, or the one that is in process.

MS. DAVIS: Okay. Thank you.

MS. HOTALING: Thank you.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. JONES: No questions, Mr. Chairman.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

(No response.)

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions, Mr. Chairman.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

MR. COX: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. McNUTT: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Hi, Ms. Hotaling.

A Good morning.

Q My name is Steve Hewitson. I represent Georgia Power Company.

At the risk of completely oversimplifying your testimony on load forecasting, is it a fair characterization to say that you believe Georgia Power's load forecast should be planned to the P50 level because that is the amount of load that is more likely to occur than not?

A That is correct. That is the P50. It's the most probable outcome from the model.

Q And you understand, though, that the load forecasts are a snapshot in time; right?

A Yes. It's based on a lot of uncertain variables.

Q Okay. So the P50 you include in your testimony on page 10, lines 2 to 3, is the P50 value at that point; right?

A At the -- at the point of the load realization model that was provided in this case, yes.

Q Okay. If load growth is continuing to occur and forecasts are getting larger, the current P50 value may now be less than P50 when accounting for that growth; right?

A It's possible. I haven't seen updated

workbooks. There's important assumptions that would go into that related to the timing of the load, what year, how fast the ramp-up is. I just -- I wouldn't know until I saw that.

Q Did you listen to the direct hearings when Georgia Power's customers -- or Georgia Power's witnesses were testifying and they said that the load is continuing to grow in their analysis?

A When the Georgia Power panel testified or yesterday?

Q No. When the Georgia Power panel testified.

A I heard that there was a -- the reference I remember was that there was an increase in growth. But I don't know exactly what year or, you know, ramp-up or anything like that. Just that the total load projected had increased.

Q Okay. Do you think it is advisable for a utility to plan to be able to serve a level of expected new load that is 50 percent likely to be understated?

A In this case, Georgia Power does have flexibility with the reserve margin because the 26 percent is based on the determination from the economic reserve margin point. So you have to balance the risk of overbuild and underbuild and over -- overbuilding and exposing customers to the cost of that.

Q Well, is that true when the rapid growth being seen is too large for the reserve margin to accommodate?

A I'm sorry. Could you restate that question?

Q Sure. Do you agree with me that 50/50 planning is not a good way to ensure reliable service when the rapid growth being seen is too big for the reserve margin to accommodate?

A No. So typical capacities -- when forecasts are put into typical capacity expansion models, they are based on a 50/50 probability. And at this point with the 26 percent reserve margin, you know, the 20 percent has been determined as the minimum needed to meet the industry standard LOLE requirement of .1 days per year.

And Georgia Power has up to 26 percent planning from that economic perspective. So there is that buffer built in because that is the planning reserve margin that Georgia Power is projecting for the future.

Q Yes. And while I understand that P50 planning might be fine during normal conditions where load growth is modest, when you have new announcements of data centers, large manufacturing loads, and other large loads coming at you fast, don't you agree that a utility needs to get ahead of it and it would be prudent to consider something a little bit more aggressive than P50?

A Well, there's a lot of uncertain variables that

are going into that model. So as we've seen from the projections put forward by staff, those are highly sensitive and can change your results.

And a lot of those -- these are new load customers. We're not exactly sure the pace and their construction time and getting built. So there's still a lot of uncertainty with that. And so if you go with a more aggressive P95, you still have that exposure of the potential to overbuild.

Q Yes. I understand that.

But my question is: Do you think with the large loads that are expected to come, that P50 is advisable and prudent for the company to plan for?

That's your testimony?

A Yes, it is.

Q Okay. On page 14, lines 8 to 16, you discuss the impact of planning to P50 versus P95. In your view, it would be fine to plan to P50 because there's an equal chance that Georgia Power will be overbuilt as opposed to underbuilt; is that correct?

A I'm sorry. Could you repeat the page number and the lines?

Q Yes. Fourteen, lines 8 to 16.

A Yes. I'm discussing the risks that there are of -- related to this load forecast that you have the

chance of overbuilding and underbuilding.

Q Okay. If Georgia Power's resource plan is adopted but the load does not arrive, then Georgia Power will be in that overbuilt situation; right?

That's your testimony?

A Yes.

Q Okay. And if you're trying to avoid that cost to customers and your -- in your testimony by avoiding that overbuilt situation, you're trying to avoid that additional cost to customers; is that fair?

A Yes.

Q Okay. But the Commission has the authority and the ability to address cost issues through rate cases. Don't you agree with that?

A It's possible.

Q It's possible or do you know that?

A I -- that's what I would expect to see, a rate case.

Q And are you aware that the company must still come back to the Commission to get resources certified based on current load forecasts at the time of the certification?

A Yes.

Q Okay. Now, on page 15, on Table 7, you discuss that over half of the announced load is outside of

Georgia Power's service territory; right?

A Yes.

Q But it's still within the state of Georgia; right?

A That is correct.

Q And for those customers to come to Georgia, there must be sufficient generation; would you agree with that?

A Yes.

Q Okay. Now, if Georgia Power finds itself in an underbuilt situation, the company will not have adequate capacity to serve that load. Would you agree with that?

A That's a potential pathway that could happen.

Q And there's no way to catch up quickly because it takes time to build capacity; right?

A Well, there's potential for reserve sharing agreements or things like that. But, yes, pending that not being an option, you would need time to build.

Q And are you aware of the market having -- well, let me ask it this way. The market does not have enough existing capacity available to meet Georgia Power's needs in that situation right now; right?

A If you're talking about a year from now -- is that what your question is referencing?

Q Yes.

A Yeah, you would need time to build. But at this point Georgia Power has the capacity to meet those needs --

Q Okay.

A -- for this year. For these, like, next coming years where there is a surplus.

Q Based on your P50 analysis?

A Yes.

Q But not based on their P95 analysis?

A No.

Well, I have a table in my testimony, if I can refer to that.

Q Go ahead.

A Where I looked at the P95. That was Table 12. So that was P95 with the PPAs included. So there would be a capacity need starting in 2027.

Q Okay. Have you performed any analysis of whether another supplier in the state of Georgia could meet the needs of the large-load customers coming into the state of Georgia?

A I have not.

Q Okay. If Georgia Power doesn't have the capacity to meet the needs of the large-load customers when they arrive and the other smaller suppliers in Georgia cannot supply it either, those customers are

likely going to relocate to some other state; would you agree with that?

A It's possible.

Q Do you agree that it is unlikely that they would wait five years until 2029 to come back to Georgia?

A It just -- it would depend on the circumstances of their business, construction time. You know, if the time aligned, it would probably be a customer-by-customer basis.

Q But it's unlikely if they're looking to locate in the state of Georgia in 2026, '25 that they're going to wait four years or five years to build that manufacturing facility or bring that data center to a state; wouldn't you agree with that?

A It's likely.

Q All right. Now, on page 16, lines 16 to 18, you say that the Plant Yates CTs are not needed even under the P95 analysis.

Now, just for clarification, is that because you recommend the 1410 megawatts of BESS resources be used instead?

A Yes. If I can refer back to my Table -- in my testimony, Table 12. Sorry. Excuse me. Not Table 12.

Looking at Table 10 and 11 with and without the PPAs, yes, because the capacity need of -- with a 430.

And then if you factor in the level of the PPAs and if they were not approved, that is how you would arrive at the 1,410 level that I recommended.

Q Okay. But you're -- you're aware that that amount of battery storage does not currently exist in Georgia; right?

A Well, there was battery storage that was bid into the -- or provided with the RFI. And we're also asking for the company -- for their own proposed resources -- those pool of resources that the company has to be evaluated against all projects that they could receive in the RFP, which could very likely be the projects that bid into the RFI.

Q Could likely, but we don't know for sure; right?

A Would not know for sure until the RFP was completed.

Q Right. And the RFI, you understand, were not actual bids; right?

A Yes.

Q It was just requests for information?

A I understand that.

Q And there was responses about what is planned and available and could be available, but not -- it doesn't mean that the projects are actually going to go

forward; right?

A Well, my understanding was that it's possible that they could already be in the interconnection queue. I think the categorization was asked to be either planned or existing based on the RFI language. So it's possible that some projects are further along than others, but I wouldn't say that they are not viable.

Q But they haven't been built and they may drop out of the queue; right?

A That's a possibility.

MR. HEWITSON: Okay. I think that's all I have for you. Thank you very much for your time.

MS. HOTALING: Thank you.

CHAIRMAN SHAW: Any redirect?

MS. WHITFIELD: No redirect, Chairman.

I ask that GIPL Exhibits 1 through 3 be admitted and entered into the record and that Ms. Hotaling be excused.

CHAIRMAN SHAW: So marked.

(GIPL Exhibits 1, 2, 3 and Demonstrative were admitted into evidence.)

CHAIRMAN SHAW: Thank you for your time today.

MS. HOTALING: Thank you.

CHAIRMAN SHAW: And you can be excused.

All right. The next panel to be called up will

be that of Georgia Solar Energy Association.

MR. MORELAND: Mr. Chair, we ask that Bobby Baker be able to swear in our witness.

VICE-CHAIRMAN ECHOLS: That will be fine.

CHAIRMAN SHAW: Yeah. Please do.

Thereupon,

GRAHAM TURK,

having been duly sworn, testified as follows:

MR. BAKER: Thank you very much.

DIRECT EXAMINATION

BY MR. MORELAND:

Q Please state your name and spelling your last name for the court reporter, employer, and business address.

A Yep. My name is Graham Turk, T-u-r-k. I'm employed by Massachusetts Institute of Technology. And my business address is 40 Ames Street in Cambridge, Massachusetts.

Q Are you here today testifying on behalf of the Georgia Solar Energy Association?

A Yes.

Q On February 15th, did you file or cause to be filed 30 pages of written direct testimony for this proceeding in question -- in question-and-answer format in Docket 55378?

A Yes.

Q Do you have any corrections to that testimony?

A No, I don't.

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

A Yes.

MR. MORELAND: Mr. Chair, we move to have the witness's prefiled testimony be copied into the record as if read orally today?

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Graham Turk follows:)

STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's 2023 Integrated Resource Plan Update	)	**Docket No. 55378**

DIRECT TESTIMONY OF GRAHAM TURK
ON BEHALF OF GEORGIA SOLAR ENERGY ASSOCIATION

FEBRUARY 15, 2024

I. INTRODUCTION

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

A. My name is Graham Turk. I am a researcher at the MIT Energy Initiative, a research consortium housed within Massachusetts Institute of Technology. My business address is 50 Ames St, Cambridge, MA 02142.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

I am submitting testimony on behalf of the Georgia Solar Energy Association ("GA Solar").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. No, I have not.

Q. HAVE YOU BEEN INVOLVED IN UTILITY REGULATORY PROCEEDINGS IN OTHER STATES?

A. Yes. While at Green Mountain Power, I prepared analysis and discovery responses for several contested Vermont Public Utility Commission dockets related to new tariff offerings (19-3167-TF, 19-3537-TF, and 19-3586-TF) as well as for the 2021 Integrated Resource Plan.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Princeton University with a Bachelor of Engineering in Computer Science in 2017. From 2017 to 2018, with the support of a Fulbright grant, I researched European energy markets at the Royal Institute of Technology in Stockholm, Sweden. From 2018 to 2022, I worked for Green Mountain Power (GMP), an investor-owned electric distribution utility based in Colchester, Vermont, in various roles.

At GMP, I began on the Innovation Team – as an innovation strategist I designed and administered customer programs in electric vehicles, battery storage, and demand flexibility. I then joined the Power Supply Team where I performed data analysis, including on the performance of capacity resources, marginal cost to serve new load types, and the potential value from bidding a portfolio of residential batteries into the New England wholesale energy market. I was the lead author of

GMP's 2021 Integrated Resource Plan chapters on demand forecasting. I also prepared compliance filings for Vermont's renewable portfolio standard.

From 2021-2022, I was the Head of Customer Care at GMP, supervising a team of 30 customer care representatives that served as the front line for all customer inquiries across all channels.

At the MIT Energy Initiative, my research focuses on understanding the impacts on electric distribution grids of distributed energy resources (primarily heat pumps, batteries, and electric vehicles). I also investigate retail rate design to complement resource adequacy planning.

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY AND HOW IT IS ORGANIZED.

A. The purpose of this testimony is to propose a new residential "bring your own device" (BYOD) tariff to help meet the capacity constraints of Georgia Power Company ("the Company") in the immediate future and provide information to the Commission about similarly-designed BYOD programs available in other states.

These recommendations are based on my direct experience at GMP managing a BYOD tariff and knowledge of similar offerings by other US utilities. My testimony is organized into the following sections:

- Section II describes GMP's "Bring Your Own Device" (BYOD) tariff, including program details, regulatory history, and key outcomes. I also outline details from other BYOD-style programs by other US utilities.
- Section III argues why the Company should be required to offer a new residential BYOD tariff, consistent with least cost planning principles, to meet future resource adequacy challenges posed by expected load growth, based on my analysis of the Company's 2023 Integrated Resource Plan.
- Section IV contains my proposal for such a BYOD tariff.
- Section V contains my concluding remarks.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission direct the Company to file within 6 months after the final order in this docket a new tariff for a residential BYOD program with the following features:

- A hybrid compensation structure with both upfront and ongoing compensation based on actual system performance, with the level of ongoing compensation locked in for a term of at least 5 years. The exact level of compensation should be determined jointly by the Company and the Commission using a similar methodology as the DCO-1 tariff, which allocates 75% of the projected program value to participating customers.
- A maximum of 60 events per year, with a maximum duration of 3 hours per event
- The use of the battery's inverter for the purpose of verifying performance, as opposed to relying on the installation of a secondary utility meter.
- Eligibility for multiple battery manufacturers, with a pathway for new manufacturers to become eligible.
- Consumer protections, including a standard disclosure form, mandatory installer training, advance event notifications, and the ability to opt out of events (which will impact the ongoing compensation payment).
- The ability for participants in the BYOD tariff to participate in other utility programs.

A BYOD tariff would complement other resources requested in the Company's 2023 IRP while allowing the Company to gain expertise in managing aggregations of customer-sited resources, which can be leveraged in future IRPs to meet near term capacity deficits similar to what the Company is currently projecting for Winter 2025/2026.

II. DETAILS ON GMP'S BRING YOUR OWN DEVICE TARIFF AND OTHER RELATED OFFERINGS AROUND THE U.S.

Q. HOW DO YOU DEFINE A VIRTUAL POWER PLANT?

A. A virtual power plant (VPP) is an aggregation of Internet-connected distributed energy resources (DERs) that can be dispatched collectively to provide grid services, for example reducing system-wide peak demand or performing frequency regulation. Dispatch is typically performed directly by a utility or by a third-party aggregator. While VPPs can include many device types (e.g., electric vehicle charging stations, smart thermostats, smart water heaters), in this testimony my use of the term "VPP" refers specifically to aggregations of residential battery energy storage systems unless otherwise specified.

Q. DO YOU CONSIDER VPPS TO BE A FIRM CAPACITY RESOURCE?

A. Yes. VPPs are instantly dispatchable and have successfully demonstrated their reliability in both wholesale capacity markets and utility-managed demand flexibility programs. By aggregating many individual systems, the risk of non-performance can be lower than large resources with single points of failure. Unlike traditional demand response programs, a VPP does not rely on changes in customer behavior. This treatment of VPPs is corroborated by a recent Brattle Group report, which found that VPPs "could perform as reliability as conventional resources and contribute to resource adequacy at a similar scale."[1] Furthermore, VPPs enable consumers to play a more active role in helping to meet grid reliability challenges.

Q. PLEASE PROVIDE AN OVERVIEW OF GMP'S SERVICE TERRITORY AND VERMONT'S REGULATORY STRUCTURE AS CONTEXT FOR SUBSEQUENT RESPONSES.

A. GMP is the largest electric distribution utility in Vermont, serving 265,000 homes and businesses. Its service territory is predominantly rural, and residential customers account for the majority of total load served. Vermont is the only state in New England where electric distribution utilities remain vertically integrated. GMP owns generation, sub-transmission, and distribution infrastructure. It is the exclusive load-serving entity in its service territory (i.e., there is no retail choice). The transmission system in Vermont is owned and operated by a separate entity, VELCO, which is jointly owned by the Vermont electric distribution utilities. The state's peak load is approximately 1000 MW.

Q. PLEASE DESCRIBE, AT A HIGH LEVEL, GMP'S CURRENT BYOD OFFERING.

A. In GMP's "Bring Your Own Device" (BYOD) tariff,[2] customers receive an upfront compensation payment in exchange for allowing GMP to remotely discharge their energy storage system for the purpose of peak demand reduction over a 10-year period. The term, "bring your own device" (not to be confused with workplace policies on personal laptop usage) refers to customers' voluntary enrollment of battery systems that they own. GMP is allowed to discharge

[1] https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf
[2] https://greenmountainpower.com/rebates-programs/home-energy-storage/bring-your-own-device/

systems for a maximum of 8 times per month (though in practice the number of events per month averaged 5 during my time administering the program). All residential customers are eligible for participation; batteries are installed behind the customer's utility meter.

Q. HOW LONG HAS THE PROGRAM BEEN ACTIVE AND WHAT WAS THE PROCEDURAL HISTORY?

The tariff was approved in September 2019 (Docket 19-3537-TF) following a 9-month investigation by the Vermont Public Utility Commission (VPUC). The VPUC found the tariff to meet the just and reasonable standard. The tariff filing was made after an 18-month pilot with similar features. GMP has approval in its Multi-Year Regulation Plan (MYRP) to conduct limited-time innovative pilots "beyond the sale of basic electric service…that advance the goals of Vermont's state energy policy."[3] Innovative pilots have led to several tariffed programs, including BYOD, two residential electric vehicle (EV) charging tariffs, and a public EV fast charging rate. BYOD enrollment was initially capped at 5 MW per calendar year, but the cap was lifted in August 2023 (VPUC Docket 23-1335).

Q. WHAT WAS YOUR ROLE IN PROPOSING AND THEN ADMINISTERING GMP'S BYOD TARIFF?

Together with one other colleague, I created the program's financial model, drafted and edited tariff filing letters and customer agreements, responded to discovery requests, and worked closely with third party battery manufacturers and installers to ensure system compatibility. Once the tariff was approved, I oversaw day-to-day program management, including approving new program applicants, scheduling peak events in our distributed energy resource management system (DERMS), tracking actual performance during called events, and creating regulatory reports that were submitted to the VPUC as part of our annual Multi-Year Regulation Plan (MYRP) compliance filing. These reports included enrollment figures, the number of systems that failed to respond to discharge signals, and actual realized financial benefits compared to projected benefits at the time of tariff filing.

[3] https://greenmountainpower.com/wp-content/uploads/2024/01/Final-2023-Regulation-Plan-as-amended-March-30-2023.pdf

Q. HOW MUCH ARE CUSTOMERS COMPENSATED IN EXCHANGE FOR ENROLLING THEIR ENERGY STORAGE SYSTEMS IN THE BYOD TARIFF?

A. Participating customers receive an up-front compensation payment of $850 per enrolled kW for a 3-hour resource or $950 per enrolled kW for a 4-hour resource, up to a maximum of 10 kW (the distinction between 3- and 4-hour resources is explained later in this testimony). Customers can elect to enroll the entire capacity of their system (the total kWh energy capacity divided by either 3 or 4 hours), or a portion of the capacity. GMP provides an additional $100 per enrolled kW for systems installed within sections of GMP's service territory that experience distribution delivery constraints.

Q. WHAT IS THE VALUE PROPOSITION TO PARTICIPATING CUSTOMERS IN THE BYOD PROGRAM?

A. By installing residential storage, customers receive the benefit of a resilient resource to protect against unexpected outages. Unlike conventional backup generators, during times when the battery is not being used to provide backup power, it can be dispatched to reduce peak demand for the benefit of all customers.

Q. HOW WAS CUSTOMER COMPENSATION CALCULATED IN THE BYOD TARIFF?

A. Customer compensation was calculated first by performing a forecast of transmission and capacity prices in New England. While GMP is a vertically integrated utility, system operation falls within the purview of a regional transmission organization: ISO New England (ISO-NE). As a load-serving entity within ISO-NE, GMP is allocated a portion of regional transmission and capacity costs based on its coincident demand during the maximum statewide demand hour in each calendar month (for transmission) and its coincident demand during the maximum region-wide demand hour across the full year (for capacity). ISO-NE provides its own forecast of transmission and capacity prices 10 years into the future. Starting with these forecasts, we built a cost-benefit model to estimate the net present value of a battery resource dispatched to reduce coincident peak demand (both monthly and annual) over a 10-year period. We used historical performance from the BYOD pilot to adjust nameplate capacity values; this included forecast accuracy (how often we correctly predicted monthly and annual peaks), battery availability (the percentage of systems available for dispatch at any given time), and the optimal peak load reduction assuming perfect

foresight (e.g., for each 1 MW of nameplate capacity, by how much can we expect to reduce peak demand?)

We also adjusted up for line losses and the capacity reserve margin since all BYOD resources are interconnected at the distribution level and reduce GMP's net demand. We chose a 10-year duration for the cost-benefit analysis because at the time, that was often listed as the minimum expected battery lifetime in manufacturers' warranties. 70% of the expected net present value is allocated to participating customers in the form of the upfront credit, while 30% is reserved for non-participating billpayers. This methodology closely mirrors that proposed by the Company in its proposed DCO-1 tariff: "The participating customer's credit will be calculated as 75% of the projected system value of the DER asset paid over the contract period."

Q. WHY DID GMP CHOOSE NOT TO ALLOCATE THE FULL VALUE OF PEAK REDUCTION TO PARTICIPATING CUSTOMERS?

A. Whenever proposing a new tariff, we believed it was important to allocate a portion of the program's expected value to apply downward rate pressure for all billpayers. For GMP's BYOD tariff specifically, we set participant compensation levels below our calculated value of peak reduction to ensure net benefits for both participants and non-participants. This was also a way to de-risk any expenditures. The 30% non-participant share acted as a hedge against imperfect projections. If instead the full net present value of battery dispatch were allocated to participants, then any shortfall in program performance would mean that the program applied upward rate pressure.

Q. WHY ARE THERE DISTINCT COMPENSATION AMOUNTS FOR 3- AND 4-HOUR STORAGE RESOURCES?

The two categories reflect the difference in expected reduction in peak demand as a percentage of the energy storage system's nameplate capacity. Figure 1 illustrates this concept via a simple example featuring a 2 MW/4 MWh battery and two different system load profiles during a 24-hour period. In both cases, the battery charges during overnight hours when system load is low. In the left panel, where the peak is sharper, 2 MW battery can be discharged over 2 hours to achieve 2 MW of peak load reduction (100% of nameplate capacity). In the right panel, a flatter peak means that the battery must be dispatched over a period of 3.5 hours to achieve the optimal peak load

reduction of 1.7 MW (85% of nameplate capacity). When the BYOD tariff was originally filed, we expected there would be more diversity in battery chemistries and nameplate power-to-energy ratios that would make some systems better suited to enroll as 4-hour resources. In my time administering the program, the vast majority of customers elected to enroll 3-hour resources.

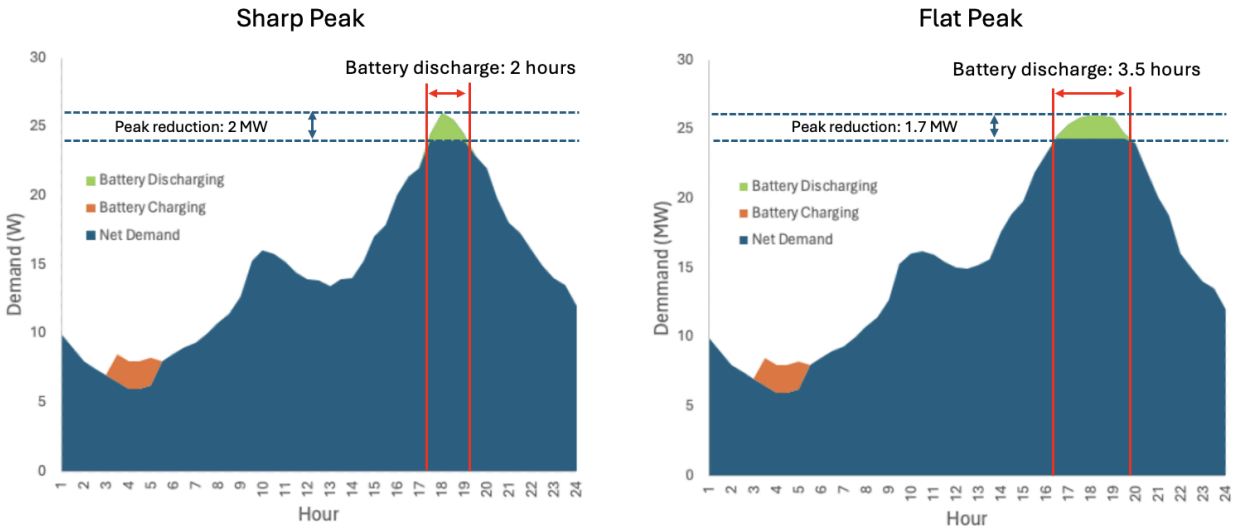

Figure 1: Illustration of optimal battery dispatch for different load profiles.

Q. WHAT WAS THE BASIS FOR THE $100 PER KW ADDITIONAL COMPENSATION PAYMENT?

GMP's service territory has many distribution feeders that are congested due to distributed generation (primarily rooftop photovoltaic systems).[4] Batteries can help alleviate these congestion conditions by charging during solar hours and reducing the amount of energy backfed through a distribution substation to the transmission grid. $100/kW reflects a portion of avoided cost of future distribution investments.

Q. WHAT HAPPENS IF CUSTOMERS' ENERGY STORAGE SYSTEMS FAIL TO RESPOND TO CALLED EVENTS?

A. If an energy storage system enrolled in BYOD experiences a communication failure and the issue is not remedied within 30 days after notification by GMP, participating customers are charged $12.70 per enrolled kW per month until communication is restored. A BYOD battery that

[4] https://www.arcgis.com/apps/webappviewer/index.html?id=4eaec2b58c4c4820b24c408a95ee8956

fails to perform within +/- 10% of its enrolled capacity is charged $12.70 per deficient kW. For example, a three-hour resource that enrolled at 8 kW but delivers 5 kW on average during the month's called events will be charged a penalty of $12.70 * (8 kW – 5 kW) = $38.10 for that month. These provisions were included to protect non-participating billpayers and ensure that the program delivers the expected value and the associated downward rate pressure.

Q. ARE BATTERIES IN THE BYOD PROGRAM ALLOWED TO EXPORT TO THE GRID AND HOW ARE CUSTOMERS COMPENSATED FOR THAT EXPORTED ENERGY?

A. Yes. All batteries in the program are allowed to export to the grid. Any energy exported by the batteries to the grid is credited at the full retail electricity rate. In practice, peak events tended to coincide with periods when prices in ISO-NE's real-time electricity market were higher than average. On the other hand, battery charging tended to occur during midday or overnight hours, when wholesale prices were lower than average. This "arbitrage" (charging the battery during low-price hours and discharging during high-priced hours) was not quantified or included in customer compensation.

Q. IS PERFORMANCE DETERMINED BY THE CUSTOMER'S NET DEMAND OR THE BATTERY'S OUTPUT?

A. Performance is calculated based on the battery inverter's metered output during called peak events. While the battery is physically installed behind the customer's meter and discharging appears as negative load from a system balancing perspective, it is treated as a supply-side resource for peak demand resource adequacy. The customer's appliance load, lighting, and HVAC-related demands are unaffected by the battery's activity.

Q. IN CASES WHERE BATTERY INSTALLATIONS REQUIRED UPGRADES (E.G., REPLACEMENT OF A DISTRIBUTION TRANSFORMER), HOW ARE THOSE COSTS ADDRESSED?

A. GMP does not use a special procedure for the treatment of upgrades related to BYOD enrollment. These are treated the same as any other customer-triggered upgrades.

Q. WHY NOT SIMPLY ALLOW CUSTOMERS WITH BATTERIES TO ENROLL ON EXISTING TIME-OF-USE RATES? WHY WAS THE BYOD TARIFF NECESSARY?

A. Time-of-use rates are typically designed with simplicity in mind so that customers can make small behavioral changes to reduce their electricity costs. In a two-part time-of-use rate, the on- and off- peak prices are typically averages of the cost to provide kilowatt-hours during each period over a full season or year. These prices are not accurate proxies for the instantaneous marginal cost of generating and delivering electricity. On a purely volumetric time of use rate, batteries would only be incentivized to charge during off-peak hours and discharge during on-peak hours, with no differentiation within those blocks or across days. This may provide value to participants but offers no benefit for resource adequacy, which is shared among all billpayers. Rather than publish a rate that makes it so that every battery owner solves their own optimization problem with no value to other billpayers, the BYOD tariff allows GMP to incorporate batteries into a centralized optimization problem, dispatching them at times that achieve the maximum value for all customers.

Q. WHAT CONSUMER PROTECTION MEASURES ARE USED FOR BYOD PARTICIPANTS?

A. GMP works closely with participating installers to ensure that they have been trained on program details and can communicate those details to their customers. While customers have the ability to enroll their maximum battery capacity, GMP recommends that customers concerned about battery availability for backup power should consider reserving a portion of their battery (e.g. 20%) that GMP cannot access during peak events. During my time overseeing day-to-day program operation, we made an attempt not to dispatch battery resources if weather-related outages were expected, since customers enrolled in the program had purchased their batteries for resilience purposes. Customers are always notified of peak events 24 hours in advance.

Q. WERE YOU AWARE OF ANY INSTANCES WHERE GMP DISPATCHED BYOD RESOURCES AND A CUSTOMER EXPERIENCED AN OUTAGE AS A RESULT OF NOT HAVING SUFFICIENT ENERGY REMAINING IN THE BATTERY?

A. In over 3 years of program operation, I am aware of one instance where this occurred, which was due to a car-pole accident immediately after the peak event ended. The outage was restored within two hours.

Q. CAN CUSTOMERS TERMINATE THEIR PARTICIPATION IN THE BYOD TARIFF?

A. Yes. If for whatever reason a participating customer wishes not to participate in called BYOD events, they can exit the program by providing 30 days' written notice of termination. Customers who terminate participation are responsible for making a one-time payment to GMP that reflects the pro-rated value of the compensation amount they received proportional to the number of months remaining in the initial term (10 years).

Q. HOW HAVE BYOD SYSTEMS PERFORMED SINCE THE TARIFF WAS APPROVED?

A. As of the summer of 2022 (when I left GMP), the program had performed in line with expectations. The majority of participating systems responded to all called peak events at their full enrolled capacity. There was a small number of systems that consistently failed to perform at their enrolled level during winter months. After investigating the issue, we determined that the cause was customers had been told by installers to only allow their systems to charge from on-site solar energy so they would remain eligible for the federal investment tax credit (ITC). At the time, only energy storage systems that were charged exclusively by solar could receive the ITC. This is no longer the case. Under the Federal "Inflation Reduction Act" (IRA), all residential energy storage systems over 3 kWh are eligible for the ITC as of 2023, regardless of how they are charged. Had this provision been in place earlier, I do not believe those delinquent systems would have performed poorly.

Q. WHICH BATTERY STORAGE SYSTEMS ARE ELIGIBLE TO PARTICIPATE IN THE BYOD TARIFF?

A. Currently, there are 6 eligible storage system brands that can participate in the BYOD tariff: Emporia, Enphase, FranklinWh, Generac, SolarEdge, and Tesla.

Q. IS THERE ANY WAY FOR NEW BATTERY STORAGE SYSTEMS TO BECOME ELIGIBLE TO PARTICIPATE IN THE BYOD TARIFF?

A. Yes. To become eligible for participation in the BYOD tariff, an energy storage system manufacturer must integrate its control system with GMP's DERMS platform so that GMP can remotely discharge the battery during peak events. An amendment to the list of systems eligible for participation can be done without a full tariff amendment.

Q. DID GMP INCLUDE THE VALUE OF THE UPFRONT BYOD COMPENSATION PAYMENT IN ITS RATE BASE?

No. The upfront compensation payment was booked as a direct power supply operating expense and not subject to regulated rate of return.

Q. ARE YOU AWARE OF ANY OTHER PROGRAMS IN THE US SIMILAR TO GMP'S BYOD?

A. Yes. Hawaiian Electric Company (HECO) offers a Bring Your Own Device tariff that was modeled on GMP's tariff after extensive discussion with their innovation team. Up until March 1, 2024, participating customers received an upfront credit of $850 per committed kW plus an ongoing credit of $5 per committed kW per month in exchange for allowing HECO to discharge the battery for a pre-specified 2-hour period in the evening. HECO recently updated the tariff to allow for more flexibility in event participation.[5]

In Massachusetts' Connected Solutions program, participants receive $275 per kilowatt per year for a battery's average contribution during summer peak events. Each event lasts a maximum of 3 hours, and there can be no more than 60 called events per summer.[6] As of the end of 2020, the program had enrolled 310 MW of capacity across 34,000 participants.[7]

In March 2023, the North Carolina Utilities Commission (NCUC) ordered Duke Energy in North Carolina to work with stakeholders to develop an energy storage pilot program for Commission

[5] https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/sre_byod_flyer.pdf

[6] https://www.masssave.com/residential/rebates-and-incentives/battery-storage-and-evs/batteries

[7] https://www.cleanegroup.org/wp-content/uploads/ConnectedSolutions-An-Assessment-for-Massachusetts.pdf

approval.[8] The NCUC approved Duke's proposed "PowerPair" program in January 2024, which provides an upfront solar payment of $360 per kW, up to 10 kW, and an upfront storage payment of $400 per kWh up to 13.5 kWh, for a maximum upfront compensation payment of $9,000 for a solar paired storage system.[9] In addition to these upfront compensation payments, participants are placed into one of two cohorts. In Cohort A, participants are enrolled on a time-of-use retail rate and have full control of their battery. In Cohort B, participants are enrolled in a VPP with Duke Energy having direct control over the battery during peak events up to 27 times per year. Participants in Cohort B will receive an additional performance-based compensation payment of $6.50/kW-month. Duke is scheduled to begin accepting applications in May.

In California, Pacific Gas & Electric launched a BYOD-style program in partnership with Tesla.[10] Participating Powerwall owners receive $2 per kWh delivered during events called by PG&E that align with periods in which the California independent system operator (CAISO) declares an alert or emergency. Participants can set their backup reserve to ensure that their full battery is not depleted during an event. In practice, a per-kWh compensation payment is similar to a per-kW compensation payment that uses the average dispatch across all events. The key difference is that the value to participants of a per-kWh compensation payment depends strongly on the number of events called.

III. JUSTIFICATION FOR RESIDENTIAL BYOD TARIFF

Q. GEORGIA POWER HAS ALREADY PROPOSED THREE CUSTOMER-SITED DER TARIFFS AND ARE PROPOSING TO BUILD MULTIPLE UTILITY SCALE BATTERY PROJECTS. WHY DO YOU BELIEVE THE COMMISSION SHOULD ORDER THE COMPANY TO FILE A RESIDENTIAL BYOD TARIFF?

A. There are six core reasons a residential BYOD program should be included in Georgia Power's IRP, which I will expand on in subsequent responses.

[8] https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=36643204-d163-45fd-a960-255eba5b10b9
[9] https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=9af65653-9428-41c7-b99e-935ae26967c8
[10] https://www.tesla.com/support/energy/virtual-power-plant/pge

1. **Speed and flexibility of deployment:** VPPs are composed of many small-scale distributed resources, each of which can be installed and commissioned in a matter of days, not months or years. VPPs can also be scaled easily to match evolving capacity needs.

2. **Private capital:** by aggregating customer-owned resources, a BYOD tariff would leverage private capital for the benefit of all billpayers.

3. **Resource diversity:** a residential BYOD tariff helps diversify the pool of resources used to meet resource adequacy.

4. **Resilience:** residential batteries provide the direct benefit of resilience in the case of grid outages.

5. **Distribution constraints:** unlike transmission-interconnected capacity resources, a residential BYOD program can address both bulk system issues *and* local distribution constraints, even when the two types of issues are not coincident.

6. **Operational Experience:** launching a BYOD tariff will provide the Company with experience managing fleets of customer-sited resources, which will be invaluable for future planning to meet capacity needs due to expected electrification of residential heating and vehicles.

Q. PLEASE EXPAND ON THE FIRST REASON RELATED TO THE SPEED AND FLEXIBILITY OF DEPLOYMENT.

A. The Company testified that the new BESS projects proposed in the 2023 IRP are projected to be online by the winter of 2026/2027. In that same winter season, the Company is projecting a capacity need of 1875 MW (IRP Main Document, p. 11). If any of the proposed projects are delayed for any reason and actual demand remains aligned with forecasts, the Company will face a significant capacity shortfall in the winter of 2026/2027.

As the Company stated in its direct testimony, "there is limited time available to procure or construct the resources needed to meet customers' capacity needs." Residential BYOD programs can be spun up at a speed that matches this urgency. As one example, Ontario's independent system

operator recently launched a residential VPP with over 90 MW of capacity in just 6 months.[11] While Ontario's program relied primarily on smart thermostats, it is illustrative of the potential of VPPs to meet urgent capacity needs. Similarly, Sunrun and PG&E launched a residential battery pilot in 2023 to meet summer peak demand related to air conditioning load. The program launched just 6 months after it was approved by the California Public Utilities Commission.[12] Residential BYOD programs can also be deployed without the need for transmission infrastructure or extensive interconnection studies.

Furthermore, compared to other resources whose capacity must be determined during the design and engineering phase, an aggregation of many small-scale battery systems can expand over time to meet additional demand growth simply by enrolling new systems. This ability to "right size" the BYOD program based on evolving demand forecasts reduces the risk of over procurement in cas some portion of new load included in the Company's demand forecast fails to materialize. This in turn would reduce the risk that billpayers shoulder the cost of capacity resources that are not ultimately required for resource adequacy.

According to oral testimony by Francisco Valle during the Direct Hearing on 1/16/24, among large anticipated industrial loads included in their forecast, only 14 out of 52 are actually committed. Without historical precedence for this recent level of investment in energy-intensive manufacturing and data center loads (shown in Figure 1 of the Company's Direct Testimony), it is unclear how the Company calculated the probability distributions used to adjust upward the load and energy forecasts.

For any new confirmed projects, load will not materialize instantly. Those projects will need to go through permitting, design, engineering, and construction. While typically these timelines are shorter than utility procurement cycles, a BYOD program would allow capacity needs to match new loads as they materialize rather than preemptively making capital investments based on models that have not been validated against actual data.

[11] https://www.utilitydive.com/news/ontario-vpp-virtual-power-plant-energyhub/706496/

[12] https://investors.sunrun.com/news-events/press-releases/detail/279/sunrun-and-pge-collaborate-on-residential-battery-powered

Q. PLEASE EXPAND ON THE SECOND REASON RELATED TO PRIVATE CAPITAL.

A. A BYOD tariff would enable the Company to procure the benefit of fast-acting battery storage for all customers' benefit without increasing the rate base. Often the only required capital investment is the software used to control individual batteries enrolled in the program. The Commission could compare the costs for the new BESS, PPA, or CT projects (inclusive of regulated rate of return) to the cost of procuring peaking capacity from a BYOD tariff via the compensation structure proposed below. Furthermore, by providing peaking capacity interconnected at the distribution grid adjacent to load, residential batteries avoid the line losses associated with transmission-interconnected capacity resources.

Q. PLEASE EXPAND ON THE THIRD REASON RELATED TO RESOURCE DIVERSITY.

In its Direct Testimony, the Company states, "[T]o preserve system reliability and resilience for all customers during all hours, the Company needs a diverse portfolio of dispatchable resources." The importance of resource diversity is well established in utility planning. In addition to diversity in technology type, it is important to have diversity of deployment context. Large-scale resources benefit from economies of scale by using a single point of common coupling with the distribution or transmission grid. Yet this also represents a single point of failure. On the other hand, individual systems contained within a BYOD program can fail without materially impacting the aggregate capacity. Similar to risk pools in the insurance industry, a BYOD program spreads the risk of non-performance over thousands of individual assets.

Q. PLEASE EXPAND ON THE FOURTH REASON RELATED TO RESILIENCE.

A. Similar to the DCO-1 and DCL-1 tariffs, which are only open to commercial and industrial customers, a BYOD tariff would expand resilience options for residential customers by defraying the total cost of ownership of battery storage (through the upfront and ongoing compensation payments). For homes with existing solar PV, the addition of a battery transforms the solar into a resilient resource by allowing the solar to charge the battery during grid outages.

As more consumers purchase electric cars – supported in part by historic investments in manufacturing in Georgia –having uninterrupted power will mean not only keeping on the lights

and running the heat but also getting to work, picking up food and essentials, and driving kids to school. At GMP, we treated the BYOD tariff as an extension of our responsibility to provide reliable service to Vermonters, regardless of whether power was delivered via our distribution infrastructure or via a residential battery that a customer was able to install because of our cost-based compensation payments.

While we did not do so for GMP's BYOD tariff, in calculating the value of a BYOD program the Company could even include avoided interruption costs, for example using the Interruption Cost Estimator tool as developed by Lawrence Berkeley National Laboratory.[13]

Q. PLEASE EXPAND ON THE FIFTH REASON RELATED TO DISTRIBUTION CONSTRAINTS.

A. While the Company's 2023 IRP deals primarily with bulk system capacity needs, other utilities in the US are projecting constraints on their distribution systems, particularly at the substation level, due to electrification of residential heating and passenger vehicles.[14]

Residential batteries can help alleviate these distribution constraints in addition to meeting system-wide peak demand. Transmission-connected resources can only address the latter. Whereas all batteries within a residential BYOD program *can* receive the same dispatch signal, this is not required. The Company could send a signal for only those batteries on specific congested residential distribution feeder to discharge at a specific time (as long as these hours are not coincident with system-wide peaks) or send a signal for batteries to charge when solar generation is abundant to help avoid curtailment (the company forecasts adding over 10,000 MW of solar in its MG0 capacity expansion model). This practice of targeted local peak reduction through the dispatch of small cohorts within a larger BYOD program could be used to defer distribution investments, delivering savings to all Georgia Power billpayers. Similar to GMP's BYOD program, the Company could offer an additional performance-based compensation payment for battery systems installed in congested areas of the distribution grid in exchange for the ability to dispatch more frequently than the base offering.

[13] https://icecalculator.com/home

[14] https://www.mass.gov/doc/gmacesmp-drafteversource/download

Q. PLEASE EXPAND ON THE SIXTH REASON RELATED TO OPERATIONAL EXPERIENCE.

A. While much has been written about how utilities can operate VPPs to reduce costs for their customers,[15,16] there is no substitute for direct experience. It takes time for utilities to fine-tune enrollment, billing, and day-to-day program operation. At GMP, we had the benefit of "learning by doing" during an 18-month pilot project prior to filing the BYOD tariff. This experience proved invaluable for ensuring that by the time tariff enrollment opened, the program delivered its expected value.

This testimony deals specifically with VPPs composed of battery storage systems, but the core operating concepts are similar for other technology types. Experience with this type of program (aggregating and dispatching customer-sited resources via a software platform) can be extended to help the Company plan and launch similar programs for other customer-sited flexible loads, including EVs and electric water heaters. A report by The Brattle Group found that VPPs are among the most cost-effective resources for providing resource adequacy.[17]

In essence, VPP expertise will become a tool in the Company's tool belt to quickly meet new capacity needs, for example if new load were to materialize beyond what was forecasted in the 2023 IRP.

Q. ARE YOU PROPOSING THAT THE BYOD TARIFF TAKE THE PLACE OF OTHER PROPOSED RESOURCES?

A. No. I am proposing a BYOD tariff to complement the resources already proposed in the Company's 2023 IRP as part of the 1,000 MW of additional battery resources the Company requested (p. 37 of Direct Testimony). The Company's MG0 capacity expansion scenario provided in its December 2023 supplemental filing (Document Filing #216585) builds 2,850 MW of battery resources over the next 5 years. This demonstrates that adding more battery storage resources

[15] https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf
[16] https://rmi.org/insight/virtual-power-plants-real-benefits/
[17] https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf

beyond what is currently proposed in the 2023 IRP would be part of the optimal supply mix according to current load forecasts.

Without access to the Company's incremental capacity costs, it is difficult to directly compare the cost of the BYOD tariff with other proposed resources. However, if the Commission believes a residential BYOD tariff can provide the same services as other proposed resources at the same or lower cost *and* lower risk of overinvestment, then it should take the place of those resources.

Q. COULD ANY OF THE COMPANY'S EXISTING OR PROPOSED TARIFFS BE USED TO SUPPORT A BYOD PROGRAM?

A. No. While a battery could help a customer reduce their bills under either the Nights and Weekend or Smart Usage tariffs by shifting demand from peak to off-peak hours, these tariffs do not offer a mechanism for the Company to dispatch battery storage systems to meet bulk capacity needs. Similarly, the RNR-11 tariff financially motivates customers to configure a battery to maximize solar self-consumption. Under both, the time-of-use (TOU) tariffs available and RNR-11, customers are only rewarded for configuring their battery in such a way as to minimize their own bill, with no incentive to align discharging with system-wide peak periods. To unlock the full value of residential energy storage, the Company must be able to dispatch systems directly, and to do that they must compensate customers directly outside existing tariffs.

Q. WHY ARE YOU PROPOSING A BYOD TARIFF AND NOT A PILOT PROGRAM?

A. Residential batteries dispatched in aggregate are a proven resource that have been deployed by utilities outside Georgia for resource adequacy. Pilot programs typically have enrollment caps and create uncertainty for customers investing in distributed energy resources. Furthermore, the Company has proposed two other tariffs to address the near-term capacity need in its 2023 IRP (DCO-1 and DCL-1).

IV. PROPOSAL FOR GEORGIA POWER RESIDENTIAL BYOD TARIFF

Q. WHAT ELEMENTS DO YOU BELIEVE SHOULD BE INCLUDED IN GEORGIA POWER'S BYOD TARIFF?

A. Besides the compensation structure, which I address below, a successful program design should include the following elements:

1. **Event notification**: participating customers should be notified of battery discharge events, ideally 24 hours in advance.

2. **Installer training and registration**: companies installing battery systems eligible for enrollment in the BYOD tariff should be required to attend training sessions with the Company so that they understand program rules and the compensation structure. The Company should then publish a list of certified installers on their public website.

3. **Consumer protections**: certified installers should be required to submit, to the Company, a standard disclosure form signed by the participating customer during the interconnection application process. This standard disclosure should at minimum include the contact information of all stakeholders, system specifications and cost, and a summary of Program terms.

3. **Eligibility of multiple battery systems**: so as not to pick winners and losers in the competitive residential storage market, the tariff should be open to multiple battery manufacturers.[18] There should also be a clear pathway for new battery companies to become eligible for participation. A list of eligible systems should be made available on the Company's website.

4. **Opting out of events**: consumers should be able to opt out of individual events. Opting out would impact the customer's ongoing compensation payment via the calculation of average event discharge, as described below.

5. **Maximum number of events and event duration**: BYOD control events should be limited to a maximum of 60 per year, with a maximum event duration of 3 hours.

[18] As stated by the VPUC in its final order on the BYOD Tariff, "Effective competition in the small-scale storage market will over time drive efficiency, lower prices, result in a diversity of services, and provide better-quality service for the benefit of all consumers. When utilities are engaged in competitive markets, there is the potential for them to exert market power that harms the development of competitive markets." (Vermont PUC Docket 19-3537-TF, Final Order).

6. **Use of battery inverter for metering**: performance during called events should be measured using the battery's inverter, which will avoid the need to install a secondary utility meter. Using only the net export would undervalue the battery's role in reducing peak demand, since the customer's real-time gross consumption is unaffected by the battery's behavior and would need to be met by other supply side resources.

7. **"Stackability"**: Customer participation in the BYOD tariff should not preclude them from participating in any other utility program, residential tariff, or RNR.

Q. DO YOU BELIEVE THE COMPANY SHOULD USE THE SAME COMPENSATION STRUCTURE AS WHAT GMP USES FOR ITS BYOD TARIFF?

A. No. While a purely upfront compensation payment is an effective mechanism to drive program uptake, I believe it creates too much risk for non-participating billpayers. Further, compensating customers for actual performance encourages ongoing program participation and therefore sustained grid benefit.

I believe the compensation structure should be a hybrid of "upfront" and "ongoing" performance compensation (implemented as a bill credit) based on the average discharge of the battery storage system during called peak events, measured by the battery system's inverter. The combination of upfront and ongoing compensation balances between two objectives: rapid uptake (to meet the urgency of the impending capacity need) and reducing risk to non-participants. An upfront payment is important for reducing customers' out-of-pocket costs, which often pose a barrier to adoption.[19] An ongoing payment, based on the average annual performance of the battery system, will ensure that compensation is linked with actual realized program benefits. We propose that the majority of compensation (60%) be allocated to ongoing compensation.

Q. SHOULD THE PARTICIPANTS BE COMPENSATED BASED ON MONTHLY OR ANNUAL EVENT PERFORMANCE?

A. Compensation should be calculated based on average performance across all events in a calendar year. There may be certain months in which no events are called (for example, the spring

[19] In GMP's BYOD pilot (the precursor to the BYOD tariff), uptake was extremely low under the initial compensation structure of exclusively ongoing payments.

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or fall when temperatures are mild); participants should not be penalized for the lack of need for peaking resources during those months. The compensation amount could be paid either as a single lump sum or spread out evenly across the 12 months of the following calendar year to smooth out the customer's bills.

Q. WHAT WOULD BE AN APPROPRIATE COMPENSATION LEVEL AND PROGRAM TERM?

A. I believe a fair payment for this program should be determined jointly by the Company and the Commission using a similar methodology as the draft DCO-1 tariff, which allocates 75% of the projected program value to participating customers. However, unlike the DCO-1 tariff, which appears to provide a guaranteed monthly credit, the ongoing compensation payment in the BYOD tariff should be determined by actual performance. For the remainder of this testimony, I use a placeholder value of $250/kW-year for illustrative purposes.

The program term should be at least 5 years, both to create stability for participants and to meet the capacity need until resources from the All-Source RFP become available. Over the 5-year program term, the ongoing compensation *level* ($/kW-year, multiplied by average event performance to calculate payment) should remain the same. This will provide participants with the certainty that if their systems perform as requested, they can expect to be rewarded at the same compensation level over time. Without such a guarantee, it would be difficult to secure financing to install an energy storage system.

From the $250/kW-year placeholder value, we propose 40% be allocated to the upfront compensation payment ($100/kW-year * 5 years = $500/kW) and 60% be allocated to the ongoing compensation payment ($150/kW-year).

Q. HOW WOULD UPFRONT COMPENSATION BE DETERMINED?

A. At the time of enrollment, the customer will earn an upfront compensation amount based on the battery's capacity available to the Company for dispatch during BYOD peak events. The enrolled capacity is equal to the total energy capacity (in kWh) divided by 3 hours (the proposed maximum event duration). For example, a residential storage system with an energy capacity of 15 kWh would enroll 15 kWh / 3 hours = 5 kW.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE HOW A CUSTOMER'S COMPENSATION WOULD BE CALCULATED?

A. The table below shows example event performance values for a single 15 kWh / 5 kW battery system. In this simplified example, only 5 events are called during the calendar year.

Event Number	Event Duration (hours)	Discharge (kWh)	Average Discharge (kW)
1	2	10	5
2	3	15	5
3	3	12	4
4	3	0*	0
5	2	9	4.5

*customer opted out of this event

The customer's upfront compensation payment for enrolling the 5 kW battery would be:

$$\$100/\text{kW}-\text{year} * 5\ years * 5\ kW = \$2{,}500$$

The customer's annual performance-based compensation based on the event table above is:

$$\$150/\text{kW}-\text{year} * \frac{(5+5+4+0+4.5)}{5\ \text{events}} = \$555$$

Q. SHOULD THERE BE A CLAWBACK PROVISION FOR THE UPFRONT PAYMENT IF SYSTEMS DO NOT PERFORM AS EXPECTED?

A. Yes. If a system enrolled in the BYOD tariff experiences a communication failure and it is not remedied within 30 days after notification by the Company, the participant should be charged a monthly fee that reflects 1/60th (reflecting the 60 months of the 5-year term) of the upfront compensation payment. If a system is online but performs at a lower level than the initially-enrolled amount, this would be reflected in the ongoing compensation payment. With the majority of compensation (60%) tied to ongoing performance, participants will have a strong reason to ensure that their systems are performing at the maximum level. Alternatively, the Company could decide on a performance threshold (e.g. average discharge below 50% of initially enrolled capacity) at which they would enact the clawback provision.

Q. SHOULD THE COMPENSATION AMOUNT REMAIN THE SAME EACH YEAR?

A. Not necessarily. Each year the Company may recalculate the value of peaking capacity based on updated load and generation forecasts, or the previous year's average residential capacity costs. This value would then be multiplied by 75% to arrive at the new "all-in" compensation amount ($/kW-year) for new systems enrolling in the tariff during that calendar year. The ongoing portion of this amount should then be locked in for the 5-year term.

Q. WHY NOT COMPENSATE CUSTOMERS BASED ON THEIR BATTERY'S PERFORMANCE DURING THE ACTUAL PEAK HOUR EACH YEAR?

A. There are a few issues with compensating based on performance during the actual annual peak hour. First, there might be several hours (rather than a single hour) where the Company faces capacity constraints during which customers should be incentivized to participate. If they were only compensated based on a single hour, they might opt out of other events. Second, participants might not receive compensation even if responding perfectly to called events. Such a scenario could arise if the Company, through dispatch of customer-sited resources, shifted the peak to a different hour in which batteries were not called upon to discharge. Figure 2 shows a simplified case for such a scenario for a single day.

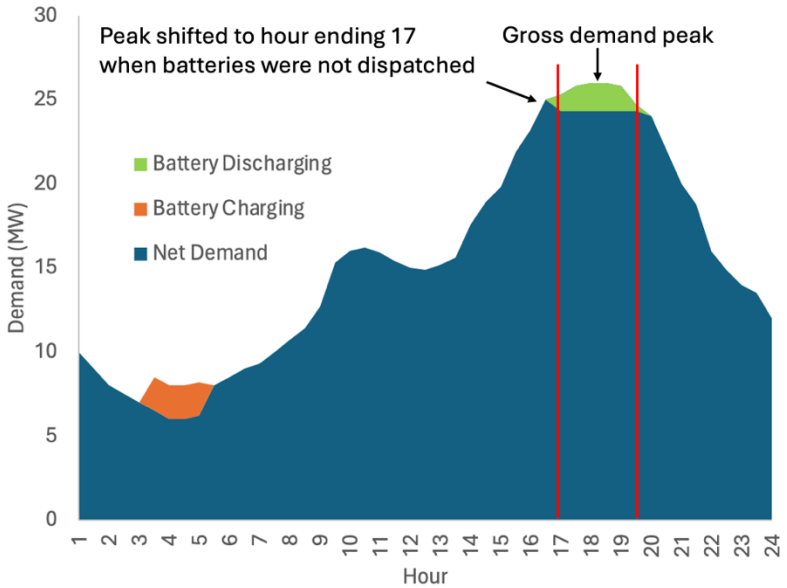


Figure 2: Illustration of peak shifting due to battery dispatch.

Participants should not bear the risk of forecasting peak demand or concern themselves about whether event signals coincide with system peak demand. That is the Company's domain of expertise. If participants' systems respond when signaled, they should receive full compensation.

Q. WOULD BYOD OPERATION RESEMBLE OTHER EXISTING OR PROPOSED GEORGIA POWER CUSTOMER PROGRAMS?

A. Yes, the proposed BYOD tariff is similar to the Company's existing Temp Check program, which it is asking for permission to expand in the 2023 IRP. In that program, the Company remotely adjusts the smart thermostats' temperature setpoints during extremely hot or cold days. The Company's technology partner in that program, Uplight, also has experience working with utilities to manage enrollment and operation of residential battery programs.

Q. SHOULD PARTICIPANTS BE REQUIRED TO TAKE SERVICE ON A SPECIFIC RESIDENTIAL SERVICE TARIFF?

A. No. Program participation should not preclude customers from enrolling in any residential tariff for which they are otherwise eligible. One of the advantages of battery storage is the potential for value "stacking." In addition to providing resource adequacy during hours with extremely high system-wide demand, residential battery storage can be used to shift a home's net consumption towards hours when the marginal cost to generate and deliver power is low, reducing the Company's operating costs. BYOD participants should be compensated for services performed outside of hours when they are called upon for resource adequacy, such as configuring their batteries to "soak up" behind the meter generation (helping to avoid backfeeding energy to the distribution grid) and participate in time-of-use rates.

Q. SHOULD PARTICIPANTS BE REQUIRED TO INSTALL SOLAR AND STORAGE TOGETHER LIKE IN DUKE ENERGY'S POWER PAIR PILOT?

A. No. Participation should be open to customers with and without solar. While the coexistence of solar and storage does offer resiliency benefits for extended outages, it does not affect the program's core value proposition, which is based on the storage resource's performance during system-wide peak hours. From this perspective, standalone storage charged from the grid provides the same benefits as solar charged by an attached solar array.

However, it is worth noting that the pairing of solar and storage transforms residential solar into a firm capacity resource that could be used in future resource planning. In its Direct Testimony, the company stated (about its proposed utility-scale BESS projects):

> "The BESS will also firm up the winter planning capacity of the existing solar facilities at both sites by storing energy that can then be dispatched by system operators to benefit the grid. Without BESS, the winter planning capacity for the solar resources at each site is 10% of the nameplate capacity of each facility." (p 36).

The same argument can be made for residential solar, which can be deployed much more quickly than large-scale projects that are subject to risk of delays.

Q. WHAT SHOULD BE THE PROCESS FOR INTERCONNECTING STANDALONE STORAGE?

A. As a form of inverter-based distributed generation, standalone storage should go through a similar interconnection process as resources covered under the Company's RNR-11 tariff.

Q. SHOULD BATTERIES ENROLLED IN THE BYOD TARIFF BE ALLOWED TO EXPORT TO THE GRID?

A. Yes. The BYOD tariff is designed to help meet the Company's capacity need, which is urgent given the rapid demand growth. Capping battery discharge at the household's real-time consumption (i.e., disallowing export) would hamper the program's ability to contribute to meeting this need.

Q. HOW SHOULD EXPORTED ENERGY BE COMPENSATED DURING CALLED EVENTS?

A. Energy exported to the grid during called events should be compensated under the instantaneous netting provision of the RNR-11 tariff: the avoided energy rate plus 4 cents. When charging the battery for the purpose of providing peaking capacity, the customer is either purchasing energy from the grid at the full retail rate (for standalone storage or solar-plus-storage when charging outside of solar hours) or foregoing export compensation under the RNR-11 tariff (for solar-plus-storage charging during solar hours). This energy is not used for the customer's sole benefit but instead for the benefit of all billpayers. Compensating for the energy provided

(separate from the capacity) at the avoided cost + 4 cents ensures that participants are not unduly penalized for providing this service.

Q. WHAT DO YOU BELIEVE IS AN APPROPRIATE TARGET FOR THE BYOD TARIFF?

A. I believe 50 MW is an appropriate target, representing approximately 10,000 participants. GA Solar believes that number is achievable prior to the winter of 2025/2026 as long as the tariff is open for enrollment within 6 months of the final order of this docket.

Q. DO YOU BELIEVE TARIFF ENROLLMENT SHOULD BE CAPPED?

A. No. The compensation structure (reserving 25% of net present value for non-participants) ensures that the program will provide net benefits to all customers. The tariff does not require deployment of the Company's capital, instead leveraging private capital. As such, a cap is not necessary or warranted.

Q. WHAT IS A REASONABLE MAXIMUM FOR THE NUMBER OF EVENTS PER YEAR AND THE NUMBER OF HOURS PER EVENT?

A. There should be no more than 60 events per calendar year. The exact number should be determined through an analysis of the Company's load forecast and the cost of constructing and operating its existing and proposed generation resources. To give the Company maximum operating flexibility, there should *not* be a limit on the number of events in a calendar month or season, as long as the total number in the year does not exceed 60.

Each event should be capped at a maximum of three hours. This would not stop the Company from calling shorter-duration events. In fact, the Company should always strive to call the shortest event possible to meet the capacity need. In any case, compensation would be determined by the average discharge value during events regardless of each event's duration.

V. CONCLUSION

Q. WHAT OTHER BENEFITS BEYOND THOSE ALREADY DISCUSSED WOULD A BYOD TARIFF PROVIDE THAT SHOULD BE CONSIDERED?

A. Georgia has already emerged as a leading state for clean energy manufacturing, especially in electric transportation and battery storage. A BYOD tariff would create jobs in the design, sale, installation, operation, and maintenance of battery systems, complementing the state's manufacturing industry and creating a pipeline to ensure that technologies built in Georgia serve its residents.

Q. WHAT ADDITIONAL DATA WOULD BE HELPFUL IN DETERMINING AN APPROPRIATE LEVEL OF COMPENSATION FOR BYOD PARTICIPANTS?

A. Hourly demand projections (both at the distribution and bulk system level) would enable further analysis to calculate the avoided cost associated with dispatching batteries enrolled in the BYOD tariff not only for hours in the year where all capacity resources are utilized but also as part of the Company's economic dispatch model to displace high marginal cost generation at other hours. Even if batteries are charging from the grid (versus on-site generation), the charging could occur during hours with lower marginal cost generation.

Q. DO YOU HAVE ANY CLOSING REMARKS TO MAKE TO THE COMMISSION ON THE MATTERS THAT YOU HAVE ADDRESSED IN YOUR TESTIMONY?

A. Yes. To summarize my testimony, Bring Your Own Device programs can provide cost-effective resource adequacy at significantly lower overinvestment risk compared to large-scale capacity resources. There are several operational BYOD programs in the US that provide a template for successful program operation.

A BYOD tariff can be launched rapidly to meet the urgent capacity need in the Company's service territory, leveraging private capital to benefit all customers. Unlike large-scale resources, a BYOD program's size does not need to be planned years in advance; it can be scaled flexibly to match additional capacity needs as they materialize, which reduces the risk of overforecasting demand far into the future. A BYOD tariff will also expand the options for resilient backup power and provide the Company with invaluable operational experience in managing distributed energy resources, which can be used to meet both bulk system and distribution constraints.

I recommend that the Commission direct the Company to file within 6 months after the final order in this docket a new tariff for a residential BYOD program as proposed in Section IV and summarized in the Introduction.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. MORELAND:

Q Mr. Turk, do you have a summary of your testimony prepared today?

A I do.

MR. MORELAND: Mr. Chair, we ask if he could do so now.

CHAIRMAN SHAW: Yes, sir. Please proceed.

MR. TURK: Thank you, Mr. Chairman, and Commissioners. My name is Graham Turk. I'm a researcher at the Massachusetts Institute of Technology, focusing on distribution grid impacts of residential electrification.

I formerly worked for Green Mountain Power, GMP, an investor-owned utility based in Colchester, Vermont. And during my time at GMP, I managed the Bring Your Own Device tariff and supported GMP responses to data requests related to the program.

I'm here on behalf of the Georgia Solar Energy Association. And I had a line about how nice it is to be away from the Boston winter, but I'm afraid I brought that weather down. So apologies. But thanks for making me feel at home.

In my written testimony, I propose a residential battery tariff designed to provide net savings to all bill payers. This program can be

considered a type of virtual power plant, or VPP, which is an aggregation of customer-sited resources directly controlled by utility for grid services, such as addressing bulk system peak demand or alleviating distribution constraints. While my testimony deals with VPPs composed of residential batteries, other device types are possible. For example, smart thermostats, electric vehicle charging stations, and electric water heaters.

In recent years, VPPs have emerged as a new form of firm, reliable capacity resource capable of reducing costs by leveraging customer-sited assets. There's been a flurry of recent activity related to VPPs in various regulatory contexts. For example, in January, the Colorado PUC filed a recommended decision for Xcel Energy to create a VPP program open to residential customers.

In the same month, North Carolina Utilities Commission filed a final order to create a solar-plus-storage PowerPair Program, with Duke Energy directly controlling batteries for a subset of participants.

Rhode Island Energy filed an application to the Rhode Island PUC to include "bring your own device" and "bring your own thermostat" in its portfolio of

demand-response programs.

And the Arizona Corporation Commission in February voted on an amendment in Arizona Public Service rate case to require the creation a 5,000-customer BYOD pilot.

These recent developments build on successful VPP programs around the country. In my testimony, I outline Green Mountain Power's Bring Your Own Device, BYOD tariff, which, to my knowledge, was the first residential battery tariff approved by a public utility commission in the U.S., which happened in 2019.

The program compensates customers who install residential battery storage systems and make them available for GMP to discharge during a limited number of control events per year. This resource is used to reduce the utility's transmission and capacity costs, as allocated by New England's regional transmission operator based on coincident peak demand.

I worked directly on the design and day-to-day administration of the BYOD program, which included creating the financial analysis submitted to the Vermont Public Utility Commission as part of its tariff investigation, managing enrollment and

billing, and analyzing system performance for periodic regulatory reports.

After describing GMP's BYOD tariff, I share my argument for why a similar Bring Your Own Device tariff is warranted to complement other proposed resources in addressing the near-term capacity need identified in Georgia Power Company's 2023 IRP.

To summarize my argument briefly: A BYOD program, one, can be launched quickly and scaled flexibly to match currently forecasted and future load additions. Two, leverages private capital to benefit all bill payers. Three, increases resource diversity. Four, expands options for customers seeking resilient backup power. Five, can be used to address distribution constraints, in addition to bulk system capacity needs. And, six, provides the company with invaluable operating experience dispatching customer resources, a new tool in its resource arsenal for delivering cost-effective reliable service.

I then propose details for a BYOD tariff, including compensation structure, performance assessment, target enrollment capacity, consumer protections, and frequency and duration of events, which can be found on pages 20 through 23 of my

written testimony.

I recommend a hybrid compensation payment that includes both an upfront and ongoing performance-based payment to balance between two objectives: Speed of deployment and protection for non-participating bill payers. These recommendations are based on my direct experience with GMP's BYOD tariff, as well as my knowledge of similar offerings in other U.S. states.

The all-in compensation value we propose is in line with what the company has proposed for other capacity resources historically. The exact value should be determined jointly by the Commission and the company based on the program's projected value, allocating a portion of benefits to nonparticipating bill payers, just like in the proposed DCO, DCL, and CL tariffs.

However, I want to point out that none of those tariffs are open to residential customers, and the minimum resource size is 200 kilowatts, which is an order of magnitude greater than a typical residential battery.

The BYOD tariff could be part of the up to 1000 megawatts of total BESS resources that the company has requested to be online by 2027, or part

of the flex capacity provision. The company's MG0 capacity expansion plan builds 2880 megawatts of 4-hour battery resources over the next 5 years. This demonstrates that adding more battery storage resources beyond what is currently proposed in the IRP would be part of the optimal supply mix, according to current load forecasts.

The company has shown in its main IRP document, and several supplemental filings, that there is a capacity need as early as the winter of 2025/'26. Even if the other resources proposed in this IRP were approved, any delay in bringing new capacity online could jeopardize the company's ability to serve forecasted load.

A BYOD program can be launched rapidly to address this risk, without the need for extensive interconnection studies or transmission expansion. My testimony provides several examples where VPPs went from initial concept to operational in just six months.

One other key advantage of a BYOD program is that the nameplate capacity does not need to be specified in advance. More systems can be added to align with demand as new projects are confirmed. And this ability to right size the aggregation

reduces the risk of overbuilding capacity if a portion of load forecasted in the P95 scenario does not materialize.

Once systems are in place, aggregations of small-scale batteries also diversify the risk of resources not performing during critical periods because individual systems can fail without materially impacting the capacity of the entire aggregation.

A BYOD storage program would also create local jobs in the design, installation and maintenance of residential battery storage systems. This is the ideal downstream complement to Georgia's burgeoning battery manufacturing sector.

A BYOD program would help ensure that technologies built in Georgia are deployed within the state for the benefit of its residents. With expertise at all levels of battery storage value chain, Georgia can continue to lead as the national center of clean energy manufacturing and deployment.

And should the commission adopt my recommendation, I would be happy to advise the company on developing and launching its BYOD offering at no cost to Georgia Power bill payers.

Thanks for the opportunity to offer testimony

and I look forward to your questions.

MR. MORELAND: Mr. Chair, he's now available for questions from the Commission and for cross-examination.

CHAIRMAN SHAW: Thank you, sir.

Commissioners. Go ahead, Commissioner Echols.

VICE-CHAIRMAN ECHOLS: Hey. Great -- great to have someone actually from Green Mountain Power here.

MR. TURK: Good to be here.

VICE-CHAIRMAN ECHOLS: Couple questions about the program. Was the original program a leasing program?

Do I have that -- do I have that wrong and has it morphed into something else?

MR. TURK: Yeah. So there were originally two pilot programs; one lease, one customer-owned. They were advanced together in the same PUC investigation. And both tariffs now exist side by side.

VICE-CHAIRMAN ECHOLS: And which is the most popular?

MR. TURK: So total enrollment, I don't have the exact numbers right now. It's been two years since I've been at the company.

But in the initial tranche of customer enrollments, it skewed a little more towards the lease. I think since then it's equalized a little bit. Part of the reason for that was in the days that we offered that program, there was not an ITC available for battery-only installations.

And so most customers that were installing batteries were charging them exclusively with solar, as opposed to allowing grid charging, which reduced the overall value available to them. With the IRA passage and ITC now available for battery only, I don't believe that would be the case anymore.

VICE-CHAIRMAN ECHOLS: The new one, you still have to have some money to buy it; right?

Where the old one you didn't have to make an investment, is that correct, on the leasing program?

MR. TURK: You're referring to the difference between the lease?

VICE-CHAIRMAN ECHOLS: Uh-huh.

MR. TURK: That's right. So the lease works as a -- it's a line item on the customer's bill. The BYOD program, the customer does provide their own financing. They could lease it with a third party and we -- GMP at the time provides an upfront incentive in exchange for the ability to dispatch

that battery.

VICE-CHAIRMAN ECHOLS: What brand were the batteries that were being leased; do you remember?

Were they Tesla Powerwalls or sonnen or --

MR. TURK: Yeah. So the leasing program was Tesla Powerwalls. The BYOD program had six eligible battery manufacturers. I'm just going to look through the testimony where I list them.

VICE-CHAIRMAN ECHOLS: And did they have problems with those Powerwalls?

Were they having to replace them prematurely, to your knowledge?

MR. TURK: In my experience, no. There were perhaps a handful of events where maintenance needed to be done, but on the order of single digit in the two years that the program was operational when I managed it.

VICE-CHAIRMAN ECHOLS: And the newer program, the BYOD program, is it similar to Rocky Mountain Power in that the utility has complete control and complete visibility?

MR. TURK: So for the BYOD program, the utility has direct discharge control. However, the utility does not control charging.

Part of the reason for that was because of the

ITC requirement. Batteries had to be charged exclusively from solar and GMP did not want to jeopardize customers' ability to take that credit by controlling charging. However, as I mentioned, now that that requirement is no longer in place, effectively total control would be something I would expect.

And in terms of discharging the batteries for peaks, it works identically in the lease program and the BYOD program. They're both dispatched to reduce coincident peak demand.

VICE-CHAIRMAN ECHOLS: In the upfront and then the ongoing payment, what is the difference between the Vermont payment and the Colorado payment?

MR. TURK: Sure. So Vermont's payment is $850 per kilowatt. That's paid for a ten-year program term.

VICE-CHAIRMAN ECHOLS: That's upfront; right?

MR. TURK: Exactly. There's also an additional $100 for systems installed in constrained areas of the distribution grid.

So to your point earlier about is there a possibility to do that, there is. And GMP did that exactly to manage solar congestion.

VICE-CHAIRMAN ECHOLS: 100 per kilowatt?

MR. TURK: One hundred extra dollars per kilowatt.

VICE-CHAIRMAN ECHOLS: Per kilowatt, okay.

MR. TURK: That's right.

VICE-CHAIRMAN ECHOLS: And how about the Colorado; what did they get upfront?

MR. TURK: I don't know exactly what their there upfront payment is. I think perhaps we could ask Mr. Richetta from sonnen.

VICE-CHAIRMAN ECHOLS: I think it's less, but -- it seems like it was 450, but I could be wrong.

You know, my concern on the utility having the complete control -- and I've asked a lot of questions during this hearing about batteries. Obviously, I'm interested in the program.

Is our Check Temp program -- and I've run this against the Austin's Utilities version -- our program is very popular. Super high customer satisfaction because we don't -- we don't wear the customer out. And I think it's very well designed by the utility.

I just wonder if customers would eventually resent the utility having the control. Like if there was, you know, a storm that came through, but

their battery had already been discharged and they -- I'm just wanting to make sure we don't get ourselves into something where people are going to be angry.

MR. TURK: Sure. So I agree that there is some degree of event fatigue if these are dispatched all the time. In my testimony I propose a maximum 60 events per year for that reason. They're really meant to be discharged during constrained periods happening during the hottest or coldest days of the year.

I know there are other examples where batteries are discharged every day for load shifting. The proposal that I make here is not necessarily for that. It's, instead, for targeted dispatch for capacity-constrained events.

VICE-CHAIRMAN ECHOLS: Do you think -- do you think plugged-in EVs would ever be a part of a virtual power plant where -- I know in Colorado Rolling Energy Resources has 10,000 subscribers. And they can curtail those EVs from charging.

So when I go home today, I'm going to plug my Leaf in. And if there was an event -- which there's not today, of course. But if it was the summer, for example, the utility might be able to curtail me for

15 minutes; right? Just like we do on the thermostat.

Do you feel like those things are ever going to be a part of a VPP?

MR. TURK: Absolutely. And, actually, GMP does have a direct-managed EV tariff that I was also involved with proposing and then administering. In that program, events are four -- three or four hours long. And customers get a discount on the per-kilowatt-hour price in exchange for allowing the utility to curtail their charging during those periods.

I'll say in the three years that I managed that program, there were -- the opt-out rate during those events was fewer than 1 percent. We found that customers generally -- it was set and forget.

So they, through an app, enrolled on the rate. Charging would happen overnight. Typically, cars are plugged in for ten plus hours. You might need to do one or two hours of charging over that period.

And so a deferral of four hours into the middle of the night generally was accepted very well and customers enjoyed that program.

VICE-CHAIRMAN ECHOLS: Yeah. And geeky customers -- and I don't know if you've seen these

studies of these customer segments. But, you know, the geeky segment, 15 percent or whatever it might be now, they like that kind of thing; right?

They don't mind. And I was teasing with my colleague about, you know, increasing the smart thermostat thing tenfold. And I think, to her point, we may not have that many customers that are -- have an aptitude for that, that want to do that kind of thing.

There is probably a finite number of them; right?

MR. TURK: So I think the beauty of some of those programs is it really is meant to be set and forget. During my time at GMP, I helped manage the call center and spoke to customers who were enrolling in these programs.

There were a few who they didn't have a TV on the wall, but were enrolled in a managed VPP charging program. It was really that simple to get set up. And I think that having the enrollment piece be really well designed so that it's not a high burden to get in, once that's set up, the utility can manage the complexity of when to call events. That doesn't need to fall on the customer. So as long as enrollment is easy, I don't think you

necessarily have to be an energy nerd in order to participate.

VICE-CHAIRMAN ECHOLS: I think this is the third leg of the stool here. We've got the utility wanting to put solar -- I mean, wanting to put batteries at the solar arrays. And then we've given them permission to do a pilot with the Publixes and Walmarts of the world to work with that diesel generator to be able to call that, you know, for the store and freeing up that power.

So we've got a lot of those entities replacing those, putting Tier 4, you know, Volvo generators back there. So that's the second leg.

And now this is the third leg. This is taking it down to the consumer level, giving consumers an opportunity to participate in something that would yield high customer satisfaction. It's just a matter of us making sure that we're getting the right -- the right program.

Do I have all that -- all that right? Do those three -- probably the three ways to utilize these batteries?

MR. TURK: Generally, yes. And I think that the program structure we proposed where it's a -- there's a percentage allocated for nonparticipants

and the split of an ongoing and upfront is meant to balance those objectives.

VICE-CHAIRMAN ECHOLS: Thanks for coming down from Boston and being with us.

MR. TURK: Absolutely.

CHAIRMAN SHAW: Any other questions, Commissioners?

(No response.)

CHAIRMAN SHAW: All right. We will start with cross.

Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. CARVER: No questions.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: GAM.

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local

Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy Association.

MR. COX: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. McNUTT: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: Commissioner Echols took all my questions. I have nothing else for Mr. Turk.

CHAIRMAN SHAW: Me, too. Mine, too. Mine, too.

VICE-CHAIRMAN ECHOLS: Funny guy.

CHAIRMAN SHAW: Redirect, Mr. Moreland.

REDIRECT EXAMINATION

BY MR. MORELAND:

Q Just one question on redirect in regards to the utility having complete control over the battery. In your testimony, do you propose a limit to the amount of battery capacity that could be discharged for customer resiliency purposes?

A I think that would be something the company and the Commission could jointly decide. For the BYOD program, customers were able to decide how much to enroll. So they could choose to reserve 20 percent, 10 percent of the battery's capacity that it would never be discharged under.

And I do think something like that for resilience purposes can be helpful. We spoke to customers who powered through four- or five-day outages when they had batteries and solar installed running, you

know, every appliance in the house.

I think one customer said that they ran their hot tub, which I wouldn't necessarily recommend during a five-day winter outage, but it is doable. And it is a reliable backup resource that customers appreciated, compared to others that require a little more effort and uncertainty.

I think the benefit of seamless battery backup without the need to worry about fuel that kicks in instantly was something that customers really wanted to go for.

MR. MORELAND: Nothing further. Thank you.

CHAIRMAN SHAW: All right. Thank you.

So your witness can be excused. Anything --

MR. MORELAND: We just ask that the direct testimony be entered and admitted into the record.

CHAIRMAN SHAW: So marked.

Thank you, sir. You can be excused.

MR. TURK: Thank you, Mr. Chairman.

CHAIRMAN SHAW: The next panel will be that of Georgia WAND.

Just a little housekeeping in terms of timing. I'm thinking somewhere around 12:15ish maybe we can break for lunch for about 45 minutes.

I'm just trying to speed things along in case

anyone wants to use technology and do a little DoorDashing or whatever it takes to bring some food in.

Also, I don't think the cafeteria will be very crowded today since the legislature is not in session. So we'll say 50 minutes for lunch.

Okay. Ms. Scott.

MS. SCOTT: Good morning. I call Ms. Durand --

MR. SHERRIER: To the stand.

MS. SCOTT: This is my first time. So thank you for your patience. All right.

MR. SHERRIER: Ms. Durand, could you please raise your right hand.

Thereupon,

PATTY DURAND,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. SHERRIER:

Q Could you please state your name for the record and spell your last name for the court reporter.

A Patty Durand, D-u-r-a-n-d.

Q And by whom are you employed?

A I'm not -- well, Cool Planet Solutions.

Q On whose behalf are you testifying?

A Georgia WAND.

Q On February 15th of this year, did you prefile or cause to be prefiled approximately 29 pages of direct testimony in question-and-answer format --

A Yes.

Q -- in Docket 55378?

A Yes.

Q Okay. Do you have any corrections or changes to your prefiled direct testimony at this time?

A I do not.

Q If I were to ask you the same questions that appear in your testimony at the hearing today under oath, would your answers be the same?

A Yes.

MR. SHERRIER: Okay. Mr. Chairman, I move to have the public disclosure version of Ms. Durand's testimony entered into the record as if given from the stand today.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Patty Durand follows:)

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

DOCKET NO. 55378

In the Matter of:

Georgia Power Company's 2023 Integrated Resource Plan Update, Certification of the Power Purchase Agreement between Georgia Power Company and Mississippi Power Company, Certification of the Power Purchase Agreement between Georgia Power Company and Santa Rosa Energy Center LLC, and Amended Certification of the Residential Thermostat Demand Response Demand Side Management Program

DIRECT TESTIMONY

AND EXHIBITS

OF

PATTY DURAND, MBA

ON BEHALF OF

GEORGIA WAND EDUCATION FUND INC.

FEBRUARY 15, 2024

Q. Please state your name, profession, and business location.

My name is Patty Durand and I am founder and president of Cool Planet Solutions LLC which is a consultancy specializing in consumer engagement with energy and grid modernization. I am also a candidate for the Georgia Public Service Commission. My business is located online and my residence is Conyers, Georgia.

Q. On whose behalf are you testifying?

GEORGIA WAND (Women's Actions for New Directions). Georgia WAND Education Fund Inc. is a non-profit advocacy group focused on quality-of-life issues, health hazards resulting from nuclear energy and weapons, and social justice grounded in building racial equity.

Q. What is the purpose of your testimony?

On July 21, 2022, the GA Public Service Commission approved Georgia Power's 2022 Integrated Resource Plan which authorized the retirement of 1,517 megawatts of coal and the addition of 5,154 megawatts of gas and renewables for a net of 3,647 megawatts of new capacity. That does not include 1,020 megawatts of new capacity that Plant Vogtle will add to GA Power's capacity. Together the 2022 IRP and Plant Vogtle will add 4,667 megawatts of generating capacity. Just 15 months after the 2022 IRP was approved, a plan that is supposed to last 10 years, GA Power filed a surprise IRP on October 27, 2023, asking this commission for an additional 6600 megawatts of generating capacity. The purpose of my testimony is to explain why this new request is unreasonable, inappropriate, and should be disallowed.

Q. Ms. Durand, please summarize your educational background and professional experience.

A. I received a Bachelor of Science degree in Business from Virginia Commonwealth University in Richmond, Virginia in 1988, and a Master of Science in Business Administration in 1993 from the College of William and Mary in Williamsburg, Virginia. I worked for three years as a regulatory compliance agent with the Virginia Alcoholic Control Board, and 10 years in various roles in Information Technology before entering the field of environmental advocacy and energy research. Prior to the recent founding my consultancy, Cool Planet Solutions, for 10 years from 2010-2020 I served as President and CEO of the Smart Energy Consumer Collaborative. In that role I was responsible for conducting research studies on consumer and grid modernization, because by all accounts the electric grid was changing rapidly while few people in the energy industry knew much about what consumers knew and wanted in a future in which they were active participants. In addition to conducting research, we also directly educated consumers on the topic of grid modernization and energy through newsletters, videos, social media, infographics, and the like. During my role at SECC I had occasion to attend workshops or seminars at over a dozen state commissions where I presented consumer research to commissioners interested in expanding consumer participation in energy, and I presented consumer research at least three NARUC (National Association of Regulatory Utility Commissioners) meetings and two NASUCA (National Association of State Utility Consumer Advocates) meetings. In addition, I attended between 10 and 20 energy conferences annually in which I presented energy research content to professionals in the energy industry on the topic of consumers. In addition, I have spoken before the Georgia Public Service Commission at least six times, and presented consumer research findings to commissioners outside of formal hearings at least twice.

Q. Have you included a bio?

No. A bio is not necessary because my previous description is comprehensive.

Q. Ms Durand, have you previously testified as an expert witness before this Commission?

Yes. I testified on December 5th, 2023, as an expert witness for Concerned Ratepayers of Georgia regarding Plant Vogtle's stipulated agreement. In addition I have testified as a public witness numerous times.

Q. What were some of the key points you testified to as an expert witness?

That the Commission erred in accepting the August 31, 2023 stipulated agreement because the agreement was reached by a subset of intervenors that were hand selected by Georgia Power, that both intervenors and PSC staff involved in negotiations had no training, experience or skills in negotiating billion-dollar business agreements, or even million-dollar agreements, and that it was wholly inappropriate for a small group of hand-selected nonprofit leaders to negotiate a deal with a sophisticated utility behind closed doors on behalf of 2.7 million Georgia Power customers, making the agreement literally the definition of a backroom deal, which violates the public process and undermines the public trust. And the Commission erred in accepting the August 31, 2023 stipulated agreement because, for the first time in history of PSC proceedings, the stipulated agreement was reached prior to any testimony, reports, filings, or hearings being held on the docket. Finally, the Commission failed to meet its own commitments to hold prudency hearings at the end of the construction process for Plant Vogtle, having declined to do so throughout the 15 years of construction with repeated and strong claims that it made no sense to review cost overruns until the end of the project during prudency hearings. Such hearings were then not held, thus eliminating insight into why Plant Vogtle went so far over budget and was

seven years behind schedule. In fact, as of this writing Plant Vogtle is still not done, with another delay for Unit 4's in-service date announced on January 31, 2024.

Q. Why do you state that GA Power's 2023 IRP should be rejected? GA Power indicates that the large amount of new economic development is creating this need.

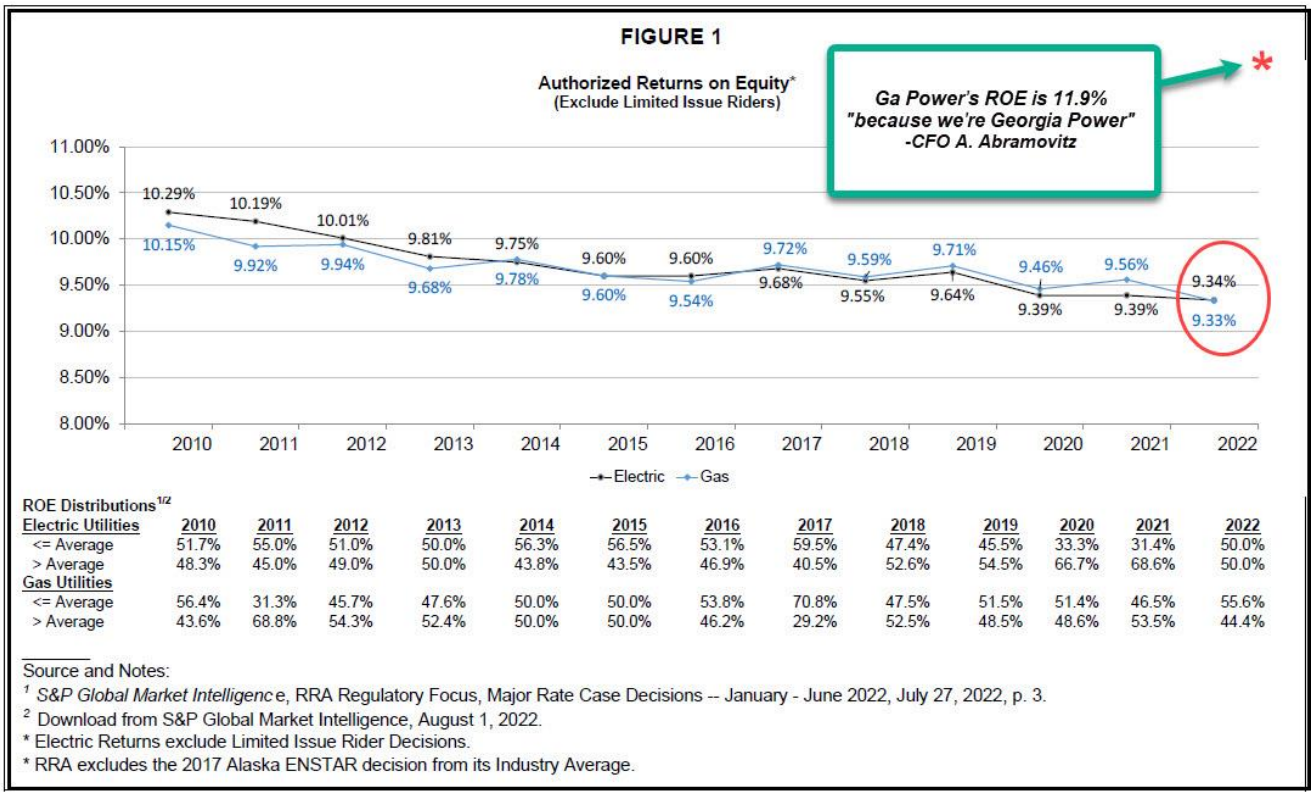
Georgia Power has a long history of submitting false growth projections that are used to justify expanding capacity but which does not materialize. The "Averch–Johnson effect" is an economic term used to describe the tendency of regulated utilities to engage in excessive amounts of capital accumulation in order to expand their profit.[1] This can happen when the allowed rate of return exceeds the cost of capital, since the difference between the two represents pure profit.

Q: Has this happened in Georgia?

Yes. Not only does GA Power's allowed rate of return exceed the cost of capital, GA Power's allowed rate of return exceeds that of nearly every investor-owned utility (IOU) in the United States and is far above industry norms. Thus, GA Power has even more incentive than most IOUs to overinvest capital in order to increase profits. During both the 2019 Rate case and the 2022 Rate Case, expert witness Michael P. Gorman testified that GA Power's ROE requests were not justified and that the utility can easily meet its needs for financial stability and investor profits with a normal ROE. Mr. Gorman prepared a chart to accompany his testimony which depicted the history and current status of utility IOU returns on equity in the United States.

[1] Averch–Johnson effect (March 19, 2023) In *Wikipedia* https://en.wikipedia.org/wiki/Averch%E2%80%93Johnson_effect

Figure 1 – Authorized Returns on Equity [2]



ROE Distributions[1/2]

Electric Utilities	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
<= Average	51.7%	55.0%	51.0%	50.0%	56.3%	56.5%	53.1%	59.5%	47.4%	45.5%	33.3%	31.4%	50.0%
> Average	48.3%	45.0%	49.0%	50.0%	43.8%	43.5%	46.9%	40.5%	52.6%	54.5%	66.7%	68.6%	50.0%
Gas Utilities													
<= Average	56.4%	31.3%	45.7%	47.6%	50.0%	50.0%	53.8%	70.8%	47.5%	51.5%	51.4%	46.5%	55.6%
> Average	43.6%	68.8%	54.3%	52.4%	50.0%	50.0%	46.2%	29.2%	52.5%	48.5%	48.6%	53.5%	44.4%

Source and Notes:
[1] *S&P Global Market Intelligence*, RRA Regulatory Focus, Major Rate Case Decisions -- January - June 2022, July 27, 2022, p. 3.
[2] Download from S&P Global Market Intelligence, August 1, 2022.
* Electric Returns exclude Limited Issue Rider Decisions.
* RRA excludes the 2017 Alaska ENSTAR decision from its Industry Average.

However, in 2019 the Georgia Public Service Commission authorized GA Power's ROE's earnings band far above industry norms at a 11.25%, and in 2022 commissioners set GA Power's ROE earnings band even higher at 11.9%, so far above industry norms as to be nearly off the charts when plotting their ROE on Mr. Gorman's chart.

This generous earnings band appears to place an upper limit on GA Power ROE; however the commission allows GA Power to keep profits above the top tier of the earnings band. In 2022 GA Power's ROE was an astonishing 13.69%. This extremely high ROE violates the basic risk return ratio that governs capital investments which says that the greater the risk, the greater the return. GA Power earns a return far above the risk it faces for capital investments.

[2] Gorman, Michael P. Rate of Return expert witness testimony "https://psc.ga.gov/search/facts-document/?documentId=191870 p. 5

Figure 2 – GA Power ROE 2022 [3]

GEORGIA POWER COMPANY
RETAIL RATE OF RETURN SUMMARY
TWELVE MONTHS ENDED DECEMBER 31, 2022

	Retail Return Consistent with Rate Treatment
Return on Investment - Retail (from Section 2)	9.33%
Less:	
Weighted Component Cost of Long-Term Debt	-1.64%
Return Available on Retail Equity	7.69%
Divided by: Equity as a Percent of Total Capital	56.16%
Retail Return on Equity	13.69%

Q. Why does the commission allow GA Power to receive a rate of return above industry norms?

One reason is that commissioners were trying to avoid a credit downgrade for GA Power that credit and stock markets would normally assess on a publicly traded company such as Southern Company (GA Power is a wholly owned subsidiary of Southern Company) due to the excessive risk for the extreme cost overruns, cash flow problems, and delays from Plant Vogtle.

Q. How do you know that?

Commissioner Tim Echols denied a motion from Commissioner Bubba McDonald on 12/17/2019 during the 2019 administrative session in which Commissioner McDonald asked for

[3] GA Power Company Annual Surveillance Report 2022
https://psc.ga.gov/search/facts-document/?documentId=193593

a slight reduction on GA Power's ROE to save GA Power ratepayers hundreds of millions of dollars. Commissioner Echols stated, "I will not agree to that reduction because that would trigger a downgrade based on what I heard last week in New York."[4].

Figure 3 – GA PSC Administrative Session 12/17/19

Commissioner Tim Echols insists on high ROE

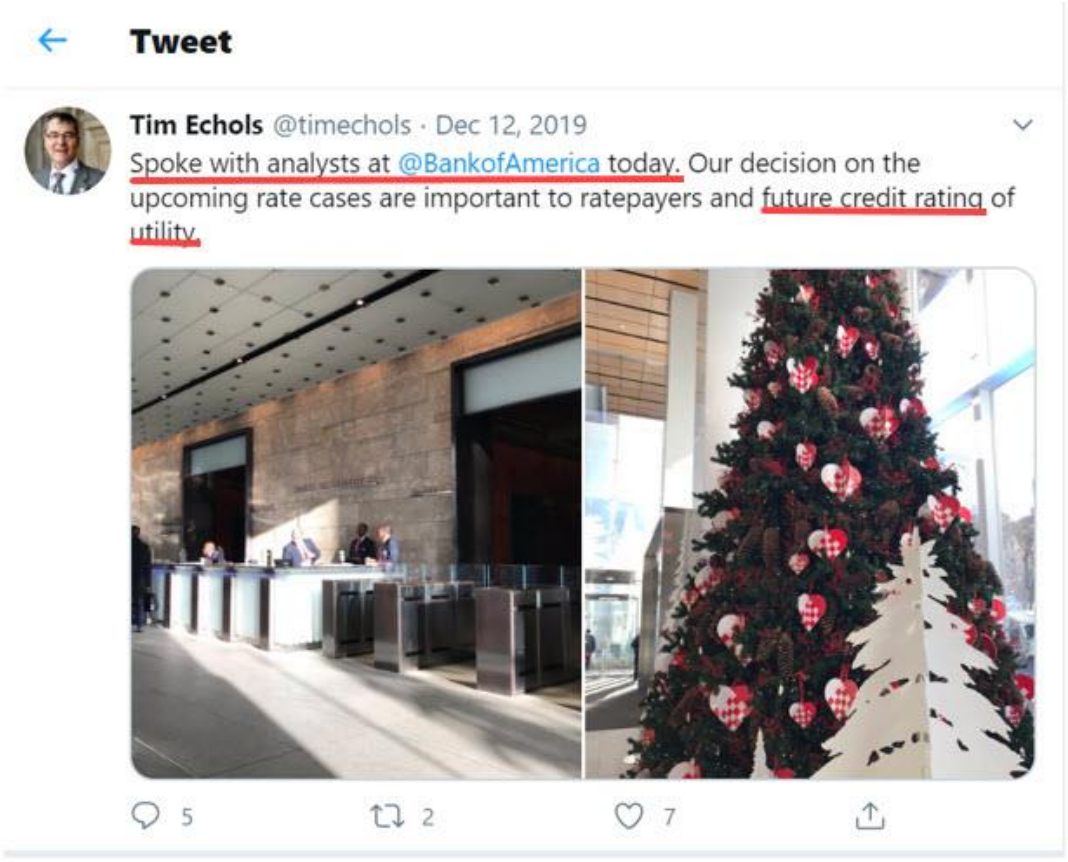
On December 12, 2019 Commissioner Echols was in New York to ask Wall Street analysts at Bank of America what they wanted from the Commission for the 2019 rate proceeding.

Q. How do you know that?

Commissioner Echols stated that in a tweet he sent on 12/12/2019 with a picture of the lobby of Bank of America in New York.

[4] GA Public Service Commission Administrative session 12/17/2019 https://youtu.be/R-RNUZHlmNc

Figure 4 – Commissioner Tim Echols in New York City [5]



In 2019, not only did GA Power receive an ROE far higher than industry norms, but GA Power also received a larger rate increase than the next 10 utilities combined according to data obtained from S&P Global:

[5] X formerly known as Twitter @timechols tweet https://twitter.com/timechols/status/1205128936432324608

Figure 5 – 2019 IOU rate increases

Utility	State	2019 Rate Increase ($ millions)
Georgia Power	Georgia	909
DTE Electric	Michigan	273
Duke Energy Carolinas	South Carolina	107
Virginia Electric & Power Company	Virginia	104
Massachusetts Electric	Massachusetts	90
Wisconsin Electric Power	Wisconsin	81
Atlantic City Electric	New Jersey	70
Kentucky Utilities	Kentucky	56
Southwestern Electric Power	Arkansas	53
Pacific Gas & Electric	California	46
Public Service Company of Oklahoma	Oklahoma	46
Northern Indiana Public Service Company	Indiana	45
Appalachian Power Company	West Virginia	44
Northern Indiana Public Service Company	Indiana	43
Duke Energy Progress	South Carolina	41
Wisconsin Public Service Corporation	Wisconsin	39
Virginia Electric & Power Company	Virginia	38
San Diego Gas & Electric Company	California	36
NSTAR Electric Company	Massachusetts	34
Duke Energy Florida LLC	Florida	29
Southern California Edison Company	California	25
Baltimore Gas and Electric Company	Maryland	25
Duke Energy Indiana, LLC	Indiana	24
Virginia Electric & Power Company	Virginia	18
Green Mountain Power Corporation	Vermont	17
Northern Indiana Public Service Company	Indiana	17
Orange & Rockland Utilities	New York	13
Maui Electric Company	Hawaii	12
Virginia Electric & Power Company	Virginia	10
Potomac Electric Power Company	Maryland	10
Entergy Arkansas	Arkansas	10
MDU Resources Group	Montana	9
Appalachian Power Company	Virginia	7
Southern Indiana Gas & Electric	Indiana	7
NorthWestern Corporation	Montana	7
The Potomac Edison Company	Maryland	6
Otter Tail Power Company	South Dakota	5
Southern Indiana Gas & Electric Company	Indiana	4
Oklahoma Gas and Electric Company	Arkansas	3
Virginia Electric & Power Company	Virginia	3
Louisville Gas & Electric Company	Kentucky	2
Virginia Electric & Power Company	Virginia	2
Upper Peninsula Power Company	Michigan	2

Northern States Power Company	Wisconsin	1
Empire District Electric Company	Kansas	0
Oklahoma Gas and Electric Company	Oklahoma	0
Puget Sound Energy	Washington	0
Monongahela Power Company	West Virginia	0
Appalachian Power Company	Virginia	0
Ameren Illinois	Illinois	(3)
Commonwealth Edison Company	Illinois	(3)
Virginia Electric & Power Company	Virginia	(3)
Virginia Electric & Power Company	Virginia	(4)
Virginia Electric & Power Company	Virginia	(4)
Sierra Pacific Power Company	Nevada	(5)
Avista Corporation	Idaho	(7)
Virginia Electric & Power Company	Virginia	(9)
Wind Energy Transmission Texas	Texas	(16)
Virginia Electric & Power Company	Virginia	(18)
Consumers Energy Company	Michigan	(24)
Entergy New Orleans LLC	Louisiana	(42)
Monongahela Power Company	West Virginia	(101)
Southern California Edison Company	California	(523)
	Average Increase	**26**

Source: S&P Global, 2019 rate increase[6]

And again, in 2022's rate proceeding, GA Power's rate increase was among the top three largest in the United States, up there with California, the most populated U.S. state with over 39 million people and the 5th largest economy in the world. California's IOUs are faced with making huge investments to underground power lines to reduce wildfire risk.

[6] S&P Global Reports 4th Quarter and Full-Year 2019 Results
https://press.spglobal.com/2020-02-06-S-P-Global-Reports-4th-Quarter-and-Full-Year-2019-Results

Figure 6 – 2022 IOU rate increases [7]

Utility	State	**2022 Requested Increase ($ millions)**
Pacific Gas & Electric*	California	3452
Consolidated Edison Company of New York	New York	1038
Georgia Power	**Georgia**	**1004**
Southern California Edison Company	California	971

** PG&E announced last year that it will underground 10,000 miles of power lines at a projected cost of $15 billion to $30 billion, basically rebuilding the grid.*

That GA Power's rate increase would be situated among these much larger populated states demonstrates gold plating as predicted by the Averch Johnson effect.

GA Power now makes a surprise 2023 IRP filing claiming enormous capacity expansion need even though large grid investments far above any other state were delivered from their 2019 and 2022's rate proceedings.

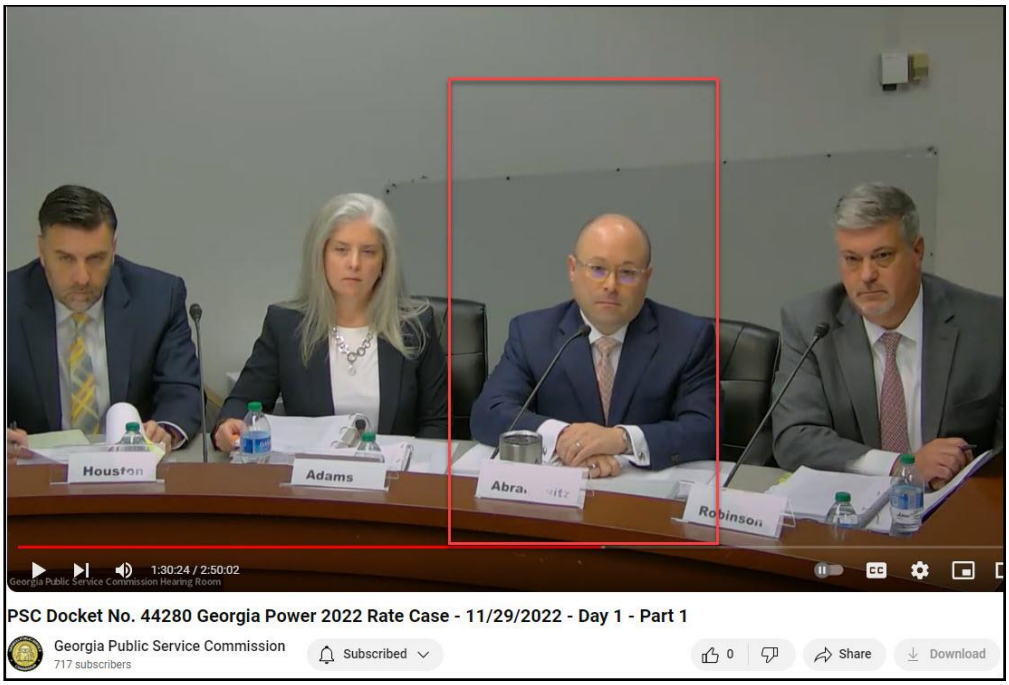
Q. How does GA Power explain these grid investments far larger than any other utility in 2019 and in line with California utilities in 2022, and its above industry norm ROE requests?

During the 2022 rate proceeding, when GA Power's CFO Aaron Abramovitz was asked to explain why GA Power should receive an ROE far above industry norms, and why GA Power had characterized GA Public Interest Advocacy staff as "radical" for asking the Commission to grant GA Power an ROE that matched utility industry norms, Mr. Abramovitz had no meaningful reply, not being able to admit that GA Power's failure to deliver Plant Vogtle increased risk to investors, and thus increased costs of credit – normal market behavior. Or it

[7] S&P Global Reports 4th Quarter and Full-Year 2022 Results https://investor.spglobal.com/news-releases/news-details/2023/SP-GLOBAL-REPORTS-4th-QUARTER-AND-FULL-YEAR-2022-RESULTS/default.aspx

would increase costs of credit, unless GA Power could get the GA PSC to increase Power's ROE above industry norms to compensate investors for increased risk with increased profits. Since Mr. Abramovitz could not say any of that he the question by saying, "We're talking about GA Power here. We're not talking about the average utility." [8]

Figure 7 GA PSC GA Power 2022 Rate Case 11/29/22



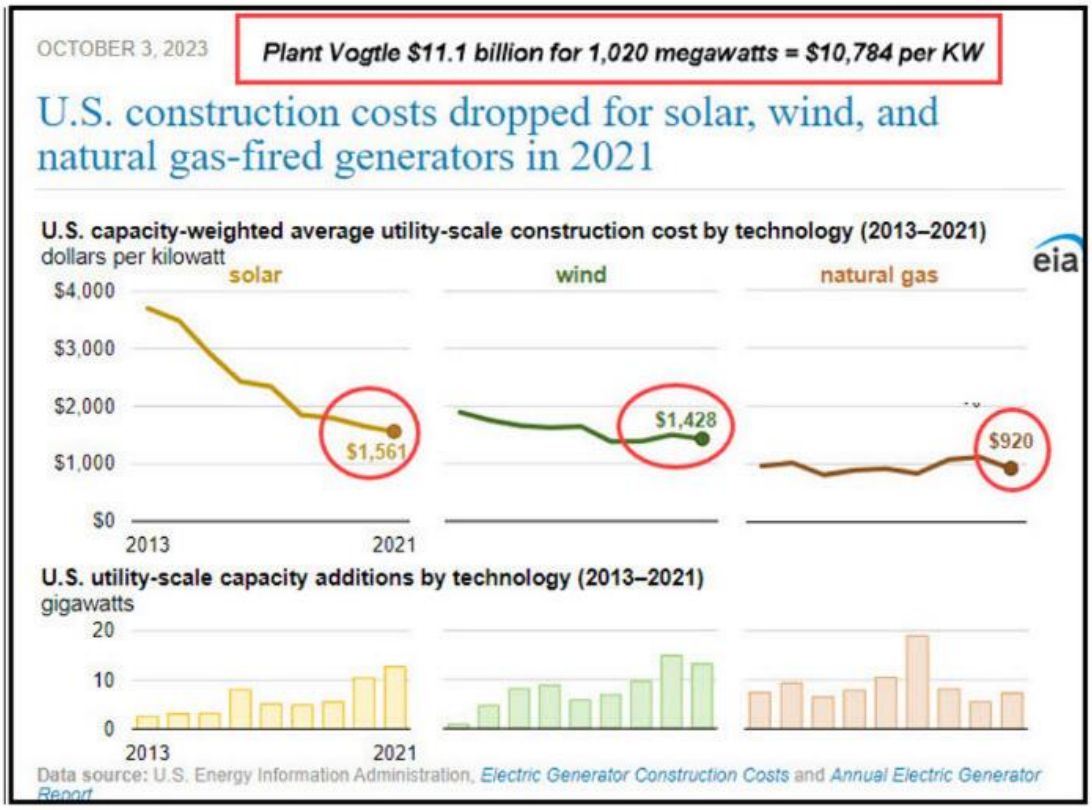
Q. Why do you say GA Power's 2019 and 2022 rate increases are gold plating?

Excessive capital accumulation under rate-of-return regulation is informally known as "gold plating" which is a term implying that too much money is spent on capital. One result of the Averch Johnson effect is that utilities spend too much money, for example spending $2 billion on a power plant that should only cost $1 billion. We saw this with Plant Vogtle, which cost GA Power ratepayers $11.1 billion (capital plus financing, on which GA Power also profits) for only

[8] PSC Docket No. 44280 Georgia Power 2022 Rate Case - 11/29/2022 - Day 1 - Part 1 https://www.youtube.com/live/vzzGKj63-r8?si=c9me44M-cM_dV4sI&t=5421 Timestamp 1:30:21

1,020 megawatts of energy. This astonishing $11 billion cost is so far above what any other type of energy would have cost it strains credulity to claim that the GA Public Service is regulating a monopoly utility in the public interest.

Figure 8 – Vogtle costs compared to U.S. construction costs [9]



Plant Vogtle was pursued by GA Power to maximize profits for them and their parent, Southern Company. It was clear in 2009, and especially in 2017 when the decision to proceed with Plant Vogtle was made, that GA Power's energy sales were flat and that their growth projections were incorrect. Flat energy sales were not unique to Georgia – this was true throughout the United

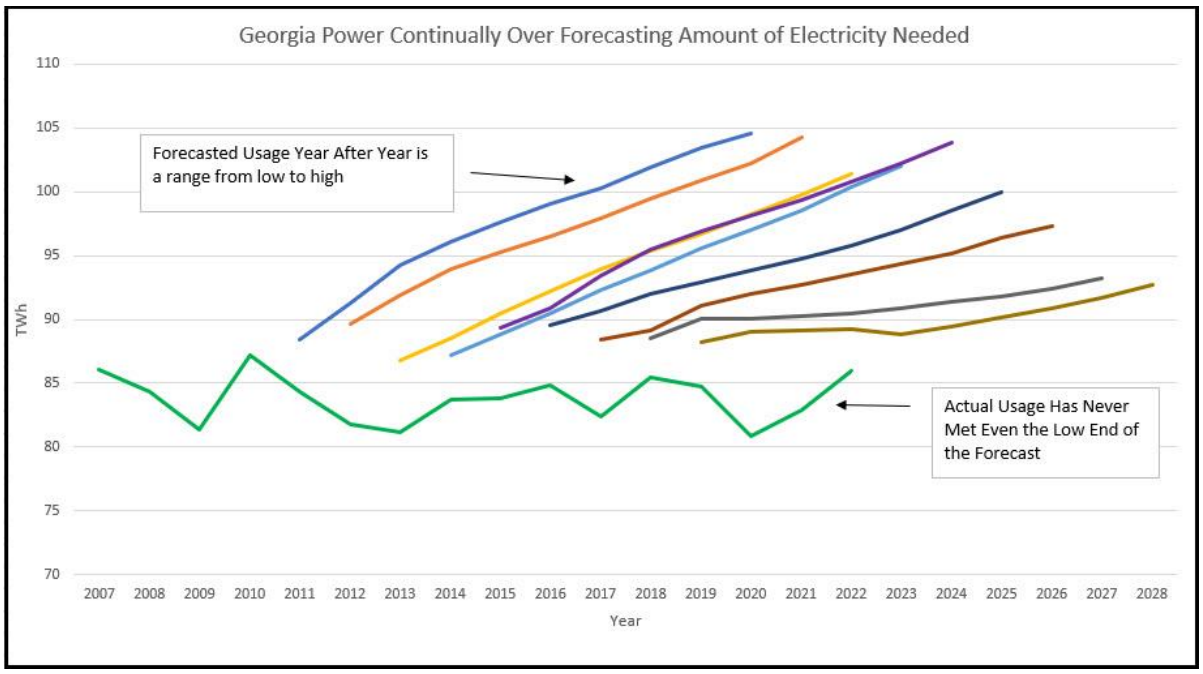
[9] U.S. construction costs dropped for solar, wind, and natural gas-fired generators in 2021, *Energy Information Administration*, 10/3/2023 https://www.eia.gov/todayinenergy/detail.php?id=60562

States. In order to continue to make capital investments and continue to grow Southern Company profits for investors, GA Power's strategy was to wildly exaggerate future energy sales in IRPs to maximize shareholder profit, which then led to large rate requests to pay for new generation capacity approved in their 2019 and 2022 IRPs. Pursuing inflated growth projections GA Power is able to deliver far more profits to shareholders

Q. Earlier you stated that GA Power inflates growth projections. What evidence exists for your belief?

GA Power must submit project future energy demand to FERC, the Federal Energy Regulatory Commission.[10] An examination of GA Power's growth projections between 2007 – 2022 shows wildly exaggerated future energy sales as depicted in this graph:

Figure 9 – GA Power forecasts plotted against actual [11]

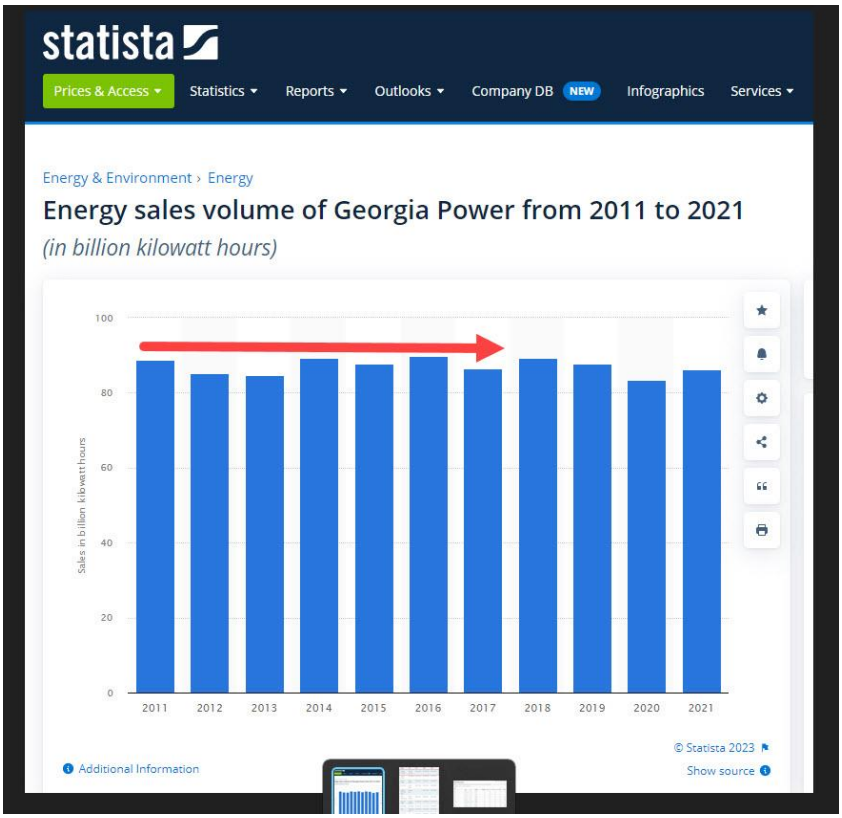


[10] Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report, FERC https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data

[11] Annual Electric Power Industry Report, Form EIA-861 detailed data files Electric Sales, Revenue, and Average Price https://www.eia.gov/electricity/data/eia861/

This graphic was created by plotting FERC forecasts that GA Power filed for summer and winter peaks using the colored lines to visually show the highs and lows, and the green line depicts actual sales. The highs are wildly exaggerated, and even the low end of their forecasts never touches the actual demand. In fact between 2007 and 2022 GA Power saw zero growth in in electricity sales, yet received authorization from the GA Public Service Commission to build two new reactors at Plant Vogtle in 2008, and the Commission recommitted to that project despite being aware in 2017 that the growth projections GA Power used for authorization had not materialized as seen in this chart. In fact, even in 2022 that growth had still not materialized. This lack of growth can be seen in this chart:[12]

Figure 10 – Energy sales volume of Georgia Power from 2011 to 2021



[12] Statista Energy sales volume GA Power from 2011 to 2021
https://www.statista.com/statistics/588262/energy-sales-of-georgia-power/

Although GA Power's sales did not grow, their rate increases did, resulting in a large expansion of their rate base, which is the figure on which GA Power earns their return on equity.

Figure 11 – Energy sales volume of Georgia Power from 2011 to 2021

Georgia Power Company		
Year	Retail Rate Base ($ Billion)	Retail Sales (TWh)
2007	11.21	86.08
2008	14.11	84.30
2009	*	81.35
2010	14.47	87.16
2011	14.31	84.30
2012	15.24	81.74
2013	15.79	81.18
2014	15.42	83.74
2015	16.01	83.80
2016	16.5	84.87
2017	17.54	82.40
2018	17.74	85.49
2019	19.11	84.70
2020	20.77	80.81
2021	21.65	82.94
2022	23.19	85.96
% Inc. 2007-2022	**50.3%**	**-1%**

*filing not available
Retail rate base from Ga PSC ASR reports
Retail sales figures from EIA 861: https://www.eia.gov/electricity/data/eia861/

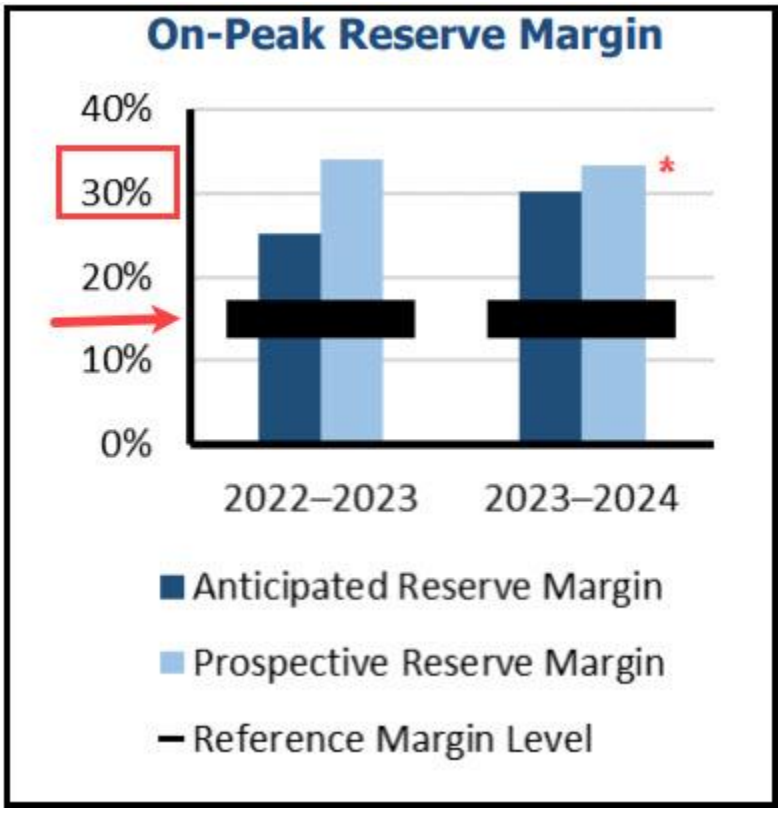
Note this does not include Plant Vogtle

Because GA Power is building far more capacity than required, GA Power's load factor is very low and their reserves are far too high.

Q. What evidence is there that GA Power's reserves are too high?

There are national guidelines for appropriate electricity reserves, which is how much generating capacity is available above what the grid is expected to need. These guidelines ensure vital U.S. interests in electric stability are met. According to NERC, the National Electric Reliability Corporation, the Southeast region, or SERC-Central, which includes Georgia Power, exceeds winter guidelines two-fold and summer guidelines by nearly three-fold. NERC recommends Summer and Winter reliability reserves for the SERC region of the U.S. to be 15% even before the additions of capacity from Plant Vogtle and the 2022 IRP. This excessive capacity costs costumers millions, if not billions of dollars.

Figure 12 SERC-Central Winter Reliability Assessment [13]



[13] NERC Winter Reliability Assessment 2023
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf p. 26

Figure 13 SERC-Southeast Summer Reliability Assessment

Note that 2023 On-Peak Reserve Margin is 40%, nearly three times NERCs recommended 15% for this region and far above GA Power's state goal of 26% reserve margin which is already far higher than recommendations, and all of this is before the 2022 IRP and Vogtle capacity is added to the grid. [14]

Q. What evidence is there that GA Power's load factor is too low and how does that relate to reserve margin?

Reserve margin's purpose is to make sure GA Power, or any utility, has enough reserve capacity to meet peak demand. It says nothing about grid efficiency in terms of utilization of generation capacity. For that you must look at load factor. Load factor is the amount of power required from the grid over a period of time divided by the amount of energy that can be supplied by the grid.

[14] NERC Summer Reliability Assessment 2023
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf p. 26

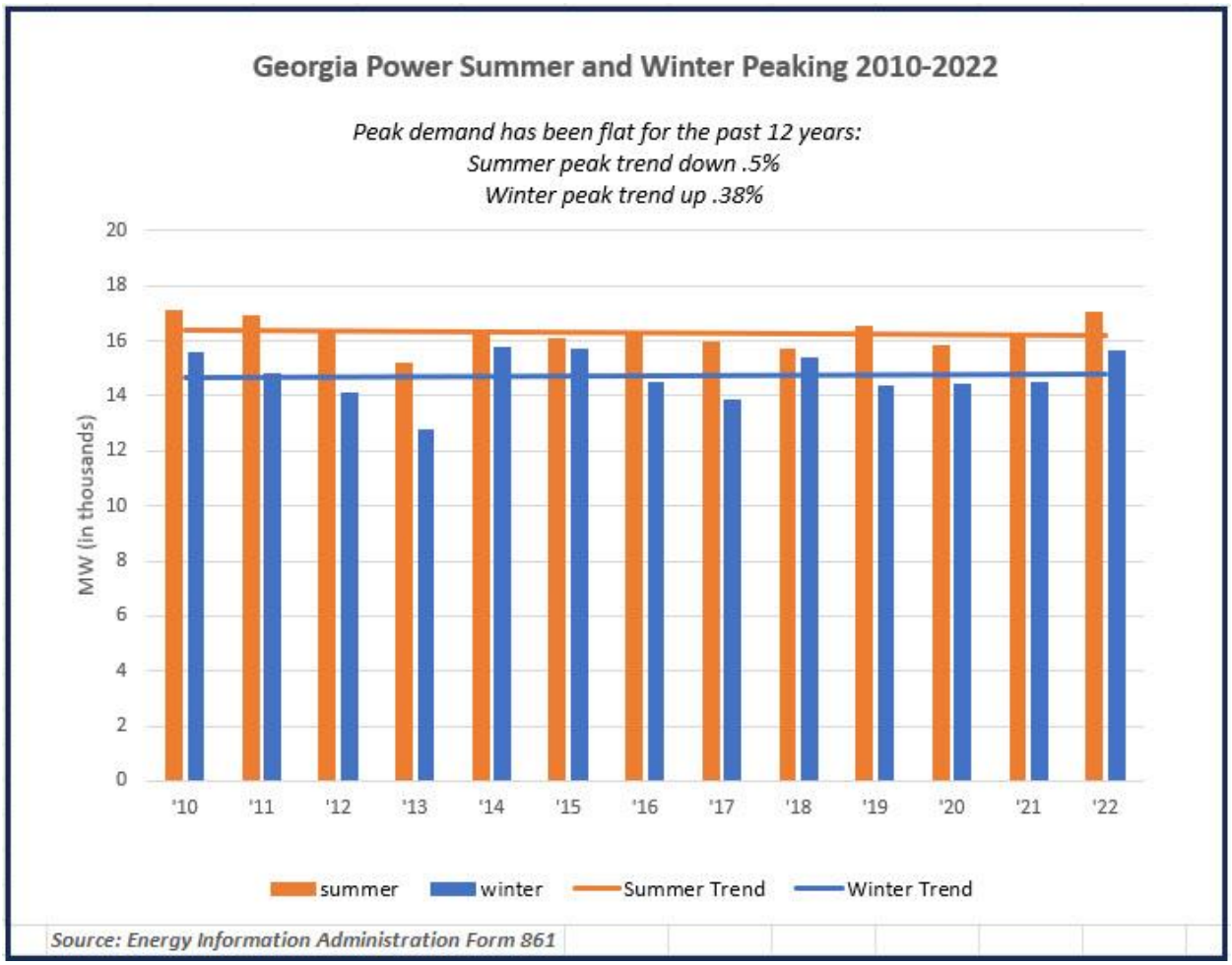
There usually isn't enough demand (or load) for energy around the clock and, as a result, the utilization of any power plant might only be half—or even less. The cost of the plant, however, remains the same. Therefore, regulators try to improve grid efficiency by requiring increases in system load factor, or a regulated utility is simply rewarded for adding generating capacity to meet system peak increases which is expensive for ratepayers and inefficient for grid utilization. Since GA Power is allowed to recover its costs, plus a return on equity, it is incented to build new capacity as previously discussed. Peaking electric facilities in Georgia are rarely turned on, but are needed for quick bursts of peak generation to prevent black outs. Electric rates must pay for this inefficient use of generating facilities. Even worse, peaking generation facilities are exempt from the Clean Air regulations and emit large amounts of pollution. Therefore it is in the public interest to have as high a load factor as possible, and that is achieved by reducing peak demand through any number of load shifting/load shaving programs.

Q. Georgia Power says that it needs a massive amount of new capacity to meet the state's economic growth and new demand, especially peak demand in winter. Is this true?

GA Power has chosen a new prediction model which it claims will be more accurate than its previous growth forecasting model, yet GA Power's past growth forecasting model was wrong for at least the past 15 years. This new model predicts much more aggressive growth than its previous more modest, but still inaccurate growth model. It hardly seems possible that a more aggressive growth model would bring accuracy when the previous model with modest growth predictions was consistently inaccurate. Furthermore, new loads in the 2023 IRP are redacted, along with just about every supporting detail, making analysis of GA Power claims to need astonishing amounts of new growth impossible to understand or believe. Furthermore, an analysis of the past 12 years of GA Power's winter peak and summer peak trend lines shows flat

growth and offers no insight into why GA Power thinks peak demand will spike 38% greater than it thought in 2022 during that IRP proceeding.

Figure 14 GA Power peak demand 2010 - 2022



These trend lines show normal weather-related variability but no growth. Furthermore, any increase in peak demand is easily managed with the addition of a residential demand response program, a program with great potential that GA Power has underutilized. This type of program is widely used in most states, would greatly benefit consumer engagement and put real downward pressure on rates instead of the false downward pressure on rates GA Power claims this IRP would produce.

Q. Why do you say GA Power's downward pressure on rates claims in this IRP are false?

It is not possible to have downward pressure on rates while adding new capacity and/or deferring retirement of old, uneconomical coal and gas plants. Both of those actions add costs. It is literally impossible to add costs and reduce rates. This makes no sense and is clearly false. The only way to put downward pressure on rates is to adopt programs that reduce costs. Full stop. GA Power's 2023 IRP filing asks for approx. 3000 megawatts of new capacity and approx.. 3000 megawatts of expensive coal and gas plant retirement deferrals. Taking any one of these will add significant costs. Together they will add enormous cost and most definitely will increase rates to pay for it.

Q. What is a likely impact to ratepayers if Georgia Power is authorized to increase generating capacity and defer coal plant retirements as it requests in this docket?

It would result in more pain for ratepayers, already under extreme duress from the previous nearly $20 billion of rate increases that have taken place just since the 2019 rate proceeding. These rate increases have added nearly $65/month to an average household's GA Power bill. In 2019's rate case hearings, Dr. William M. Cox with the GreenLink Group provided analysis[15] on behalf of the City of Atlanta on the expansion of the number of households that will be energy burdened if the $1.8 billion request for that rate case was approved. Dr. Cox's analysis predicted that the number of Atlanta households that are energy burdened would double if the $1.8 billion was approved in full, which it was.

In 2022 another rate increase of $1.8 billion took place. So in 2019 and 2022 we had two separate rate increases of $1.8 billion each and if Dr. Cox's analysis is correct, Atlanta

[15] Cox, William M. and Hawthorne, William L., GreenLink Expert testimony, GA PSC filing https://psc.ga.gov/search/facts-document/?documentId=178648

households who are energy burdened would have quadrupled. Then, in May of 2023 another $2.5 billion rate increase took place for the fuel cost recovery docket. And in August of 2023 another $2.1 billion was added to the rates for Unit 3 for Plant Vogtle. Last December, just last month, this commission approved a $7.56 billion rate increase for Vogtle Unit 4, along with $3.5 billion in financing charges, adding a total of $11.1 billion to rates. Those rate increases all total $19.26 billion.

Meanwhile, in 2022 over 240,000 GA Power customers were disconnected from power[16], with 68% of GA Power customers who are disconnected from power are people of color. Although GA Power has claimed that all this new demand will put downward pressure on rates, that is literally impossible if GA Power is authorized to add generating capacity to service this new demand as adding generating capacity will increase rates. That rate increase will take place in the rate hearing. In Georgia, GA Power files their IRP for new generating capacity separately from their rate increase request to pay for that new generation. In the past, GA Power has stated during IRP proceedings that it cannot estimate rate impacts as the IRP is not a rate proceeding and such impacts will be discussed at the rate proceeding where it belongs. It has done this again with their October 2023 surprise IRP filing. Then during the rate proceeding, GA Power will state that it is inappropriate to discuss generating capacity issues as those decisions were made during the IRP proceeding. In this way GA Power prevents any meaningful discussion of how their requests for generating capacity impact the ratepayer. Unless an expert like Dr. Cox is hired to assess rate increase impacts on GA Power ratepayers and how energy burden might expand along with steps

[16] GA Power Incremental Bad Debt report GA PSC filing December 2022
https://psc.ga.gov/search/facts-document/?documentId=192730

to reduce the pain of the ratepayer, steps that GA Power has never taken, this information is unknown.

Q. What if Georgia Power turns out to be right and more capacity is needed to power new businesses in Georgia?

The new businesses that Georgia Power wants to service are electric vehicle and EV battery manufacturers, solar panel manufacturers and data centers. All of these industries have clean-energy goals. Their needs can be readily met by rapidly deployable rooftop solar panels. If those businesses were to relocate or end, solar panels can be easily reclaimed and reused. Furthermore, Georgia Power is promoting gas-fired plants for the capital-based reasons and because its parent Southern Company owns numerous gas subsidiaries that profit from the use of gas in producing electricity. Finally, the PSC should not consider gas-fired capacity at all when 2023 was the hottest year in earth history and it is clear that climate change is accelerating.

Q. Recommendations

GA Power's surprise 2023 IRP filing is unreasonable, inappropriate, and should be disallowed for two main reasons:

1. Georgia Power's future load forecasts are flawed and this new forecasting method takes those flaws in the wrong direction and amplifies them. The commission should not allow GA Power to redact information proving a need for additional capacity when no other state commission allows such redactions, and which are unreasonable and violate the public trust. Flawed forecasting and redacted information on the need for growth are unacceptable behaviors for GA Power. The 2025 IRP, without redactions, is when the next decision point should be made for future load growth.

2. GA Power's grid is overbuilt and capacity factor is very low. The commission should direct GA Power to better utilize grid investments GA Power ratepayers have already before authorizing any new capacity.

If the commission were to proceed with this IRP and allow GA Power to expand capacity it should be done in the following ways:

1. Incorporate a residential demand response program following best practices from states with excellent DR programs that engage customers and compensates those who enroll. Only 10% of a utility's customer base need enroll to make meaningful reductions in peak demand. PEPCO's Two ways to save program is top notch.
2. Create voluntary residential time-of-use rate plans that direct consumers to reduce peak demand by compensating them for reducing energy use at peak time. Research from the Smart Energy Consumer Collaborative shows that when consumers are offered choices among various types of TOU rate plans to allow them to select one that meets their needs, they are more likely to enroll in such a plan than a traditional rate plan.[17] New TOU rates plans should include an online bill calculator that allows customers to have their data analyzed to identify the best plan for their lifestyle.
3. Incentivize commercial rooftop solar. A big flat roof—like a warehouse—is a perfect place for solar panels. According to Environment America's *Solar on Warehouses* report, "Putting solar panels on the nation's warehouses would be good for businesses, good for electricity customers, good for the grid and good for the environment."[18] In Georgia there are over 15,000 commercial warehouses with 540

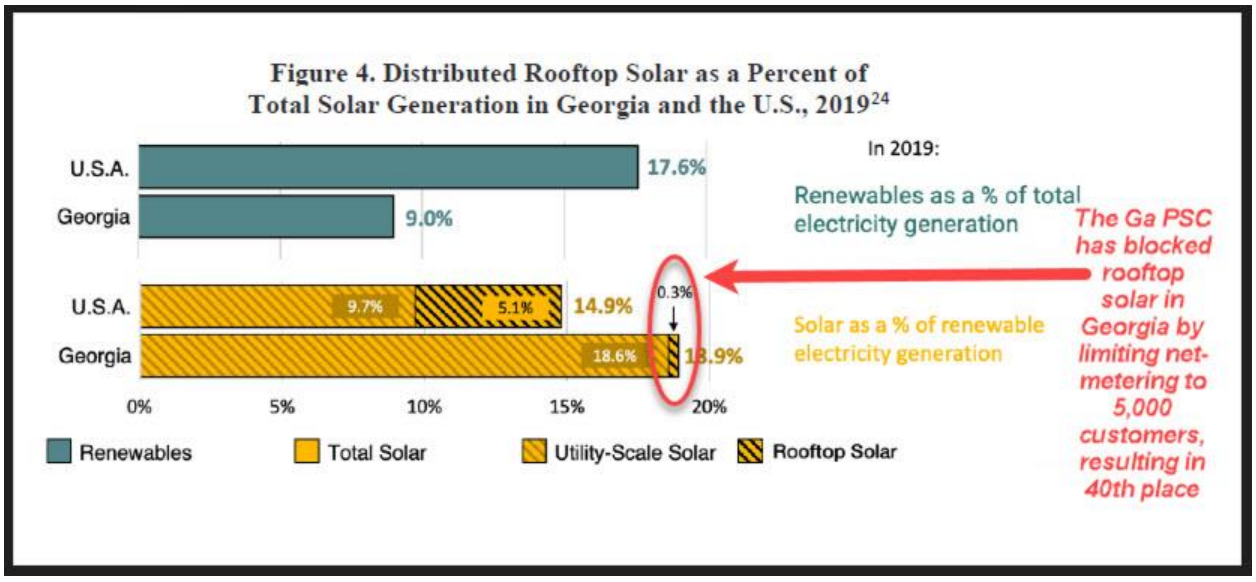
[17] Rate Design: What do consumers want and need? https://smartenergycc.org/rate-design-what-do-consumers-want-and-need/?_sf_s=rates

[18] Solar on Warehouses: Environment America 4/23/23 https://environmentamerica.org/center/resources/solar-on-warehouses/

million sq. ft. with potential 9688 GWh (gigawatt hours) of energy according to that same report. This would also eliminate pressure on farmland and forests being taken out of production for GA Power utility scale solar which is profitable to them and harmful to Georgia's farmland and forests.

4. Adopt net-metering for community and residential solar. Similar to commercial rooftop solar, there is tremendous untapped potential for rooftop solar with Georgia's residential and small-medium businesses, and tremendous desire for these programs. GA Power's monopoly franchise agreement granted to them by the people of Georgia through the state legislature a century ago never foresaw the ability of people to generate their own electricity through rooftop solar. This franchise agreement was not intended to mean that GA Power should use their political power and financial might from profits on electricity sales to harm ratepayers by blocking programs that benefit ratepayers such as net-metering, demand response and energy efficiency. Grid modernization and grid edge services and programs and devices all benefit consumers, or would if GA Power allowed them or if the GA PSC required it. Georgia is a top 10 sunny state but only ranks 40th in rooftop solar because GA Power will not allow the commission to adopt traditional net metering. At only .3% penetration, residential rooftop solar is a nascent technology and clearly needs assistance to gain a foothold in Georgia, which is why over 30 states have adopted net metering to create the assistance that their residential homeowners need.

Figure 15 Georgia's rooftop solar % of total generation



Claims that rooftop solar is a cross subsidy that benefits the wealthy and harms low- and moderate-income ratepayers fall apart when examining the income level of who puts rooftop solar on their homes. Furthermore, concerns net metering negatively impacting rates for low- and moderate-income homeowners is clearly false when considering the numerous programs that could be adopted to benefit such households, but aren't. For example, low utilization of GA Power's grid capacity is extremely expensive to low- and moderate-income households, and no one is proposing to improve GA Power's capacity factor to assist them. Furthermore, it was harmful to such households for GA Power to build Plant Vogtle, the most expensive energy choice possible, but that did not stop GA Power from pursuing an energy source that is eight to ten times more expensive than other sources. Indeed, if concern for low-and moderate-income households were real, lowering the ROE to utility industry norms would have significant and immediate downward pressure on rates but there is no mention of reducing GA Power's top tier ROE. No, blocking net metering for rooftop solar is not about

limiting harm to such households or preventing a cross subsidy. Blocking net metering is a strategy to protect GA Power as the only entity to produce electricity so that they may maximize profits, even as technology has changed around them.

Other states who have recently rolled back net-metering, such as California, should not be used as evidence that net-metering is a flawed program. California has used net-metering to benefit their homeowners for decades and is #1 in the nation in rooftop solar. Let's be honest: California is never used as an example for Georgia to follow no matter how well California is doing any area. The reverse should hold true now: California's decision to reduce net metering compensation should not be used in Georgia to deny residential ratepayers the ability to produce their own energy by assisting them with a program that enables them to afford home solar. In fact, Commissioner Tim Echols enjoys net metering on his home in Jackson County, courtesy of net metering he enjoys from his utility provider, Jackson EMC. Clearly it is a program that works and provides benefits to those lucky enough to have it, and net metering should be a program offered to GA Power ratepayers before adding any new generation to an already overbuilt and underutilized grid.

5. Invest in Energy Efficiency. According to the 2023 Utility Energy Efficiency Scorecard [19] produced annually by The American Council for an Energy-Efficient Economy (ACEEE) Georgia Power ranks 33rd in the nation with a score of us 27 points out of 100, a failing grade. Energy efficiency plays a crucial role in meeting our nation's energy needs and should play a much larger role in meeting Georgia Power customers' energy needs. Efficiency lowers customer energy bills, reduces energy burden, improves in-home comfort, enhances

[19] The American Council for an Energy-Efficient Economy (ACEEE)2023 report card https://www.aceee.org/sites/default/files/pdfs/U2304.pdf

resilience, and improves indoor air quality. It is widely known that energy efficiency investment helps utilities avoid energy, power plant, transmission, and distribution costs that would otherwise be passed onto customers. It plays a crucial role in decarbonization. And, when compared to fossil fuel resources such as natural gas power plants, efficiency is a clear least-cost energy resource. GA Power agreed in their 2022 IRP to "strive" to increase energy efficiency investments 15%, a paltry amount of increase for an already paltry investment. And strive means nothing. It can just as easily be done as not. It is up to the commission to regulate GA Power in the public interest and it is in the public interest for GA Power to maximize energy efficiency investments to benefit all ratepayers, particularly vulnerable populations: low- and moderate-income households. If we care about those people, and we do, then real changes need to be made to put real downward pressure on rates. Installing large amounts of new capacity will not do that.

Q. Does this conclude your testimony?

Yes

BY MR. SHERRIER:

Q Ms. Durand, did you prepare a summary of your testimony?

A Yes.

MR. SHERRIER: Mr. Chairman, with your permission, I would like to ask Ms. Durand to read her summary.

CHAIRMAN SHAW: Yes, sir. Ms. Durand, please -- please proceed.

MS. DURAND: Okay. Georgia Power has a long history of submitting false growth projections that are used to justify expanding capacity, but which does not materialize. The Averch-Johnson effect is an economic term used to describe the tendency of regulated utilities to engage in excessive amounts of capital accumulation in order to expand their profit.

Georgia Power submits their future energy demand to FERC, the Federal Energy Regulatory Commission. An examination of their growth projections between 2007 and 2022 shows wildly exaggerated future energy sales.

In fact, between those years, Georgia Power saw zero growth in electricity sales, yet received authorization from this Commission to build two new

reactors at Plant Vogtle in 2008.

And the Commission recommitted to that project, despite being aware in 2017 that the growth projections that Georgia Power used for authorization had not materialized. In fact, even in 2022 that growth had still not materialized.

Georgia Power has chosen a new prediction model now in this surprise IRP filing which it claims will be more accurate than its previous growth forecasting model. Yet, Georgia Power's past growth forecasting model was wrong for at least 15 years. I didn't go back before 2007. It could have been longer.

This new model predicts much more aggressive growth than its previous model, but still inaccurate growth model. It hardly seems possible that a more aggressive growth model would bring accuracy when the previous model with modest growth predictions was consistently inaccurate.

Furthermore, new loads in the 2023 IRP are redacted, along with just about every supporting detail, making analysis of Georgia Power's claims to need astonishing amounts of new growth impossible to understand or believe. Because Georgia Power is building far more capacity than required, Georgia

Power's load factor is very low and their reserves are far too high.

There are national guidelines for appropriate electricity reserves, which is how much generated capacity is available above what the grid is expected to need for peak demand. These guidelines ensure a vital U.S. interest in electric stability are met. According to NERC, the National Electric Reliability Corporation, the southeast region, which includes Georgia Power, exceeds winter guidelines twofold and summer guidelines by nearly threefold.

The target is 26 percent, Commissioners. That's not what they do, though. But everyone often says Georgia Power's 26 percent reserves. That's not their reserves. That's their target.

All that is even before the addition of capacity from Plant Vogtle in the 2022 IRP. This excessive capacity costs consumers millions, if not billions, of dollars.

On July 21st, 2022, this PSC approved Georgia Power's 2022 Integrated Resource Plan, which authorized retirement of 1517 megawatts of coal, and the addition of 5154 megawatts of gas and renewables -- mostly gas, though -- for a net of 3647 megawatts of new capacity. If you add

3647 megawatts of new capacity with the 1020 megawatts for Plant Vogtle, you get 4667 megawatts of new capacity just authorized last year.

There's plenty of room to increase the very low utilization amount of Georgia's current grid to meet the new demand. That utilization rate is 40 percent even before that 4000-something megawatts, which is already an enormous addition to Georgia Power's capacity.

The new businesses that Georgia Power wants to service are electric vehicle and EV battery manufacturers, solar panel manufacturers, and data centers. All these industries have clean energy goals. Their needs can be readily met by rapidly deploying warehouse data center or manufacturing facility rooftop solar panels.

If those businesses were to relocate or end, the solar panels can easily be reclaimed and reused. Furthermore, Georgia Power's promoting gas-fired plants for capital-based reasons, not to actually meet this growth demand, which can be easily met with their current capacity, or through rooftop solar; commercial, small-medium business.

There's enough unused rooftop -- commercial

rooftop solar capacity in Georgia to meet all of their growth projections, or the 6600 megawatts that they want in this IRP filing. Just in that alone. But they profit their Southern Company affiliates by adding gas. So that's why they're proposing gas, instead of this other cleaner, less-expensive way.

The Georgia Coalition of Local Government's witness Blake Richetta just spoke about the capabilities of virtual power plants. According to Jigar Shah, who I was texting with this morning at the loan program office for the Department of Energy, they have $100 billion available to support VPPs right now.

If the project is structured as an intentional equity project, the loans program office will match that money ten-to-one with long-term debt. As you all must know, 70 percent of Georgia Power's disconnects are people of color in a state with only 32 percent minority population. And you must also know that Georgia has one of the highest, or maybe the highest, energy burdens in the United States.

So it -- well, let me not speak extemporaneously. In addition to those facts, small-scale rooftop solar is producing ten times as much energy in the United States now as it was a

decade ago, but we've only scratched the surface. Right now that only provides 1.5 percent of U.S. electricity and has the potential to produce 45 percent.

So in conclusion -- if I can find it -- oh, here it is. The Commission should not allow Georgia Power to redact information providing a -- that proves a need for additional capacity when no other state commission allows such redactions in their IRPs. This is unreasonable and violates the public trust. Flawed forecasting and redacted information on the need for growth are unacceptable behaviors for Georgia Power.

The 2025 IRP without redactions is when the next decision point should be made for future load growth. Or this IRP would be fine if the Commission would grant clean energy using VPPs pursuing the loan program's office grant opportunities, which expires in 2027. So time is of the essence to get that money.

Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

MS. SCOTT: Commissioner Shaw, Commissioners, Ms. Durand is available for questions now.

CHAIRMAN SHAW: All right. Commissioners, any

questions for the panel?

(No response.)

CHAIRMAN SHAW: Okay. We'll start with cross.

Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. CARVER: No questions.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: GAM.

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

MR. COX: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. McNUTT: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: No questions, Mr. Chairman.

CHAIRMAN SHAW: Any redirect?

MS. SCOTT: No.

CHAIRMAN SHAW: That would be no redirect.

All right. Ms. Scott, can we -- is it okay if

we excuse your panel or do you have any exhibits that you want to --

MS. SCOTT: No. May she be excused, Mr. Chair?

CHAIRMAN SHAW: Yes, ma'am. Thank you.

Thank you, Ms. Durand.

MS. DURAND: Thank you.

CHAIRMAN SHAW: All right. The next panel will be that of Sierra Club.

MR. FABISH: Thank you, Mr. Chair.

Thereupon,

OFDEVI GLICK,
LUCY METZ,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. FABISH:

Q Okay. Could you please state your names for the record.

A (Witness Glick) Devi Glick.

A (Witness Metz) Lucy Metz.

Q Okay. And who are you employed by?

A (Witness Glick) I am a senior principal at Synapse Energy Economics.

A (Witness Metz) I'm an associate at Synapse Energy Economics.

Q Thank you. And who are you testifying on behalf of today?

A (Witness Glick) The Sierra Club.

Q And did you cause to be filed on February 15th approximately 58 pages of prefiled written testimony in question-and-answer format in this proceeding?

A (Witness Glick) Yes.

Q And there were a series of associated attachments with that, as well?

A (Witness Glick) That's correct.

Q Okay. Do you have any corrections to that?

A (Witness Glick) Yes. One small correction. On page 14, line 6, where it says the PPA was signed. The next word should be Georgia Power Company, not Mississippi Power Company.

Q Thank you.

Other than that small change, if I were to ask you the same questions as in the prefiled testimony, would you answer in the same way here today?

A (Witness Glick) Yes, we would.

MR. FABISH: Okay. So a corrected version of the testimony has been provided to the court reporter. I would ask that it be labeled Sierra Club Exhibit 1.

CHAIRMAN SHAW: So marked.

(Sierra Club's Exhibit 1 was admitted into evidence.)

MR. FABISH: Thank you.

BY MR. FABISH:

Q Let's see. Do you have a summary that you would like to give?

A (Witness Glick) Yes, we do.

MS. GLICK: Good morning, Chairman, Commission. My name is Devi Glick. I'm with my colleague, Lucy Metz. We work at Synapse Energy Economics, which is an economic consulting firm in Cambridge, Massachusetts.

We are engaged in integrated resource planning dockets across the country and we are happy to be here to provide our advice. My colleague Lucy is going to read a summary that we prepared of our testimony.

MS. METZ: Good morning, Commissioners. Our direct testimony in this case focuses on Georgia Power Company's requests for approval of new supply-side resources. Most critically, we find that Georgia Power has not justified that its proposed near-term capacity additions, including the combustion turbines at Plant Yates and the power purchase agreements with Mississippi Power Company and the Santa Rosa Energy Center are competitive relative to alternatives.

The company did not conduct a competitive procurement process or adequately evaluate alternative resource and ownership options when evaluating these resources. The company's own data shows that the Yates combustion turbines in particular will be expensive to build and operate and will be transmission constrained through May 2028.

By May 2028, Georgia Power will have had time to procure alternative capacity sources, such as battery storage and solar PV. Georgia Power's 2023 resource mix study found that it was economic for the company to bring online substantially more battery storage and solar PV than it currently has planned.

We recommend that Georgia Power accelerate procurement efforts through All-Source RFPs to evaluate the economics of expanded and accelerated deployment of battery storage and other resource options. And the company should demonstrate that all proposed resource additions reflect the lowest cost option.

In our testimony, we first assess Georgia Power's proposed power purchase agreements with Mississippi Power Company and the Santa Rosa Energy

Center. The PPA with Mississippi Power Company begins two years before Georgia Power needs capacity in the winter of 2025/2026.

The PPA with Santa Rosa Energy Center similarly begins a year and a half before Georgia Power's first capacity need. And the company does not have firm transmission capacity to serve the Santa Rosa Energy Center until May 2026.

In addition to the risk posed by these early start dates, it is concerning that Georgia Power did not adequately consider alternatives to the power purchase agreements with Mississippi Power Company and Santa Rosa.

The company issued a request for information, or RFI, in September 2023, but the timing is such that it could not have seriously considered the RFI results prior to executing the contract for the PPA with Mississippi Power Company, which it signed only two weeks later.

In fact, Georgia Power executed the power purchase agreements with both Mississippi Power Company and Santa Rosa before the closing date of its RFI in late October. Furthermore, an RFI is distinct from a request for proposal, or RFP, in that no bids or pricing are required to be provided

by all respondents.

If Georgia Power was serious about securing capacity from the market, it would have issued a full RFP, instead of just the RFI, and it would have done so earlier in the summer. Overall, Georgia Power has not justified procuring the capacity from either PPAs so far in advance of need and passing unnecessary costs on to Georgia ratepayers.

Our testimony next reviews Georgia Power's proposal to construct three dual-fuel combustion turbines at Plant Yates. We find that Georgia Power has not justified construction and operation of these units, which would impose unnecessary costs and pollution burdens on Georgia residents.

Because Georgia Power cannot secure firm gas transportation for the plants, the combustion turbines would rely on oil during peak periods. Oil is much more expensive than gas and these are costs that will be entirely passed on to ratepayers absent action by the Commission. The units will also emit more toxic air pollutants and greenhouse gases while operating on oil.

In our testimony, we compare the 15-year net present value of the capacity cost of one of the combustion turbine units with a comparable amount of

4-hour battery storage and find that it would be more economic for Georgia Power to fill part of its firm capacity need with battery storage and reduce the quantity of, or else eliminate, the gas combustion turbines it installs.

Especially given that the combustion turbines will be transmission constrained through May 2028, there is sufficient time for the company to procure alternative capacity resources, such as battery storage, instead. Accelerated deployment of battery storage would align with the company's 2023 resource mix study, which found that it was economic to deploy over three times as much battery storage capacity and seven times as much solar pre-2030 than the company proposes in its 2023 IRP update. Georgia Power should accelerate its procurement of both resource types through All-Source RFPs.

In addition to the specific resource additions the company proposes as part of its IRP update, our testimony addresses Georgia Power's long-term planning practices more broadly. The company's 2023 resource mix study and its 2023 IRP update show that it plans to maintain its existing fleet of coal and gas resources and to build large amounts of new gas combined-cycle gas capacity.

This heavy reliance on fossil fuels will expose ratepayers to fuel price volatility and potentially expensive new regulations, most notably the proposed rules under Section 111 of the Clean Air Act.

Additionally, Georgia Power's failure to plan for resource retirement and replacement beyond the next few years limits the Commission's ability to effectively oversee the company's resource planning decisions. One clear example of Georgia Power's last-minute planning practices is the rushed timeline of its September 2023 RFI.

Georgia Power must move away from last-minute planning and allow sufficient time to consider all economic resource options, especially clean energy options that can more economically serve the company's new and existing load.

Although not directly at issue in the 2023 IRP update, if the Commission does not consider long-term planning practices now, it will find itself back in the same situation for the company's 2025 IRP; namely, with Georgia Power pushing limited options and an urgent need to immediately approve whatever the company puts forth.

In sum, our testimony makes the following recommendations: First, the Commission should not

approve the PPA with Mississippi Power Company before the winter of 2025/2026. If the PPA is approved, the Commission should require removal from rates of all costs incurred in the months prior to when Georgia Power needs the capacity to serve ratepayers.

Second, the Commission should not approve the PPA with the Santa Rosa Energy Center before the winter of 2025/2026. The Commission should also not approve this PPA without firm transmission access.

If the PPA is approved, the Commission should require removal from rates of all costs in the month prior to when GPC needs the capacity to serve ratepayers.

Third, the Commission should only allow Georgia Power to use the flex capacity framework to deploy battery storage, given that the company's resource plan found that it was economic to deploy substantially more battery storage than the company currently plans to bring online.

Fourth, the Commission should not approve all three of the Yates combustion turbines and should instead direct Georgia Power to test the market and procure as much battery storage, both paired with solar PV and standalone, as it can.

Georgia Power should only consider combustion turbine capacity to fill the gap that it cannot economically meet with clean energy resources based on on-the-ground market results.

Fifth, Georgia Power should focus its near-term resource planning efforts on obtaining as much new renewable capacity and energy as possible, focusing on battery storage and solar PV provided by the market.

Sixth, the company should fully account for the proposed Section 111 regulations in its modeling, including realistic cost estimates for carbon capture and storage on existing and new proposed fossil resources, and the potential for capacity factor limits and hydrogen co-firing.

Seventh, the company should adopt more proactive planning processes so it can procure sufficient capacity in the future without suspending RFP procedures.

And, finally, the Commission should require that the Georgia Power present as part of this 2023 IRP update any resource additions and retirement decisions that the company is now considering that deviate from its last IRP.

Thank you.

MR. FABISH: With that, I would like to make the panel available for questions from the Commission and cross-examination.

CHAIRMAN SHAW: Thank you.

Commissioners, any questions?

COMMISSIONER PRIDEMORE: Yes, ma'am. Good afternoon.

You mentioned that EPA Clean Power Plant or whatever -- whatever phrase they're using now for it. 111. And -- but you're aware, though, that 111 is proposed, it has not been adopted; correct?

MS. GLICK: That's right, yes.

COMMISSIONER PRIDEMORE: So it is proposed.

Are you aware that yesterday that the EPA rolled back a major portion of 111 that includes existing natural gas plants?

MS. GLICK: I am, yes. So in the majority of what we're talking about in our testimony is the impact on existing coal, which is still included, and the new gas.

I definitely understand they're only proposed, but what we're asking is for modeling. So IRPs are fundamentally about understanding uncertainty and understanding what resource options are best given uncertainty.

We're asking the company to consider it and do a scenario. It's very common to do an IRP scenario where you consider different regulatory structures for the future.

COMMISSIONER PRIDEMORE: Well, that's certainly the case in what we're doing here this week and we do with the Georgia Power IRP process. But is it safe to assume, though, that if the EPA is so willing to roll back -- that's the EPA now.

If the EPA is so willing to roll back conditions that they've already put forward in the proposed rule just yesterday, that they wouldn't roll back more of the proposed rule or adopt none of it?

I mean, that's safe to assume, as well; right?

MS. GLICK: It's certainly possible. I think it's quite likely based on what we've seen that the EPA will issue some manner of control for existing coal plants and the new gas plants.

And we're just asking the company to model. So it doesn't take that much time or resources to do a modeling exercise. And the benefit of knowing the results is the company will know.

There might be resource options that look good regardless of whether the EPA rule is finalized or

not. Then the company knows: We can go ahead with those because it doesn't matter.

And it can identify which resource options could be at risk. It's information. It's additional information to make better planning decisions.

COMMISSIONER PRIDEMORE: Okay.

CHAIRMAN SHAW: Any other questions?

(No response.)

CHAIRMAN SHAW: All right. We'll start with cross.

Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

(No response.)

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: GAM.

MR. JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft. Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions, Mr. Chairman.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

MR. COX: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. McNUTT: No questions.

CHAIRMAN SHAW: Georgia Power.

I'm sorry. I've left out Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: Questions.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Good afternoon, panel. Steve Hewitson on behalf of Georgia Power Company.

A (Witness Glick) Good afternoon.

Q Let's start at page 5 of your testimony, lines 10 to 11, where you state that Georgia Power did not consider alternatives to the PPAs with Mississippi Power and Santa Rosa.

Now, you understand that those PPA are supported by existing resources that do not have to be built; right?

A (Witness Glick) Yes.

Q Okay. Are you aware of any other resources that could have been procured in time to meet the company's capacity needs in the winters of '26 and '27?

A (Witness Glick) So it's my understanding -- and a lot of this is confidential -- that the resources that are procured would be -- at least for the Mississippi Power PPA would have been available regardless of whether

they were secured for 2024 and 2025 or just secured for the time period needed.

Q No. I'm sorry. Let me ask that again.

Are you aware of any other resources, other than Mississippi Power PPAs, that would have been able to be procured prior to the need in '26 and '27?

A (Witness Glick) I don't. Because Mississippi Power did not do a full RFP. So you're asking a question I can't have the answer to because you have not provided the data that I would need to say yes.

Q You don't have any of that data on your own?

A (Witness Glick) I don't do RFPs for Mississippi Power.

Q For Mississippi Power?

A (Witness Glick) I'm sorry. For Georgia Power. My apologies.

Q Okay. But you're not aware of any existing resources in the area, regardless of whether you do a RFP; right?

A (Witness Glick) So it's my understanding, based on the company's timeline it is outlined for procuring battery storage, that there could have been a possibility to bring online other resources by the -- well, I guess not by the 2026 timeline. So that's for May 2028. So I'll rescind that. Sorry.

Q Thank you.

Okay. Moving on to Plant Yates, you recommend against approval of Plant Yates on page 7 of your testimony and instead recommend that the company procure as much battery storage as it can.

Is that your position?

A (Witness Glick) Yeah. So I think our position is pretty similar to what I heard staff saying yesterday in that we would like Georgia Power to do competitive procurement to demonstrate that the resource options it brings online at this time really are the most cost effective. And Georgia Power is welcome to enter the CTs into that bidding process.

Q Okay. So you don't -- well, do you also agree with staff when staff said that they are agnostic as to the resource -- the generation resource?

They just care about safety, reliability, and cost?

A (Witness Glick) I would say we're agnostic insofar as all the costs and risks are properly reflected. And we don't believe at this point that the full costs and risks of relying upon the CTs have been properly reflected, given that there's already been delays with the CT schedule. That the CTs don't have a firm gas supply, that there are transmission constraints.

There are a lot of risks that I've seen with these CTs that I don't think are fully reflected in consideration of a CT as an alternative.

Q Okay. Do you agree that the company should maintain a balanced portfolio of generation resources?

A (Witness Glick) I guess we might disagree on what balanced means, but I do think that diversity and balance is generally good in many aspects of life.

Q Okay. Are you aware that the resource planning models choose gas units as part of the mix to serve Georgia Power customers?

A (Witness Glick) That would not surprise me.

Q Okay. You mentioned the cost of oil related to Yates on page 5, lines 17 to 21. Are you aware that Georgia Power will only use fuel oil during times when natural gas will not be available?

A (Witness Glick) I understand that is what Georgia Power says, yes.

Q Okay. And having that oil backup means that the units will be able to operate during the times where natural gas is not available; right?

A (Witness Glick) Yeah. I live in New England so I understand that dynamic very well.

Q Okay. And those times are often times of high winter peak capacity, like cold winter mornings?

A (Witness Glick) Yeah. Absolutely. It's more expensive, though. I mean, I understand that it is a firm supply, but it's not firm gas. And so it's fundamentally just more expensive, more polluting and not as efficient or economic.

Q Okay. And you say that on page 26, line 9, when you call oil and expensive and highly polluting fuel. Do you see that?

A (Witness Glick) Yeah. There's a reason why it's being used as kind of a second resort, instead of a primary fuel being used. It's not the preferred source.

Q Right. But you are aware the Yates CTs will have state-of-the-art controls, including SER and oxidation catalysts for both gas and oil generation; right?

A (Witness Glick) Yes. I understand that to be true.

Q Okay. Are you aware that these are advanced CTs that are highly efficient compared to existing CTs on the system?

A (Witness Glick) That would make sense.

Q Okay. Would you agree that the greenhouse gas emissions from a more-efficient unit are less on a per-megawatt-hour basis than a less-efficient unit?

A (Witness Glick) Yes. But with oil, we're not

just talking about greenhouse gas emissions. There are other pollutants that are really concerning with oil that you don't have as severe with natural gas. So it's more than just the carbon that we're concerned about here.

Q Okay. Would you agree that if Plant Yates on oil dispatches ahead of older, less-efficient units on oil during those times when natural gas is not available, that the overall emissions associated with electricity generation could be less?

A (Witness Glick) There's many factors to consider because it's not just about whether a unit is efficient. It's about the operating level of a unit can also impact the emissions level like heat rates. So you can't make a generalized statement about that not knowing what the dispatched stack looks like.

Q That was my question. If it dispatches -- if a more-efficient unit dispatches over a less-efficient unit, then the pollution would be less?

A (Witness Glick) It depends what else you have available on the grid. If you're saying one-to-one, then, yes, absolutely it is more efficient than an older, less -- fundamentally, a more-efficient unit is more efficient than a less-efficient unit.

Q Okay. And you understand that the Yates CTs will go through a permitting process that is designed to

ensure the project does not negatively impact public health; right?

A (Witness Glick) That sounds reasonable. I'm not familiar with the full permitting process.

Q Okay. On page 6, lines 14 to 17, you wrote that Georgia Power failed to proactively account for load growth in the 2022 IRP.

Do you see that testimony?

A (Witness Glick) What page again?

Q Six. It's one of your recommendations, recommendation No. 12. I'm sorry. Conclusion --

A (Witness Glick) Oh, finding number --

Q Finding No. 12.

A (Witness Glick) Yes, yes. I see that.

Q Okay. Is it your contention that Georgia Power should have seen this historic load growth back in 2022?

A (Witness Glick) Georgia Power should have been more proactive when it did see this load growth. So part of what we talk about is the discussions around the need for additional resources started in the summer. I think in as early as July of 2022.

So I understand that data center load growth is a new trend, but, overall, the company did not respond proactively enough when it became aware that there was additional load growth that it had not projected

previously.

Q I think you might be a little bit wrong on your timeline. Did you understand from the testimony yesterday and from Georgia Power's testimony in this case that the need date for -- which required additional resources didn't happen until June of 2023?

A (Witness Glick) I'm talking about when discussions began around the procurement of additional resources, which was in -- my understanding was July of 2023.

Q Yes. July of 2023.

A (Witness Glick) Right.

Q Not July of 2022. I think you misspoke and said July of 2022.

A (Witness Glick) Oh, I apologize. I meant July of 2022.

Q Yeah. And July of 2023 is necessarily after the July -- or after the 2022 IRP; right?

A (Witness Glick) That's correct, yes.

Q Okay. And are you aware that Georgia Power's load growth had been flat for several years prior to the 2022 IRP?

A (Witness Glick) Yes. I believe so. That sounds right.

MR. HEWITSON: Okay. That's all I have for

you. Thank you very much for your time.

MS. GLICK: Thank you.

CHAIRMAN SHAW: Redirect.

MR. FABISH: Just one or two questions of redirect.

REDIRECT EXAMINATION

BY MR. FABISH:

Q Do you recall just now when Mr. Hewitson was asking you about whether or not a more-efficient unit, if it displaced a less-efficient unit, would be -- lower pollution; is that correct?

A (Witness Glick) Yes.

Q Would a non-emitting resource be even less polluting than that resource?

A (Witness Glick) Yes.

MR. FABISH: Okay. That's all I have.

With that, I would like -- if we could release the panel. And if we could move to have their testimony entered into the record.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Ofdevi Glick and Lucy Metz follows:)

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	**)**	**Docket No. 55378**
2023 Integrated Resource Plan Update	**)**	

DIRECT TESTIMONY OF

DEVI GLICK

AND

LUCY METZ

ON BEHALF OF

SIERRA CLUB

FEBRUARY 15, 2024

(PUBLIC VERSION)

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please list your names and occupations.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc, (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

My name is Lucy Metz. I am an Associate at Synapse. My business address is also 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Ms. Glick, please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 11 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q Ms. Metz, please summarize your work experience and educational background.

A At Synapse, I conduct analysis and write publications on a variety of topics related to integrated resource planning and power plant economics. I regularly support the development of comments and testimony in IRP dockets across the country, including performing analyses of electric power systems using spreadsheet tools and industry-standard models such as EnCompass.

I hold a Bachelor of Science in Engineering Science from Smith College. A copy of my resume is attached as Exhibit LM-1.

Q On whose behalf are you testifying in this case?

A We are testifying on behalf of Sierra Club.

Q Have either of you testified previously before the Georgia Public Service Commission?

A No.

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

A In this proceeding, we review Georgia Power Company's ("GPC" or "the Company") 2023 Integrated Resource Plan update (2023 IRP Update) and evaluate its proposed resource additions, modeling methodology, and input assumptions. We also evaluate how this update fits into the Company's larger resource planning process and assess the prudency of the Company's resource planning process.

Q How is your testimony structured?

A In Section 2, we summarize our findings and recommendations for the Commission.

In Section 3, we give an overview of GPC's 2023 IRP Update.

In Section 4, we provide a critique of the new resources the Company requests as part of this proceeding.

In Section 5, we discuss GPC's long-term resource planning practices and suggest ways the Company could plan more effectively in the future.

Q What information do you rely upon for your analysis, findings, and observations?

A Our analysis relies primarily on the workpapers, exhibits, and discovery responses of GPC's witnesses. We also rely on other publicly available documents and data, which we cite throughout our testimony.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A Our primary findings are:

1. GPC's projection of rapid industrial and data center load growth in its 2023 IRP Update is driving the need for substantial new near-term capacity relative to its 2022 IRP.
2. The Company's proposed power purchase agreement ("PPA") with Mississippi Power Company ("MPC") begins two years before the

Company needs capacity in the winter of 2025/2026. GPC has not justified procuring the capacity so far in advance of need and passing an estimated [redacted] in unnecessary costs on to Georgia ratepayers.

3. The Company's proposed PPA with Santa Rosa Energy Center begins a year and a half before the Company needs capacity in the winter of 2025/2026. GPC also does not have firm transmission capacity to serve the Santa Rosa Energy Center until May 2026. GPC has not justified procuring the capacity so far in advance of need and passing an estimated [redacted] in unnecessary costs on to Georgia ratepayers.
4. GPC did not adequately consider alternatives to the PPAs with MPC and Santa Rosa.
5. The Company's proposed PPA resources with MPC and Santa Rosa are stopgap solutions that will only help mitigate the Company's capacity shortfall through the winter of 2028/2029. The Company still plans to address its capacity needs beyond that time with resources selected through an RFP and ones already approved in the 2022 IRP.
6. The combustion turbines ("CT") that GPC proposes to construct at Yates would rely heavily on expensive oil during the winter peak months. Oil is expected to be [redacted] times more expensive than gas. These are costs that will be entirely passed on to ratepayers, absent action by the Commission.
7. The Company's 2023 Resource Mix Study deploys over three times as much battery energy storage ("BESS") capacity pre-2030 than the Company proposes in its 2023 IRP Update.
8. It is more economic for GPC to fill part of its firm capacity need with BESS (both paired with solar PV and standalone) and reduce the quantity of, or else eliminate, the gas CTs it installs.
9. If the greenhouse gas regulations proposed under Section 111 of the *Clean Air Act* are finalized, the cost to continue operating the Company's existing fossil plants beyond 2031 and to build new gas plants could be substantially

higher, and the plants' operation limited, relative to what GPC projected in its 2023 Resource Mix Study.

10. GPC's long-term reliance on gas resources will expose customers to fuel price volatility and the associated risks, which the Company did not account for in its IRP. Accelerated deployment of renewables will reduce the Company's reliance on volatile fuel prices and the associated risks to customers.
11. GPC is currently attempting to [redacted] and indicated that it is likely to extend the retirement dates for some of the existing coal and gas assets it owns as part of its next (2025) IRP. The Company's plan to continue reliance on coal and other fossil resources exposes its ratepayers to high costs and risks.
12. GPC's failure to proactively account for upcoming load growth in its 2022 IRP has effectively limited the Company's near-term resource options (for winter 2026) and limited the Commission's ability to effectively oversee GPC's resource planning decisions.

Based on these findings, we offer the following recommendations:

1. The Commission should not approve the PPA with MPC before the winter of 2025/2026. If the PPA is approved, the Commission should require removal from rates of all costs incurred in the months prior to when GPC needs the capacity to serve ratepayers.
2. The Commission should not approve the PPA with Santa Rosa before the winter of 2025/2026. The Commission should also not approve the PPA without firm transmission access. If the PPA is approved, the Commission should require removal from rates of all costs in the months prior to when GPC needs the capacity to serve ratepayers.
3. The Commission should only allow GPC to use the Flex Capacity framework to deploy BESS given that the Company's resource plan found

that it was economic to deploy substantially more BESS than the Company current plans to bring online.

4. The Commission should not approve all three of the Yates CTs and should instead direct GPC to test the market and procure as much battery storage (paired with solar PV and standalone) as it can. GPC should only consider CT capacity to fill the gap that it cannot economically meet with clean energy resources based on on-the-ground market results.
5. GPC should focus its near-term resource planning efforts on obtaining as much new renewable capacity and energy as possible, focusing on BESS and solar PV provided by the market.
6. The Company should fully account for the proposed Section 111 regulations in its modeling, including realistic cost estimates for carbon capture and storage ("CCS") on existing and new proposed fossil resources, and the potential for capacity factor limits and hydrogen co-firing.
7. The Company should adopt more proactive planning processes so it can procure sufficient capacity in the future without suspending request for proposal ("RFP") procedures.
8. The Commission should require that GPC present as part of this 2023 IRP Update any resource additions and retirement decisions that GPC is now considering that deviate from its last IRP.

3. SUMMARY OF COMPANY PROPOSAL

Q Explain the purpose of GPC's 2023 IRP Update.

A In September 2023, GPC released its load forecast for the 2023 IRP Update. GPC's projection of load growth between now and the winter of 2030/2031 is around 17

times greater in the 2023 IRP Update than it was in the 2022 IRP; GPC now projects 6,600 MW of growth by 2030/2031 rather than 400 MW.[1]

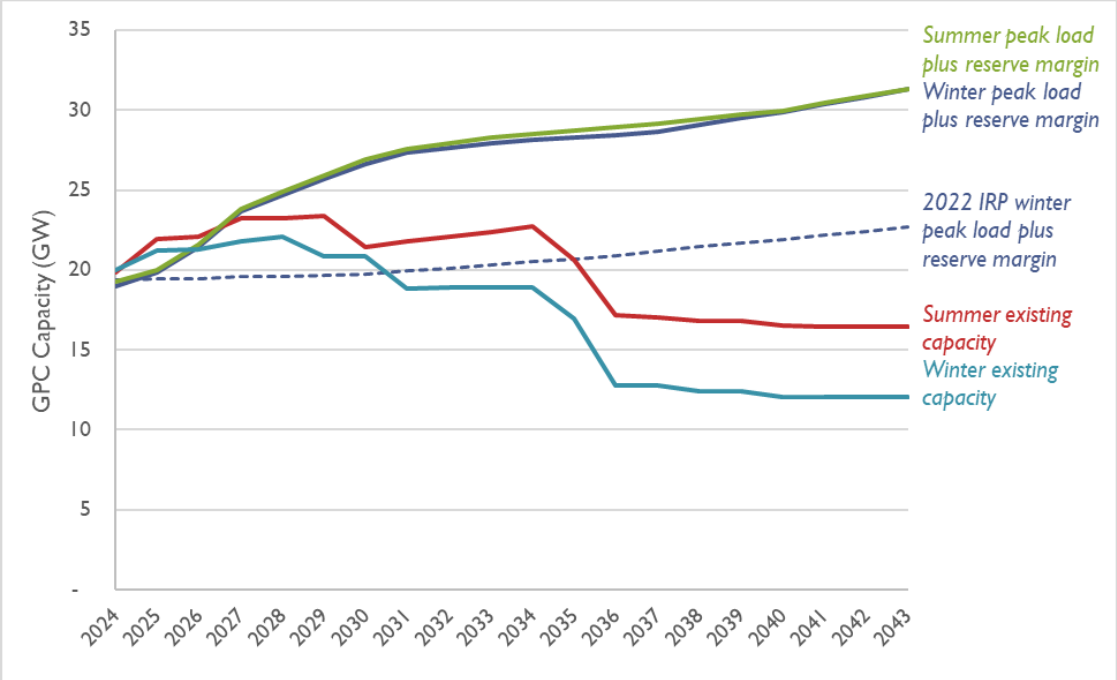
With this update, the Company has also updated its projections of when it will have a capacity shortfall—which is now two years sooner, in the winter of 2025/2026.[2] GPC continues to project that its system will be summer peaking through the end of the study period, but it will have a larger capacity shortfall in the winter. This is driven by its higher winter reserve margin and lower firm capacity ratings of certain resources in the winter (Figure 1). GPC's updated load growth projection has driven its winter capacity need in the 2023 IRP Update (solid purple line) up. Specifically, its projected winter capacity need is now 8.6 GW higher by 2043 than it was in the 2022 IRP projection (dotted purple line).[3]

[1] Georgia Power Company 2023 Integrated Resource Plan Update, October 2023 [known hereafter as "GPC 2023 IRP Update"] at 8.

[2] *Id*. at 10.

[3] *Id*.

Figure 1. Georgia Power Company projected capacity need and existing capacity



Source: "PD GPC and System IRP Summary Data.xlsx", "Figures 4, 5, 6, & 9 – Capacity Needs Data for B22, B23, and 2023 IRP Update.xlsx"

Q Do you have any concerns with GPC's load forecasting methodology?

A Yes. GPC uses a probabilistic model to develop its load forecasts. The forecast that the Company selected as the basis of the 2023 IRP Update is the P95 load level, meaning that "95% of all potential combinations fall at or below this level".[4] This forecast represents an upper limit on load growth rather than the most likely scenario as reflected by the P50 scenario.[5] GPC stated that it relied on this P95 scenario because of the uncertainty surrounding future growth.[6] However, it is not appropriate for GPC to switch to a low-probability load forecast simply because the

[4] GPC 2023 IRP Update, PD Technical Appendix, PD Load and Energy Forecast at 3.
[5] GPC Response to STF-DEA-1-5 (a), attached as Exhibit DG/LM-1.
[6] *Id.*

Company is uncertain about future load growth and its standard P50 forecast does not match with its growth plans and aspirations.

Large new customers such as the new industrial and data center customers anticipated do not come online without lead time and notice to GPC. GPC should have revised its entire forecasting methodology to yield a more accurate forecast in light of the changing nature of new load on its system. Additionally, GPC should evaluate how these new industrial and data center loads are impacting system costs to ensure it is not unfairly shifting costs to existing residential customers.

Q How likely is it that GPC will realize the rapid load growth it currently projects?

A It's highly uncertain, and this is problematic. That is the very reason why GPC opted for the P95 forecast instead of the P50 forecast—because of the uncertainty surrounding future load growth.[7] If load growth does not materialize at the P95 level, GPC may not truly need all the resources for which it is requesting Commission approval. The Company must incorporate this uncertainty into its planning by acquiring more flexible capacity resources (such as BESS) that will not saddle existing ratepayers with extra costs if load growth turns out to be smaller than GPC currently anticipates.

[7] *Id*.

Q What is GPC asking for in its application?

A In the 2023 IRP Update, GPC proposes a set of resources that would close the capacity gap through the winter of 2027/2028, but create a capacity surplus in the near term (Table 1). The Company's proposed resource additions, which it would obtain through exceptions to the Commission's RFP process, include:

- PPA with MPC for 750 MW of capacity and energy[8]
- PPA with the Santa Rosa Energy Center for 230 MW of capacity and energy[9]
- 1,400 MW from three simple-cycle CTs at Plant Yates that would be dual-fueled with oil and gas, due to a lack of firm gas transportation available at the site[10]
- Up to one gigawatt of BESS, including 178 MW of 4-hour lithium-ion batteries at the Robins and Moody Air Force Base and 200 MW of BESS co-located with 200 MW of new solar[11]

The Company also seeks approval of the following as part of the 2023 IRP Update:

- Two new distributed energy resource programs, one new tariff-based demand response program, and an amended certificate for one existing demand-side management program[12]
- A Flex Capacity framework[13]
- Expansion of the transmission system to accommodate the resources above[14]

Table 1. GPC winter capacity deficit and (surplus) before and after proposed resource additions

	2023/24	2024/25	2025/26	2027/28	2028/29	2029/30

[8] GPC 2023 IRP Update at 17.
[9] *Id*. at 17-18.
[10] *Id*. at 21-22; GPC Response to PD STF-JKA-2-22, attached as Exhibit DG/LM-2.
[11] GPC 2023 IRP Update at 20.
[12] *Id*. at 22.
[13] *Id*. at 23-24.
[14] *Id*. at 28.

Initial Winter Capacity Need	(964)	(1,352)	175	1,875	2,601	4,807
Proposed New Resources	239	469	980	1,877	2,500	1,989
Mississippi Power PPA	750	750	750	750	750	-
Santa Rosa PPA	-	230	230	230	230	-
Yates CT	-	-	-	357	600	1,070
Battery storage	-	-	-	540	920	920
Sales to regional provider	(511)	(511)	-	-	-	-
Final Winter Capacity Need	(1,203)	(1,821)	(805)	(1)	102	2,818

Source: GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx. We assume that the Santa Rosa PPA will begin in May 2024 based on GPC's response to PD STF-JKA-6-7 (d).

4. CRITIQUE OF IRP UPDATE PROPOSED RESOURCES

i. The PPA with Mississippi Power Company saddles GPC ratepayers with excess capacity over the next two years, and GPC signed it without adequate consideration of alternatives

Q Provide a summary of the MPC PPA.

A In October 2023, GPC executed a PPA with MPC for 750 MW of capacity and energy for the term January 1, 2024 – December 31, 2028.[15] The capacity and energy provided through the PPA is not contractually tied to any one generating asset. However, it appears that the PPA is being used to justify MPC's decision not to close its coal unit at Plant Daniel and gas steam unit Watson 4 at year end 2027 and year end 2023, respectively, as planned. [redacted]

[15] *Id*. at 17.

[redacted]

Q What is GPC asking for with regards to the MPC PPA in this docket?

A GPC is asking for: (1) a certification of public convenience and necessity (CPCN) for the PPA between GPC and MPC; (2) regulatory asset treatment to defer the energy and capacity payments it is making to MPC, net of the revenues it makes from reselling any energy and capacity for the period January 1, 2024 – December 31, 2025.[20]

Q Did GPC adequately consider alternatives to the PPA with MPC?

A No. GPC asserted that it opted for this PPA instead of going to the market because "There is not enough time for an RFP to be conducted, resources to be constructed

[16] GPC Response to TS STF-PIA-7-15, TS Attachments A-P, attached as Exhibit DG/LM-3.

[17] GPC Response to TS STF-PIA-7-15, Attachment O, *see* Exhibit DG/LM-3.

[18] GPC Response to TS STF-JKA-2-19, Attachment B, attached as Exhibit DG/LM-4; also provided in GPC Response to TS STF-JKA-4-19, Attachment.

[19] GPC 2023 IRP Update, TS Technical Appendix, TS Power Purchase Agreement Between Georgia Power Company and Mississippi Power Company Executed [known hereafter as "TS Executed PPA between GPC and MPC"].

[20] GPC 2023 IRP Update at 17.

following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027."[21]

But the Company has not demonstrated that there were no alternative options available to meet its 2025/2026 capacity needs. The MPC PPA was identified in July 2023 as a potential resource option[22] and by October 2023, less than four months later, the PPA was signed. GPC rushed the decision without adequately considering alternatives.

Q What actions did GPC take to evaluate alternative resource options to meet its 2025/2026 capacity need?

A GPC issued a Request for Information ("RFI") on September 26, 2023.[23] But the timing is such that GPC could not have seriously considered the RFI results prior to executing the contract.

- July 27, 2023: GPC identified a supposed capacity need as early as July and [redacted].[24]
- [redacted]
- [redacted]
- [redacted]

[21] GPC 2023 IRP Update, 2023 IRP Update Supplemental Filing PD, Request for Information Summary [known hereafter as "Request for Information Summary"], Section 2.3. December 4, 2023.

[22] GPC Response to PD STF-JKA-6-5 (c), attached as Exhibit DG/LM-5.

[23] GPC Response to PD STF-JKA 4-10, attached as Exhibit DG/LM-6; *also see*, Request for Information Summary.

[24] GPC Response to PD STF-JKA-6-5 (c), attached as Exhibit DG/LM-5; GPC Response to TS STF-PIA-7-15, Attachment O, *see* Exhibit DG/LM-3.

[25] GPC Response to TS STF-PIA-7-15, Attachment A, *see* Exhibit DG/LM-3.

- September 26, 2023: The RFI was issued by GPC. By this time, [redacted]
- October 11, 2023: GPC signed the PPA contract with MPC.[28]
- October 24, 2023: RFI closing date, nearly two weeks *after* GPC signed the PPA with MPC.[29]

Q Are there any other concerns with GPC's consideration of alternatives?

A Yes. GPC issued an RFI and not a Request for Proposals ("RFP"). An RFI is distinct from an RFP in that no bids or pricing is required to be provided by all respondents. This is something GPC knew. The Company did get multiple bids under the RFI but nonetheless GPC didn't seriously consider any of the results. Specifically, GPC said:

> The Company did not perform a detailed analysis on the potential projects identified in Table 2-3-2 in the RFI summary showing that 100 MW of capacity could be acquired for 2025, 1,100 for 2026 and 1,495 in 2027 because there was not adequate time to administer and conduct an RFP that provides for all bids to be properly evaluated, conduct transmission studies, and ultimately construct new assets or interconnection facilities to meet the capacity needs being addressed in the 2023 IRP Update. In addition, if provided, pricing information was optional and non-binding for participants responding to the RFI and

[26] GPC Response to TS STF-PIA 7-15, Attachment O, *see* Exhibit DG/LM-3.
[27] GPC Response to TS STF-PIA 7-15, Attachment M, *see* Exhibit DG/LM-3.
[28] 2023 IRP Update at 17.
[29] Request for Information Summary.

interconnection plans are not known, any of which could significantly impact a potential project's availability.[30]

GPC knew that an RFI didn't require respondents to provide information sufficient to assess a project's feasibility, yet it still issued an RFI instead of a full RFP. In addition, it waited until the end of September to do so and then claimed it didn't have time to consider alternatives. If GPC was serious about securing capacity from the market it would have issued a full RFP instead of just the RFI and it would have done so earlier in the summer. Instead, it appears that the RFI was issued after the fact to justify a decision the Company had already made. The Company performed no robust analysis on the RFI results and never appeared to seriously consider any resources from the RFI.

Q Where is the power coming from that MPC is providing under the PPA?

A The power is coming from excess capacity that MPC was ordered to retire by the Mississippi Public Service Commission (the "Mississippi Commission"). Specifically, back in 2020, the Mississippi Commission ordered MPC to include in its next IRP filing "the schedule of early or anticipated retirement of approximately 950 megawatts of generating capacity by year-end 2027 or show cause with detailed evidence why the continued operation of some or all of MPC's existing fossil steam generation is in the best of interest of customers and MPC."[31] In its

[30] GPC Response to STF-JKA 4-10, attached as Exhibit DG/LM-6.

[31] Mississippi Public Service Commission. 2020. Final Order in Docket No. 2018-AD-145. Pages 5-6.

2021 IRP, MPC submitted a plan to retire 976 MW of coal and gas steam capacity.[32] This included a retirement date of year end 2023 for Watson Unit 4 (gas steam), and year end 2027 for MPC's share of Plant Daniel (coal steam).[33]

Sometime between 2021 and now MPC decided that it would attempt to re-market the power to GPC instead of retiring the capacity.

Q Is it guaranteed that the power will be available starting in winter 2025/2026?

A No. GPC intends for this PPA to maintain several MPC plants within the Southern Company pool. And while MPC and its parent company Southern Company may want to remarket the capacity, the Mississippi Commission may not view the PPA as a sufficient justification for keeping additional capacity online past the end of 2027. There is no obvious benefit to Mississippi ratepayers, whose utility maintains liability for excess capacity not needed to serve its native load.[34] The Mississippi Commission does not need to review the PPA before it is executed,[35] leaving open the possibility that it would find the PPA imprudent at a later date. This could put the availability of the PPA at risk towards the end of the contract period, just when GPC's capacity need will be greatest.

[32] Mississippi Power Company. 2021. *Mississippi Power 2021 IRP Filing*. Mississippi Public Service Commission Docket No. 2019-UA-231. Page 4.

[33] *Id*.

[34] Review and Assessment of Mississippi Power Company's Reserve Margin Plan, Report to the Mississippi Public Utilities Staff. Prepared by Bates White, LLC. September 17, 2020.

[35] GPC Response to PD STF-JKA-2-19 (b), attached as Exhibit DG/LM-4.

Q Are there risks to GPC customers of signing a PPA for power that relies on an aging coal plant?

A Yes. As discussed in Section 5 below, there are significant risks from environmental regulations, price volatility, and contraction in the coal market.

Q Is the PPA with MPC well-matched to GPC's capacity need?

A No. Even under GPC's revised and dramatically increased forecast, GPC doesn't need capacity and energy until winter 2025/2026. That means that it is paying for excess capacity and energy for almost two years, or else taking on the risk of reselling it.

Q Why did GPC take on the capacity two years before it needed capacity?

A As stated above, GPC claims that it took the excess capacity for the next two years because "[h]ad Georgia Power not executed the PPA for the full five years, the proposed resource very likely would not have been available for the last three years when the Company has a capacity need."[36] But evidence provided in discovery does not support this claim:

[redacted]

[36] GPC Response to PD STF-JKA-2-20 (a), attached as Exhibit DG/LM-7.

[37] GPC Response to TS STF-PIA-7-15, Attachment A, *see* Exhibit DG/LM-3.

[38] GPC Response to TS STF-JKA 2-19, Attachment B, attached as Exhibit DG/LM-4; also provided in GPC Response to TS STF-JKA 4-19, Attachment.

[39] TS Executed PPA between GPC and MPC.

[40] GPC Response to TS STF-JKA 2-19, Attachment B, attached as Exhibit DG/LM-4; also provided in GPC Response to TS STF-JKA 4-19, Attachment.

[redacted]

[redacted]

Q What costs is GPC asking to pass on to its ratepayers associated with the MPC PPA prior to winter 2025/2026?

A The PPA will cost GPC [redacted] ($2024 NPV) in capacity payments[41] for the years 2024–2025.[42] GPC asserts that it has already contracted to sell 500 MW for the term January 1, 2024–September 30, 2025.[43] From that sale, GPC will recover around [redacted] in 2024–2025.[44] That leaves GPC ratepayers with [redacted] for capacity that it doesn't need and isn't using over the next two years.[45]

GPC stated in discovery that it is negotiating with the buyer of the first 500 MW to sell the remaining 250 MW.[46] It is unclear if and when this will happen given that we are already a month and a half into 2024 and GPC is already paying [redacted] a month for the 250 MW of capacity that it doesn't need while receiving no value in return.[47]

[41] This includes capacity costs and a cost labeled "Additional Sum."

[42] Calculated based on GPC 2023 IRP Update, TS Updated Economic Analysis of Capacity Resources spreadsheet [known hereafter as "TS Updated Economic Analysis of Capacity Resources"]; TS Executed PPA between GPC and MPC.

[43] GPC 2023 IRP Update at 17.

[44] Calculated based on TS Updated Economic Analysis of Capacity Resources; GPC Response to TS STF-JKA-4-19, Attachment.

[45] *Id*.

[46] GPC Response to STF-JKA-4-19 (c), attached as Exhibit DG/LM-8.

[47] Calculated based on TS Executed PPA between GPC and MPC.

Q Is GPC aware that there is a risk of disallowance from the Georgia Public Service Commission with this PPA arrangement?

[redacted]

Q What do you recommend regarding the PPA with MPC?

A I recommend that the Commission disallow inclusion in retail rates of the PPA costs prior to when the capacity is needed in winter 2025/2026. GPC has not demonstrated that it made sufficient efforts to procure capacity from other resources that aligned more closely with the timing of its capacity needs. While the Company is making efforts to remarket the excess capacity, there is no guarantee it will be successful, therefore the costs and risk of that should not be borne by GPC ratepayers.

[48] GPC TS Response to STF-PIA-7-15, Attachment P, *see* Exhibit DG/LM-3.
[49] GPC TS Response to STF-PIA-7-15, Attachment H, *see* Exhibit DG/LM-3.

ii. The PPA with Santa Rosa Energy Center saddles GPC ratepayers with excess capacity over the next year and a half, and it does not guarantee firm transmission access for the entire contract term

Q Provide a summary of the Santa Rosa PPA.

A GPC is requesting approval to sign a PPA with the Santa Rosa Energy Center for 230 MW of capacity and energy. This PPA will provide capacity from a CC plant located in Pace, Florida. The PPA has been executed but GPC has not begun to pay for capacity yet. The PPA is scheduled to begin one month after Commission approval (GPC estimates that is May 1, 2024)[50] and continue through the end of December 2028.[51]

Q What is GPC asking for specifically in this case?

A GPC is asking for: (1) a CPCN for the PPA between GPC and Santa Rosa; (2) regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, net of revenue from resales.[52]

Q Is the PPA with Santa Rosa Energy Center well-matched to GPC's capacity need?

A No. Once again, GPC doesn't need capacity and energy until winter 2025/2026. That means that if the Commission approves the PPA prior to January 1, 2026, GPC

[50] GPC Response to PD STF-JKA-6-7(d), attached as Exhibit DG/LM-9.
[51] GPC 2023 IRP Update at 17.
[52] *Id*. at 17-18.

ratepayers will be paying for excess capacity and energy or else taking on the risk of reselling it.

In defense of this PPA, GPC repeats its assertion that it opted for this PPA instead of going to the market because "There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027."[53] GPC goes on to claim that the Santa Rosa Energy Center was a known, existing generation asset that was identified in July 2023. Since the project could meet resource needs without any new transmission projects, the Company negotiated an agreement before October 2023.[54]

But, as discussed above, the Company failed to demonstrate that there were no alternative options to purchasing excess and unnecessary capacity.

Q What efforts did GPC take to evaluate alternative resource options to meet its 2025/2026 capacity need?

A As discussed above, GPC made no real efforts to procure capacity from the market. I have the same concerns with GPC's procurement of this PPA as I did with the MPC PPA—mainly the timeline and the use of an RFI rather than an RFP in a veiled attempt to justify the decisions that the Company had already made.

[53] GPC Response to PD STF-JKA-6-5, attached as Exhibit DG/LM-5.
[54] *Id*.

Q What costs is GPC asking to pass on to its ratepayers associated with Santa Rosa PPA prior to winter 2025/2026?

A Assuming the PPA started May 1, 2024, it would cost GPC [redacted] ($2024 NPV) in capacity payments[55] for the years 2024–2025.[56] Given that the PPA doesn't start until it is approved by the Commission, customers would save approximately [redacted] in capacity costs for each month the Company is not under contract to purchase the Santa Rosa capacity.[57]

GPC asserts that, once approved, it will include the Santa Rosa capacity available prior to winter 2025/2026 in an RFP.[58] Further, GPC states that it expects to remarket the capacity to a regional electrical service provider at a [redacted].[59] However, GPC did not disclose which potential parties may be interested in the capacity. GPC's ability to re-sell the capacity is not certain, and if the PPA is approved and the Company cannot remarket the capacity, GPC ratepayers will be on the hook for the full cost.

Additionally, GPC revealed in a supplemental discovery response it doesn't have firm transmission capacity for the PPA from 2024–May 2026.[60] This includes the entire time the Company would attempt to re-market the capacity, as well as the

[55] This includes capacity costs, accounting lease, and a cost labeled "Additional Sum."

[56] TS Updated Economic Analysis of Capacity Resources; GPC 2023 IRP Update, TS Technical Appendix, TS Power Purchase Agreement Between Georgia Power Company and Santa Rosa Energy Center LLC Executed [known hereafter as "TS Executed PPA between GPC and Santa Rosa"].

[57] Calculated based on TS Updated Economic Analysis of Capacity Resources; TS Executed PPA between GPC and Santa Rosa.

[58] GPC 2023 IRP Update at 17; GPC Response to STF-JKA-4-19 (e), attached as Exhibit DG/LM-8.

[59] GPC Response to TS STF-PIA-10-3, attached as Exhibit DG/LM-10.

[60] GPC Supplemental Response to STF-JKA-2-2 (f), attached as Exhibit DG/LM-11.

first half of 2026 when the Company needs the capacity. This is concerning because it means that the PPA doesn't actually provide firm capacity for the first half of 2026 when GPC needs it. It also renders the capacity less valuable on re-sale and will impact the price that GPC could get for the power if it attempts to re-market it. GPC stated that it is pursuing short-term firm transmission for the resources during this period[61] but it's unclear whether this will happen and how much that will cost.

Q What do you recommend with regard to the PPA with Santa Rosa?

A I recommend that the Commission disallow inclusion in retail rates of the PPA costs prior to when the capacity is needed in winter 2025/2026. The Commission should also not approve the PPA until the firm transmission capacity issue is resolved. As discussed above, GPC did not adequately consider alternatives, or otherwise make efforts to procure capacity resources that aligned more closely with the timing of its capacity needs. While the Company claims it will make efforts to remarket the excess capacity, it provides no specifics. And regardless there is no reason why the costs and risk of that should be borne by GPC ratepayers. At best, the arrangement will be net neutral for ratepayers. At worst, it will cost them [redacted] over the next two years in exchange for zero value. This arrangement provides no upside benefit to ratepayers.

[61] *Id*.

iii. The Yates combustion turbines will be costly to build and operate, and are likely to cost more than an equivalent amount of 4-hour BESS

Q Summarize your concerns with GPC's proposal to construct three combustion turbines at Plant Yates.

A The three dual-fueled CTs at Yates would impose unnecessary costs and pollution burdens on Georgia residents. First, [redacted].[62] Second, because no firm gas capacity is available to the plants, the CTs would rely on oil—an expensive and highly polluting fuel—during peak periods.[63] Overall, we find it would be more economic to replace the firm capacity of one or more of the CTs with 4-hour BESS, which could be charged at low cost with energy from solar PV as well as the grid.

[redacted] **Q** [redacted]

[redacted]

[redacted] **A** [redacted]

[redacted] [redacted]

[redacted] After the Company finalized an

[62] GPC Response to TS STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12; GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[63] GPC Response to PD STF-JKA-2-22, attached as Exhibit DG/LM-2.

[64] Calculated based on GPC Response to STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12; GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[65] GPC Response to TS STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12.

Engineering, Procurement, and Construction (EPC) agreement for the units in January 2024,[66] [redacted] [67] GPC indicated in discovery that the lateral was being build adjacent to the existing pipeline lateral to Plant Yates from Transco,[68] [redacted]

Q Explain your concern with GPC's plan to build new peaking gas plants without a firm gas supply.

A Gas pipeline capacity in GPC's service area is increasingly constrained.[70] GPC did not procure firm transportation capacity for the Yates CTs and reports that the units are unlikely to have a reliable supply of gas during peak conditions as a result.[71] Instead, the CTs will be dual-fueled and will burn oil whenever sufficient gas is unavailable. The turbines will have a combined capacity of 1,400 MW when operating on gas and 1,000 to 1,100 MW when operating on oil.[72] Notably, the Company failed to provide estimates for the amount of oil and gas each unit will

[66] GPC 2023 IRP Update, PD Georgia Power Company Application for Certification of Plant Yates 8–10 at 19.

[67] GPC Response to TS STF-DEA-3-6, Attachment G, attached as Exhibit DG/LM-12; GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[68] GPC Response to STF-JKA 2-22 (d), attached as Exhibit DG/LM-2.

[69] Calculated from GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G, attached as Exhibit DG/LM-13.

[70] GPC Response to STF-JKA-2-14 (e), attached as Exhibit DG/LM-14.

[71] GPC Response to PD STF-JKA-2-22, attached as Exhibit DG/LM-2.

[72] GPC 2023 IRP Update at 21.

burn in a given year. It modeled the units as using oil during winter months (December through February) and gas in other months,[73] but elsewhere stated that the units might also rely on oil during summer peak periods.[74]

Q How will oil-burning impact the cost to operate the CTs?

A Oil is much more expensive per unit energy than gas.[75,76] [redacted] shows GPC's projections of dispatch costs for the Yates CTs operating on gas and oil. The cost per megawatt-hour using oil is [redacted] times greater than gas throughout the study period. While the units are technically capable of providing firm capacity during winter months when GPC has the greatest capacity need, it will be extremely expensive to run them during these times based on high fuel costs. These are fuel costs that will be passed directly through to customers, absent Commission disallowance of fuel costs.

[redacted]

Source: TS Attachment B – Plant Yates Units 8 – 10 Applicable Variable Cost and Operations Data.

[73] GPC Response to STF-JKA-3-10, attached as Exhibit DG/LM-15.

[74] GPC Response to STF-JKA-2-22 (d), attached as Exhibit DG/LM-2.

[75] U.S. Energy Information Administration. 2024. "Henry Hub Natural Gas Spot Price." Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

[76] U.S. Energy Information Administration. 2024. "Petroleum & Other Liquids Spot Prices." Available at: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

Q How will the performance of the CT units be impacted by burning oil relative to burning gas?

A Emissions rates for both toxic air pollutants and greenhouse gases are higher for a CT when operating on oil than when operating on gas, as shown in Table 3 below. The Company estimates that the emissions rates of nitrogen oxides ("NO_X") will be more than twice as high when the Yates CTs operate on oil compared to gas. Similarly, the emissions rates for particulates and air toxics will be over four times higher on oil, and the carbon dioxide (CO_2) emissions rate will be 36 percent higher. Burning oil at Yates will therefore not only be more costly; it will also negatively impact public health and will make the units vulnerable to future environmental regulation relative to operation on gas.

Table 3. Emissions rates for Yates combustion turbines operating on gas and oil

Pollutant	Unit	Gas	Oil	Percent difference
NO_x	lb/MMBtu	0.0099	0.022	122%
Particulates and air toxics	lb/MMBtu	0.0034	0.015	341%
CO_2	lb/MMBtu	119	162	36%

Source: PD Georgia Power Company Application for Certification of Plant Yates Units 8-10, page 17.

Q What types of resources should the Company procure to meet its firm capacity needs?

A BESS would provide the same dispatchable firm capacity value as a gas CT, and 4-hour BESS are readily available and cost-competitive today. In the 2023 IRP Update main document, GPC suggests that CTs provide unique benefits that short-

duration storage would not, but this claim is unsupported.[77] And GPC itself is seeking to develop, operate, and own up to 1,000 MW of BESS, including 378 MW of 4-hour BESS across two different projects as early as the winter of 2026/2027.[78]

GPC's system has ample capability to add 4-hour storage before its capacity contribution will begin to decline (based on GPC's own effective load carrying capability (ELCC) assumptions). This is because GPC specifically, and Southern Company as a whole, currently has very little battery storage installed on the system. GPC does not yet own any operational BESS, although it does have PPAs for 409 MW nameplate capacity of paired solar and storage (as of the winter of 2023/2024).[79] According to the IRP Update, the Company plans to begin bringing Company-owned BESS online as soon as 2024.[80] Mississippi Power Company owns one demonstration solar-storage project,[81] and Alabama Power Company does not report any BESS currently on its system.[82] As shown in Table 4, Southern Company assigns a 100 percent ELCC to the first 3,000 MW of BESS installed on its system.[83]

[77] GPC 2023 IRP Update at 21.

[78] *Id*. at 19.

[79] Calculated based on GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16.

[80] GPC Response to STF-JKA-4-14 (a), attached as Exhibit DG/LM-17.

[81] Mississippi Power Company. 2021. *Mississippi Power 2021 IRP Filing*. Mississippi Public Service Commission Docket No. 2019-UA-231. Page 4.

[82] Alabama Power Company. 2022. *Alabama Power 2022 Integrated Resource Plan Summary Report.* Available at: https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/company/compliance---regulation/IRP.pdf.

[83] GPC Response to STF-JKA-2-11, Attachment F, attached as Exhibit DG/LM-18; the ELCC study appears to be for the entire Southern Company system and not just Georgia Power's system.

It is true that adding batteries for firm capacity will require GPC to develop new capabilities for managing the charge and discharge of BESS, for example to make sure that the batteries charge during time periods with high energy availability to ensure that they are available during peak periods. But this is something utilities with installed BESS system around the country are already doing. There is over 15 GW of BESS installed in the United States right now, and of that 1.8 GW is owned by utilities.[84] And much more is planned to come online in the new few years. GPC will have to learn in short order to maintain an economic electricity system. This process will be smoother if the Company moves aggressively to integrate BESS now rather than delaying until it has a large capacity need.

Table 4. GPC / Southern Company's estimate of incremental ELCC for 4-hour battery storage installed on its system

Total Battery Capacity (MW)	Incremental ELCC: Winter	Incremental ELCC: Summer
1,000	100%	92%
2,000	100%	100%
3,000	98%	100%
4,000	92%	100%
5,000	84%	95%
6,000	75%	85%

Source: STF-JKA-2-11 Attachment F.

[redacted]

[84] U.S. Energy Information Administration, form 860 monthly, December 2023.

[redacted] GPC expects the three Yates units to be "substantially completed" 32, 37, and 40 months after finalization of the EPC agreement (equivalent to December 2026, May 2027, and August 2027).[87] [redacted] especially given that the Yates CTs will be transmission-constrained until May 2028 and will provide only 600 MW of firm capacity until transmission upgrades are complete.[88] [redacted]

Q Has GPC provided [redacted] information suggesting that it could procure BESS on a similar timeline to constructing CTs at Yates?

A Yes. In its January supplemental filing, GPC implicitly confirmed that it is capable of procuring BESS on a more rapid timeline than building the Yates CTs. Between the initial and supplemental IRP Update filings, the in-service date of Yates Unit 9 was delayed from December 2026 to May 2027, and Yates Unit 10 was delayed

[85] GPC Response to TS STF-PIA-10-1, attached as Exhibit DG/LM-19.

[86] GPC plans to include SCRs at the Yates CTs according to GPC 2023 IRP Update, PD Georgia Power Company Application for Certification of Plant Yates Units 8–10.

[87] GPC Supplemental Response to STF-JKA-2-22 (f), attached as Exhibit DG/LM-11.

[88] GPC Response to PD STF-JKA-1-4 (e), attached as Exhibit DG/LM-20.

from April 2027 to August 2027.[89] To make up for the capacity shortfall that was supposed to be filled by Yates 9 during the winter of 2026/2027, GPC shifted forward 180 MW of battery storage.[90] This confirms that GPC itself thinks that it can procure battery storage in time for the winter of 2026/2027, and therefore should be more ambitious about constructing storage and solar instead of building all three gas CTs.

Q Do the CTs offer the lowest cost option for GPC to procure firm capacity?

A No. We compared the 15-year net present value of the capacity cost for a single CT, Yates Unit 8, with a comparable quantity of 4-hour battery storage. We found that the BESS costs [redacted] less than the CT[91] by comparing just the fixed and capital cost (including financing, taxes and tax credits, insurance, etc.) of the two resources. Because CTs are a low utilization capacity resource, we did not consider variable costs including fuel as well as energy revenues. If we had, the cost difference likely would have come out even more in favor of the BESS system given the high-cost GPC projects it will have to pay for oil to operate the CTs and

[89] PD Technical Information Supporting the Proposal to Develop up to 1,400 MW of CTs, October 2023 (original filing); Georgia Power Company's Application for Certification of Plant Yates Units 8-10, Supplemental filing, January 31, 2024 (document labeled DKT 55378 Yates 8-10 App for Certification).

[90] GPC Supplemental Response to STF-JKA-2-2 (f), Supplemental Attachment B, attached as Exhibit DG/LM-21; GPC Response to STF-JKA-2-2 (f), Attachment C, attached as Exhibit DG/LM-16.

[91] Calculated from GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G.xlsx, attached as Exhibit DG/LM-13; GPC 2023 IRP Update, TS Updated Economic Analysis, TS Updated Economic Analysis of Capacity Resources.xlsx; GPC 2023 IRP Update, TS Technical Appendix, TS Southern Company 2023 Integrated Resource Plan Update Resource Mix Study at 5 and 14; GPC 2023 IRP Update, TS Technical Appendix, TS Technical Information Supporting the Proposal to Develop up to 1400 MW from Three Simple Cycle Combustion Turbines at Plant Yates.

the ability for BESS to charge from zero marginal cost solar PV and low-priced market power.

Q Does the Company need the CTs at Yates to maintain 70 percent ownership of its supply-side resources?

A No. The Company's justification that it needs the Yates CTs to comply with a "long-standing Commission policy [that] requires Georgia Power to own at least 70 percent of its supply-side resources"[92] is specious. First, our understanding is that this "long-standing policy" is not a binding requirement and that there is no requirement for GPC to own 70 percent of its supply-side resources. The Company may desire to directly control most of its assets, but Commission oversight should apply equally to assets paid for by ratepayers, regardless of whether they are owned by the Company or contracted under a PPA. Second, GPC can self-build BESS, and doing so would help the Company maintain its 70 percent self-build goal. Finally, policies can and should be updated as the grid changes and markets evolve. The Commission order referencing 70 percent ownership "policy" dates to 2001, when power sector regulatory concerns were different from today.[93]

Q Are ownership requirements like this beneficial to ratepayers?

A No. Competition in electricity supply is good for ratepayers. The only party that benefits from a utility ownership policy is GPC itself. GPC should be securing

[92] GPC 2023 IRP Update at 18.

[93] Georgia Public Service Commission. 2001. Final Order in Docket Nos. 12499-U, 13305-U and 13306-U. Page 21.

resources based on what is available in the market at the lowest cost, not based on which resources can provide the biggest rate of return for its shareholders. If the Company knows it is allowed to self-build a resource without competing in the market, there is no incentive for GPC to be cost competitive—especially if the Company earns a rate of return on anything it builds. It is unlikely the Commission intended to arbitrarily limit or eliminate competition in a way that results in higher costs for ratepayers.

Additionally, a rule that limits third-party ownership would deter renewable developers from coming to the state, impede state economic growth, and cause GPC to incur unnecessary costs for new resources, while providing no additional reliability benefits. As mentioned above, third-party ownership does not limit the Commission's ability to provide oversight. But third-party ownership does decrease the size of the utility's rate base. Because PPA payments are collected as pass-through costs without a rate of return, they are sometimes less unattractive to utilities focused on shareholder returns.

Q What does evidence from other states suggest about the likely cost-effectiveness of Company-owned resources compared to PPAs?

A PPAs are lower cost than utility-owned resources in much of the country right now. If the Commission were to enforce a 70 percent utility ownership requirement, GPC would over-pay for new resources. Asking the utility to compete with the market does not inhibit the utility's ability to self-build, it just requires the utility to

demonstrate that doing so is in the best interest of ratepayers relative to alternatives from developers.

iv. GPC should only use the Flex Capacity Framework for resources it has already found to be economic, such as BESS

Q What is the Flex Capacity framework that GPC is proposing?

A GPC is requesting approval of a framework that it claims would allow it to more quickly respond to additional increases in its load forecast and help the Company meet new capacity needs prior to the winter of 2028/2029.[94] Specifically, the proposal requests that the Commission:

1. Provide authorization to undertake preliminary development activities in connection with the development, operation, and ownership of new capacity resources.[95]
2. Provide approval for GPC to defer collection of costs for preliminary development activities related to new sources of capacity, that would normally be expensed, to instead be placed in a regulatory asset with the amortization period to be determined in the Company's next base rate case.[96]

[94] GPC 2023 IRP Update at 23-24.
[95] *Id*. at 23.
[96] *Id*. at 24.

Q What do you recommend with regards to the Flex Capacity framework?

A We recommend that GPC use the framework to support the installation of BESS resources to meet its near-term capacity needs. The Company's Resource Mix Study already found that it was economic for GPC to procure a large quantity of BESS capacity over the next 5–10 years.[97] This is substantially more than the 1,000 MW of BESS GPC proposed in its IRP Update.[98] Therefore, we find it would be reasonable for GPC to use this framework to have its build-plans most closely match with the results of its resource planning analysis.

Q Should the Commission allow GPC free reign to use the Flex Capacity framework for all resource types?

A No. Although the Resource Mix Study also found additional gas resources to be cost-effective,[99] we are concerned that the Company's modeling did not adequately account for the costs and risks associated with continued reliance on fossil capacity. Further, the Company is already proposing a substantial build-out of gas in the near term.

[97] GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16; GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx, attached as Exhibit DG/LM-21.

[98] GPC 2023 IRP Update at 23.

[99] GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16; GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx, attached as Exhibit DG/LM-21.

v. GPC should procure more BESS and renewables to align with its findings around the economics of new resource options

Q What does GPC's 2023 IRP Update show about its near-term plans for adding BESS to its system?

A GPC's 2023 IRP Update includes plans to add up to 1 GW of new BESS,[100] as shown in Table 5 below. This is in contrast with GPC's own modeling in its 2023 Resource Mix Study, which finds that it would be economic for GPC to procure over three times as much (3.4 GW) of BESS by 2030 in the moderate fuel price scenario and between 3.1 and 4.4 GW in the other scenarios.[101]

Table 5. Cumulative battery storage additions in megawatts (nameplate capacity)

	2027	2028	2029	2030
IRP Update	**578**	**1,000**	**1,000**	**1,000**
Robins & Moody BESS	178	178	178	178
BESS Co-located Solar	200	200	200	200
Other BESS	200	622	622	622
Resource Mix Study (MG0 scenario)	**900**	**1,680**	**3,380**	**3,380**
2022 IRP ESS RFP	-	-	500	500
4-hr Battery Tier 1	900	1,680	2,460	2,460
4-hr Battery Tier 2	-	-	420	420

Source: Calculated from GPC Response to STF-JKA-2-2, Attachment C.xlsx; GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B.xlsx; GPC 2023 IRP Update Supplemental Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supplemental - Errata.xlsx; GPC 2023 IRP Update at 20.
Note: Table does not include previously approved projects such as Mossy Branch and McGrau Ford which GPC included in both the 2023 IRP Update and Resource Mix Study (See GPC Response to STF-JKA-4-14).

[100] 2023 IRP Update at 20.

[101] Including the builds from GPC 2023 IRP Update Supplemental Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supplemental - Errata.xlsx and the 2022 IRP ESS RFP from GPC Response to STF-JKA-2-2, Attachment C, attached as Exhibit DG/LM-16.

Q How does the near-term buildout of solar PV in GPC's 2023 IRP Update compare to its Resource Mix Study?

A Similar to BESS, GPC includes much less new solar capacity in its 2023 IRP Update than would be economic based on its 2023 Resource Mix Study. In the 2023 IRP Update, GPC only plans to add 0.2 GW of new solar, as part of a paired solar-storage project.[102] The moderate fuel scenario in the Resource Mix Study shows that it would be economic for GPC to procure 1.5 GW of new solar by 2030,[103] which is over seven times the capacity in the 2023 IRP Update.

Q How should GPC adjust its plans for BESS and solar PV buildout between now and 2030?

A Given the quantity of economic BESS and solar PV built in its own modeling, GPC should focus its near-term procurement efforts on BESS, both paired with solar PV and stand-alone, to address its projected near-term capacity needs. The Company should procure as much BESS and solar as it can economically obtain from the market based on All-Source RFPs.

[102] GPC 2023 IRP Update at 20.

[103] GPC 2023 IRP Update Supplemental Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supplemental - Errata.xlsx.

5. GPC'S LONG-TERM RESOURCE PLANNING PRACTICES

Q Please summarize your concerns with GPC's long-term planning practices.

A GPC's 2023 Resource Mix Study and its 2023 IRP Update show plans for GPC to maintain[104] [redacted] its existing fleet of coal and gas resources and to build large amounts of new gas combined-cycle capacity.[106] This heavy reliance on fossil fuels will expose ratepayers to fuel price volatility and potentially expensive new regulations, most notably the proposed rules under Section 111 of the *Clean Air Act*. Additionally, GPC's failure to plan for resource retirement and replacement beyond the next few years limits the Commission's ability to effectively oversee the Company's resource planning decisions. GPC must move away from these last-minute planning practices, such as it did with signing the MPC PPA, to allow sufficient time to consider all economic resource options, especially clean energy resource options that can more economically serve the Company's new and existing load.

Q Why should the Commission address long-term planning practices now, rather than waiting for next year's IRP proceeding?

A In this IRP Update, GPC is once again attempting to force the Commission's hand by not planning far enough in advance to allow for consideration of the full range

[104] GPC Response to STF-JKA-2-2, Attachment C.xlsx, attached as Exhibit DG/LM-16.

[105] GPC 2023 IRP Update, TS Technical Appendix, TS Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generating Asset.

[106] GPC 2023 IRP Update Supplementary Filing Errata 12-7-23 PD, PD Capacity Expansion Plan Supp – Errata.xlsx.

of resource options. The Company is also asking for approval for a PPA that it already signed and executed without properly considering alternatives. Although not directly at issue in the 2023 IRP Update, if the Commission does not consider long-term planning practices now, it will find itself back in the same situation for GPC's 2025 IRP; namely, GPC pushing limited options and an urgent need to immediately approve whatever the Company puts forth.

i. GPC's long-term planning relies heavily on fossil fuels

Q What is the Company's plan for its aging coal and gas assets?

A As shown in Table 6 below, GPC plans to extend the operation of many of its coal and gas plants that it had sought permission to deactivate in its 2022 IRP.[107] Specifically, GPC plans to extend the operation of Bowen Units 1–2 through 2035 (Units 3–4 already have 2035 retirement dates),[108] and delay the retirement of Scherer 3[109] as well as Gaston Units 1–4 and Unit A beyond 2028.[110] Scherer 3 and the Gaston Units all had 2028 retirement dates approved in the Company's 2022 IRP.[111]

[107] Georgia Power Company. 2022. *2022 Integrated Resource Plan*. Docket No. 44160. Page 12; GPC 2023 IRP Update at 27.

[108] GPC 2023 IRP Update at 26-27; Supplemental GPC Response to STF-JKA-2-2, Supplemental Attachment B, attached as Exhibit DG/LM-21.

[109] GPC 2023 IRP Update at 27.

[110] *Id*.; Supplemental GPC Response to STF-JKA-2-2, Supplemental Attachment B.xls, attached as Exhibit DG/LM-21.

[111] GPC 2023 IRP Update at 27.

Table 6. Updated retirement plans for GPC's gas and coal plants

Plant Name	GPC share (MW)	Resource type	Owner	Previous retirement Plan	Proposed retirement date
Bowen Units 1–2	1,538	Coal	GPC	2027	2035
Bowen Units 3–4	1,878	Coal	GPC	2035	2035
Scherer 3	682.5	Coal	GPC	2028	Beyond 2028
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gaston Units 1–4	460	Gas Steam	GPC	2028	Beyond 2028
Gaston Unit A	10	CT	GPC	2028	Beyond 2028
Plant Daniel Unit 2	500	Coal	MPC (PPA)	2027	Beyond 2027
Plant Watson Unit 4	250	Gas Steam	MPC (PPA)	2023	Beyond 2027

Source: See text.

Q Is the Company considering [redacted]?

A [redacted] As part of the 2023 IRP Update original filing, GPC stated that it was negotiating a potential option to acquire an additional ownership interest in an existing asset within the Southern Company Footprint.[112] GPC didn't reveal publicly what that asset is, but in a trade secret appendix the Company revealed that it is [redacted]

[112] Direct Testimony of Grubb, Valle, Evans, and Bush on behalf of Georgia Power Company. Page 41.

[113] GPC 2023 IRP Update, TS Technical Appendix, Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generation Asset.

[redacted].[114] GPC stated that parties could not come to an agreement at this time, but that the Company will continue to explore other options.[115] Additionally, as discussed above, by signing the PPA with MPC, GPC is extending the life of Plant Daniel.

Q Does the Company plan to construct additional gas capacity?

A Yes. As shown in Table 7 below, in all scenarios in the Resource Mix Study, GPC builds between 8.4 and 10.9 GW of new gas capacity.[116] GPC modeled six scenarios, three of which vary fuel costs: moderate fuel costs (MG0), high fuel costs (HG0), low fuel costs (LG0). The remaining three scenarios examine carbon prices: $20 per ton carbon price (MG20), $50 per ton carbon price (MG50), and an emissions limit (EL). Figure 2 shows GPC's total winter firm capacity in the MG0 scenario; the majority of the Company's firm capacity comes from oil and gas. Additionally, by signing the PPA with MPC, GPC is extending the life of the Plant Watson gas plant.

[114] *Id*.

[115] Direct Testimony of Grubb, Valle, Evans, and Bush on behalf of Georgia Power Company. Page 41.

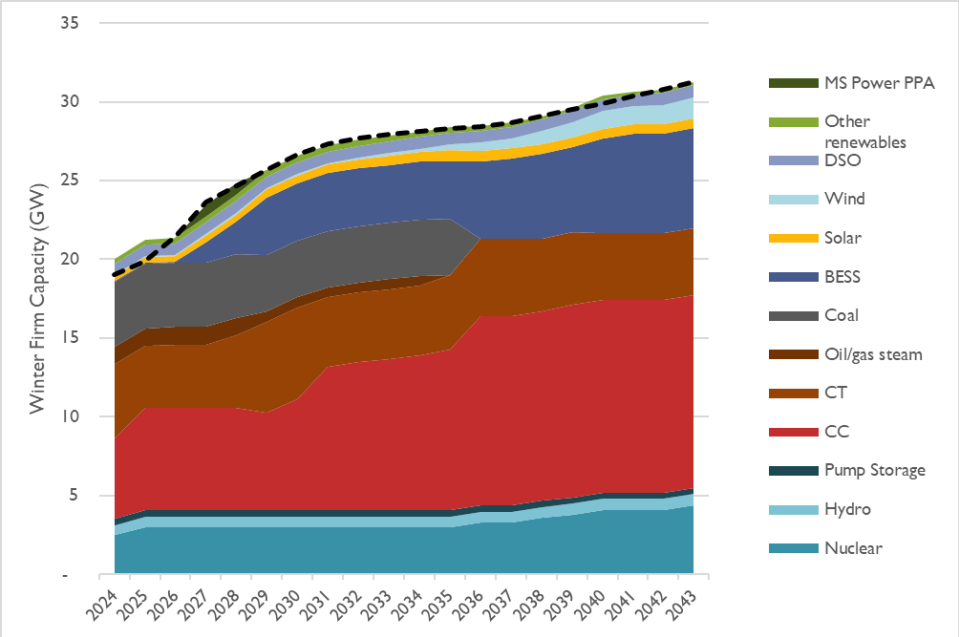
[116] GPC 2023 IRP Update Supplementary Filing Errata 12-7-23 PD, PD Capacity Expansion Plans Supp – Errata.xlsx.

Table 7. Nameplate capacity of cumulative resource additions from the Resource Mix Study in megawatts (GPC only)

	LG0	MG0	HG0	MG20	MG50	EL
Gas	10,860	10,440	8,430	9,390	10,710	9,930
Combined cycle	7,920	8,040	7,890	3,990	900	600
Combined cycle with CCS	30			3,900	7,800	8,220
Combustion turbine	2,910	2,400	540	1,500	2,010	1,110
Nuclear	960	1,410	2,100	2,130	1,950	1,860
Short-duration storage	4,920	6,810	6,270	7,830	8,640	11,190
Medium-duration storage	1,620		300	60	-	-
Solar	10,860	11,610	11,610	11,550	11,520	16,470
Wind	3,330	3,870	5,370	5,700	5,940	5,160

Source: GPC 2023 IRP Update Supplemental Filing Errata 12-7-23, PD Capacity Expansion Plans Supplemental - Errata.xlsx.

Figure 2. Capacity expansion plan for GPC from Resource Mix Study, Scenario MG0 (winter firm capacity)



Source: GPC response to STF-JKA-2-2, Attachment C.xlsx.
Note: Figure breaks out both owned and purchased generating capacity by resource type rather than showing purchased capacity as a separate category.

Q How do resource additions in the high carbon price (MG50) scenario differ from resource additions in the MG0 scenario?

A The largest difference between the two scenarios is that in the MG50 scenario, GPC builds 7.8 GW of gas CC capacity with CCS, while in the MG0 scenario the model builds traditional CC plants with no CCS. Also, in the MG50 scenario, GPC builds 1.8 GW of short-duration BESS and 2.1 GW of wind incremental to what it builds in the MG0 scenarios.

ii. GPC's plan to continue relying on coal, gas, and oil is risky for ratepayers

Q What risks is the Company exposing ratepayers to from its planned expanded dependance on coal, gas, and oil?

A GPC's intention to maintain and expand its portfolio of gas, oil, and coal resources exposes its ratepayers to fuel price volatility and the potential for sizeable additional expenses from proposed and upcoming federal legislation (if finalized), including the 2023 Effluent Limitations Guidelines (ELG) Rule and greenhouse gas regulations under Section 111 of the *Clean Air Act*.

Q Explain the risks posed to ratepayers by fuel price volatility.

A High reliance on gas resources can expose ratepayers to fuel price volatility for which ratepayers cannot plan. Gas is a global commodity, which means that both domestic and global market forces can impact the price and demand for the resource. After roughly doubling from 2019 to 2022, North American liquid natural gas export capacity is projected to double again by 2027, from current levels to

more than 24 billion cubic feet per day.[117] To put this in perspective, US total gas consumption in 2022 averaged rough 88 billion cubic feet per day.[118] The global market consumption effect on prices in the United States will continue to increase significantly over even just the next few years.

When the market is constrained and prices spike, those costs are passed on directly to ratepayers. For example, DTE Electric Company in Michigan just filed its 2022 Fuel Reconciliation Docket and noted that gas spending was 74 percent higher than planned. These higher-than-expected prices resulted in large part from the Russian invasion of Ukraine, and European gas customers turning increasingly to U.S. gas. As a result, DTE is requesting to recover an additional $154 million for 2022 fuel costs alone.[119] Absent action from the Michigan Commission, DTE and its shareholders are not impacted by these gas price spikes—these costs are entirely passed on to ratepayers. The same phenomenon could happen just as easily in Georgia or elsewhere in the Southeast. GPC should take this into account in its IRP modeling, and in planning its future resource mix.

Q What other risks does GPC face from reliance on gas resources?

A As discussed above, firm gas pipeline capacity is constrained in GPC's service area. That means that unless an expensive new pipeline is built, the Company does not

[117] Victoria Zaretskaya and Max Ober, U.S. Energy Information Administration, "LNG export capacity from North America is likely to more than double through 2027," (Nov. 13, 2023), available at: https://www.eia.gov/todayinenergy/detail.php?id=60944.

[118] U.S. Energy Information Administration, "Natural Gas Consumption by End Use," (Oct. 2023) available at: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a htm.

[119] DTE Elec. Co. 2023. *Exhibit A-7.* Mich. Pub. Serv. Comm'n Docket No. E-21051. March 31, 2023.

have a firm source of gas to supply new gas resources. Any new gas resource without a firm supply of fuel is not actually a firm resource unless it can also operate on oil. As discussed above, operation on oil is [redacted] times more expensive, dirty, and overall a bad long-term strategy—especially when there are cost-effective, lower-cost, and lower-risk alternatives.

Q What risks does GPC face from continued, and even [redacted], reliance on coal assets?

A The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[120] There have also been labor challenges both at the mines and the railroad companies that transport the coal, as coal workers demand better pay and have more options in the labor market. Additionally, as more and more coal plants across the United States retire and the demand for coal contracts, this combined with the labor challenges could result in consolidation among coal companies and subsequently higher prices.[121]

Coal use was down in 2023 and never reached more than 20 percent of power market share (through October). This is novel because market share had been around 20 percent each month between 2020–2022; and prior to 2020, coal had

[120] U.S. Energy Information Administration, "Coal Markets." Available at https://www.eia.gov/coal/markets/.

[121] Duke Energy. "Coal Retirement Analysis," available at: https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-f-coal-retirement-study.pdf?rev=4c1c4df441a14248b2e23ba0368d9855.

never comprised less than 20 percent market in any month.[122] Additionally, risks from increased environmental regulation, as we will discuss next, could result in higher costs and higher risks. Higher risk impacts not just resource planning economics but company risk profiles which can lead to downgraded credit ratings, and that can impact access to capital.

Q Explain the proposed 2023 ELG Rule and its impact on the Bowen and Scherer coal plants.

A The proposed 2023 ELG Rule strengthens the discharge standards for three types of wastewater produced by coal-fired units: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate.[123] If the rule is finalized, GPC could incur costs at Bowen for two flue gas desulfurization measures (a membrane-based wastewater treatment system and a zero-liquid discharge system) and a wastewater treatment system for combustion residual leachate.[124] Similarly, Scherer could require retrofits to improve its treatment of combustion residual leachate.[125] GPC estimates that a membrane-based flue gas

[122] Institute for Energy Economics and Financial Analysis, "Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024," (Nov. 2, 2023), available at: https://ieefa.org/resources/coal-use-us-power-plants-continues-downward-spiral-full-impact-mines-be-felt-2024.

[123] 88 Fed. Reg. 18824 (Mar. 29, 2023).

[124] GPC Response to STF-PIA-10-6, attached as Exhibit DG/LM-22.

[125] *Id*.

desulfurization system at Bowen would cost approximately $580 million but does not yet have estimates for the costs of the other retrofits.[126]

Q Explain the recently proposed Section 111 Rules and their impact on both existing and new fossil resources.

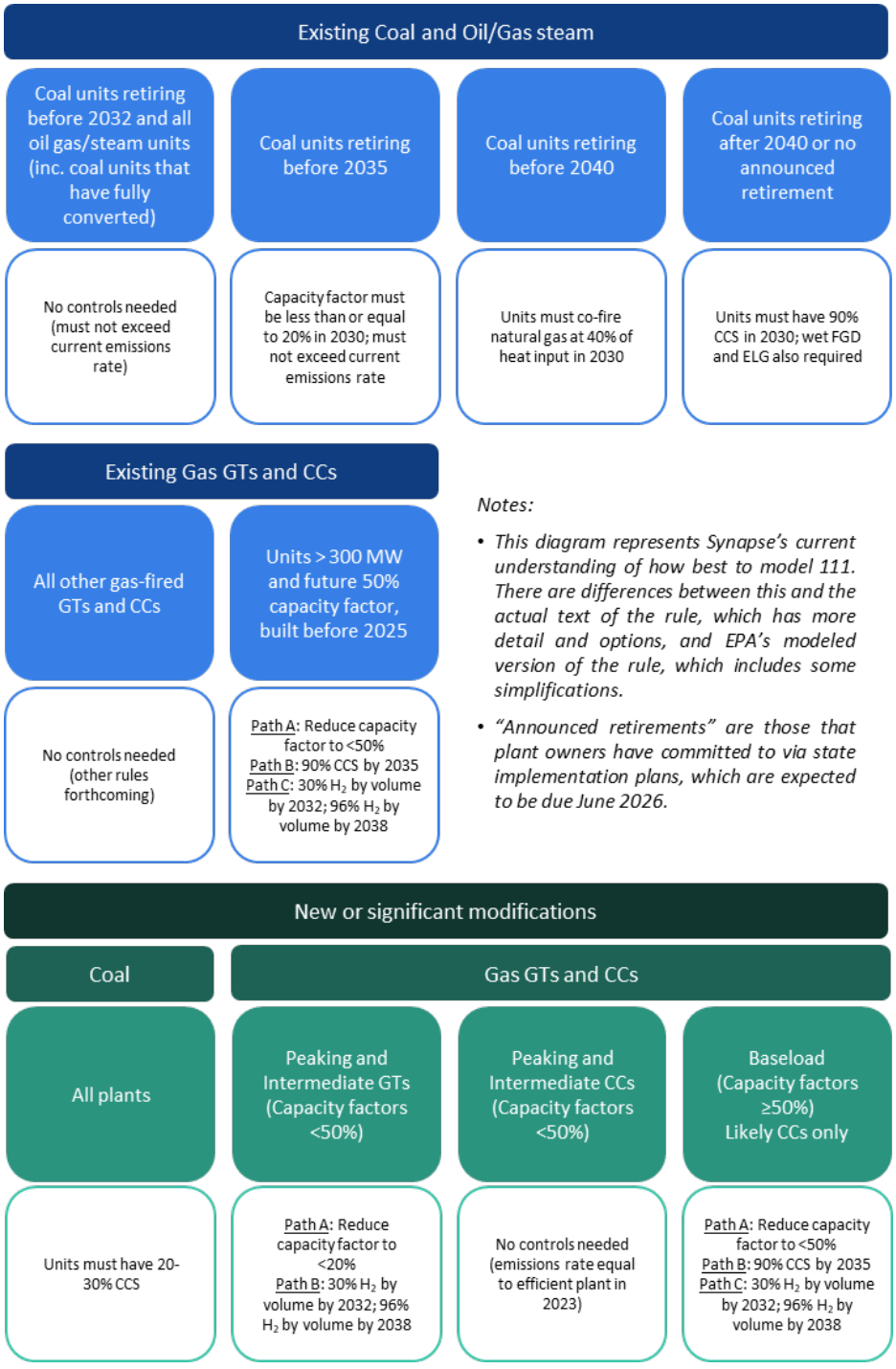
A The proposed Section 111 Rules apply to both coal- and gas-fired units, existing and new, and provide several pathways for compliance (Figure 3).[127] These pathways differ based on: (1) whether the unit is coal or gas; (2) whether the unit is existing or new; (3) how much the unit runs; and (4) when the unit is scheduled to retire. GPC does not include any new coal in its Resource Mix Study, so the Section 111 Rules would apply only to its existing coal, existing gas, and new gas resources. Importantly, if GPC were to acquire [redacted] as it contemplated in its original 2023 IRP Update filing,[128] the Section 111 Rules would apply to those units as well. Additionally, even though the PPA with MPC currently ends in 2028, if GPC were to try and extend it, beyond 2032 MPC would be obligated to comply with the proposed rules at Plant Daniel and Plant Watson.

[126] *Id*.

[127] 88 Fed. Reg. 33240 (May 23, 2023).

[128] GPC 2023 IRP Update, Technical Appendix, TS Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generation Asset.

Figure 3. Synapse's understanding of EPA's proposed Section 111 Rules



Q Did GPC incorporate the proposed Section 111 Rules in its Resource Mix Study?

A No. The Company did not explicitly model the proposed Section 111 Rules, stating that "a compliance evaluation cannot be completed at this time, because uncertainty remains in the compliance options and requirements for existing facilities until the development of the Georgia state plan required by the rule."[129] GPC did model three carbon pressure scenarios (see Table 7 above). Regardless of uncertainty around the rule's final form, GPC should have conducted a model sensitivity run at the very least to understand how the rule would impact its current resource plan. Failing to plan for a proposed regulation doesn't make it less likely to be finalized, but it does make GPC less likely to be prepared to comply.

Q How will the Section 111 Rules impact each of GPC's fossil fuel power plants, including their planned retirement dates and operational decisions?

A If the proposed Section 111 Rules are finalized, Georgia Power will need to adjust its plans for its coal and gas units as shown in Table 8 below. It is simply not economic for GPC to maintain its current plan at each plant if the proposed rule is finalized.

Bowen and Scherer 1 and 2 coal plants are currently scheduled to retire in 2035.[130] These units will need to be retrofitted to co-fire with natural gas starting in 2030 if

[129] GPC Response to STF-PIA-10-7, attached as Exhibit DG/LM-23.

[130] GPC 2023 IRP Update at 27; Supplemental GPC Response to STF-JKA-2-2, Supplemental Attachment B, attached as Exhibit DG/LM-21.

they are to stay online through 2035. But if the retirement dates were shifted earlier, to 2032, they do not need to do anything to comply with the proposed Section 111 Rules. This would allow them to avoid costly investments for conversion to co-fire on gas. Scherer 3 and Gaston 1-4 will not be required to take any compliance actions unless GPC extends their retirement dates to 2032 or beyond. Any existing and new CC units will have to cap their capacity factors at 50 percent starting in 2032 or else install 90 percent CCS by 2035, or co-fire with hydrogen starting in 2032. It is most likely that limiting utilization to a 50 percent capacity factor will be the most economic compliance option.

Table 8. Section 111 compliance options at GPC's coal- and gas-fired power plants based on current retirement dates

Power Plant	Type	Retirement Date (EOY)	111 Compliance Options
Bowen Units 1–4	Coal	2035	Co-fire natural gas at 40% starting in 2030
Scherer Units 1–2	Coal	2035	Co-fire natural gas at 40% starting in 2030
Scherer Unit 3	Coal	2028	No action required unless GPC delays retirement beyond 2032
Gaston Units 1–4	Gas Steam	2028	No action required unless GPC delays retirement beyond 2032
Yates Units 6–7	Gas Steam	2034	Capacity factor limit of 20% starting in 2030
Existing CCs	CC	Various	Reduce capacity factor to under 50% starting 2032, 90% CCS by 2035, 30% H_2 by 2032 and 96% H_2 by 2038
New CCs	CC	None	Reduce capacity factor to under 50% starting 2032, 90% CCS by 2035, 30% H_2 by 2032 and 96% H_2 by 2038
Existing CTs	CT	Various	No action required
New CTs	CT	None	20% capacity factor limit or 30% H_2 by 2032

Q Has GPC adequately considered the risks posed by the proposed Section 111 Rules in its planning?

A No. GPC stated in discovery that it did not include any assumptions regarding the proposed Section 111 rules in the 2023 IRP Update.[131] GPC should add a scenario to its Resource Mix Study that fully analyzes compliance with the proposed Section 111 Rules. Even if the there is uncertainty about some details of the rule, the Company needs to start understanding the likely impacts of Section 111 now so that it can begin positioning itself for future compliance, rather than investing in assets that will require either expensive retrofits or capacity factor limits within a few years. Given that neither CCS nor hydrogen blending are currently demonstrated at scale, capacity factor limits may be the preferable method for most covered resources to comply with the Section 111 Rules in the near term. This could significantly alter GPC's long-term planning for both existing fossil plants and new build plants.

Q Do GPC's carbon pressure scenarios provide insight into the costs that the Section 111 Rules could impose on the Company?

A No. These scenarios provide minimal insight into the potential impact of the Section 111 Rules on the Company, contrary to GPC's claim that "the implications of a final EPA 111 rule are captured within the range of carbon pressure scenarios included in the 2023 IRP Update."[132] The Company only included very limited

[131] GPC Response to STF-PIA-7-4, attached as Exhibit DG/LM-24.
[132] *Id*.

potential compliance pathways in its modeling, it also did not account for the risk associated with nascent CCS technologies, and it has not analyzed the impacts of the Section 111 Rules on existing units such as Bowen and Scherer.

The carbon pressure scenarios rely on large buildouts of CC with CCS (3.9–8.2 GW).[133] CCS is expensive, and the cost is even more unknown given that there are no operational gas plants with CCS currently existing in the United States to look to as data points.[134]

Q Explain the risks associated with CCS that GPC has not captured in its modeling.

A The biggest risk with CCS is cost over-runs. While the 45 (q) tax credit appears lucrative, the level of uncertainty around the cost is much greater than for existing non-emitting technologies like solar and storage, and thus, and thus not accurately captured in the Company's analysis. CCS technology has not been deployed at scale yet, so cost estimates are likely to be wrong. And given how expensive CCS projects are, that could mean hundreds of millions to even billions in underestimated costs. It is also worth noting that, given Southern Company's experience with gasification and carbon capture at the Kemper Project, it is concerning that the Company is considering jumping back into another carbon

[133] GPC 2023 IRP Update Supplementary Filing Errata 23-7-23 PD, PD Capacity Expansion Plans Supp – Errata.xlsx.

[134] Schlissel, D. *Carbon Capture from Coal Plants: A Step in the Wrong Direction* (2021). Institute for Energy Economics and Financial Analysis.

capture project. The Kemper project cost escalated to an estimated three times its initial project estimate (from $2.5 billion to $7.5 billion)[135] before the Mississippi Commission ultimately pulled the plug on the project and ordered MPC to continue to operate the plant on just natural gas.[136] MPC demolished the gasification infrastructure in dramatic fashion in 2021.[137] There is no guarantee that if GPC attempted another project of this magnitude, it would not face similar cost challenges.

There is also uncertainty surrounding the level of performance that CCS equipment will achieve. Since plants must achieve at least 90 percent carbon capture to be eligible for the tax credit and to satisfy the Section 111 Rules, this makes CCS a risky strategy for compliance.

Q Are there steps that GPC should take now to avoid future expense and risk from exposure to fuel price volatility, the 2023 ELG Rule, and Section 111 Rules?

A Yes. In addition to studying compliance pathways in its Resource Mix Study, GPC should take steps to procure renewables and battery storage as rapidly as possible, with a particular focus on capacity from the market, as we discuss in more detail below. Only once it has exhausted its ability to economically procure BESS and solar PV (paired and stand-alone) through issuing All-Source RFPs to the market

[135] Kristi Swartz, "Southern Co.'s clean coal plant hits a dead end," EnergyWire (June 22. 2027), available at https://subscriber.politicopro.com/article/eenews/1060056418.

[136] Kristi Swartz, *The Kemper project just collapsed. What it signifies for CCS.* EnergyWire, October 2021, available at https://www.eenews net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/.

[137] *Id*.

and rousting evaluating self-build costs and options, should it turn to other resource options.

iii. GPC needs to plan proactively going forward by issuing All-Source RFPs and requesting Commission approval for new resources far enough in advance to allow for consideration of alternatives

Q Is the Company planning far enough ahead to allow for adequate Commission oversight?

A No. GPC's failure to account for upcoming load growth in its 2022 IRP means that it is now too late to bring most new resources online before the shortfall begins in winter 2025/2026. This has limited the Commission's ability to effectively oversee GPC's resource planning decisions in this docket. Furthermore, the resources that the Company proposes in the 2023 IRP Update are stopgap solutions that resolve its capacity shortfall only through the winter of 2027/2028.[138] If GPC experiences the full amount of load growth that it currently projects, this pattern may well continue with GPC's 2025 IRP. If the Company does not ramp up its evaluation and procurement of new resources by issuing All-Source RFPs and evaluating self-build options for BESS and solar PV, by the time GPC files the 2025 IRP, it will again be too late to procure most types of new resources before the next capacity shortfall.

[138] GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B, attached as Exhibit DG/LM-21.

GPC's failure to plan for resource retirement and replacement beyond the next few years has the effect of locking ratepayers into decisions the Company has made, even ones that have not yet been approved or considered by the Commission. GPC limits the Commission's ability to effectively oversee its resource planning decisions by delaying resources decisions until the timing eliminates any real choice.

Q Give a specific example of GPC's incremental decision-making forcing the Commission's hand.

A The Company declined to address the possible extension in Scherer 3 and Gaston 1–4 in this IRP Update,[139] despite the fact that their scheduled retirement in 2028 is only four years away.[140] By the time of the next IRP in 2025, there will be even less time to procure alternate resources in lieu of extending these units. On average, the Company estimates that it takes [redacted] to construct new solar capacity and [redacted] to construct new battery storage, not including time to conduct an RFP.[141] Given that the Company is aware of these construction timelines, its consistent pattern of leaving less time than this to procure replacement resources is poor planning that the Commission should require GPC to correct.

[139] GPC 2023 IRP Update at 27; GPC 2023 IRP Update, TS Technical Appendix, TS Technical Information Supporting the Potential Acquisition of Additional Ownership in an Existing Generation Asset.
[140] GPC Response to STF-JKA-2-8, attached as Exhibit DG/LM-25.
[141] GPC Response to TS STF-PIA-10-1, attached as Exhibit DG/LM-19.

Q How should GPC change its planning in the future?

A Battery storage, solar, and wind provide low-cost capacity and energy, but siting and constructing these resources takes time. As a result, just-in-time resource planning is increasingly inadequate to meet the needs of ratepayers now and will likely become even more so over the next decade and beyond. This is especially true given that GPC needs to meet load growth from new businesses moving into Georgia, many of which have clean energy goals. To adapt to changing paradigms in the power sector—including broad-scale decarbonization—GPC should recognize the energy value of renewables and push to bring renewables online on a rolling basis and whenever they are economically available, rather than trying to align resource additions perfectly with capacity needs. GPC should be sure that its next RFP is All-Source (open to all resources) and that it communicates to the market that GPC is seeking as much BESS and solar as possible. The Company should also evaluate its own ability to self-build BESS and solar PV.

Early renewable procurement will ensure that GPC can procure sufficient replacement resources without suspending RFP procedures, as it requests in the 2023 IRP Update. This approach will save ratepayers money. It will also help GPC keep pace with national policy development, and it will give the Company an opportunity to learn how to manage a system with a high level of renewable penetration, providing a safety net for system reliability.

Q Does this conclude your testimony?

A Yes.

Appendix A: List of Exhibits

DG-1 ..... Devi Glick Resume
LM-1 ..... Lucy Metz Resume
DG/LM-1 ..... GPC Response to STF-DEA-1-5
DG/LM-2 ..... GPC Response to PD STF-JKA-2-22
DG/LM-3 ..... GPC Response to TS STF-PIA-7-15, TS Attachments A-P
DG/LM-4 ..... GPC Response to TS STF-JKA-2-19, Attachment B
DG/LM-5 ..... GPC Response to PD STF-JKA-6-5
DG/LM-6 ..... GPC Response to PD STF-JKA 4-10
DG/LM-7 ..... GPC Response to PD STF-JKA-2-20
DG/LM-8 ..... GPC Response to STF-JKA-4-19
DG/LM-9 ..... GPC Response to PD STF-JKA-6-7
DG/LM-10 ..... GPC Response to TS STF-PIA-10-3
DG/LM-11 ..... GPC Suppl. Response to STF-JKA-2-2
DG/LM-12 ..... GPC Response to TS STF-DEA-3-6, Attachment G
DG/LM-13 .. GPC Suppl. Response to TS STF-DEA-3-6, Suppl. Attachment G
DG/LM-14 ..... GPC Response to STF-JKA-2-14
DG/LM-15 ..... GPC Response to STF-JKA-3-10
DG/LM-16 ..... GPC Response to STF-JKA-2-2, Attachment C
DG/LM-17 ..... GPC Response to STF-JKA-4-14
DG/LM-18 ..... GPC Response to STF-JKA-2-11, Attachment F
DG/LM-19 ..... GPC Response to TS STF-PIA-10-1
DG/LM-20 ..... GPC Response to PD STF-JKA-1-4
DG/LM-21 ..... GPC Suppl. Response to STF-JKA-2-2, Suppl. Attachment B
DG/LM-22 ..... GPC Response to STF-PIA-10-6
DG/LM-23 ..... GPC Response to STF-PIA-10-7
DG/LM-24 ..... GPC Response to STF-PIA-7-4
DG/LM-25 ..... GPC Response to STF-JKA-2-8

DG-1:
Devi Glick Resume

Devi Glick, Senior Principal

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Kwok, S., D. Glick, R. Anderson, T. Gyalmo. 2023. *Review of Southwestern Public Service Company 2023 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Kwok, S., J. Smith, D. Glick. 2023. *Review of Cleco Power's 2021 IRP Report.* Synapse Energy Economics for Sierra Club.

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, J. Hall, A. Takasugi. 2021. *A Clean Energy Future for MidAmerican and Iowa.* Synapse Energy Economics for Sierra Club, Iowa Environmental Council, and the Environmental Law and Policy Center.

Glick, D., S. Kwok. 2021 *Review of Southwestern Public Service Company's 2021 IRP and Tolk Analysis.* Synapse Energy Economics for Sierra Club.

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Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

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Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

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Public Service Commission of South Carolina (Docket No. 2023-154-E): Supplemental Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. January 29, 2024.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Surrebuttal Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. November 17, 2023.

Public Utilities Commission of Ohio (Case No. 21-477-EL-RDR): Direct Testimony of Devi Glick in the Matter of the OVEC Generation Purchase Rider Audits Required by 4928.148 for Duke Energy Ohio, Inc. the Dayton Power and Light Company, and AEP Ohio. On behalf of Union of Concerned Scientists and the Citizens Utility Board. October 10, 2023.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Direct Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. September 22, 2023.

Public Utilities Commission of Ohio (Case No. 20-165-EL-RDR): Direct Testimony of Devi Glick in the matter of the review of the Reconciliation Rider of the Dayton Power and Light Company. On behalf of Office of the Ohio Consumers' Counsel. September 12, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00066): Direct Testimony of Devi Glick in re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Virginia Code to §56-597 *et seq.* On behalf of Sierra Club. August 8, 2023.

Public Utility Commission of Texas (PUC Docket No. 54634): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. August 4, 2023

Arizona Corporation Commission (Docket No. E-1345A-22-0144): Surrebuttal Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. July 26, 2023.

Arizona Corporation Commission (Docket No. E-01345A-22-0144): Direct Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. June 5, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00005): Direct Testimony of Devi Glick in the Petition of Virginia Electric & Power Company for revision of rate adjustment clause, Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 23, 2023.

New Mexico Public Regulation Commission (Case No, 22-00286-UT): Direct Testimony of Devi Glick in the matter of Southwestern Public Service Company's application for: (1) Revisions of its retail rates under advance no. 312; (2) Authority to abandon the Plant X Unit 1, Plant X Unit 2, and Cunningham Unit 1 Generating Stations and amend the abandonment date of the Tolk Generating Station; and (3) other associated relief. On behalf of Sierra Club. April 21, 2023.

Michigan Public Service Commission (Case No. U-20805): Direct Testimony of Devi Glick in the matter of the Application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2021. On behalf of Michigan Attorney General. April 17, 2023.

Michigan Public Service Commission (Case No. U-21261): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval to implement a Power Supply Cost Recovery Plan for the twelve months ending December 31, 2023. On Behalf of Sierra Club. March 23, 2023.

New Mexico Public Regulation Commission (Case No. 19-00099-UT / 19-00348-UT): Direct Testimony of Devi Glick in the matter of El Paso Electric Company's Application for Approval of Long-Term Purchased Power Agreements with Hecate Energy Santa Teresa, LLC, Buena Vista Energy, LLC, and Canutillo Energy Center LLC. On Behalf of New Mexico Office of the Attorney General, January 23, 2023.

Arizona Corporation Commission (Docket No. E-01933A-22-0107): Direct Testimony of Devi Glick in the matter of the application of Tucson Electric Power Company for the establishment of just and

reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona for related approvals. On Behalf of Sierra Club. January 11, 2023.

New Mexico Public Regulation Commission (Case No. 22-00093-UT): Direct Testimony of Devi Glick in the amended application for approval of El Paso Electric Company's 2022 renewable energy act plan pursuant to the renewable energy act and 17.9.572 NMAC, and sixth revised rate no. 38-RPS cost rider. On Behalf of New Mexico Office of the Attorney General, January 9, 2023.

Iowa Utilities Board (Docket No. RPU-2022-0001): Supplemental Direct and Rebuttal Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. November 21, 2022.

Public Utility Commission of Texas (PUC Docket No. 53719): Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilities Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential

increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Reply to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Public Utility Commission of Texas (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Resume updated August 2023

LM-1:
Lucy Metz Resume

Lucy Metz, Associate

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lmetz@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Associate* April 2023 – Present; *Research Associate,* July 2022 – April 2023

- Consults on energy-sector issues, including building decarbonization, electric utility resource planning, state and local climate policy, and the future of gas
- Supports the development of comments and testimony in integrated resource planning dockets across the country
- Conducts analysis using Synapse's Building Decarbonization Calculator (BDC), a stock turnover model that calculates the emissions and energy impacts of heat pump adoption
- Produces data visualization tools in R, including interactive webtool of U.S. industrial emitters
- Assists with power sector dispatch modeling using EnCompass
- Co-developer of Synapse spreadsheet model comparing the lifetime cost and performance of district geothermal systems and air-source heat pumps across a variety of climate zones

Laboratory of Dr. Alexander Barron, Department of Environmental Science and Policy, Smith College, Northampton, MA. *Research Assistant*, June 2020 – May 2022

- Co-authored paper on carbon neutrality initiatives in higher education
- Designed data visualization and analysis for USREP-ReEDS modeling of Clean Air Act policy
- Calculated CO_2 emissions reductions achievable under Massachusetts climate legislation and drafted white paper with results

Co-Equal, Washington, D.C. *Policy Intern*, February 2021 – March 2022.

- Performed analysis on a wide range of policy topics requested by members of Congress
- Finalized economic modeling study for public release and presented results
- Coordinated with research team at MIT and Co-Equal to meet policy-relevant deadlines

EDUCATION

Smith College, Northampton, MA
Bachelor of Science in Engineering Science, *Magna Cum Laude with Highest Honors*, 2022

SKILLS

Computer: Excel, R, EnCompass, MATLAB, Mathematica, ENERGY STAR Portfolio Manager

Languages: Spanish (proficient)

PUBLICATIONS

Eash-Gates, P., **L. Metz**, K. Schultz, S. Kwok, A. Hopkins. *Connecticut Comprehensive Energy Strategy: Buildings White Paper*. Prepared by Synapse Energy Economics for Connecticut Department of Energy and Environmental Protection. Forthcoming.

Synapse Energy Economics and Connecticut Department of Energy and Environmental Protection. "Buildings and Industry." In *Connecticut 2023 Comprehensive Energy Strategy*. Forthcoming.

Eash-Gates, P., **L. Metz**, S. Kwok, K. Schultz, K. Takahashi. *Pathways for Connecticut Building Decarbonization: Analysis of Thermal Decarbonization Scenarios Aligned to the Global Warming Solutions Act.* Prepared by Synapse Energy Economics for Connecticut Department of Energy and Environmental Protection. Forthcoming.

Metz, L., A. Napoleon, P. Eash-Gates. *Memo: Equity Metrics for Building Thermal Decarbonization in Connecticut.* Prepared by Synapse Energy Economics for Connecticut Department of Energy and Environmental Protection. Forthcoming.

Metz, L., E. Carlson, O. Griot. 2023. *Methane Waste and Pollution State Factsheets.* Synapse Energy Economics for the Environmental Defense Fund.

Eash-Gates, P., O. Griot, A. Hopkins, **L. Metz**, E. Sinclair, J. Smith. 2023. *Coming Clean on Industrial Emissions: Challenges, Inequities, and Opportunities in U.S. Steel, Aluminum, Cement, and Coke.* Prepared by Synapse Energy Economics for Sierra Club.

Frost, J., P. Knight, S. Sharaf, **L. Metz**, and S. Kwok. 2023. *RGGI's Economic Benefits for Pennsylvania: Exploring the benefits of the Regional Greenhouse Gas Initiative.* Prepared by Synapse Energy Economics for Evergreen Collaborative.

Metz, L., M. Whited, P. Rhodes, E. Carlson. 2023. *Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification.* Synapse Energy Economics for the Environmental Defense Fund.

Knight, P., J. Frost, T. Fitch, E. Sinclair, J. Tabernero, O. Griot, B. Havumaki, J. Smith, **L. Metz**, S. Chavin. 2023. *TVA's Clean Energy Future: Charting a course to decarbonization in the Tennessee Valley.* Synapse Energy Economics for GridLab and Center for Biological Diversity.

Yuan, M., A. Barron, N. Selin, P. Picciano, **L. Metz**, J. Reilly, and H. Jacoby. 2022. "Meeting U.S. greenhouse gas emissions goals with the international air pollution provision of the Clean Air Act." *Environmental Research Letters* 17 (5): 054019.

Barron, A., M. Domeshek, **L. Metz**, L. Draucker, and A. Strong. 2021. "Carbon neutrality should not be the end goal: Lessons for institutional climate action from U.S. higher education." *One Earth* 4 (9): 1248–1258.

Longnecker, E., **L. Metz**, R. Miller, and A. Berke. 2021. “Probing Liquid–Liquid Phase Separation in Secondary Organic Aerosol Mimicking Solutions Using Articulated Straws.” *ACS Omega* 6 (49): 33436–33442.

Figueroa, L., M. Blinder, C. Grincavitch, A. Jelinek, E. Mann, L. Merva, **L. Metz**, A. Zhao, R. Irwin, S. McArt, and L. Adler. 2019. “Bee pathogen transmission dynamics: Deposition, persistence and acquisition on flowers.” *Proceedings of the Royal Society B*, 286: 20190603.

Resume updated February 2024

DG/LM-1:
GPC Response to STF-DEA-1-5

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF- DEA-1-5

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF- DEA-1-5 ("Response"). In the Response, the Company has provided an additional load forecast sensitivity. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive commercial and strategic information related to Georgia Power's projected load forecasts and corresponding short- and long-term capacity needs. The Information includes the Company's short- and long-term forecast estimates and impacts, competitive choice opportunities, and capacity need estimates. Public dissemination of the Information would allow Georgia Power's competitors, suppliers, and customers access to the Company's anticipated load strategies and objectives, thereby bestowing insight into the Company's strategic initiatives and forecasting capabilities. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can structure their offers for competitive choice opportunities based on the Information rather than their own costs, capacity, abilities, strategies, or analysis. Any sensitive budgetary Information, if disseminated, would provide insight to competitors regarding the Company's financial positions, performance, and status. Further, prospective bidders may artificially set bid prices based on the Information to their advantage, preventing the Company from securing the best cost resources for customers.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-DEA-1-5

Question:

Refer to the 2023 IRP Update Load and Energy Forecast, p. 3, noting that the analysis of the economic development loads use a P95 load value.

a. Please explain why GPC decided on a P95 load value rather than a P50 or other level. How does GPC incorporate risk of over-supply in the decision-making?
b. Please provide the P50 and P75 forecast of economic development loads.
c. Please provide an updated load forecast and annual capacity balancing using the P50 and P75 values provided in response to part (b).

Response:

a. Georgia Power selected a P95 load value in response to the unprecedented pace of economic development in the state of Georgia and because the Company has seen more increases in large projects interested in the state over the last several months than decreases. The P95 value establishes an upper limit for potential large load outcomes, offering a heightened level of load realization that is expected to benefit all customers and additional capacity resources to accommodate potential load increases in the ongoing economic development pipeline. Considering the uncertainty surrounding future growth, the Company opted for the P95 load value to ensure sufficient capacity to meet the anticipated loads and continue to support economic development in Georgia and to benefit all customers.

   Regarding the risk of over-supply, the Company consistently takes measures to sell any capacity above the target reserve margin in the wholesale market. For instance, the power purchase agreement ("PPA") with Mississippi Power Company has already been sold to another regional supplier for 2024 and 2025 since those years are prior to the Company's year of need as identified in the 2023 IRP Update.

b. Please refer to TS STF-DEA-1-5 Attachment A for the P50 forecast of economic development loads. Georgia Power has not created a P75 forecast of economic development loads; therefore, one cannot be provided.

c. Please refer to STF-DEA-1-5 Attachment B for the P50 load forecast and annual capacity balancing. A P75 load forecast and annual capacity balancing cannot be provided since Georgia Power did not create a P75 forecast of economic development loads.

Contact: Francisco Valle

DG/LM-2:
GPC Response to PD STF-JKA-2-22

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-22

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-22 ("Response"). In the Response, the Company has provided data supporting the economic analysis of projects proposed in the 2023 IRP Update including an acquisition with sensitive pricing and confidential details (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information includes competitively sensitive details specific to the resources under contract, proposed to be acquired or developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current or future negotiations, as counterparties may use the Information as a bargaining tool in negotiations or fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-2-22

Question:

a. Please provide all documents that serve as the basis for the cost assumptions for the Yates CTs.

b. What is the primary fuel for Yates CTs? If gas, has the Company made arrangements to obtain firm gas transportation?

c. Explain why Yates can be modeled to use natural gas while the generic CTs are modeled using oil?

d. Please provide all assumptions regarding gas deliverability to Yates, including firm transportation costs, the need to construct natural gas pipeline capacity, etc.

e. Why does page 21 state that the CTs will add between 1,000 MW and 1,400 MWs of capacity. Why isn't this statement more definitive and when will the decision about that be made? If the Company had wanted, would the Yates site support the addition of a 4th CT addition?

f. If the CTs are approved in this case, how long after that would be required for the Company to construct the CTs.

Response:

a. Please see STF-JKA-2-19 for costs the Company has already incurred. The Company remains in active negotiations on the project. These negotiations and Southern Company's recent experience building new natural gas plants informed the cost estimates for the Yates CTs. As mentioned in the "Technical Information Supporting the Proposal to Develop up to 1,400 MW from Three Simple Cycle Combustion Turbines at Plant Yates," found in the Technical Appendix to the 2023 IRP Update filing, these costs estimates are subject to change prior to the execution of an Engineering, Procurement, and Construction ("EPC") agreement. As mentioned in the Technical Appendix the Company will update the Commission upon execution of a final EPC contract and request certification of Plant Yates Units 8-10 at that time.

b. Plant Yates Units 8-10 are dual fuel units. They can operate on natural gas as available, but they are unlikely to have reliable supply of natural gas during peak winter periods without firm transportation ("FT"). No FT has been procured for these units. Therefore, these units will be supplied with oil to support continued operation during peak conditions. These units will be able to utilize gas when FT is available from other units such as the Plant Yates steam units or when interruptible pipeline transportation is available.

c. The Company modeled Plant Yates Units 8-10 assuming oil dispatch costs for the winter months. For the non-winter months, the Company assumed availability of natural gas in its economic analysis production cost modeling, which is weather normalized. Plant Yates Units 6-7 have firm gas transportation that can be utilized for Plant Yates Units 8-10 if economic. Additionally, natural gas pipelines are generally less constrained during non-winter months. This may differ from generic repeatable combustion turbines ("CT") as the available of natural gas is highly location dependent and generic CTs do not have a specific location. Please see the Company's response to STF-JKA-2-14 subpart (e) for more information on the generic CT assumption.

d. Plant Yates Units 8-10 will primarily run on fuel oil during peak winter and summer periods when the pipeline is constrained. No FT or additional gas capacity is being proposed to support these units since these units can burn oil year around. It is being proposed to build a new pipeline lateral from Transco's mainline to the plant. The new lateral would be adjacent to the existing pipeline lateral to Plant Yates from Transco.

e. The range of output capacity was used to illustrate the variance between oil and gas fired operations. Active negotiations over **REDACTED** guaranteed capacity have informed this range. The guaranteed capacity will be finalized upon execution of the final EPC contract. A fourth combustion turbine has not been evaluated for the 2023 IRP Update but could be considered in the future.

f. Under the preliminary schedule as shown in Figure 2 of the Technical Appendix for the Yates CTs, construction of the first two units will be substantially completed in 32 months with the third unit under construction for 36 months assuming a final decision for the 2023 IRP Update is obtained in April 2024. The Company has already begun activities in advance of a final decision to preserve the current timeline. Information on these activities is further described in STF-JKA-2-19, which are necessary to support engineering and procurement of critical equipment in a timely manner.

DG/LM-3:

GPC Response to TS STF-PIA-7-15, TS Attachments A-P

Fully Redacted as it Contains Trade Secret Information

DG/LM-4:
GPC Response to TS STF-JKA-2-19, Attachment B

Fully Redacted as it Contains Trade Secret Information

DG/LM-5:
GPC Response to PD STF-JKA-6-5

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-6-5

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-6-5 ("Response"). In the Response, the Company has provided assumptions and information about proposed expansion projects used in the economic analysis of the resources proposed as part of the 2023 IRP Update. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details regarding sites that are being proposed for new BESS projects. If revealed to the public, a generation wholesaler, power marketer, or original equipment manufacturer could use the Information to arbitrarily tailor proposals with the intention of pricing products and services according to the Company's expected costs, which could undermine the Company's ability to procure the best cost products and services for customers. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-6-5

Question:

Regarding the Company's Request for Information Summary, Section 2.3, the Company states, "There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027."

a. Please explain if the Company could have considered an agreement outside of an RFP process, such as an unsolicited offer.
b. Please explain how the Company was able to negotiate the Santa Rosa PPA outside of an RFP, but did not consider negotiating an agreement for any of the RFI identified projects the same way.
c. Please explain how the Company was able to negotiate the Mississippi Power agreement outside of an RFP, but did not consider negotiating an agreement for any of the RFI identified projects the same way.
d. Please explain what transmission constraints are a barrier to the ESS projects identified in the RFI, but are not a barrier to the **REDACTED** Solar + BESS projects.

Response:

a. Yes, the Company could consider an agreement outside of a Request for Proposal ("RFP") process for the potential new or planned projects that responded to Georgia Power's Request for Information ("RFI"). However, the Company would need to solicit additional information, including pricing, from such projects and evaluate the generation and transmission costs and benefits for each response to determine which projects are viable, which projects are most cost-effective, and when the Company could receive delivery from each potential project. Any transmission upgrades required by new generation resources must be identified and constructed, which can take substantial time given the current long lead times on the procurement and supply of transmission equipment. Instead, as described in the Company's response to STF-PIA-4-16(d), the Company is currently focusing its efforts on identifying existing sites where battery energy storage systems ("BESS") can be deployed and deliver energy to the transmission system prior to November 2027.

b. The Santa Rosa Energy Center was a known, existing generation asset that was identified in July 2023 as a potential resource to meet the Company's 2023 IRP Update capacity needs. Given identification in July 2023 and the fact that it is an existing asset that can meet the Company's generation needs in the 2023 IRP Update without the construction of transmission projects, the Company was able to negotiate a power purchase agreement ("PPA") with Santa Rosa Energy Center, LLC, prior to filing the 2023 IRP Update on October 27, 2023. The Company issued its RFI in September 2023 to gather market

information regarding the availability of existing and planned capacity resources for years 2026-2031. The RFI closed on October 24, 2023 and confirmed that no existing capacity resources could help meet the Company's capacity needs being addressed in the 2023 IRP Update. For potential new or planned projects, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

c. The Mississippi Power PPA consists of known, existing generation assets and was identified in July 2023 as a potential resource to meet the Company's 2023 IRP Update capacity needs. Given identification in July 2023 and the fact that it contains existing assets that can meet the Company's generation needs in the 2023 IRP Update without the construction of transmission projects, the Company was able to negotiate a PPA with Mississippi Power prior to filing the 2023 IRP Update on October 27, 2023. The Company issued its RFI in September 2023 to gather market information regarding the availability of existing and planned capacity resources for years 2026-2031. The RFI closed on October 24, 2023 and confirmed that no existing capacity resources could help meet the Company's capacity needs being addressed in the 2023 IRP Update. For potential new or planned projects, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

d. The **REDACTED** BESS plus solar project utilizes existing transmission interconnection infrastructure, and the Company's transmission screening analyses indicate that the project can deliver up to 200 MW of energy to the transmission system through the summer of 2029. Once prior planned transmission projects are completed by the summer of 2029, the project could deliver up to 415 MW to the grid. For potential new or planned projects in the RFI, the Company would need additional information, including pricing, from the respondents to determine viability, cost-effectiveness, and deliverability of each potential project. See the Company's response to part (a) for transmission considerations for potential new or planned projects.

DG/LM-6:
GPC Response to PD STF-JKA-4-10

STF-JKA-4-10

Question:

Please refer to the paragraph on page 21, line 4, beginning with the statement: "The second driver, the decreased supply of electricity, is related to the limited amount of electric generation capacity available in the wholesale market."

a. Please provide all documentation that the Company used to support that statement, in addition to the Company's RFI referenced on page 22 of the testimony.

b. Please provide all workpapers the Company created associated with the RFI. Provide those electronically, with all formulae intact. For example, referring to the testimony on page 22, there were 44 submissions to the RFI. Please provide any summary available such as a table the Company created containing bid details that identify each submission by provider, provide the bid prices and terms offered, and indicate the reason(s) why the Company determined they were not viable options. If no table of this type, or a similar type was created, explain why not.

c. Provide copies of all bids received in the RFI.

d. See the Company's Supplemental Filing containing the review of the RFI. At pdf page 9, the Company noted there were 2 Qualifying Projects that were existing resources. At pdf page 11, the Company stated, "no existing resources were identified which could help meet the capacity needs being addressed in the Company's 2023 IRP." Why couldn't the 2 projects mentioned at pdf page 9 be acquired to help meet the capacity needs in the 2023 IRP?

e. The RFI Table 0-3-2 at pdf page 10 shows that 100 MW of capacity could be acquired for 2025, 1,110 in 2026, and 1,495 in 2027. Why didn't the Company perform a comparison to compete those options against the Santa Rosa PPAs, Yates CTs, Mississippi PPA, 1,000 MW of Company developed, owned, and operated BESS, the DER option, or the new demand response tariff that the Company has proposed to acquire, build, or establish in this IRP? If any analysis was performed please provide all workpapers and modeling analyses that were performed, electronically, with all formulae intact.

Response:

a. Based on the responses received to the Company's Request for Information ("RFI") issued in September 2023, there were no existing capacity resources available in the market to meet the need years addressed in this 2023 IRP Update. The Company's RFI is located in

Exhibit A of the RFI Summary that was filed as part of the Supplemental Filing made on December 4, 2023. Also, please reference the market activity referenced on page 15 of the 2023 IRP Update Main Document.

b. Please see the Company's response to STF-JKA-2-24. In addition, the Request for Information conducted was not a Request for Proposals; therefore, the submissions were not bids and pricing was not required or provided by all respondents.

c. Please see the Company's response to STF-JKA-2-24.

d. The two existing Qualifying Projects that submitted a response to the RFI are units that are (i) currently under contract with the Company and (ii) are subsequently not available during the need years addressed in this 2023 IRP Update.

e. The Company did not perform a detailed analysis on the potential projects identified in Table 2-3-2 in the RFI summary showing that 100 MW of capacity could be acquired for 2025, 1,110 in 2026, and 1,495 in 2027 because there was not adequate time to administer and conduct an RFP that provides for all bids to be properly evaluated, conduct transmission studies, and ultimately construct new assets or interconnection facilities to meet the capacity needs being addressed in the 2023 IRP Update. In addition, if provided, pricing information was optional and non-binding for participants responding to the RFI and interconnection and construction plans are not known, any of which could significantly impact a potential project's availability.

DG/LM-7:
GPC Response to PD STF-JKA-2-20

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-20

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-20 ("Response"). In the Response, the Company has provided information related to the strategy, provisions, and evaluation of the Mississippi Power power purchase agreement ("PPA"). All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive pricing and operational capability data, specific to the resources under contract within the PPA. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the PPA provide for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current or future PPA negotiations, as counterparties may fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-2-20

Question:

Mississippi Power PPA

a. Why did the Company acquire the Mississippi Power resource as early as 2024 when there is no need for capacity that early?

b. Provide copies of any orders in which the Mississippi Commission required Mississippi Power to shut down resources or otherwise eliminate excess capacity that was ultimately relevant to the decision to enter into the PPA with Georgia Power.

c. Explain what issues will be addressed by the Operating Committee specifically related to the "day-to-day operating procedures".

d. Please explain all requirements for FERC approval and what the status of obtaining that approval is.

e. **REDACTED REDACTED REDACTED

Response:

a. The term of the Mississippi Power Company ("Mississippi Power") power purchase agreement ("PPA") begins January 1, 2024, because Mississippi Power was ordered to retire approximately 950 MW of capacity by the end of 2027 or show with detailed evidence why continued operation of the resources is in the best interests of its customers. Therefore, Mississippi Power planned to retire some of that capacity by the end of 2023 and was actively remarketing the remaining capacity to be sold outside of the Southern Company system. Had Georgia Power not executed the PPA for the full five years, the proposed resource very likely would not have been available for the last three years when the Company has a capacity need. By purchasing 750 MW from Mississippi Power through this PPA, Georgia Power ensures that this resource not only remains in the Southern Company pool but also provides dedicated, reliable, market-priced capacity and energy to Georgia Power's customers to meet its burgeoning short-term demand.

   For the benefit of customers, Southern Wholesale Energy ("SWE"), on behalf of Georgia Power, will attempt to remarket capacity for the years prior to the winter of 2025/2026. The Company has already contracted for the sale of 500 MW to a regional electrical service provider for January 1, 2024, through September 30, 2025, thereby recovering costs from a third party in a period before the capacity is needed to serve Georgia Power retail customers.

b. Please see STF-JKA-2-20 Attachment for the applicable order from Mississippi Public Service Commission in Docket No. 2018-AD-145.

c. Since both Georgia Power and Mississippi Power are members of the Southern Company Pool, which adheres to Southern Dispatch practices and the Intercompany Interchange Contract ("IIC"), "day-to-day operating procedures" will not be necessary. If the affiliate or pool relationship were to change during the term of the PPA, the Operating Committee would have responsibility for developing any subsequently needed operating procedures.

d. This PPA is executed under Southern Operating Companies' Market Based Rate Tariff ("MBR") with Mississippi Power as an electric utility operating company engaged in the sale of electric power at wholesale that has received authorization from the Federal Energy Regulatory Commission ("FERC") to provide wholesale power supply services at market-based rates. Transactions made under MBR do not require separate filings at FERC for approval. Further, Georgia Power is an electric utility operating company which provides retail electric service to end-use customers in its franchise service territory in the state of Georgia that is authorized to purchase wholesale power supply services.

e. As discussed in the response to subparts (a) and (b) above, purchasing 750 MW that can be met by any resources available to Mississippi Power prevented this capacity from being

removed from the Southern Company pool where it would no longer be available through system reserve sharing to serve Georgia Power customers. The Mississippi Power PPA was set up to be similar to system reserve sharing as allowed under the IIC, which is based on total capacity available from each Operating Company. Mississippi Power will continue to evaluate any necessary actions associated with the Mississippi Public Service Commission order in Docket No. 2018-AD-145.

f. As defined in the Power Supply Service Schedule, "seller generating resources" are, at any given time, the electric generating units owned or controlled by Mississippi Power that are in commercial operation and are submitted to Southern Dispatch. The PPA obligations can be met by any resources available to Mississippi Power.

g. Georgia Power and Mississippi Power both operate as part of the Southern Company system pool, and the expectation is that the conditions in Section 4.2 of the Power Supply Service Schedule would potentially occur under emergency situations, such as winter weather events, where the Southern Company system is impacted. Mississippi Power has every incentive for high levels of unit performance under the Southern Company system and its obligation to provide reliable service to its customers through the Southern Company system pool. No other data was acquired from Mississippi Power or Southern Company to evaluate the inclusion of this provision in the Mississippi Power PPA.

h. Please see the "9 TS Economic Analysis" folder in the Technical Appendix to the 2023 IRP Update for an economic assessment of the Mississippi Power PPA. This resource is available to meet near-term capacity needs. The results of the economic analysis demonstrate this PPA is competitive with other options. Furthermore, the capacity prices listed in Table 1 reflect the market price of capacity and are consistent with other recently executed contracts, such as TS STF-JKA-2-19 Attachment B. Finally, the 2024 reserve sharing rate as prescribed in the IIC and filed with FERC as part of the informational filing is $73.20/kw-year which is within REDACTED of the annualized rate in Table 1.

i. Please see the "TS Economic Analysis of Capacity Resources.xlsx" file in the "9 TS Technical Appendix Economic Analysis" folder of the "TS Technical Appendix," which was previously provided to the Commission Staff on October 27, 2023, in the 2023 IRP Update filing. The formulas associated with the contract capacity price and computed costs are on the "Cost Inputs" worksheet.

DG/LM-8:

GPC Response to STF-JKA-4-19

Redacted as it Contains Trade Secret Information

DG/LM-9:
GPC Response to PD STF-JKA-6-7

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-6-7

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-6-7 ("Response"). In the Response, the Company has provided capacity need information for the Southern Company System. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details on the capacity balance of the Southern Company System. If the Information was revealed to the public, a generation wholesaler, other public utility, or power marketer could use the Information to tailor purchased power offerings that could undermine the Company's market position. This could artificially drive up purchased power prices that would cost the Company and its customers more than had the Information been kept confidential. Publicly disclosing this Information could potentially harm customers by not allowing the Company to procure the best cost resources for customers. This Information also contains specific affiliate operating company details. Publicly disclosing these details could provide competitors with a competitive advantage over the affiliate operating companies to their detriment and the Company's detriment. Also, as a participant in the wholesale market through its affiliate Southern Wholesale Energy ("SWE"), disclosing the amount of generation available for sale in the market could impact the Company's market position. Finally, the Company's competitors are not required to disclose this type of information and to require the Company to do so would place it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-6-7

Question:

Refer to the Company's 2023 IRP Testimony on pages 33 and 35 that discusses the remarketing of Santa Rosa and the Mississippi Power capacity prior to Georgia Power's year of need. The Company noted that it is requesting regulatory asset treatment of its costs.

a. Please explain if the Company included this impact in the economic evaluation presented for the Santa Rosa project. If not, why not? If so, where?

b. Please explain who the counterparty is for the Mississippi Power sale, and provide a discussion of the terms and conditions of the sale. Please provide a copy of the agreements reached.

c. Please provide a narrative update as to the status of the Santa Rosa sale and whether a counterparty has been identified and terms reached. Please provide a copy of the agreements reached.

d. Please confirm that the terms of the Santa Rosa contract spans January 2024 through December 2028, and that the Southern Company system doesn't have a need until REDACTED **REDACTED**.

e. Please explain if GPC could have obtained capacity through the IIC from Southern Company in the **REDACTED** period, and that the Santa Rosa contract is only serving a resource need for the system in **REDACTED**.

Response:

a. The Company's economic evaluation includes the benefits of remarketed capacity associated with the Mississippi Power Company Power Purchase Agreement ("PPA") based on an already executed sale of capacity and energy to another regional electrical service provider. The Company did not assume this benefit for the Santa Rosa PPA in the economic evaluation as there is no executed contract currently in place. If additional capacity is remarketed from the Santa Rosa PPA, this would improve the economics of the Santa Rosa PPA assuming no other changes and remarketed capacity remains before the year of need. The Company did not explicitly reflect the regulatory asset treatment of its costs in the economic evaluation. However, the Company did consider the annual revenue requirement impact of the regulatory asset in its assessment of net impact to customers. Please see the Company's response to STF-DEA-3-6 for this information.

b. Please see the Company's response to STF-JKA-4-19(b) for the requested information.

c. Please see the Company's response to STF-JKA-4-19(e) for the requested information.

d. The term of the Santa Rosa PPA, if approved by the Commission, begins on the first day of the month following Commission issuance of a certificate of public necessity and convenience for the PPA. If approved in accordance with the procedural and scheduling order of the 2023 IRP Update, the Santa Rosa PPA would become effective on May 1, 2024, and continue through December 31, 2028.

   The Southern Company System is projected to have a capacity need by the winter of **REDACTED**. The Intercompany Interchange Contract ("IIC") for the Southern Company System provides for coordinated planning between the Operating Companies and for the sharing of temporary surpluses and deficits of capacity. While the IIC affords participants the ability to rely on temporary surplus capacity on the System, each Operating Company is responsible for and expected to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations. Any retail Operating Company that has excess reserves may decide at any point to retire some of the capacity or make wholesale sales predicated on some or all of that capacity provided that such Operating Company is maintaining adequate resources to reliably serve its own obligations. In either case (resource retirement or wholesale sale), the effect would be a reduction in the level of available capacity reserves on the System. Additionally, the other retail Operating Companies may experience increased economic development activity similar to what the Company is experiencing and may decide to not make their surpluses available to the Company while the economic development activity is being assessed.

e. See the Company's response to part (d). Projected surplus capacity on the System is not guaranteed to be available to serve Georgia Power's retail customers. The Santa Rosa PPA helps meet Georgia Power's capacity needs for 2026-2028. For the benefit of customers, Southern Wholesale Energy, on behalf of Georgia Power, is attempting to remarket capacity associated with the Santa Rosa PPA for 2024-2025.

DG/LM-10:
GPC Response to TS STF-PIA-10-3

Fully Redacted as it Contains
Trade Secret Information

DG/LM-11:
GPC Supplemental Response to STF-JKA-2-2

STF-JKA-2-2

Question:

Refer to the Load and Resource Balance presented in "TS 2023 IRP Update Models and Workpapers.zip\Main Document\Figures 4, 5, 6, & 9 - Capacity Needs Data for B22, B23, and 2023 IRP Update.xlsx"

a. Explain the change in capacity values for Bowen 1-2, 3-4, and Scherer 3, as the capacity values of those units appear to be different than what was assumed in the 2022 IRP.
b. Explain the decrease in assumed DSO capacity, as the capacity value for DSO resources appears to be different than what was assumed in the 2022 IRP. Also, please explain any change in assumptions such as customer participation since the 2022 IRP.
c. What capacity equivalence (ICE, ELCC, etc.) factors are assumed for new and existing resources in the Company's load and resource balance as presented? Also, importantly, provide a view of the "2023 IRP Update w Extensions" tab but with nameplate capacity ratings for winter for each resource.
d. What capacity equivalence (ICE, ELCC, etc.) factors are assumed for the proposed capacity resources evaluated in "TS Economic Analysis of Capacity Resources?" Provide such capacity equivalence factors for every unit.
e. What capacity equivalence (ICE, ELCC, etc) factors are assumed for the proposed resources in the GenMix Study? Provide such capacity equivalence factors for every unit.
f. Has the Company generated a load and resource balance view with the proposed capacity resources included associated with "TS Economic Analysis of Capacity Resources"? If not, why not? Please provide such a view if it is available.
g. Has the Company generated a load and resource balance view with the proposed capacity resources included associated with each GenMix case? If not, why not? Please provide such a view if it is available.
h. Please provide the Company's assumptions for capacity additions (technology, collocated with or without BESS, baseload/intermediate/peaking, MW target factors to adjust the solicitation target amounts by the expected procurement amounts, etc.) that are planned to be procured through RFPs that were approved in the Company's 2022 IRP.

Response:

a. The winter capacity values for Plant Bowen Units 1-4 and Plant Scherer Unit 3 increased due to additional demonstrated winter peaking capacity.

b. The Demand Side Option ("DSO") capacity resources are updated annually to reflect the best available information on program participation and Economic Load Carrying Capability ("ELCC"). The decrease in planning capacity between the 2022 IRP and the 2023 IRP Update is primarily driven by a change in the ELCC for the Demand Plus Energy Credit ("DPEC") program. Updated ELCC values reflect modeling of program parameters (resource availability, call limits, call conditions, required notice) and recently observed response rates.

c. Please see STF-JKA-2-2 Attachment A.

d. Please see TS STF-JKA-1-4 Attachment columns H and I for the annual capacity contribution for each resource in the economic analysis.

e. The MPC PPA was the only proposed resource explicitly modeled in the Resource Mix Study, and it was assumed to have an ELCC of 100%.

f. Please see STF-JKA-2-2 Attachment B. The Company did not include the potential option to acquire an additional ownership interest in an existing generating asset within the Southern Company footprint because the parties were unable to reach agreement at this time, as described in the Company's Direct Testimony filed on December 4, 2023.

January 12, 2024 Supplemental Filing Update: Please see STF-JKA-2-2 Supplemental Attachment B for the Company's latest projected capacity needs including the 2023 IRP Update proposed resources. In accordance with the Agreement for Engineering, Procurement, and Construction between Georgia Power Company and a consortium of Mitsubishi Power Americas, Inc. and Black & Veatch Construction, Inc., with an effective date of January 12, 2024, and provided as TS STF-JKA-2-19 Supplemental Attachment P, Georgia Power reflects the latest construction schedule for the proposed Plant Yates combustion turbines ("CTs"). Due to one of the proposed CTs expecting to achieve commercial operation in 2027, rather than 2026, approximately 200 MW of Other BESS were advanced to 2026 to fulfill the resulting projected capacity need for the winter of 2026/2027. Furthermore, the Company updated the Santa Rosa PPA firm capacity based on the results of a Southern Company Native Load Reservation interface study report for the Santa Rosa PPA resource. While annual firm transmission cannot be confirmed for 2024 through May 2026, Georgia Power is pursuing and may obtain short-term firm transmission for the resource during this period. Consistent with the transmission screening

analyses in the 2023 IRP Update, no transmission project costs are attributable to the Santa Rosa PPA.

g. Please see STF-JKA-2-2 Attachment C for the load and resource balance views that include the generic expansion resources for each planning scenario from the Resource Mix Study associated with the Errata to the 2023 IRP Update Supplemental Filing that was filed on December 7, 2023. The Mississippi Power Company ("MPC") power purchase agreement ("PPA") was the only proposed resource explicitly modeled in the Resource Mix Study. The MPC PPA is immediately available, without construction delay or transmission restrictions, and represents a supply-side resource of extraordinary advantage. Additionally, the MPC PPA negotiations were near finalized at the time modeling began for the 2023 IRP Update, and the MPC resources are already included in the model, which simplified capturing the MPC PPA. Therefore, the MPC PPA was represented in the Resource Mix Study analysis.

h. Please see STF-JKA-2-2 Attachment D for the Company's assumptions for capacity values for additions that are planned to be procured through requests for proposals ("RFPs") that were approved in the Company's 2022 IRP. The target procurement amounts can be found in Column E. The Company does not model or assume the results of future RFPs to be conducted to meet the Company's capacity needs for certain periods, such as the 2029-2031 All-Source RFP.

DG/LM-12:
GPC Response to TS STF-DEA-3-6,
Attachment G

Fully Redacted as it Contains
Trade Secret Information

DG/LM-13:

GPC Supplemental Response to TS STF-DEA-3-6, Supplemental Attachment G

Fully Redacted as it Contains Trade Secret Information

DG/LM-14:
GPC Response to STF-JKA-2-14

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-2-14

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-2-14 ("Response"). In the Response, the Company has provided cost and performance criteria for a variety of resource planning technologies. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive details on the costs of carbon capture equipment as well as cost and performance criteria for generic generating resources included in the resource plan. Publicly disclosing these costs would allow bidders in future solicitations to tailor their proposals and potentially set an artificial floor on bidding, which would harm customers by not allowing the Company to conduct a proper solicitation and obtain the best cost estimates for future consulting work.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-2-14

Question:

See Candidate Expansion Unit Section 2.6.1

a. Please provide all reports, analysis, studies, etc., that supports the fact that Georgia Power could capture 90% of CO2 emissions.
b. Provide all reports showing where Georgia Power could possibly store 90% of the CO2 emissions from CC resources.
c. Explain why Georgia Power did not assume that CC units would operate on hydrogen instead of assuming that those CC resources would store 90% of the CO2 emissions.
d. Please provide a copy of any comments that Southern Company or Georgia Power filed on August 8th or later in response to the EPA's request for comments in review of the EPA Section 111 proposed rule.
e. Please explain why the Company chose to use the assumption that CTs "are assumed to operate with oil as a primary fuel source." Why not natural gas and what assumption was used for the secondary fuel source given that the CTs were assumed to be Dual-fuel CTs?
f. Explain what assumptions have changed associated with the following resources between the 2022 IRP and the 2023 IRP. This should include capacity, costs, modeling limits, etc.

    i. Solar
    ii. Battery Storage
    iii. Wind
    iv. CTs
    v. CCs
    vi. Nuclear

g. Explain why the Mississippi Power PPA was included as a resource option, and none of the other PPAs such as Santa Rosa, etc. were included as resource options.

Response:

a. Please see TS STF-JKA-2-14 Attachment A for details on the generic carbon capture equipment assumption included in the Resource Mix Study.

b. Please see STF-JKA-2-14 Attachment B for details on storage viability in the United States. STF-JKA-2-14 Attachment B is a Department of Energy/National Energy Technology Laboratory report on sequestration viability in the United States that details a large amount of storage capacity available in the southeast as well as ongoing projects in the region to characterize that storage.

c. Production and transport of low greenhouse gas hydrogen is currently not demonstrated to the scale required to qualitatively satisfy the requirements of multiple retrofit or expansion

resources operating at an 85% capacity factor assumption used for the generic combined cycle expansion units.

d. See STF-JKA-2-14 Attachment C for the Company's comments on the EPA section 111 proposed rule for Electric Generating Units.

e. The Company assumed oil dispatch for new generic combustion turbines ("CTs") because the pipelines serving the Company region have become increasingly constrained and less flexible in recent years. These constraints limit the amount of swing and daily imbalance through frequent issuance of daily Operational Flow Orders (i.e., curtailment of gas supply). These constraints bind the Southern Company retail operating companies' ability to operate any of its natural gas units on the same pipeline system, including new CTs. The Company can successfully manage this through the usage of fuel oil. Additionally, the ability to construct new pipeline infrastructure to alleviate pipeline constraints has been very challenging (e.g., Mountain Valley Pipeline). Therefore, assuming new pipeline infrastructure will be available for all future natural gas units is unrealistic. Given the current operational realities and the challenges facing the pipeline infrastructure industry, the Company assumes the most reliable operational plan for new generic expansion CTs is for them to be dual-fueled with the ability to burn fuel oil year-round and plan to be augmented with natural gas when it is available. The availability of firm natural gas supply is highly location dependent. Therefore, the Company will evaluate the applicability of firm transportation on a case-by-case basis as specific resource decisions are identified.

f. See TS STF-JKA-2-14 Attachment D for details on year-to-year changes in the requested technologies.

g. The Mississippi Power Company power purchase agreement ("MPC PPA") was the only proposed resource allowed to be selected in the Resource Mix Study. The MPC PPA negotiations were near final when the modeling was being conducted, and the Mississippi Power Company resources are already included in the model, making it easy to implement this assumption. The other proposed resources will be included in future modeling if approved in this docket.

DG/LM-15:
GPC Response to STF-JKA-3-10

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-3-10

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-3-10 ("Response"). In the Response, the Company has provided various assumptions used in the economic analysis of the resources proposed as part of the 2023 IRP Update. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. Specifically, the Information includes detailed information regarding the Company's forecasted prices and fuel assumptions. Disclosure of the Information would provide extensive insight into the Company's projected unit operations. If revealed to the public, a generation wholesaler, power marketer, or original equipment manufacturer could use the Information to arbitrarily tailor proposals with the intention of pricing products and services according to the Company's expected costs, which could undermine the Company's ability to procure the best cost products and services for customers. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-3-10

Question:

It appears that in the B2023 Aurora database (B2023_Final_GPC_IRP_update.apz), the Yates CT 8-10 units are mapped to a fuel price proxy "Yates CT 8-10_Marginal_Fuel_B23_MG0_DEPS_202209". Please provide a B2024 database fuel price proxy that can be used as a fuel price proxy assumption for the Santa Rosa contract.

Response:

The Company assumes the last sentence in the question was simply a copy and paste error. Therefore, the Company assumes the question is seeking the fuel price proxy assumption for Plant Yates Units 8-10 and not Santa Rosa as requested in STF-JKA-3-9.

The "Yates CT 8-10_Marginal_Fuel_B23_MG0_DEPS_202209" fuel price proxy was created using a combination of Wilson Unit 1A oil prices in winter months (January, February, December) and Yates Units 6-7 gas prices in non-winter months. The B2024 fuel price proxies needed to recreate Plant Yates Units 8-10 oil/gas fuel prices are identified below:

- mn_Wilson 1A_Marginal_Fuel_B24_MG0_DEPS_202309_v2 (January, February, December)
- mn_Yates 6_Marginal_Fuel_B24_MG0_DEPS_202309_v2 (March – November)

For convenience, Plant Yates Units 8-10 B2024 oil/gas prices are provided in TS STF-JKA-3-10 Attachment.

Contact: Mike Bush

DG/LM-16:
GPC Response to STF-JKA-2-2, Attachment C

Georgia Power Territorial Base Case Load vs. Existing Capability MG0 with Generic Expansion Resources (2023 IRP Update - Winter)

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Peak Demand (MW), (A)	15,283	15,947	17,256	18,928	19,751	20,551	21,326	21,880	22,141	22,353	22,515	22,630	22,746	22,938	23,257	23,624	23,926	24,282	24,643	25,033
Owned Generating Capacity (MW), (B)	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013	10,453	10,453	10,494	10,494	10,494	10,494	10,494	10,494
Purchased Generating Capacity (MW), (C)	4,535	5,159	5,237	5,321	5,576	5,905	5,905	3,886	3,924	3,906	3,940	2,661	2,063	2,023	1,681	1,681	1,321	1,301	1,298	1,295
Dispatchable DSOs (MW), (D)	675	696	716	758	805	750	752	750	749	749	749	749	749	749	749	749	749	749	749	749
MG0 Generic Expansion Plan Resource Capacity (MW)	-	-	-	1,650	2,730	4,317	5,217	7,917	8,217	8,480	8,732	10,952	15,137	15,420	16,160	16,685	17,805	18,102	18,207	18,702
Total Capacity (MW)	19,980	21,196	21,296	23,435	24,818	25,674	26,577	27,256	27,593	27,838	28,124	28,375	28,401	28,645	29,083	29,608	30,369	30,646	30,748	31,240
Capacity Required to Meet GPC Target (MW) (E)	(964)	(1,352)	175	225	(129)	15	82	95	84	104	21	(86)	32	29	(11)	(77)	(460)	(292)	57	52
GPC Reserve Margin (%)	30.7%	32.9%	23.4%	23.8%	25.7%	24.9%	24.6%	24.6%	24.6%	24.5%	24.9%	25.4%	24.9%	24.9%	25.1%	25.3%	26.9%	26.2%	24.8%	24.8%

Notes

(A) Territorial Load requirements less non-dispatchable DSOs

(B) Assumes in-service dates of 7/31/2023 and 4/1/2024, respectively, for Plant Vogtle Units 3 & 4

(C) Includes territorial and imported power purchases.

(D) Values stated in combustion turbine equivalence terms

(E) Does not consider planning reserve sharing. GPC's small capacity need is met by System surplus. Reflects GPC's Target Reserve Margin resulting from a System Target Reserve Margin of 25.50% (2024-2026) and 26% (2027 and beyond).

Existing Capability

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Owned Generating Capacity (MW)		**14,770**	**15,341**	**15,343**	**15,706**	**15,706**	**14,702**	**14,703**	**14,703**	**14,703**	**14,703**	**14,703**	**14,013**	**10,453**	**10,453**	**10,494**	**10,494**	**10,494**	**10,494**	**10,494**	**10,494**
Nuclear		**2,468**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**
	HATCH 1	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439
	HATCH 2	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
	VOGTLE 1	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539
	VOGTLE 2	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540
	VOGTLE 3	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509
	VOGTLE 4	-	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509	509
Coal		**4,102**	**4,102**	**4,102**	**4,102**	**4,102**	**3,560**	**3,560**	**3,560**	**3,560**	**3,560**	**3,560**	**3,560**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	BOWEN 1	780	780	780	780	780	780	780	780	780	780	780	780	-	-	-	-	-	-	-	-
	BOWEN 2	758	758	758	758	758	758	758	758	758	758	758	758	-	-	-	-	-	-	-	-
	BOWEN 3	934	934	934	934	934	934	934	934	934	934	934	934	-	-	-	-	-	-	-	-
	BOWEN 4	944	944	944	944	944	944	944	944	944	944	944	944	-	-	-	-	-	-	-	-
	SCHERER 1	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-
	SCHERER 2	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-
	SCHERER 3	541	541	541	541	541	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Cycle		**4,150**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**
	MCDONOUGH 4	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945	945
	MCDONOUGH 5	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934	934
	MCDONOUGH 6	894	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926	926
	MCINTOSH 10	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692	692
	MCINTOSH 11	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Oil/Gas Steam		**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**	**648**	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	GASTON 1 GAS	127	127	127	127	127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GASTON 2 GAS	128	128	128	128	128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GASTON 3 GAS	102	102	102	102	102	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GASTON 4 GAS	103	103	103	103	103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	-	-	-	-	-	-	-	-	-
	YATES 7 GAS	326	326	326	326	326	326	326	326	326	326	326	-	-	-	-	-	-	-	-	-
Combustion Turbine		**1,880**	**1,880**	**1,880**	**1,880**	**1,880**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**
	BOULEVARD 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GASTON A	10	10	10	10	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MCDONOUGH 3A	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
	MCDONOUGH 3B	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
	MCINTOSH 1A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCINTOSH 2A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCINTOSH 3A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCINTOSH 4A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCINTOSH 5A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCINTOSH 6A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCINTOSH 7A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCINTOSH 8A	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
	MCMANUS 3A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 3B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 3C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4B	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4C	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4E	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS 4F	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	MCMANUS DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WARNER ROBINS 1	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93

	WARNER ROBINS 2	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93
	WILSON 1A	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
	WILSON 1B	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	WILSON 1C	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1D	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
	WILSON 1E	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	WILSON 1F	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WILSON DIESEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage		**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
	ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
	WALLACE DAM 1 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 5 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro		**661**	**691**	**691**	**691**	**691**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**	**696**
	BARTLETT'S FERRY 1 HY	-	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	BARTLETT'S FERRY 4 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	BARTLETT'S FERRY 5 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BARTLETT'S FERRY 6 HY	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	BURTON 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	BURTON 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	ESTATOAH 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FLINT RIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	FLINT RIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	GOAT ROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	GOAT ROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	GOAT ROCK 7 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	GOAT ROCK 8 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	LANGDALE 5 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LANGDALE 6 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 4 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	OLIVER 1 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 2 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 3 HY	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	OLIVER 4 HY	-	-	-	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	RIVERVIEW 1 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	RIVERVIEW 2 HY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SINCLAIR 1 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	SINCLAIR 2 HY	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
	TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	TERRORA 1 HY	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	TERRORA 2 HY	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	TUGALO 3 HY	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	TUGALO 4 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
	WALLACE DAM 4 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
	YONAH 1 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	YONAH 2 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	YONAH 3 HY	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar		**50**	**50**	**50**	**50**	**50**	**50**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**	**51**
	COMMUNITY SOLAR - COMER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	COMMUNITY SOLAR - GUYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	COMMUNITY SOLAR - WAYNESBORO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	FALCONS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	FORT BENNING	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	FORT GORDON	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	FORT STEWART SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	FORT VALLEY STATE UNIVERSITY	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	KINGS BAY SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	MCLB	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	MOODY AFB	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	RIGHT OF WAY SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ROBINS AFB	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	UGA SOLAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	Unassigned Self-Build Solar	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1
System Sales		**(52)**	**(52)**	**(50)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(41)**	**(41)**	**(41)**	**0**	**0**	**0**	**0**	**0**	**0**
	SYSTEM SALE	(52)	(52)	(50)	0	0	0	0	0	0	0	0	(41)	(41)	(41)	0	0	0	0	0	0
Purchased Generating Capacity (MW)		**4,535**	**5,159**	**5,237**	**5,321**	**5,576**	**5,905**	**5,905**	**3,886**	**3,924**	**3,906**	**3,940**	**2,661**	**2,063**	**2,023**	**1,681**	**1,681**	**1,321**	**1,301**	**1,298**	**1,295**
	2019 IRP RENEWABLES - DG S2230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2019 IRP RENEWABLES - DG S2330	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	2019 IRP RENEWABLES - DG W2330	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2019 IRP RENEWABLES - DG W2430	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2022 IRP Biomass	-	-	-	-	-	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
	2022 IRP ESS RFP	-	-	-	-	-	475	475	475	475	475	475	475	475	475	475	475	475	475	475	475
	2022 IRP SOLAR D	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35
	2022 IRP SOLAR DG RFP 1	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	2022 IRP SOLAR DG RFP 2	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	2022 IRP SOLAR E	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR F	-	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR G	-	-	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR H	-	-	-	-	-	-	-	-	-	-	-	38	38	38	38	38	38	38	38	38
	2022 IRP SOLAR US RFP 1	-	-	-	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
	2022 IRP SOLAR US RFP 2	-	-	-	-	-	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
	2022/2023 US - FLINT RIVER SOLAR	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	2022/2023 US - TIMBERLAND SOLAR	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	2022/2023 US - WADLEY SOLAR	-	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	2022/2023 US - WASHINGTON COUNTY SOLAR	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	ADDISON 1 (WEST GA)	177	177	177	177	177	177	177	-	-	-	-	-	-	-	-	-	-	-	-	-
	ADDISON 3 (WEST GA)	175	175	175	175	175	175	175	-	-	-	-	-	-	-	-	-	-	-	-	-
	ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1320	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1420	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1520	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG S1620	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG W1420	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG W1520	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - DG W1620	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER - DUBLIN	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: HECATE ENERGY - OLD MIDVILLE RD LLC	5	5	5	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-
	ASI CLASSIC 210 MW - US 2: SOLAR GLYNN	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-	-	-
	ASI PRIME 525 MW - DG S1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
	ASI PRIME 525 MW - DG S1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG S1725	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-
	ASI PRIME 525 MW - DG S1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - DG S1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - DG S1815	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-
	ASI PRIME 525 MW - DG S1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
	ASI PRIME 525 MW - DG S1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG S1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG W1725	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-
	ASI PRIME 525 MW - DG W1730	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - DG W1735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ASI PRIME 525 MW - DG W1815	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-
	ASI PRIME 525 MW - DG W1820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-
	ASI PRIME 525 MW - DG W1825	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-
	ASI PRIME 525 MW - DG W1830	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	ASI PRIME 525 MW - DG W1835	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	ASI PRIME 525 MW - US 1: BUTLER SOLAR	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	-	-	-
	ASI PRIME 525 MW - US 1: PAWPAW SOLAR	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	AXIUM US SOLAR HOLDINGS (SD&D)	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BLUE CANYON	82	82	82	82	82	82	82	82	82	82	82	82	-	-	-	-	-	-	-	-
	CCSP DG - ONLINE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CCSP DG - REMAINING	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	COCA-COLA	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	CONYERS RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-
	DAHLBERG 1	-	-	-	-	85	85	85	85	85	85	85	85	85	-	-	-	-	-	-	-
	DAHLBERG 10	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 2	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 3	-	-	-	-	85	85	85	85	85	85	85	85	85	85	-	-	-	-	-	-
	DAHLBERG 4	89	89	89	89	89	89	89	-	-	-	-	-	-	-	-	-	-	-	-	-
	DAHLBERG 5	-	-	-	-	85	85	85	85	85	85	85	85	85	85	-	-	-	-	-	-
	DAHLBERG 6	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 8	89	89	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	DAHLBERG 9	-	-	86	86	86	86	86	86	86	86	86	86	-	-	-	-	-	-	-	-
	EXELON HEARD 1	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 2	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 3	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 4	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 5	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	EXELON HEARD 6	158	158	158	158	158	158	158	-	-	-	-	-	-	-	-	-	-	-	-	-
	GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
	GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
	GREEN POWER SOLUTIONS	29	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-	-	-
	HARRIS 1	668	668	668	668	668	668	668	-	-	-	-	-	-	-	-	-	-	-	-	-
	HARRIS 2	-	690	690	690	690	690	690	690	690	690	690	-	-	-	-	-	-	-	-	-
	INTERNATIONAL PAPER - FLINT RIVER	25	25	25	25	25	25	25	25	25	25	25	25	-	-	-	-	-	-	-	-
	INTERNATIONAL PAPER - PORT WENTWORTH	28	28	28	28	28	28	28	28	28	28	28	28	28	28	-	-	-	-	-	-
	LSS 50 MW - HSH PEMBROOKE	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-
	LSS 50 MW - SIMON SOLAR FARM	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	LSS 50 MW - SOLAR D&D CAMILLA	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-
	LSS 50 MW - SOLAR D&D CAMP (MERIWETHER COUNTY)	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-
	MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-

	MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-
	MAS GEORGIA LFG - RICHLAND CREEK	11	11	11	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-
	MID-GEORGIA COGEN	300	300	300	300	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	MONROE POWER	309	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360	-	-	-	-
	PIEDMONT GREEN POWER	55	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-	-
	REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	REDI 1400 MW - C&I: TANGLEWOOD SOLAR	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	REDI 1400 MW - DG CS S1920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
	REDI 1400 MW - DG CS S1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG CS S1930	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - DG CS S1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - DG CS W1925	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG CS W1930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG CS W1935	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - DG S2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG S2035	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	REDI 1400 MW - DG W2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	REDI 1400 MW - DG W2035	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	REDI 1400 MW - US 1: QUITMAN SOLAR	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
	REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	REDI 1400 MW - US 2: COOL SPRINGS	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
	REDI 1400 MW - US 2: HICKORY PARK	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	REDI 1400 MW - US 2: QUITMAN II	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	REDI CS2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUPERIOR - WASTE MANAGEMENT	6	6	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-
	WALTON COUNTY	465	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WANSLEY 7	-	622	622	622	622	622	622	622	622	622	622	-	-	-	-	-	-	-	-	-
	WASHINGTON COUNTY	313	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispatchable DSOs (MW)		**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**	**749**
	CVR Level 1	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
	CVR Level 2	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155
	DER Customer Program	-	21	47	89	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
	DPEC	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
	RTPeDA	46	46	44	44	39	18	18	17	16	16	16	16	16	16	16	16	16	16	16	16
	RTPeHA	69	69	66	66	58	25	26	25	25	25	25	25	25	25	25	25	25	25	25	25

DG/LM-17:
GPC Response to STF-JKA-4-14

STF-JKA-4-14

Question:

Please refer to Bullet Point BESS on page 27 and the Commission's Approval of BESS resources in the 2022 IRP.

a. Please provide a list of battery storage projects currently installed or being installed on the Georgia Power system, provide important details about the BESS projects such as when they were installed or will be installed, how they are or will be operated, and what operational experience has been gained so far, or is expected to be gained.

b. Are the BESS resources the Company is requesting approval in this proceeding covered under the 500 MW of BESS approved in the 2022 IRP (See Paragraph 73 of the Order Adopting the Stipulation in the 2022 IRP, dated July 29, 2022)? Or is the Company's request in addition to the 500 MW that the Commission previously approved. If so, discuss whether the Company needs approval in this proceeding.

c. Referring to the statement that "Georgia Power proposes to develop, own, and operate up to 1,000 MW of BESS and or BESS plus Solar at various sites" referenced on page 27 - is this amount in excess of the BESS resources currently in operation or under construction or planned and approved? If so, please explain why the Company seeks such approval at this time.

d. Please provide a complete reconciliation of the Company's request in this proceeding with the BESS resources already previously approved by the Commission, such as in the 2019 and 2022 IRPs.

Response:

a. A table of battery storage projects being installed on the Georgia Power system is provided below. The projects being installed will serve a variety of use-cases such as operating reserves, regulation, energy arbitrage, and solar shifting. Further, as a result of Company ownership, the Company can incorporate operational changes with these Battery Energy Storage Systems ("BESS") as additional use cases are identified. The Company expects that all BESS will operate on Automatic Generation Control ("AGC") and be optimized for the overall system. After Mossy Branch achieves commercial operation, it will operate in a testing phase to refine the AGC algorithm, which will be applied to future BESS.

Project Name	COD
Mossy Branch	2024
Fort Stewart	2026
McGrau Ford	2026
Robins	2026
Moody	2026
200 MW BESS plus 200 MW Solar	2026

b. The 500 MW of energy storage system ("ESS") resources approved in the 2022 Integrated Resource Plan ("IRP") was for a request for proposals ("RFP") to the market and is not part of the 1,000 MW requested in the 2023 IRP Update.

c. Yes, the 1,000 MW of BESS are in excess of the BESS resources currently in operation, under construction, or planned and approved but the 1,000 MW includes Robins, Moody and 200 MW BESS plus 200 MW Solar listed in part a. The Company is seeking 1,000 MW in excess of what was previously approved because of the drastic changes in economic load growth from the conclusion of the 2022 IRP until now as detailed in the Company's 2023 IRP Update. The 1,000 MW will be used to meet capacity needs, while the previous approvals of BESS were demonstration projects or projects to serve as operating reserves to support the continued addition of intermittent resources on the system.

d. Please see the chart below for a complete reconciliation of the Company's request in this proceeding with the BESS resources already previously approved by the Commission, such as in the 2019 and 2022 IRPs.

IRP	Request
2019 IRP	80 MW Demonstration
2022 IRP	265 MW McGrau Ford 500 MW ESS RFP
2023 IRP Update	1,000 MW of BESS • Robins – 128 MW • Moody – 49.5 MW • BESS co-located with solar – 200 MW • Remaining MW to be determined – 622 MW Flex Capacity options beyond the 1,000 MW

DG/LM-18:
GPC Response to STF-JKA-2-11, Attachment F

Winter

Total	Avg Trended	Incremental	FINAL Incremental with 37.5GW of Solar
1,000	100%	1,000	100%
2,000	100%	1,000	100%
3,000	99%	1,000	98%
4,000	97%	1,000	92%
5,000	95%	1,000	84%
6,000	92%	1,000	75%
7,000	88%	1,000	65%
8,000	84%	1,000	55%
9,000	79%	1,000	45%
10,000	75%	1,000	37%
11,000	71%	1,000	30%
12,000	67%	1,000	27%
13,000	64%	1,000	26%
14,000	61%	1,000	25%
15,000	59%	1,000	24%

Summer

Total	Avg Trended	Incremental	FINAL Incremental with 37.5GW of Solar
1,000	92%	1,000	92%
2,000	97%	1,000	100%
3,000	100%	1,000	100%
4,000	100%	1,000	100%
5,000	99%	1,000	95%
6,000	97%	1,000	85%
7,000	93%	1,000	73%
8,000	89%	1,000	59%
9,000	84%	1,000	46%
10,000	79%	1,000	33%
11,000	74%	1,000	23%
12,000	69%	1,000	16%
13,000	65%	1,000	13%
14,000	61%	1,000	12%
15,000	58%	1,000	11%

FINAL Aurora Tranches
100%
85%
55%
30%

FINAL Aurora Tranches
100%
95%
60%
20%

DG/LM-19:
GPC Response to TS STF-PIA-10-1

Fully Redacted as it Contains
Trade Secret Information

DG/LM-20:
GPC Response to PD STF-JKA-1-4

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-JKA-1-4

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-JKA-1-4 ("Response"). In the Response, the Company has provided data supporting the economic analysis of projects proposed in the 2023 IRP Update including an acquisition with sensitive pricing and confidential details (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information includes competitively sensitive details specific to the resources under contract, proposed to be acquired or developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in current and future negotiations, as counterparties may use the Information as a bargaining tool in negotiations or fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

STF-JKA-1-4

Question:

See the file – TS Economic Analysis of Capacity Resources.xlsx, and the tab – Term Equalization.

a. For each capacity value between cells G4 and BC16 that are pasted in, provide workpapers used to derive the pasted values.

b. Row 2 of the tab shows capacity need years and shows that a need exists in 2027. Does that represent 2 years advancement of the need year or 3? If it represents 2 years explain why that was used as opposed to 3 years given the Company latest position is that the need year has advanced by 3 years compared to the 2022 IRP.

c. Cell J20 contains a pasted value of **REDACTED**. Please provide all workpapers used to derive that value, electronically with all formulae intact. Also, explain why **REDACTED REDACTED** costs were used for the Marginal cost of capacity. Also, please confirm that value includes both capacity and energy value.

d. Explain why in the case of **REDACTED**, capacity value exists in **REDACTED**, not **REDACTED**, and then again beginning in **REDACTED** and after. Why doesn't it exist in **REDACTED**?

e. Explain why capacity value for Yates 8-10 **REDACTED REDACTED**?

f. Explain why capacity value for **REDACTED** BESS +Solar **REDACTED**.

g. Explain what the Cost of Equalization is assumed to represent.

Response:

a) Please see TS STF-JKA-1-4 Attachment. This attached is redacted in its entirety to preserve working formulae.

b) The Company has a need in the winter of 2025/2026 or a 3-year advancement from the 2022 IRP. The need in winter 2025/2026 is 175 MW which grows to 1,875 MW in the winter 2026/2027. Given the relatively small winter of 2025/2026 need, the Company's economic ranking analysis assumed the first year for term equalization costs would be winter 2026/2027 to establish a relative economic ranking of resource options.

c) Please see cell F2 in the "YatesCT" tab of the "TS SAM ('23) - 7.0.1 YatesCT Final.xlsm" workpaper provided to Commission Staff on October 27, 2023. A combustion turbine resource continues to represent the lowest repeatable fixed costs option or capacity resource to meet peak demands. Plant Yates Units 8-10 represent the most recent information on the costs of a new combustion turbine. Therefore, it was used to represent the marginal costs of capacity.

The value in cell J20 is only the fixed costs and does not include energy value. Energy value is reflected on row 21 and included in the net cost of capacity on row 22 of the same spreadsheet and tab.

d) The value in 2030 is not for capacity value of the resource. Rather, it represents term equalization capacity and is used to impute a capacity cost to the resource to reflect periods when **REDACTED** **REDACTED** cannot provide reliable capacity. This is considered for the summer of 2030 as the transmission system upgrades will not be in place by the summer of 2030 for this option. In calendar year 2030, the Company's capacity constraint switches from winter to summer due to the timing of PPA expirations. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED**. Please see TS STF-JKA-1-4 Attachment for more information.

e) The values in 2027 and 2028 are not for capacity value of the resource. Rather, they represent term equalization capacity and are used to impute a capacity cost to the resource to reflect periods when the proposed Plant Yates Units 8-10 cannot provide full output. Transmission system upgrades will not be completed until May of 2028. Until these upgrades are completed, Plant Yates Units 8-10 will be limited to 600 MW during peak conditions. An additional capacity cost is imputed to the resource to reflect the resource limitations. Please see TS STF-JKA-1-4 Attachment for more information.

f) The value in 2030 is not for capacity value of the resource. Rather, it represents term equalization capacity and is used to impute a capacity cost to the resource during the summer of 2030, which is the constraining season for that year. **REDACTED** BESS + Solar is assumed to provide 100% ELCC in the winter and 50% ELCC in the summer. Please see TS STF-JKA-1-4 Attachment for more information.

g) Please see section 3.5 of Technical Appendix Economic Analysis of Capacity Resources.

DG/LM-21:

GPC Supplemental Response to STF-JKA-2-2, Supplemental Attachment B

Fully Redacted as it Contains Trade Secret Information

DG/LM-22:
GPC Response to STF-PIA-10-6

STF-PIA-10-6

Question:

Please refer to the proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18824 (Mar. 29, 2023) (the "Proposed 2023 ELG Rule").

a. Does the Company anticipate incurring costs for retrofits at the Bowen and Scherer coal units between now and 2029 to comply with the zero-discharge limitation for all pollutants in flue gas desulfurization (FGD) wastewater under the Proposed 2023 ELG Rule? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If not, please explain why not.

b. Does the Company anticipate incurring costs for retrofits at the Bowen and Scherer coal units between now and 2029 to comply with the zero-discharge limitation for all pollutants in bottom ash transport water (BATW) under the Proposed 2023 ELG Rule? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If not, please explain why not.

c. Will the Proposed 2023 ELG rule require any capital expenditures at the Bowen and Scherer coal units between now and 2029 to comply with the numeric discharge limitations for combustion residual leachate (CRL)? If yes, please describe the capital projects that are required, and the estimated costs associated with them. If no, please explain why not.

Response:

a. If the U.S. Environmental Protection Agency ("EPA") finalizes the Proposed 2023 ELG Rule, the Company anticipates incurring additional capital costs if Plant Bowen is required to install membrane-based wastewater treatment and meet a zero-liquid discharge ("ZLD") requirement for flue gas desulfurization ("FGD") wastewater. See STF-PIA-10-6 Attachment for Southern Company's comments on the Proposed 2023 ELG Rule submitted to EPA on May 30, 2023, which includes a screening level estimate of approximately $580M for membrane-based FGD wastewater treatment at Plant Bowen. This does not include costs for a ZLD system, which would likely include additional storage tanks, pumps, and piping to reuse the permeate/distillate as make-up water to the boiler or FGD.

   The Company does not anticipate incurring additional costs at Plant Scherer beyond the membrane-based FGD wastewater treatment project that is currently underway, because the proposed rule did not indicate changing the requirements for the Voluntary Incentives Program that is applicable to Plant Scherer.

b. The Company does not anticipate incurring additional capital costs for retrofits at Plants Bowen and Scherer for bottom ash transport water under the Proposed 2023 ELG Rule. Both facilities already meet the requirements of the proposed ELG requirements for bottom ash

transport water with systems that were installed by 2019 to facilitate ash pond closure and meet existing ELG requirements.

c. If EPA finalizes the Proposed 2023 ELG Rule, the Company anticipates incurring additional capital costs for retrofits if physical-chemical wastewater treatment systems are required for combustion residual leachate at coal combustion residual landfills. The Company does not yet have capital cost estimates for these treatment systems, and site-specific studies for the landfills at Plants Bowen and Scherer are currently underway to prepare for cost estimating activities once the final rule is released.

DG/LM-23:
GPC Response to STF-PIA-10-7

STF-PIA-10-7

Question:

Please refer to the proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33240 (May 23, 2023) (the "Proposed 2023 GHG Rule").

a. Has the Company evaluated the four different compliance options for compliance with the Proposed 2023 GHG Rule at the Bowen and Scherer coal units? If yes, please provide all documents supporting this evaluation. If not, please explain why not.

b. Does the Company anticipate retiring the Bowen and/or Scherer coal units prior to 2032 to avoid compliance with the Proposed 2023 GHG Rule?

c. Does the Company anticipate retiring the Bowen and/or Scherer coal units prior to 2035 and accepting an operational limit of 20% of full capacity starting in 2030 as one of the compliance options under the Proposed 2023 GHG Rule?

d. Has the Company analyzed the cost of installing carbon capture and storage with a 90% capture rate to comply with the Proposed 2023 GHG Rule? If yes, please provide all such analysis. If not, state whether the Company plans to issue any updates to the IRP that evaluate the impact that the Proposed 2023 GHG Rule on the cost to operate the system.

Response:

a. The Company has not evaluated the existing coal unit compliance options for the United States Environmental Protection Agency's ("EPA") Proposed 2023 GHG Rule for Plants Bowen and Scherer, such as the early retirement by 2032 or 2035 and carbon capture and sequestration options. Even if the rule is finalized as proposed, a compliance evaluation cannot be completed at this time, because uncertainty remains in the compliance options and requirements for existing facilities until the development of the Georgia state plan required by the rule. EPA has indicated that it plans to finalize the Proposed 2023 GHG Rule in 2024 and proposed that the state plan would be due two years later. The Company will work with the Georgia Environmental Protection Division to evaluate the final 2023 GHG Rule and compliance options for affected existing facilities in the development of the Georgia state plan, which then must also be reviewed and approved by EPA.

   As stated generally in comments submitted by Southern Company to EPA on August 8, 2023 (see STF-JKA-2-14 Attachment C), more time and compliance flexibility are required in the case of all four existing coal unit options presented in the proposal. The Company will update the Commission through a future Environmental Compliance

Strategy and IRP process when sufficient information becomes available to complete the compliance evaluation.

b. See response to subpart (a).

c. See response to subpart (a).

d. See response to subpart (a).

DG/LM-24:
GPC Response to STF-PIA-7-4

STF-PIA-7-4

Question:

Please identify all assumptions and constraints included in the Company's 2023 IRP Update and modelling associated with, or in consideration of, the U.S. Environmental Protection Agency's (US EPA) proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule. [U.S. EPA Docket No. EPA–HQ–OAR–2023–0072]

a. Please describe each assumption or constraint.

b. Explain the rationale for including the assumption or constrain.

c. Please provide all documentation, memos, industry reports, and workpapers describing these limitations, modeled or operational, and modeling choices to support these assumptions and constraints.

d. If no assumptions or constraints were included in the Company's 2023 IRP Update, please explain why this is the case.

Response:

a. The Company did not include any assumptions or constraints as proposed in EPA 111 in the 2023 IRP Update.

b. The Company did not include any assumptions or constraints as proposed in EPA 111 in the 2023 IRP Update.

c. The Company did not include any assumptions or constraints as proposed in EPA 111 in the 2023 IRP Update.

d. Since the proposed EPA 111 rule has yet to be finalized, state plans have not yet been developed, and potential legal challenges have not yet taken place, the Company believes that detailed analysis of the implications of the proposed EPA 111 rule for the 2023 IRP Update would be premature and speculative. The Company believes that the implications of a final EPA 111 rule are captured within the range of carbon pressure scenarios included in the 2023 IRP Update.

Contact: Jeff Grubb

DG/LM-25:
GPC Response to STF-JKA-2-8

STF-JKA-2-8

Question:

Main document page 27 states: "In the 2022 IRP Final Order, the Commission approved the retirement and decertification of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and Unit A by December 31, 2028. With continuing increases to the projected load forecast and capacity needs following 2028, the Company will likely evaluate extending the operation of certain units, particularly Plant Scherer Unit 3, beyond 2028."

a. Confirm that the Company has modeled Scherer 3 with retirement in 12/31/2028 in all of the Aurora runs modeled.

b. Does the Company believe the Aurora modeling reflects the Company's most up-to-date understanding of its capacity plan?

Response:

a. Yes, Plant Scherer Unit 3 was modeled with a resource end date of 12/31/2028 in all of the Aurora runs.
b. Yes, the Company believes that its system modeling using Aurora for this 2023 IRP Update provides the most up-to-date understanding of its capacity plan at this time. As stated in the 2023 IRP Update Main Document, with the increase in capacity needs in 2028 and beyond, the Company is assuming Bowen Units 1-2 will retire at the end of 2035 for planning purposes. Also, while the current assumed retirement date for Scherer Unit 3 and Plant Gaston Units 1-4 and Unit A are at the end of 2028, the Company will likely evaluate extending operation of certain units beyond 2028 in the 2025 IRP.

Contact: Mike Bush

CHAIRMAN SHAW: And thank y'all for your time. You can be excused.

We're going to break now for lunch. And we will -- let's see here. Let's come back at 1:15. We'll start with Mr. Jacob's panel next.

(A recess was held from 12:25 p.m. until 1:15 p.m.)

CHAIRMAN SHAW: All right. We will go ahead and get started back after lunch with Docket No. 55378. Our next panel to be called up is Mr. Jacob's panel from the Southern Association for Clean Energy.

Mr. Jacob?

MR. JACOB: Thank you, Mr. Chairman. I am going to, with your permission, rely on Jennifer Whitfield from SELC to swear in my witness.

CHAIRMAN SHAW: That will be perfectly fine.

MR. JACOB: Thank you. southern Alliance for Clean Energy calls Anjali G. Patel to the stand.

Thereupon,

ANJALI G. PATEL,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. JACOB:

Q Ms. Patel, please state your name for the record.

A Anjali Patel.

Q By whom are you employed?

A David Gardiner and Associates.

Q On whose behalf are you testifying?

A Southern Alliance for Clean Energy.

Q Thank you. On February 15th of this year, did you prefile or cause to be prefiled 49 pages of direct testimony in question-and-answer format in Docket 55378?

A Yes.

Q Did you also cause to be prefiled, along with your testimony, one attachment, which can be referenced as SACE Exhibit 1?

A Yes.

Q Do you have any corrections or changes to the prefiled testimony or the attachment at this time?

A No.

Q If I were to ask you the same questions that appear in your prefiled testimony, at the hearing today under oath, would your answers be the same?

A Yes.

MR. JACOB: Mr. Chairman, I move to have Witness Patel's direct prefiled testimony entered into the record as if given orally here from the stand.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Anjali G. Patel follows:)

Anjali Goel Patel
Vice President for Clean Energy
David Gardiner and Associates
2609 11th St N. • Arlington, VA 22201
anjali@dgardiner.com

EMPLOYMENT HISTORY:

David Gardiner and Associates, Clarendon, VA
Vice President for Clean Energy April 2022–present

- Provide strategic, programmatic, and management support to Americans for a Clean Energy Grid, a multi-stakeholder organization that educates and advocates for the expansion, modernization, and integration of the high-capacity transmission network to improve reliability and resilience and increase access to cleaner energy resources.
- Advocate for federal and state policies to improve corporate access to clean energy and to facilitate cost-effective and equitable transportation decarbonization initiatives.
- Educate public and private entities on energy infrastructure investment, decarbonization technologies, and tax incentives and federal funding opportunities to help advance greenhouse gas emission reductions.
- Assist with business development and supervise and manage the firm's Clean Energy team.

Office of the People's Counsel for the District of Columbia, Washington, DC
Litigation Supervisor September 2021–April 2022
Senior Assistant People's Counsel June 2018–September 2021

- Managed a complex portfolio of litigated cases, and regulatory and policy matters before PJM, state and federal agencies, and appellate courts with an emphasis on ensuring safe and reliable utility service at just and reasonable rates, promoting equity considerations, and advancing the District of Columbia (DC) government's robust decarbonization goals. Major cases include: serving as lead counsel in an electric distribution rate case in which the utility sought approval to transition to a multiyear rate plan with performance incentive mechanisms; drafting a petition to address community solar billing and metering issues; advocating for the public interest in proposed energy efficiency, transportation electrification, and infrastructure improvement programs; advocating for transparent and cost-effective market rules and policies in PJM's stakeholder processes; drafting comments to address Federal Energy Regulatory Commission (FERC) rulemaking proposals and comments and protests to FERC orders revising PJM's governing documents; serving as the Secretary of the DC Public Service Commission's Pilot Project Governance Board; participating in stakeholder meetings addressing grid modernization, energy efficiency, and electrification initiatives.
- Provided issue briefings and strategic advice to senior management and assisted in developing the agency's litigation, legislative, and policy positions.
- Supervised, mentored, and trained staff attorneys and ensured that federal, state, and court dockets pertaining to utility-related matters impacting DC consumers were staffed appropriately.
- Drafted and reviewed legal and informational materials to support the agency's mission and policies, including motions, briefs, comments, petitions, testimony, discovery, settlement agreements, public fact sheets, web articles, and press releases.
- Supervised and managed litigation teams of in- and out-of-house attorneys and technical experts.
- Managed consultant contracts and assisted the Agency's Technical Division in procurement processes.
- Conducted outreach to elected and appointed officials, civic and neighborhood associations, labor organizations, environmental and advocacy groups, and other stakeholders on pending cases and emerging issues in the energy industry.
- Served as the Freedom of Information Act (FOIA) Officer from June 2018-November 2021.

Spiegel & McDiarmid LLP, Washington, DC
Associate September 2010–May 2018

- Advocated for the interests of governmental authorities and public entities before appellate courts and federal and state agencies, including FERC, the U.S. Environmental Protection Agency, and Federal Aviation Administration, by developing litigation strategies, drafting procedural and substantive pleadings, engaging in settlement negotiations, cross-examining witnesses at hearings, drafting and reviewing discovery, reviewing and revising expert testimony, and collaborating with technical consultants. Work included: litigating gas and electric cases before state public service commissions; representing municipal utility and state agency interests in public utility merger proceedings; representing client interests in an arbitration proceeding concerning power purchase costs; representing client interests in settlement negotiations before FERC Administrative Law Judges; and drafting comments for municipal utilities on FERC's electric and merchant gas transmission policies.
- Co-founded and contributed to the public interest energy and environmental blog, consideringthegrid.com.
- Counseled clients on the application of and developments in complex regulatory and constitutional laws and policies.
- Drafted, negotiated, and interpreted contracts for municipal utilities and airport operators.
- Mentored, issued assignments to, and reviewed work product from junior associates.
- Directed and managed secretarial and paralegal support.

Law Clerk May–July 2008

Great Lakes Commission, Ann Arbor, MI
Great Lakes Commission-Sea Grant Fellow June 2009–July 2010

- Facilitated consensus building, information exchange, and policy development for the Great Lakes Wind Collaborative—a multi-sector and binational coalition dedicated to facilitating the sustainable development of onshore and offshore wind in the Great Lakes region—and the Great Lakes Panel on Aquatic Nuisance Species—a federally organized panel with binational membership dedicated to preventing the spread of new, and controlling existing, aquatic invasive species in the Great Lakes.
- Drafted resolutions, comments on proposed rulemakings, and legislative testimony on issues of regional environmental and economic significance.
- Developed grant agreements for, and addressed public comments on, the implementation of the Great Lakes Restoration Initiative, a $475 million Congressionally approved program.
- Organized and conducted regional stakeholder workshops and webinars.

Academy of Natural Sciences, Philadelphia, PA
Educator and Overnight Program Manager September 2001–June 2005

- Designed and conducted classes and teacher workshops on natural history and environmental topics.
- Created curricula, hired and managed staff, and developed and maintained an annual budget for the museum's overnight program.

LEGAL INTERNSHIPS:

Enviro-Legal Defense Fund, Noida, India
Legal Intern March–May 2009

- Assisted in developing national renewable energy legislation.
- Researched and summarized international renewable energy laws and regulations.

Great Lakes Environmental Law Center, Ann Arbor, MI
Community Protection Director January–December 2008

- Summarized impacts of climate change on thermoelectric plant water demands.
- Drafted comments on a proposed Canadian nuclear waste storage site.

Department of Justice, Washington, District of Columbia
Law Clerk, Environmental Crimes Section January–March 2007

- Researched and drafted memoranda on issues related to pending environmental prosecutions.
- Redeveloped an Endangered Species Act litigation manual for United States Attorneys.

World Bank, Phnom Penh, Cambodia
Legal Intern, Justice for the Poor Project May–August 2006

- Drafted memoranda on demand-side justice reforms in labor relations and land use.
- Drafted a literature review of property law and land dispute resolution in Cambodia.

EDUCATION:

The University of Michigan Law School, Ann Arbor, MI
Juris Doctor December 2008

Drexel University, Philadelphia, PA
Master of Science in Environmental Policy June 2005

Case Western Reserve University, Cleveland, OH
Bachelor of Arts in Biology and Environmental Studies, *magna cum laude* May 1999
Minors in Chemistry and English

SELECT PUBLICATIONS:

David Gardiner and Associates, *Options for Decarbonizing Cold-Weather Higher Education Campus Heating Systems* (expected publication April 2024) (contributing author).

David Gardiner and Associates, *Consumer Advocates of the PJM States' Transmission Handbook*, CAPS, (expected publication February 2024)(contributing author).

David Gardiner and Associates, *Accelerating Transportation Emission Reductions and Electric Vehicle Adoption: An Analysis of Retailer Commitments* (2022) (contributing author).

Lamisa Chowdhury (lead author), Megan Aki, Shelley Beaulieu, Marguerite Behringer, Cecilia Bolon, Anne Junod, Jasmine McAdams, Quinn Parker, Anjali Patel, and Judith Schwartz, Judith, *Procedural Equity – Principles, Metrics, Qualitative Approaches and Best Practices,* in Energy Equity Project Framework, University of Michigan (2022).

Anjali Patel and Jessica Bell, *The Clean Power Plan and Carbon Emission Trading in Indian Country: Exploring Opportunities and Implementation Issues*, American Bar Association, Section of Environment, Energy and Resources, Native American Resources Committee Newsletter (August 2016).

Lisa Dowden, Anjali Patel, Latif Nurani, *Alternative Resource Adequacy Mechanisms and Where Capacity Markets Go From Here*, American Public Power Association Pre-Conference Workshop (October 2014).

Robert A. Jablon, Anjali G. Patel, and Latif M. Nurani, Trinko *and* Credit Suisse *Revisited: The Need for Effective Agency Review and Shared Antitrust Responsibility*, 34 Energy L.J. 627 (Fall 2013).

National Association of Local Government Environmental Professionals, *Cultivating Green Energy on Brownfields* (2012) (co-author).

Anjali G. Patel, Katherine Glassner-Shwayder, and Tim Eder, *Halting the Invasion: Maintaining the Health of the Great Lakes and Mississippi River Basins by Preventing Further Exchange of Aquatic Invasive Species*, 12 Environmental Practice 342 (2010).

Anjali Patel, *The Role of the Great Lakes-St. Lawrence Seaway Ports in the Advancement of the Wind Energy Industry*, The Great Lakes Commission (2010).

CIVIC ENGAGEMENT

Energy Equity Project
Procedural Equity Working Group, Member October 2020-November 2022

Charitable Foundation of the Energy Bar Association, Washington, DC
Board Secretary April 2018–April 2020
Board Member April 2017–April 2018

Takoma Children's School, Washington, DC
Strategic Planning Committee October 2012–October 2014
Board Vice President October 2010–October 2012

Peace Corps, Evou-Apegamé, Togo
Volunteer, Environmental Protection Program September 1999–January 2001

PROFESSIONAL MEMBERSHIP

National Association of State Utility Consumer Advocates
Co-Chair, Electric Committee July 2019–April 2021

Energy Bar Association
Chair, Federal Energy Regulatory Commission Practice Committee June 2016–April 2017
Vice Chair, Federal Energy Regulatory Commission Practice Committee May 2015–June 2016

BAR ADMISSIONS

U.S. Court of Appeals, D.C. Circuit Admitted 2015
U.S. Court of Appeals, Second Circuit Admitted 2018
U.S. District Court, District of Columbia Admitted 2017
District of Columbia Admitted 2011
Michigan Admitted 2009

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's 2023	)	**DOCKET NO. 55378**
Integrated Resource Plan	)	

DIRECT TESTIMONY OF ANJALI G. PATEL
ON BEHALF OF
SOUTHERN ALLIANCE FOR CLEAN ENERGY

FEBRUARY 15, 2024

I. INTRODUCTION

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

A. My name is Anjali G. Patel, and I am the Vice President for Clean Energy with David Gardiner and Associates (DGA). Our firm is focused on helping our clients develop strategic solutions to address the climate crisis and accelerate decarbonization in the sectors principally responsible for emitting greenhouse gasses. We support a wide range of public and private clients and multistakeholder organizations. My business address is 3100 Clarendon Ave. Arlington, VA, 22201.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Southern Alliance for Clean Energy ("SACE").

Q. PLEASE SUMMARIZE YOUR RELEVANT WORK EXPERIENCE AND EDUCATION.

A. In my current position, I provide expert advice on policies needed to support equitable and cost-effective electric transmission expansion and modernization, to advance transportation and building sector decarbonization, and to increase access to decarbonized energy sources. I also provide organizational management support to certain of our non-profit clients.

Prior to joining DGA, I served as the Litigation Supervisor and a Senior Assistant People's Counsel at the District of Columbia Office of the People's Counsel (DC OPC). DC OPC is the statutorily designated utility ratepayer advocate for the District of Columbia. In that role, I practiced before FERC, PJM, and the District of Columbia

Public Service Commission and supervised the dockets of junior attorneys. My portfolio addressed both wholesale and distribution issues, and included electric transmission and distribution rate cases, gas and electric infrastructure proceedings, and regional market, resource adequacy, and grid modernization policies. Between 2010 and 2018, I practiced law as an Associate at Spiegel & McDiarmid where I represented public oriented clients on matters concerning regulated industries. During this time, I practiced before appellate courts, FERC, and state PSCs providing both transactional and litigation services to clients in the areas of energy, telecom, and transportation. My energy portfolio included transmission and distribution rate cases, FERC rulemakings, environmental regulations, and regional energy and capacity market rules. Prior to working at Spiegel & McDiarmid, I completed a fellowship with the Great Lakes Public Service Commission where one of my main projects was supporting the Great Lakes Wind Collaborative, a multistakeholder organization aimed at developing wind energy in the Great Lakes region.

I earned my J.D. from the University of Michigan, M.S. in Environmental Policy from Drexel University, and B.A. in Biology and Environmental Studies from Case Western Reservice University.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION ("GPSC" OR "THE COMMISSION")?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was asked by SACE to review the Georgia Power Company's ("Georgia Power" or the "Company") 2023 Update to its Integrated Resource Plan ("IRP Update") and offer policy

recommendations to the Commission on improvements that would benefit customers. In particular, my testimony concerns the role of transmission in ensuring capacity sufficiency and the IRP Update's failure to consider transmission solutions.

Q. ARE YOU SUBMITTING EXHIBITS ALONG WITH YOUR TESTIMONY?

A. Yes, I am submitting one exhibit, my curriculum vitae.

II. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. Georgia Power Updated IRP offers the Commission an extremely limited set of solutions to resolve the projected exponential load growth. By offering only generation resources in its Updated IRP package, Georgia Power overlooks other supply side solutions—namely new transmission and transmission upgrade projects—that could more cost effectively and reliably meet the Company's identified needs. Moreover, the proffered generation solutions run contrary to Southern Company's, Georgia Power's parent, sustainability goals and the decarbonization goals of potential customers, and the package would saddle Georgia customers with costs for plants that neighboring state Mississippi has found to be uneconomic.

In order to resolve these concerns, I recommend that the Commission:

- require Georgia Power to refile the Updated IRP with proposed transmission solutions, and to include in that review both new and upgrade projects.

- Direct Georgia Power to incorporate a multivalue planning analysis into its future transmission analyses.

III. TESTIMONY

A. Transmission is a supply side resource and should be considered as a potential solution for capacity needs.

Q. DO YOU HAVE ANY CONCERNS ABOUT GEORGIA POWER'S IRP UPDATE METHODOLOGY?

A. Yes. In its IRP Update, Georgia Power alleges a 17-fold increase in projected demand growth from its 2022 IRP filing, shifting from 400 MW of projected growth between 2023/24 and 2030/21 winter to 6,600 MW projected growth in the same period. Assuming that Georgia Power's projections are correct, its IRP update proposes only a narrow set of solutions to meet those needs.

Q. WHAT BASIS DO YOU HAVE FOR SAYING THAT THE SET OF SOLUTIONS IS NARROW?

A. Georgia Power examined only generation capacity additions and gave a modest nod to demand side options to address the projected growth. Specifically, Georgia Power's IRP Update Resource Study Mix concludes that "additional generation capacity requirements may involve a mixture of natural gas combined cycle, dual-fuel combustion turbine with SCR, advanced nuclear, solar photovoltaic, wind, and battery storage. Additionally, the study concludes that a market option, such as the Mississippi Power Company PPA, will be needed to meet near term capacity needs."[1]

[1] Southern Company, *2023 Integrated Resource Plan Update Resource Mix Study*, at 17, October 2023 (Updated IRP).

Q. WHAT RESOURCES ARE MISSING FROM THE STUDY?

A. The most important resource missing from the study is transmission.

Q. AS THE UTILITY, SHOULDN'T GEORGIA POWER GET THE OPPORTUNITY TO DECIDE HOW BEST TO MEET LOAD NEEDS?

A. While it is Georgia Power's responsibility to provide in the first instance options for meeting additional load needs, customers are ultimately responsible for the costs of those decisions. Georgia Power must provide a comprehensive and transparent review of all available options so that the Commission can ensure that the proffered options are the most cost-effective. This obligation is reflected in the Commission's rules which state that:

> A utility resource planning process in which an integrated combination of demand-side and supply-side resources is selected to satisfy future energy service demands in the most economic and reliable manner while balancing the interests of utility customers, utility shareholders and society-at large. In IRP, all resources reasonably available to reliably meet future energy service demands are considered by the utility on a fair and consistent basis.[2]

Q. IS TRANSMISSION A SUPPLY SIDE RESOURCE?

A. Yes. Transmission provides multiple supply side functions including providing access to power generation from diversified locations, reducing the need to procure peaking resources by improving capacity access from existing generation and providing access to energy from wider geographic areas some of which may serve load with a non-

[2] Commission Rule 515-3-4-.02(25).

coincident peak demand, and increasing reliability and resilience especially in the face of grid threats such as cyber-attacks and extreme weather events. Further, the Commission's rules treat transmission modernization and expansion as a supply side resource defining such a resource as:

> A resource which can provide for a supply of electrical energy and/or capacity to the utility. Supply-side resources include supply-side capacity options, supplies from other utilities, cogenerators, renewable resource technologies, or independent third parties via existing or new transmission facilities; and **the life extension, upgrading, plant refurbishment, efficiency improvement, or capital additions of** existing generation, **transmission** or distribution facilities of the utility.[3]

Q. GEORGIA POWER DOES NOT TRADITIONALLY INCLUDE TRANSMISSION IN ITS IRPS OR ITS CONSIDERATION OF SUPPLY SIDE RESOURCES, WHY SHOULD IT DO SO NOW?

A. There are several reasons for doing so. Chiefly, the electric network is an integrated system, and strong utility planning requires an integrated consideration of all supply and demand inputs. Georgia Power examines transmission needs only to the extent they may be needed to serve their proposed generation solutions. The Company provides no analysis of the flip side to that equation—whether integrating transmission solutions with generation solutions will result in a more cost-effective and reliable network.

[3] Commission Rule 515-3-4-.02(39).

Q. ARE OTHER UTILITIES CONSIDERING TRANSMISSION SOLUTIONS IN THEIR INTEGRATED RESOURCE PLANS?

A. Yes. For example, in Michigan, regulated utilities must include in their IRPs an "analysis of potential new or upgraded electric transmission options for the electric utility."[4]

On the West Coast, PacifiCorp—a Berkshire Hathaway Energy subsidiary with a service footprint in Northern California and portions of Oregon and Washington State—included in its March 2023 IRP plans to "add[] 2,500 miles of new transmission lines" to promote access to affordable and reliable energy.[5]

Similarly, Idaho Power, an IDACORP Company with a regulated footprint in eastern Oregon and southern Idaho, filed its most recent IRP in September of 2023. In incorporating transmission solutions into its IRP, Idaho Power explained that:

> Idaho Power's transmission interconnections provide economic benefits and improve reliability by transferring electricity between utilities to serve load and share operating reserves. Historically, Idaho Power experiences its peak load at different times of the year than most Pacific Northwest utilities; as a result, Idaho Power can purchase energy from the Mid-C energy trading market during its peak load and sell excess energy to Pacific Northwest utilities during their peak. Additional regional transmission connections to the Pacific Northwest would benefit Idaho Power customers in the following ways:
>
> - Delay or avoid construction of additional resources to serve peak demand

[4] MCL 460.6t(5)(h), *see also* MI PSC, Case Nos. U-15896 U-18461, Opinion and Order (Dec. 20, 2017)(approving the MI IRP Planning Parameters).

[5] Pacificorp, *2023 Integrated Resource Plan*, Chapter 4 (March 31, 2023), available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf.

- Increase revenue from off-system sales during the winter and spring, which would then be credited to customers through the Power Cost Adjustment (PCA)
- Increase revenue from sales of transmission system capacity, which would then be credited to Idaho Power customers
- Increase system reliability
- Increase the ability to integrate VERs, such as wind and solar.
- Improve the ability to implement advanced market tools more efficiently, such as the [Energy Imbalance Market].[6]

Idaho Power's IRP transmission projects include:

> the Boardman to Hemingway (B2H) 500-kilovolt (kV) transmission line in 2026 to connect the Pacific Northwest and Idaho; and three Gateway West (GWW) transmission phases spread across the 20-year plan to connect the Magic Valley and Treasure Valley, with the first phase (Midpoint–Hemingway #2 500-kV line, Midpoint– Cedar Hill 500-kV line, and Mayfield substation) modeled with an online date of late 2028.[7]

Idaho Power "also identified potential value associated with the addition of the Southwest Intertie Project-North (SWIP-N) transmission line," a 500-kV line that would run between Idaho and Nevada, but it did not include this project in its preferred portfolio of projects.[8] Idaho Power's IRP includes an economic evaluation of both the proposed preferred and alternative project portfolios. The evaluation found the costs for "permitting, constructing, operating, and maintaining" the B2H line "is approximately

[6] Idaho Power, *Building our Future: Integrated Resource Plan*, September 2023 ("2023 Idaho Power IRP"), available at https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-irp-final.pdf.

[7] *Id.* at 1.

[8] *Id.* at 1-2.

$836 million more cost effective" than "the best alternative resource portfolio" which did not include the B2H transmission project.[9] The Idaho Power IRP is under review by the Idaho and Oregon Public Utility Commissions.

Q. EARLIER YOU SAID THERE WERE SEVERAL REASONS WHY GEORGIA POWER SHOULD INCLUDE TRANSMISSION SOLUTIONS IN ITS CONSIDERATIONS OF SUPPLY SIDE RESOURCES, WHAT ARE THE OTHER REASONS?

A. In requesting approval of its Updated IRP, Georgia Power relies heavily on its claim that there is "no precedent for such loads in the historical records."[10] Unprecedented load shifts signal that there is an evolution occurring in the use of Georgia Power's network. Putting aside other significant changes— including, e.g., increasing extreme weather, aging infrastructure—the unprecedent growth alone speaks to the need to look for novel, proactive, and flexible solutions so that the system is better designed to meet both known and unknown challenges economically and reliably.

But Georgia Power has taken no action to evolve its generation or transmission planning processes. When asked in multiple data requests about any transmission-oriented analysis, Georgia Power repeatedly referred "to the Transmission Planning study and project development processes outlined in Technical Appendix Volume 3 of the 2022 Georgia Power Integrated Resource Plan [] (Docket No. 44160), which notes how projects are evaluated and developed." This appendix is attached to the 2022 IRP

[9] *Id.* at 83-84.

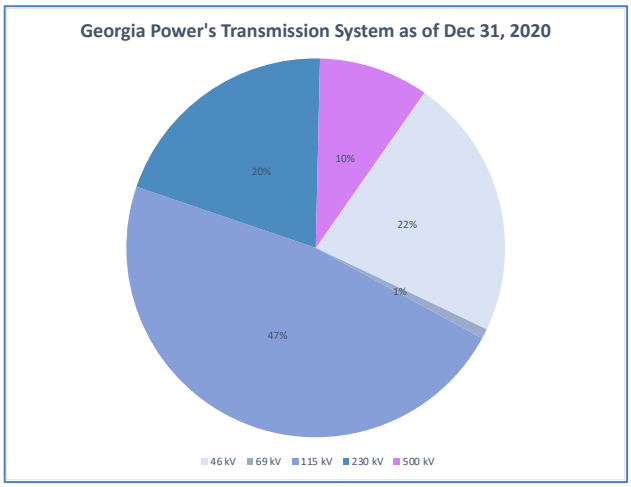
[10] *See, e.g.* GP Data Response to Data Request No. STF-DEA-5-6.

process— a process that Georgia Power used prior to its claimed realization that there is "unprecedented load growth" on its system.

Q. DO YOU HAVE ANY OTHER REASONS THAT GEORGIA POWER SHOULD BE CONSIDERING TRANSMISSION IN ITS IRP?

A. Yes. Georgia Power's existing system is primarily lower voltage transmission lines. According to the Company's 2022 IRP Technical Appendix, less than 1/3 of Georgia Power's transmission network is in higher voltage transmission >230 kV, and only 10% of the total lines are 500kV or above. See Figure 1 below:

Figure 1



Q. WHY DOES THAT MATTER?

A. In addition to potentially being more cost-effective, higher voltage and higher capacity lines can maximize a utility's ability to carry and deliver power. In contrast, transmission constraints can reduce the capacity available from existing generation, which in turn increase the utility's generation procurement requirements to meet peak load.

As Georgia Power notes in response to Data Request No. STF-GS-2-1, "transmission constraints occur in all seasons." The impact of transmission constraints on generation availability is exemplified by Georgia Power's explanation of the projects proposed in its Updated IRP. Specifically, in response to Data Request No. STF-JKA-2-25 explains that "the Company's economic analysis assumed resources could only provide capacity contribution up to the amount of capacity available on the transmission system. For example, the output of Plant Yates Units 8-10 is limited to 600 MW during peak periods until summer of 2028. After the summer of 2028, the transmission system can accommodate the full output of Plant Yates Units 8-10."[11]

B. Georgia Power's transmission planning processes are reactive rather than proactive and are not designed to meet the state's current and future needs.

Q. ARE THERE DEFICIENCIES IN GEORGIA POWER'S TRANSMISSION PLANNING STUDY APPROACH?

A. Yes. Though Georgia Power plans resources on a twenty-year basis, it plans transmission on a ten-year forward basis, and its latest transmission plan continues to be a reactive and backwards-looking examination rather than a forward-looking review of what transmission projects can help build capacity, reliability, and resiliency. Georgia Power last filed its transmission study on Feb 28, 2023, in compliance with the 2022 IRP Order.[12] In the study Georgia Power explains that its planning is conducted by Southern

[11] *See also*, Response to Data Request No. STF-GS-2-2 (stating that "the Company plans to designate all 1,350 MW of proposed Plant Yates combustion turbines, and the facility will be limited to 600 MW of firm output until all identified transmission improvements are in-service by summer 2028.")

[12] *See* Georgia Power Company's 2022 Integrated Resource Plan et al., Docket Nos. 441060 and 44161, *Order Adopting Stipulations*, ¶ 11 (2022) (IRP Order).

Company's Services – Transmission (SCST) and that planning is concerned with "maintaining system models" and includes steady state, stability, and short circuit studies."[13]

Q. WHAT DOES THAT MEAN?

A. That means that Georgia Power is examining transmission needs only to ensure that there are no current or expected reliability violations and that current generation capacity is connected (though not necessarily maximized) to the system. (See Transmission Study at 19 describing the inputs used for the base case).

Q. HOW IS PROACTIVE PLANNING DIFFERENT?

A. In contrast to a reactive process that addresses past problems, in a proactive planning process the utility conducts future-looking analysis that identifies whether new transmission solutions can help prepare the system for potential known and unknown network changes. In an ideal proactive plan, Georgia Power would run a multivalue scenario analysis that considers not only reliability issues, but also at a minimum examines: expected growth under both status quo and high growth load scenarios, new transmission that would increase import or export capability, transmission upgrades that could result in increasing system efficiency and reducing line losses, and new transmission or transmission upgrades that would increase economic efficiency. Moreover, in contrast to Georgia Power's current black box planning process, multivalue planning processes are open and transparent to allow all stakeholders—not just other

[13] Georgia Power Company's 2022 Integrated Resource Plan, Docket No. 44160, *Southern Company, 2022 GA ITS Ten-Year Plan (2023-2032)*, filed Feb. 28, 2023 ("Transmission Study").

utilities and transmission providers—to vet and inform the scenario development to ensure they match probable network changes.

Q. DID GEORGIA POWER ENGAGE IN PROACTIVE PLANNING WHEN IT CONDUCTED THE TRANSMISSION ANALYSIS TO SUPPORT THIS UPDATED IRP FILING?

A. No. The transmission analysis that Georgia Power filed in January 2024 is limited to analyzing whether new or upgraded transmission is needed to deliver Georgia Power's proposed generation options. It does not examine any independent potential new transmission solutions that could enhance or supplant the proposed generation options.

Q. DID GEORGIA POWER REVIEW ANY TRANSMISSION UPGRADES, SUCH AS NEW SUBSTATIONS AND TRANSFORMERS, GRID ENHANCING TECHNOLOGIES (GETS) SUCH AS DYNAMIC LINE RATINGS, ADVANCED RECONDUCTORING, ETC. IN ITS TRANSMISSION ANALYSIS TO ADDRESS THE UNPRECEDENTED LOAD GROWTH?

A. Not really. In response to Data Request No. STF-DEA-4-4, the company witness states that "the Company did not consider constructing additional 345kV substations and transformers as an alternative means of energy provision from the bulk transmission system in the scenarios discussed on November 27, 2023."

In response to Data Request No. STF-DEA-4-11, the Company witness stated that they "only applied dynamic line ratings to thermal constraints identified in off-peak transmission planning cases," which does nothing to minimize the generation requirements to meet peak transmission planning cases.

In response to Data Request No. STF-DEA-4-2, Georgia Power makes clear that its transmission analysis was limited, stating that "[d]ue to the timing of the transmission screens, transmission planning focused on the use of operating guides, generation redispatch, and transmission line rebuilds/reconductors to alleviate identified constraints."

Q. GEORGIA POWER SAYS IT REVIEWED REBUILDS AND RECONDUCTORS TO ALLEVIATE CONSTRAINTS, DID IT PROPOSE TO REBUILD OR RECONDUCTOR ANY LINES AS PART OF ITS UPDATED IRP?

A. No. The only mention of an upgrade is with respect to the transmission line serving Plant Yates; these efforts were already identified in the 2023 Transmission Plan which includes plans to rebuild or reconductor 27-115kV lines and 5-230 kV lines. It is not clear from the Transmission Study whether these rebuild/reconductor projects are like for like replacement or will include high performance conductors that could help maximize generator carrying capacity.

Q. CAN YOU DESCRIBE HOW GEORGIA POWER SHOULD ANALYZE RECONDUCTORING PROJECTS.

A. Yes. In lieu of just replacing existing lines with lines of the same capacity and technology or dealing with congestion, Georgia Power should analyze the potential resiliency and capacity gains from reconductoring pathways with high performance conductors. This would entail replacing the line with either a larger diameter of conductor or a new advanced conductor technology which "may add approximately 5%-10% to the total

project cost; however, the benefits can defray most or all of the upfront costs."[14] These benefits include, but are not limited to, the following:

- *Increasing efficiencies by reducing transmission line losses.* According to Grid Strategies, "[a]t the national level. . .Advanced Conductors can prevent annual transmission losses of approximately 21 million megawatt-hours (MWh)."[15]

- *Maximizing load carrying capacity which allow for the integration of additional generation resources and reduce power costs*. Grid Strategies reports that:

> Reconductoring 5,000 miles of transmission using Advanced Conductors creates 20,000 MW of transmission capacity each year, which can integrate up to 64 million MWh of renewable resource generation. . . By continuing the reconductoring over the entire 10-year time period, we estimate that cumulative renewable resource generation integration increases to 3.5 billion MWh and cumulative CO2 emission reductions increase to nearly 2.4 billion metric tons. The 3.5 billion MWh of energy savings from the use of high efficiency Advanced Conductors would save U.S. consumers about $140 billion or more over the decade.[16]

- *Increased resiliency*. New conductor technology can operate at higher temperatures and it sags less than the conventional technology, making the lines more resistant to damage in extreme weather scenarios.[17] Additionally, "even though the rated

[14] Jay Caspary and Jesse Schneider, Advanced Conductors on Existing Transmission Corridors to Accelerate Low Cost Decarbonization, at 15, March 2022, available at https://acore.org/wp-content/uploads/2022/03/Advanced_Conductors_to_Accelerate_Grid_Decarbonization.pdf.

[15] *Id.* at 18.

[16] *Id.* at 19.

[17] *Id.* at 6-7.

operating capacity of a line using an Advanced Conductor might be 40%-65% of the available capacity, Advanced Conductors can double the power density on paths using existing structures, which can be valuable during system emergencies when system operators desperately need capacity to keep the lights on."[18]

- *Fast development timelines help address near-term load increases*. Because advanced conductors use existing right of ways, they likely will not need new permits and can be constructed in <1-3 years.[19]

Q. DO YOU HAVE ANY OTHER COMMENTS ON HOW GEORGIA POWER CONDUCTED ITS TRANSMISSION SCREENING ANALYSIS.

A. Yes. In addition to failing to plan proactively, Georgia Power also did not conduct any evaluation of whether its transmission plans would do no harm. In Response to Data Request No. STF-GS-1-6, the Georgia Power witness stated that the Company "did not perform a direct evaluation" of whether any of the identified transmission upgrades would "interfere with the ability to deploy higher voltage transmission on that right-of-way to meet future needs."

[18] *Id*.

[19] Department of Energy, *Innovative Grid Deployment: Pathways to Commercial Liftoff*, at 19, Dec. 2023, available at https://www.energy.gov/sites/default/files/2023-12/Grid%20Liftoff%20Webinar%20Final.pdf.

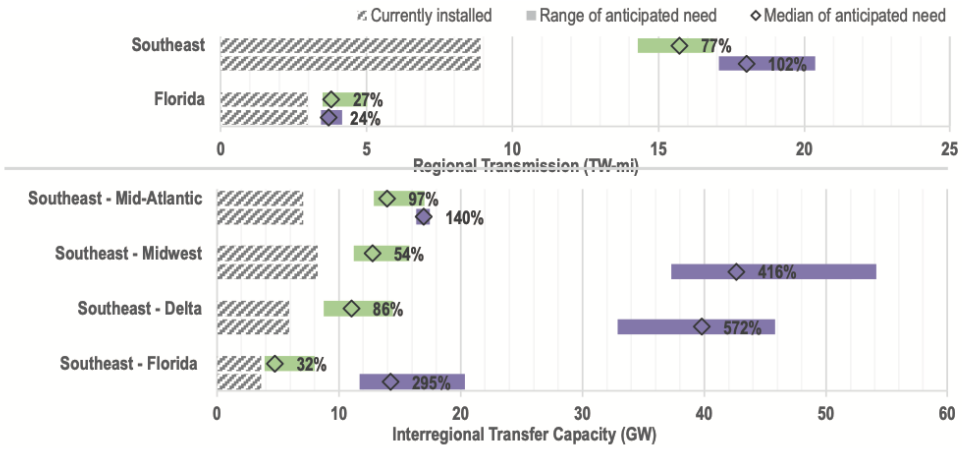
Q. OUTSIDE OF THE UPDATED IRP, DOES GEORGIA POWER HAVE ANY PLANS TO EXPAND OR MODERNIZE ITS TRANSMISSION NETWORK?

A. No. The Department of Energy's recent Transmission Needs Study identifies the need to expand transmission within the Southeast region, which encompasses Georgia Power's footprint, by 77% under a moderate load and high clean energy growth scenario and by 102% under a high load and high clean energy growth,[20] and to increase exponentially the interregional transmission capacity between the Mid-Atlantic, Midwest, Delta, and Florida regions. (See Figure 2).

Figure 2

Within-region transmission and interregional transfer capacity need for Southeast and Florida in 2035

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



[21]

[20] U.S. Department of Energy, *National Transmission Needs Study*, at vi to x, Oct. 2023, available at https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

[21] U.S. Department of Energy, *Fact Sheet: 2023 National Transmission Needs Study: Southeast and Florida*, at 2, Oct. 2023, available at https://www.energy.gov/sites/default/files/2023-12/43451_DOE_GDO_Needs_Study_Fact_Sheets_Southeast_Florida_v6_RELEASE_508_Compliant.pdf.

But Georgia Power's transmission expansion and modernization progress is sluggish, at best. The company has made relatively few additions to its system—in 2022 it added/altered only three transmission lines–one 115 kV line and two 46 kV lines, approximately one mile in cumulative length.[22] Similarly, in 2021, it added or altered 6.27 miles of lines, only 1.06 of that was a 230 kV line and the rest 115 kV.[23] The year prior, 2020, was no different in that the company added or altered 7.62 miles of lines while also removing 1.43 miles of lines.[24]

The Southern Company's Ten-Year Expansion Plan for transmission includes a limited set of new projects, but they are all aimed at addressing existing reliability issues. For example, Georgia Power proposes only three 500 kV lines over the next 10 years but the projects (Dresden – Talbot 500kV and East Walton 500/230kV area project) are designed to "addresses multiple thermal overloads resulting from Category P1 – Single Contingency events identified as part of the Georgia Integrated Transmission System (ITS) transmission planning processes in compliance with NERC TPL-001-5."[25]

[22] Georgia Power, *2022 FERC Form No. 1*, at p 422-423, April 20, 2023.

[23] Georgia Power, *2021 FERC Form No. 1*, at p 424-425, April 13, 2022.

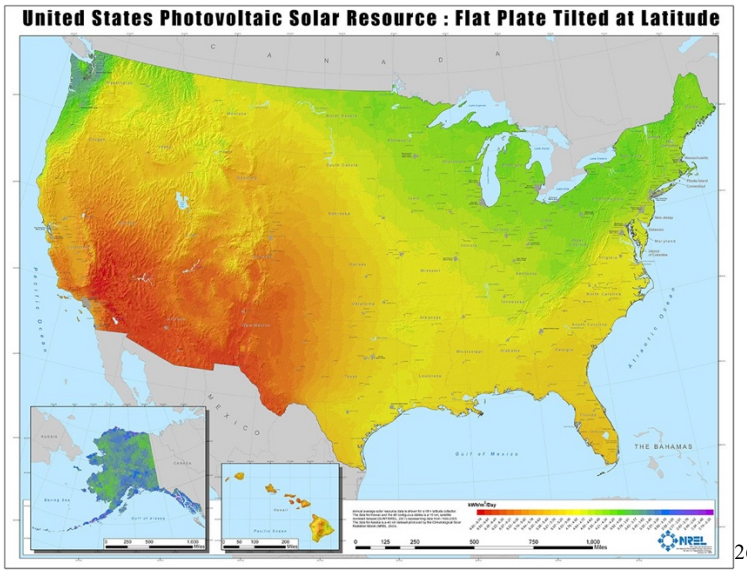
[24] Georgia Power, *2020 FERC Form No. 1*, at p 424, May 3, 2021.

[25] Georgia Power 2023 Transmission Study at 163, 169.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW GEORGIA POWER COULD HAVE USED MULTIVALUE PLANNING TO ADDRESS THE UNPRECEDENTED LOAD GROWTH.

A. A prime example of how Georgia Power could use multivalue planning models is the opportunity and ability for Georgia Power to incorporate renewable energy on its system. Georgia Power provides on its website the following solar potential map (see Figure 3):

Figure 3



[26]

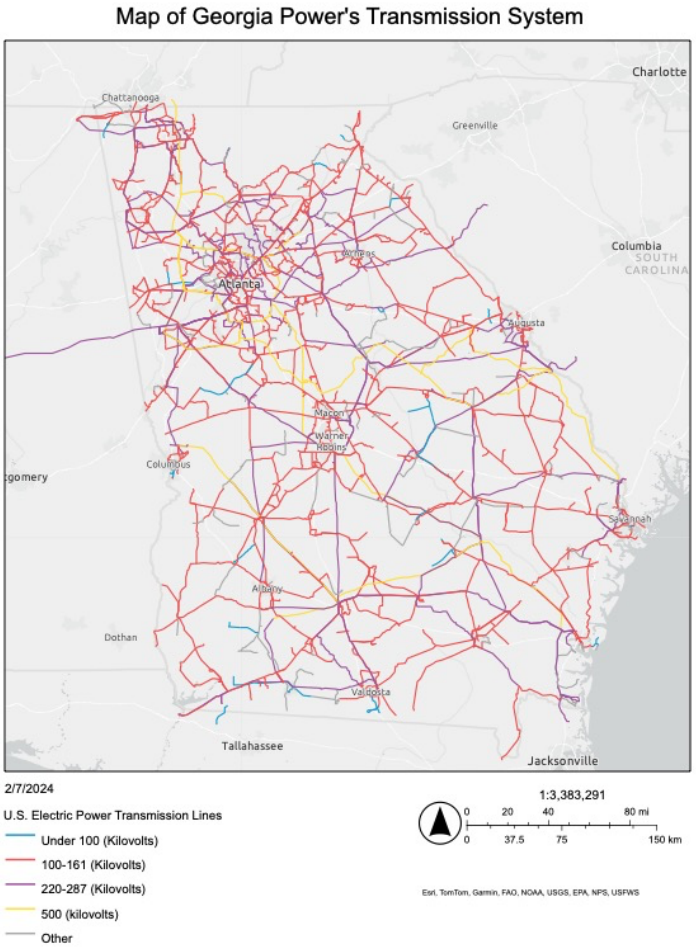
The map is accompanied by the statement that: "As can be seen on this solar map, insolation values in Georgia are significant enough to support solar energy systems in our

[26] Georgia Power, *Georgia Solar Potential*, last accessed Feb. 15, 2023, https://www.georgiapower.com/company/energy-industry/energy-sources/solar-energy/georgia-s-solar-energy.html#.

state, with the southern two-thirds of Georgia having solar insolation values equivalent to most of the state of Florida."[27]

The Sothern portion of Georgia, however, has a notable dearth of transmission, particularly high-voltage transmission (See Figure 4).

Figure 4



[28]

[27] *Id.*

[28] Source: Climate Mapping for Resilience and Adaptation (CMRA), U.*S. Electric Power Transmission Lines Data*, updated January 22, 2024, available at

If the Company had conducted a multivalue analysis, it is possible that Georgia Power may have found the lifetime combined costs of new transmission/transmission upgrades and renewable generation from the South would result in a greater benefit to cost ratio than the Company's proposed generation procurement options. As Georgia Power recognizes in Response to Data Request No. STF-JKA-4-16(d), transmission is among the factors that will impact the speed in which Georgia Power can bring solar online. But as no such analysis was conducted, stakeholders and the Commission lack data needed to evaluate whether Georgia Power's proposed solution set will meet customer needs in an economic and reliable manner.

Q. GEORGIA POWER IS DEVELOPING A NORTH GEORGIA RELIABILITY & RESILIENCE PLAN. DOESN'T THAT PLAN ADDRESS THE CONCERNS YOU RAISE?

A. Potentially it could. But Georgia Power did not incorporate that planning process in its Updated IRP analysis. Data Request No. STF-DEA-4-16 specifically asks if "For the screening analysis, were any transmission upgrades from the separate 'North-South' transmission study included, either in the base case or as a sensitivity?" The Georgia Power's witness response was "No, transmission upgrades from the separate 'North-South' transmission analyses were not included in the 2023 Integrated Resource Plan [] Update transmission screens."

https://resilience.climate.gov/datasets/d4090758322c4d32a4cd002ffaa0aa12_0/about. The CMRA map of U.S. electric power transmission uses data from Homeland Infrastructure Foundation-Level Data (HIFLD).

Q. WHAT ABOUT THE SERTP PROCESS? ISN'T THAT A MORE APPROPRIATE VENUE TO ADDRESS MULTIVALUE TRANSMISSION PLANNING?

A. SERTP should evolve its transmission planning processes, especially given the pending FERC Transmission Planning and Cost Allocation Rulemaking which proposes to require planning regions to amend their planning protocols to conduct long-term, comprehensive, multivalue planning.[29] However, the SERTP process is informed by and based on Southern Company's planning processes. As the old adage goes, "garbage in means garbage out." If planning is not improved from the ground up at Georgia Power and Southern Company, the SERTP processes will similarly be hamstrung in producing results that meet current and future system needs.

Q. ARE THERE ANY UTILITIES THAT ARE CONDUCTING PROACTIVE PLANNING?

A. Yes. As mentioned earlier, Michigan's IRP regulations require utilities to integrate their transmission and generation plans. The required transmission analysis must include the following:[30]

> a) The utility shall assess the need to construct new, or modify existing transmission facilities to interconnect any new generation

[29] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* (FERC Docket No. RM21-17-000), 87 Fed. Reg. 26504, 179 FERC ¶ 61,028 (2022) (NOPR); For a list of recommendations on steps SERTP can take to improve its planning processes, see Comments of the Southeast Public Interest Groups, FERC eLibrary No. 20220817-5175, filed Aug. 17, 2022, available at https://www.cleanenergy.org/news-and-resources/sace-signed-comments-to-ferc-on-transmission-notice-of-proposed-rulemaking-nopr/.

[30] MI PSC Case Nos. U-18461 and U-15896, *Integrated Resource Plan Filing Requirements Pursuant to Public Act 341 of 2016, Section 6t, Part XII*, December 20, 2017, available at https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/integrated-resource-plan-filing-requirements-schedule.

and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options;

b) A detailed description of the utility's efforts to engage local transmission owners in the utility's IRP process in an effort to inform the IRP process and assumptions, including a summary of meetings that have taken place;

c) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns;

d) Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, subject to confidentiality provisions;

e) Any information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources.

Q. ARE THERE ANY OTHER UTILITIES THAT ARE CONDUCTING, OR EVOLVING THEIR PROCESSES TO CONDUCT, PROACTIVE PLANNING?

A. Yes. Duke Energy Carolinas and Duke Energy Progress recently filed proposed tariff changes at the Federal Energy Regulatory Commission to implement a new planning process for Multi-Value Strategic Transmission Projects and "timely address transmission needs as the grid transitions to support a new resource mix, retire

generation, and respond to changing dynamics in energy use and demands."[31] The proposed planning process includes both scenario analyses and increased transparency and opportunities for meaningful stakeholder engagement in developing the "assumptions, models, and criteria used in the transmission planning process, as well as transmission needs and potential solutions."[32]

C. Transmission can maintain reliability in the face of extreme weather events.

Q. YOU MENTION EARLIER IN YOUR TESTIMONY THAT IT CAN BE BENEFICIAL TO HAVE INTEGRATED TRANSMISSION SYSTEMS. WHAT LEVEL OF INTERCONNECTION DOES GEORGIA POWER HAVE TO NEIGHBORING UTILITIES?

A. According to the FERC, NERC, and Regional Staff Entity Report on Winter Storm Elliott, Southern Company, which includes the Georgia Power footprint, has 55 total alternating current (AC) transmission ties to other core balancing authorities (BA) in the Eastern Interconnection. Those include: twenty-six (26) ties to Florida BAs, twelve (12) ties to Tennessee Valley Authority (TVA), nine (9) ties to Midcontinent Independent

[31] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. ER24-874, Re-Filing of Proposed Revisions to Local Transmission Planning Process in Attachment N-1 of Joint OATT, at 1, filed Jan. 12, 2024, eLibrary No. 20240112-5127.

[32] *Id.* SACE has joined other organization in filing comments in support of Duke's proposed changes. *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. ER24-874, Joint Comments of Appalachian Voices, Carolinas Clean Energy Business Association, North Carolina Sustainable Energy Association, Sierra Club, South Carolina Coastal Conservation League, and Southern Alliance for Clean Energy, filed Feb. 2, 2024, eLibrary No. 20240202-5030.

System Operator (MISO), 5 ties to Dominion Energy South Carolina (DESC), 2 ties to Santee Cooper, and 1 tie to Duke Energy Carolinas (DEC).[33]

Q. WHY DOES IT MATTER IF A UTILITY HAS TIES WITH OTHER AREAS?

A. Over the last few decades, we have seen a significant increase the intensity and frequency of extreme weather events that have impacted the ability to run generation and deliver power.[34] Because extreme weather events can cover an entire or even multiple utility footprints, it is important that utilities have connections with neighboring utilities and regions who may not be experiencing the same, or may be less impacted by, weather conditions and to use these connections to import power and keep the lights on.

Q. PLEASE DESCRIBE SOME OF THESE RECENT MAJOR WEATHER EVENTS.

A. *December 2022- Winter Storm Elliott*: Hitting right around the Christmas holiday, Winter Storm Elliott "had the largest footprint of any [extreme weather event] examined in a joint FERC-NERC-Regional Entity inquiry…the extreme cold weather covered most of the eastern half of the lower 48 United States, except for some of Florida."[35] (See Figure 5).

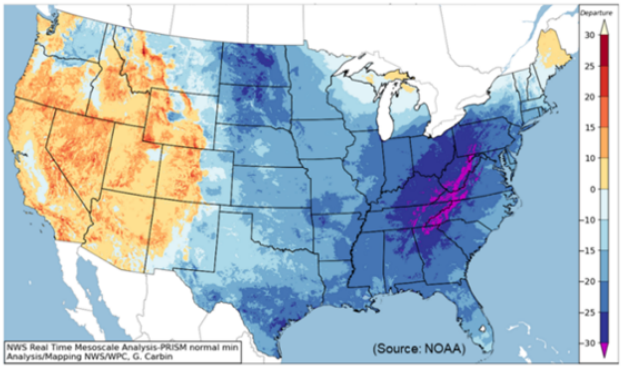
[33] FERC, NERC, and Regional Staff Entity Report, "*Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*," at 29, October 2023, available at https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf ("FERC-NERC Elliott Report) (Figure 12 provides a breakdown of AC and DC lines by Balancing Authority).

[34] IPCC, *Sixth Assessment Report*, *Working Group 1: The Physical Science Basis*, 2021, available at https://www.ipcc.ch/report/ar6/wg1/.

[35] FERC-NERC Elliott Report at 22.

Figure 5

Figure 8: Extreme Cold Weather Conditions – December 24, 2022



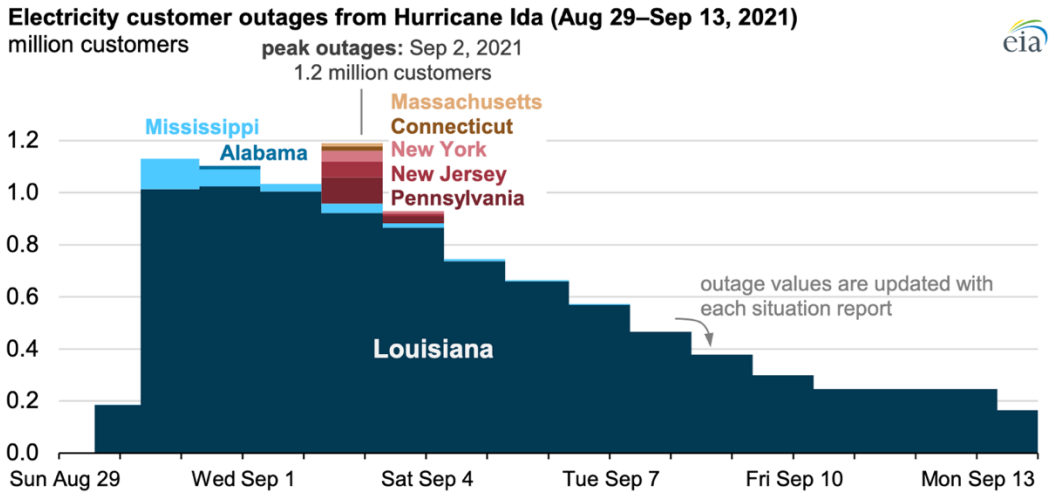
[36]

- *August-September 2021- Hurricane Ida*: This Category 4 hurricane "resulted in service outages for up to 1.2 million electricity customers across eight states," including three southern states (Louisiana, Mississippi, and Alabama) and five northeastern states (Connecticut, Massachusetts, New Jersey, New York, and Pennsylvania).[37] (See Figure 6).

[36] FERC-NERC Elliott Report at Figure 8, Page 23.

[37] Energy Information Administration, *Hurricane Ida caused at least 1.2 million electricity customers to lose power*, 2021, available at https://www.eia.gov/todayinenergy/detail.php?id=49556# (referencing Department of Energy, CESER, *Hurricane Ida Situation Reports*, available at https://www.energy.gov/ceser/hurricane-ida-situation-reports).

Figure 6



[38]

- *February 2021- Winter Storm Uri*: the storm "dumped record amounts of snow on Texas, with the frigid temperatures and severe weather impacting all 254 counties in the state in February 2021. Millions of Texans lost power…Gov. Greg Abbott issued a disaster declaration for all 254 counties in the state."[39] More than 200 people died in Texas, the majority from power outage-related causes.[40] Though the southern portion of the MISO territory was hit by the same snowstorm, they were able to keep their lights on by importing power from neighboring balancing authorities.

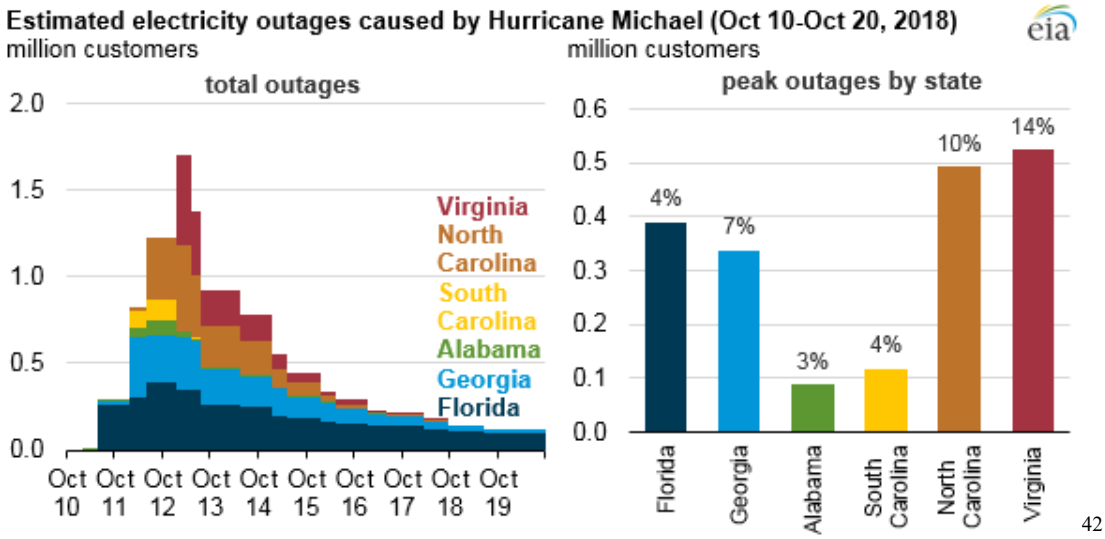
[38] *Id.* (Source: U.S. Energy Information Administration, based on data from the U.S. Department of Energy Office of Cybersecurity, Energy Security, and Emergency Response).

[39] The Texas A&M University System, *Texas Severe Winter Storm DR-4586, Winter Storm Uri*, available at https://www.tdem.texas.gov/disasters/winter-storm-uri, last accessed Feb. 15, 2024.

[40] FERC - NERC, *Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States*, Nov. 2021, available at https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

- *October 2018- Hurricane Michael*: the tropical cyclone "resulted in service outages for up to 1.7 million electricity customers across six states," making landfall in the Florida panhandle and travelling through Alabama, Georgia, North Carolina, South Carolina, and Virginia.[41] (See Figure 7)

Figure 7



[42]

Q. HAVE ANY OF THESE EXTREME WEATHER EVENTS IMPACTED ELECTRIC SERVICE IN GEORGIA?

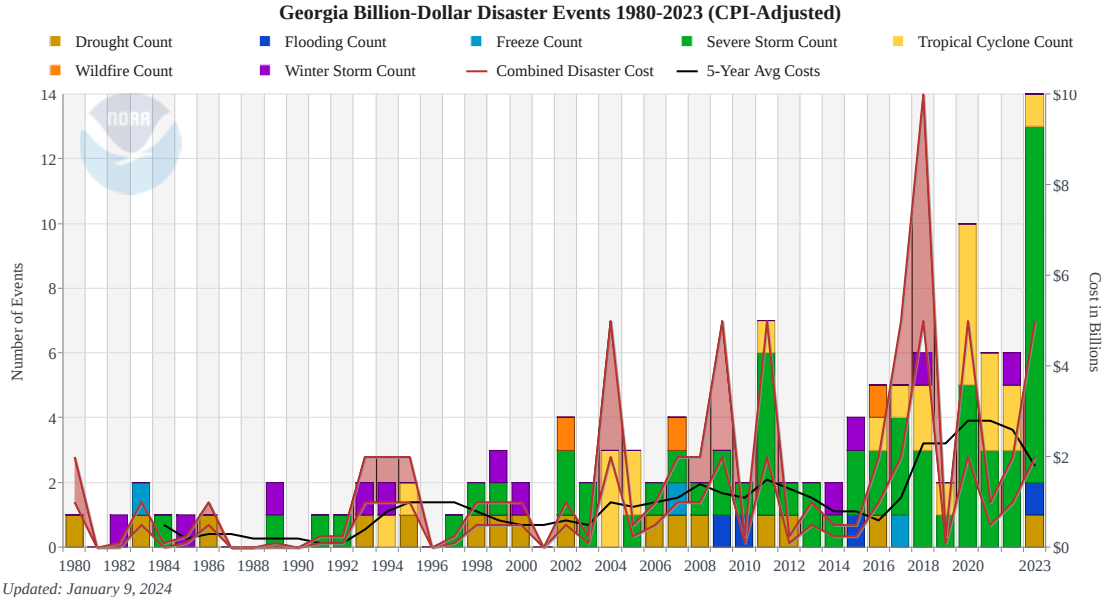
A. Yes, with respect to the events listed above, both Winter Storm Eliot and Hurricane Michael impacted power availability in Georgia. More generally, according to the National Oceanic and Atmospheric Administration (NOAA), in 2023 we experienced 28 severe weather events each costing more than $1 billion in damages, collectively totaling

[41] Energy Information Administration, *Hurricane Michael caused 1.7 million electricity outages in the Southeast United States*, October 22, 2018, available at https://www.eia.gov/todayinenergy/detail.php?id=37332#.

[42] *Id.* (Source: Energy Information Administration, compiled from U.S. Department of Energy's Office of Cybersecurity, Energy Security, and Emergency Response Situation Reports).

$92.9 billion in damages. Half (14) of those events, including heat waves, hurricanes, flooding, and severe storms, affected Georgia.[43] Based on NOAA data, Figure 8 charts the billion-dollar disaster events in Georgia between 1980-2023. Notably in the 53 years of data collection, the state faced the highest number of billion-dollar weather events in 2023.

Figure 8



[44]

[43] NOAA, National Centers for Environmental Information (NCEI), *U.S. Billion-Dollar Weather and Climate Disasters*, 2024, available at https://www.ncei.noaa.gov/access/billions/.

[44] NOAA, National Centers for Environmental Information (NCEI), *Georgia Summary*, updated January 9, 2024, available at https://www.ncei.noaa.gov/access/billions/state-summary/GA.

Q. WHAT WAS THE EFFECT OF WINTER STORM ELLIOTT ON GEORGIA POWER'S FOOTPRINT AND ON SOUTHERN COMPANY MORE GENERALLY?

A. During Winter Storm Elliott, several major utilities in the Southeast region of the U.S. were forced to implement rolling blackouts within their systems, including Duke Energy, TVA, and LG&E/KU.[45] In the Southern Company, generation also went down, but the Southern utilities were able to import sufficient power from neighboring balancing authorities to stave off large scale blackouts.

Q. PLEASE BREAK DOWN THE EVENT.

A. As per the FERC-NERC report:

> virtually all of the [balancing authorities/reliability coordinators] saw generation lost or derated due to Natural Gas Fuel Issues on December 23 and 24. SPP, TVA, LG&E/KU, and VACAR-South RC all reported gaining awareness on December 23 or 24 that generating units were struggling to find adequate natural gas supply or that pipelines were struggling or unable to maintain adequate pressure at certain locations.[46]

[45] Energy Ventures Analysis, *Operation of the U.S. Power Generation Fleet During Winter Storm Elliott*, at 17, February 202, available at https://www.evainc.com/wp-content/uploads/2023/02/2023_02_23-EVA-Winter-Storm-Elliott-Report.pdf; *see also*, Duke Energy, *Duke Energy updates North Carolina Utilities Commission on Winter Storm Elliott Emergency Outage Event*, Jan. 3, 2023, available at https://news.duke-energy.com/releases/duke-energy-updates-north-carolina-utilities-commission-on-winter-storm-elliott-emergency-outage-event; Tennessee Valley Authority, *TVA Accepts Responsibility, Starts Full Review,* December 28, 2022, available at https://www.tva.com/newsroom/press-releases/tva-accepts-responsibility-starts-full-review; Louisville Public Media, *LG&E/KU underestimated energy demand ahead of winter storm Elliott*, Jan. 26, 2023, available at https://www.lpm.org/news/2023-01-26/lg-e-ku-underestimated-energy-demand-ahead-of-winter-storm-elliott.

[46] FERC-NERC Elliott Report at 49.

For Georgia specifically, power outages in the Southern BA began at midnight on December 23, 2022. During the first two hours of December 24, Southern forced 500 MW of gas and oil generating unit capacity offline. Over the following four hours, Southern forced an additional 890 MW of gas and combined cycle generating capacity offline. Between 12:00am to 6:00am on December 24, **Southern had a total of 1,390 MW in incremental unplanned outages**.[47]

The FERC, NERC, and Regional Staff Entity report further discusses how at first Southern was able to provide emergency energy to other BAs, such as TVA who declared an Energy Emergency Alert (EEA) 3 on the morning of December 23. But by the early evening of December 23, Southern began curtailing their energy exports to TVA to deal with their own energy emergencies. On December 24 at 2:00am Southern declared an Energy Emergency Alert (EEA) 1 given increasing system loads and unplanned generation outages. By 6:25am, Southern declared an EEA 2 due to additional unplanned generation outages, declining operating reserves, and expected load increase, leading to a request for emergency energy from its neighbors: FP&L. "At 7:00 a.m., **Florida Power and Light provided 1,000 MW of emergency energy to the Southern BA Area**."[48]

PJM reports that MISO provided 100 MW of emergency power to the Southern BA during Winter Storm Elliot as well.[49]

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47 *Id.* at 48.

48 FERC-NERC Elliott Report at 64, 69, 72.

49 PJM, *Winter Storm Elliott. Event Analysis and Recommendation Report*, at 19, July 17, 2023, available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx

Q. DURING HURRICANE MICHAEL, DID SOUTHERN COMPANY AND/OR GEORGIA POWER EXPERIENCE GENERATION OUTAGES SIMILAR TO WHAT HAPPENED WITH WINTER STORM ELLIOTT?

A. Yes, similar grid outages occurred as a direct result of Hurricane Michael which struck on the morning of Thursday, October 11, 2018, During the Category 5 tropical cyclone, Georgia hit a peak of more than 336,000 customers outages, which means 7% of total customers in the state were without electricity. Over 188,000, or 56%, of those customers were in Georgia Power's service territory.[50] During the span of a week, more than 385,000 Georgia Power customers experienced power loss, with damages to 130 miles of lines, over 1,000 power poles, and more than 200 transformers.[51] Georgia Power's damages amounted to between $125 million and $150 million.[52]

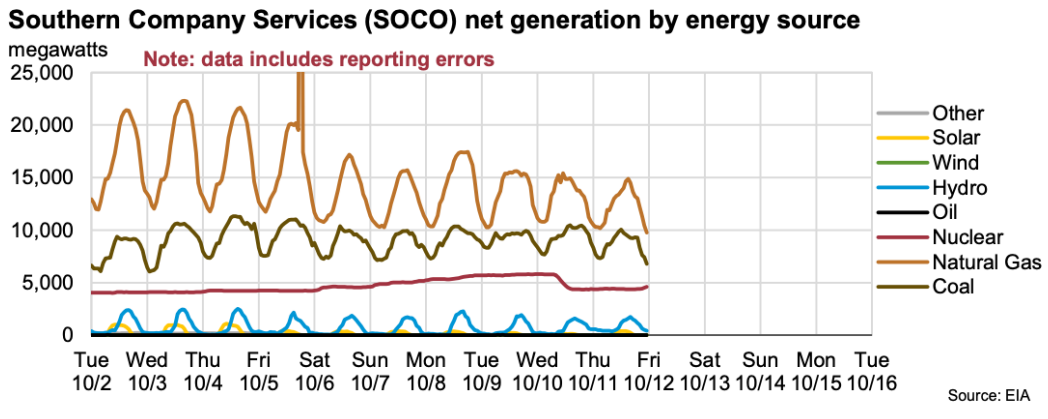
As shown on Figure 9 from the Energy Information Administration, across Southern Company service territory, natural gas net generation decreased significantly during the hurricane from a daily peak of >20,000 MW pre-Hurricane (October 3) to approximately 15,000 MW of generation in the days leading up to and during the hurricane (October 11).

[50] U.S. Department Of Energy, CESER, *Hurricane Michael Situation Reports - October 2018, Michael DOE Event Summary Report #3 Morning October 11, 2018*, available at https://www.energy.gov/ceser/articles/hurricane-michael-situation-reports-october-2018.

[51] Georgia Power, *Hurricane Michael Update*, available at https://www.georgiapower.com/company/safety/outages-and-stormcenter/after-a-storm/hurricane-michael.html

[52] Swartz, K, *Southern Co's bill for Hurricane Michael may hit $550M*, Energy Wire, November 8, 2018, available at https://subscriber.politicopro.com/article/eenews/2018/11/08/southern-cos-bill-for-hurricane-michael-may-hit-550m-036270.

Figure 9



[53]

Q. ARE THERE ECONOMIC BENEFITS TO EXPANDING REGIONAL TIES BETWEEN UTILITIES AND TRANSMISSION OPERATORS?

A. Yes. A 2023 report on the value of transmission during Winter Storm Elliot explains that "a region that primarily exports power during one severe weather event is likely to benefit from imports during another event."[54] In fact, had there been adequate transmission times between Texas and the Southeast, the "modest investments to increase power flows" that could have saved lives during Winter Storm Uri also could have provided reverse power flows during Elliott, and over the course of the two events provided close to $2 billions in value.[55] Similarly, A 2022 Energy Systems Integration

[53] Energy Information Administration, *Hurricane Michael Electricity Status Report*, at 3, October 12, 2018, available at https://www.eia.gov/special/disruptions/hurricane/michael/pdf/update_10122018.pdf.

[54] Grid Strategies, *The Value of Transmission During Winter Storm Elliott*, at 5, prepared for ACORE, February 2023, available at https://acore.org/wp-content/uploads/2023/02/ACORE-The-Value-of-Transmission-During-Winter-Storm-Elliott.pdf.

[55] *Id.* (finding that a one GW transmission line between the Electric Reliability Council of Texas (ERCOT) and TVA would have provided nearly $95 million in value, mostly to TVA customers. That adds to the nearly $1 billion in value that line, flowing in the other direction, would have provided Texans suffering through outages during Winter Storm Uri in February 2021.)

Group (ESIG) report on multi-value transmission planning highlights the relatively low cost of building out transmission to mitigate the impacts of climate events compared to the high-cost implications of said climate events to ratepayers.[56] Specifically, the analysis projects a potential 2 GW HVDC interregional line between ERCOT and Southern Company could "avert $2.7 billion of unserved energy over 30 years depending on the loss of load expectation (LOLE)."[57]

D. Georgia Power fails to account for changing generation needs in the region.

Q. DO YOU HAVE ANY OTHER COMMENTS ON GEORGIA POWERS UPDATED IRP PROPOSAL?

A. Yes. I am concerned about the resources that Georgia Power is proposing to procure as they match neither the climate/sustainability goals of the Company or of its projected load customers. And unlike transmission, which is resource neutral, lock Georgia Power into purchasing untenable power for its customers.

Q. PLEASE DESCRIBE THE COMPANY'S CORPORATE CLIMATE/ SUSTAINABILITY GOALS?

A. Southern Company's goal is to reach net zero greenhouse gas emissions by 2050, with an interim goal of 50% reduction in emissions by 2030 compared to a 2007 baseline. This

[56] Energy Systems Integration Group, *Multi-Value Transmission Planning for a Clean Energy Future*, at 55, June 2022, available at https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

[57] *Id.*

covers company-wide operations and includes their equity-share of Scope 1 emissions from all electricity and natural gas operations.[58]

Q. ARE THE GOALS VOLUNTARY OR STATE IMPOSED REQUIREMENTS?

A. At the moment, they are voluntary as Georgia does not have any statewide climate or carbon reduction goals. According to the Center for Climate and Energy Solutions: "33 states have released a climate action plan or are in the process of revising or developing one. This includes 32 states that have released plans and 1 state that is updating its plan,"[59] but Georgia is not one those states.

Q. WHY DO YOU SAY, "AT THE MOMENT"?

A. Georgia is currently developing climate action plan to reduce its greenhouse gas emissions, with an initial draft expected in Q1 2024.

Q. WHO IS DEVELOPING THE PLAN? WHAT IS THE TIMELINE FOR THE PLAN?

A. On June 30, 2023, EPA awarded Georgia $3 million through a Climate Pollution Reduction Grant to develop a state-wide climate action plan.[60] The EPA grant requires the following three key deliverables:

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[58] Southern Company, *Southern Company Emissions Reduction Progress and Reporting*, November 2023, available at https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/net-zero-transition/esg-emissions-reduction-reporting-fact-sheet.pdf.

[59] Center for Climate and Energy Solutions (C2ES), *U.S. State Climate Action Plans*, available at https://www.c2es.org/document/climate-action-plans/, last accessed Feb. 15, 2024.

[60] EPA, *Climate Pollution Reduction Grants: Planning Grants Program, Status of Grant Awards for States*, available at https://www.epa.gov/system/files/documents/2023-09/cprg_planning_grant_award_status.pdf, last updated October 10, 2023.

- March 2024: Priority Climate Action Plan (PCAP);
- June 2025: Comprehensive Climate Action Plan (CCAP); and
- Summer 2027: Status Report deadline.[61]

According to Georgia's Environmental Protection Division, its "Air Protection Branch will work with various state agencies, the Atlanta Regional Commission, industry, community and environmental organizations, and other stakeholders to develop Georgia's climate action plan. This plan will include a GHG emissions inventory, potential GHG reduction measures, and a low-income and disadvantaged communities (LIDAC) benefits analysis."[62]

Q. YOU MENTION CUSTOMER CLIMATE GOALS, CAN YOU SPEAK MORE TO THIS ISSUE?

A. When asked in Data Request No. STF-DEA-4-10 whether it "assess[ed] and incorporate[d] the clean energy requirements or preferences of each new load customer into the planning process?," the Company responded that it "often discusses the benefits and eligibility criteria for potential new large load customers to participate in one or more of Georgia Power's customer renewable programs, such as the Clean and Renewable Energy Subscription ("CARES") Program, the Flex Renewable Energy Credit ("REC") Program, the Retail REC Retirement ("R3") Program, or other renewable program solutions as outlined on Georgia Power's website." However, the Company did not

[61] Georgia Environmental Protection Division, *Georgia Climate Pollution Reduction Grant*, available at https://epd.georgia.gov/georgia-climate-pollution-reduction-grant, last accessed Feb. 15, 2024.

[62] *Id.*

provide any evidence that it accounted for the climate preferences of its new large load customers when preparing the menu of generation options in its Updated IRP.

For example, based on publicly available data, the following large industrial have announced plans to build, or are in the process of building, manufacturing plants in or near Georgia Power's footprint:

- Hyundai Motor Group and LG Energy Solutions plan to construct a $4.3 billion EV battery manufacturing plant in Bryan County; Hyundai is also constructing a $5.5 billion Electric Vehicle Metaplant also in Bryan County and a $5 billion battery plant in Bartow County.[63]

- Rivian is constructing a $5 billion EV factory near Atlanta.[64]

- Qcells plans to expand is solar panel production by building a new 3.3-gigawatt plant in Bartow County.[65]

Each of these companies has strong sustainability goals which means they will want to procure energy that meets their goals. For example,

[63] Drew Kann and Greg Bluestein, *Hyundai, LG to build $4.3B battery plant near Savannah*, The Atlanta Journal-Constitution, May 25, 2023, available at https://www.ajc.com/news/breaking-hyundai-lg-to-build-43-billion-ev-plant-near-savannah/6RTYCW7645DKFABA6PCQRZPAUY/.

[64] *Id.*

[65] Drew Kann and Greg Bluestein, *Solar manufacturer Qcells confirms historic Georgia expansion plans*, The Atlanta Journal-Constitution, Jan. 11, 2023, available at https://www.ajc.com/news/solar-manufacturer-qcells-confirms-25-billion-georgia-expansion/4UQP6CMU3JFOBKF74K3UI56CVQ/.

- With respect to its business sites, the Hyundai Company aims to transition to 60% renewable energy by 2030, 90% by 2040, and 100% by 2045, and has a company-wide goal of achieving carbon neutrality by 2045.[66]

- LG Energy Solutions' targets are even more aggressive as it aims to achieve 100% renewable energy at all business sites by 2030, Scope 1&2 carbon neutrality by 2040, carbon neutrality through its entire value chain by 2050, and become carbon negative after 2050.[67]

- Similarly, Rivian's goal is by 2030 to power its normal manufacturing plants with "100% renewable energy on an annual basis and over 90% hourly carbon-free electricity" and use "100% renewable energy at all other nonmanufacturing facilities (service centers, offices, etc.)."[68]

- QCells parent company, Hanwha Solutions, has set a "Scope 1 and 2 emission reduction target of 35% in 2030 and 60% in 2040 compared to the emissions in 2018." And with respect to electricity, Hanwha Solutions' goal is to "increase the proportion of renewable energy powered-electricity use to 21% by 2030, 37% by

[66] Hyundai, *Road to Sustainability: 2023 Sustainability Report*, at 25, available at https://www.hyundai.com/content/hyundai/ww/data/csr/data/0000000051/attach/english/hmc-2023-sustainability-report-en-v5.pdf.

[67] LG Energy Solution, *2022 ESG Report*, at 28, available at https://www.lgensol.com/upload/file/sustainability/2022_LGES_ESG_Report_ENG_FF[0].pdf.

[68] Rivian, *2022 Impact Report*, at 37, available at https://downloads.rivian.com/2md5qhoeajym/3CR7C1icQE7AFqByg853rg/bf92b6dc374cdd4ec1eb55183d94e06e/2022_Rivian_Impact_Report.pdf.

2040, and 100% by 2050. Starting in 2023, [they] will increase the supply of solar-based renewable energy power through long-term REC purchase agreements."[69]

But the majority of the procurement options proposed by Georgia Power in its Updated IRP do not match these decarbonization goals.

Q. DOES GEORGIA POWER'S INTEGRATED RESOURCE PLAN ACCOUNT FOR ITS PARENT SOUTHERN COMPANY'S CARBON GOALS?

A. No. In Data Request No. STF-DEA-4-14, Georgia Power was asked "In designing transmission solutions for the proposed new load, did Georgia Power consider and align with Southern Company's internal targets regarding clean energy?" The response was that "specific clean energy targets did not impact the selection of transmission solutions."

Q. IS THERE OTHER EVIDENCE THAT GEORGIA POWER'S PLANS DO NOT ALIGN WITH SOUTHERN COMPANY'S GOALS?

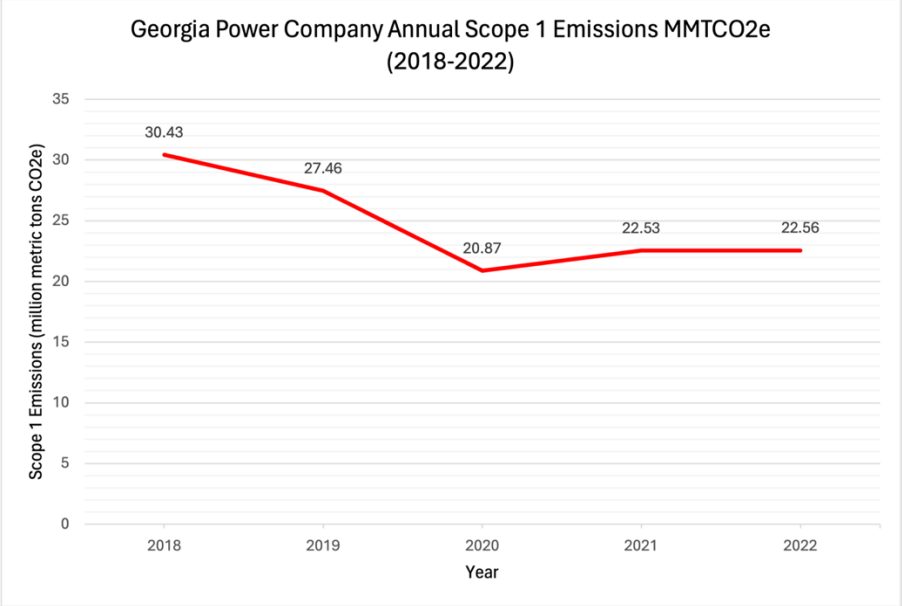
A. Yes. Southern Company voluntarily participates in the annual CDP Climate Change Disclosure reports and includes in those reports the annual greenhouse gas emissions data for Georgia Power.[70] In the latest 2023 CDP Climate Change questionnaire, Southern

[69] Hanwha Solutions, *Sustainable Solutions for All, Sustainability Report 2023*, at 49-51, available at https://www.hanwhasolutions.com/static/en/data/Hanwha_Solutions_Sustainability_Report_2023.pdf.

[70] Southern Company, CDP 2019 Climate Change Disclosure at 52, available at https://www.southerncompany.com/content/dam/southern-company/pdf/corpresponsibility/CDP-Climate-Disclosure-2019.pdf; Southern Company, CDP 2020 Climate Change Disclosure at 34, available at https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/2020_CDPClimateChangeDisclosure.pdf; Southern Company, CDP 2021 Climate Change Disclosure at 75, available at https://www.southerncompany.com/content/dam/southerncompany/pdfs/about/governance/reports/CDP-Climate-Disclosure-2021.pdf; Southern Company, CDP 2022 Climate Change Disclosure at 107, available at https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/2022_cdpclimatechangedisclosure.pdf; Southern Company, CDP 2023 Climate Change Disclosure at 120, available at

reported 22,559,027 metric tons of CO2 equivalent for Georgia Power Scope 1 emissions (see Figure below).[71] Note that the increase in emissions in 2021 was expected with electricity demand increases associated with COVID-19.[72]

Figure 10



[73]

Based on the utility's current trajectory, it is unlikely that Georgia Power will be able to meet the Company's internal targets. According to SACE's Tracking Decarbonization in the Southeast report, Georgia Power's current plans project a steeper emission reduction than that of Alabama Power and Mississippi Power, but there is a worrisome flattening of

https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/2023-cdp-climate-change-disclosure.pdf

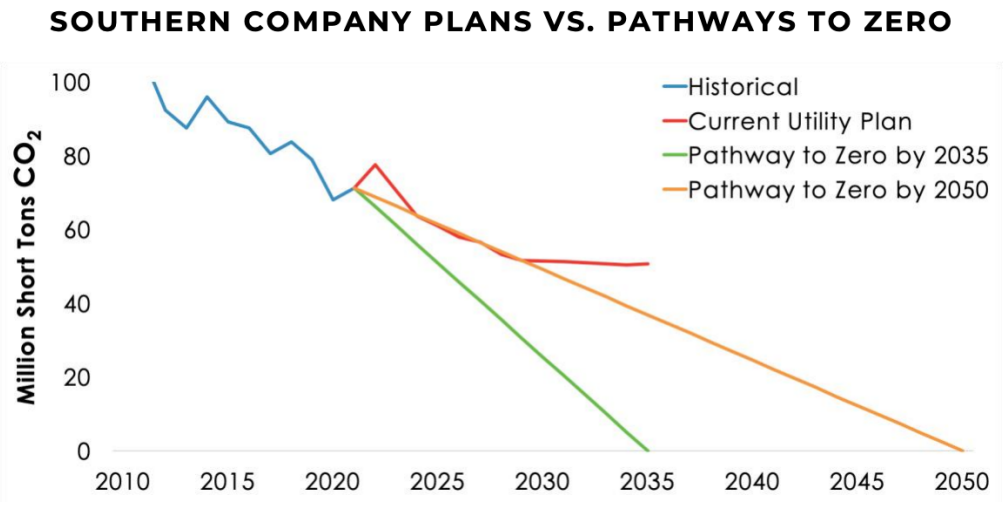
[71] Southern Company, CDP 2023 Climate Change Disclosure. Southern Company at 120, available at https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/2023-cdp-climate-change-disclosure.pdf

[72] Southern Alliance for Clean Energy, *Tracking Decarbonization in the Southeast: Fifth Edition*, at 6, 2023, available at https://www.cleanenergy.org/wp-content/uploads/Tracking-Decarbonization-in-the-Southeast-Fifth-Edition.pdf (SACE Decarbonization Report).

[73] Georgia Power Scope 1 emissions from 2018 to 2022 using CDP survey data.

emissions from all utilities after 2030 that will make it difficult for Southern Company to achieve zero emissions by 2050. As depicted in Figure 11 below, the pathways to zero emissions by 2035 and 2050 will require a significant departure from the Southern Company utilities current track of emission reductions.[74]

Figure 11



[75]

Q. IS THERE ANY OTHER EVIDENCE THAT GEORGIA POWER'S PLANS DO NOT ALIGN WITH SOUTHERN COMPANY'S GOALS?

A. Yes. In its Updated IRP, Georgia Power seeks, among other things, to enter into a power purchase agreement with Mississippi Power and to add three gas oil combustion turbine units at Yates. Both are problematic from a climate positive resource perspective.

[74] SACE Decarbonization Report at 6.

[75] *Id.*

Q. WHAT CONCERNS DO YOU HAVE WITH THE MISSISSIPPI POWER PURCHASE AGREEMENT?

A. Per Georgia Power's own admission, the Mississippi Power PPA is "not unit specific and may be supplied by any resource in the Mississippi Power fleet."[76] That said, the Company's witness also explains that "in the absence of the Mississippi Power PPA, several Mississippi Power resources would be retired and removed from the Southern Company pool. The existence of the Mississippi Power PPA ensures that these resources will continue to be part of the Southern Company pool and that the power produced will be designated for service to Georgia Power's customers."[77]

In additional responses it becomes clearer that the Mississippi PPA concerns fossil resources. Specifically, in response to Data Request No. STF-JKA-2-20, the Georgia Power witness explains that the reason the Company negotiated a term beginning on January 1, 2024, well before its increased load needs commence, was "because Mississippi Power was ordered to retire approximately 950 MW of capacity by the end of 2027 or show with detailed evidence why continued operation of the resources is in the best interests of its customers. . .. By purchasing 750 MW from Mississippi Power through this PPA, Georgia Power ensures that this resource [] remains in the Southern Company pool." These plants are fossil fueled and the Mississippi PSC ordered their retirement because they were uneconomic for Mississippi ratepayers. Yet Georgia Power

[76] Response to Data Request No. STF-JKA-4-11(d).

[77] *Id.*

seeks to continue to run the uneconomic and carbon emitting plants by having Georgia customers pay for the output.

Q. WHY DO YOU HAVE CONCERNS ABOUT THE DUAL FIRED POWER PLANT AT PLANT YATES 8-10.

A. Though the IRP update touts the natural gas aspects of the plants, discovery makes clear that Georgia Power plans to run these plants primarily on oil due to natural gas supply constraints, especially in cold weather months. Specifically, in response to Data Request No. STF-JKA-2-22, Georgia Power states that:

> Plant Yates Units 8-10 are dual fuel units. They can operate on natural gas as available, but they are unlikely to have reliable supply of natural gas during peak winter periods without firm transportation ("FT"). No FT has been procured for these units. Therefore, these units will be supplied with oil to support continued operation during peak conditions. These units will be able to utilize gas when FT is available from other units such as the Plant Yates steam units or when interruptible pipeline transportation is available. . . Plant Yates Units 8-10 will primarily run on fuel oil during peak winter and summer periods when the pipeline is constrained. No FT or additional gas capacity is being proposed to support these units since these units can burn oil year around.

In response to Data Request No. STF-JKA-2-14, the Company provides a similar response about constrained gas access stating that:

> The Company assumed oil dispatch for new generic combustion turbines ("CTs") because the pipelines serving the Company region have become increasingly constrained and less flexible in recent years. These constraints limit the amount of swing and daily imbalance through frequent issuance of daily Operational Flow Orders (i.e., curtailment of gas supply). These constraints bind the Southern

> Company retail operating companies' ability to operate any of its natural gas units on the same pipeline system, including new CTs. The Company can successfully manage this through the usage of fuel oil. Additionally, the ability to construct new pipeline infrastructure to alleviate pipeline constraints has been very challenging (e.g., Mountain Valley Pipeline). Therefore, assuming new pipeline infrastructure will be available for all future natural gas units is unrealistic. Given the current operational realities and the challenges facing the pipeline infrastructure industry, the Company assumes the most reliable operational plan for new generic expansion CTs is for them to be dual-fueled with the ability to burn fuel oil year-round and plan to be augmented with natural gas when it is available.

Q. WHY IS THAT A PROBLEM?

A. Carbon emissions are significantly higher when oil is burned instead of natural gas (which itself is significantly higher than using renewable resources to produce electricity). Table 1 provides Energy Information Administration[78] data for the generation (kWh), carbon emission (MT CO_2), and fuel consumption (MMBtu) data from five plants in the state of Georgia that have units that run on gas and petroleum. Two of these plants, McIntosh and Robins, are owned by Georgia Power, and a third, Dahlberg, is owned by Southern Company. Using the EIA data to calculate carbon dioxide emissions per energy output, it is clear that each plant emitted more carbon dioxide to produce the same amount of electricity when burning oil versus natural gas.

[78] Energy Information Administration, *Emission by Plant and Region*, "2022 Emissions by plant for CO2, SO2, and NOx," available at https://www.eia.gov/electricity/data/emissions/.

Table 1

Plant Name	Fuel	Generation (kWh)	MTCO2	Fuel Consumption (MMBtu)	lbs of CO2/MMBtu	lbs of CO2/MWh	Carbon intensity of NG v. DFO
Dahlberg	Gas (NG)	313,401,902	187,483	3,543,441	116.65	1318.85	71.37%
Dahlberg	Pet (DFO)	2,862,098	2,399	32,361	163.43	1847.90	
Talbot County Energy	Gas (NG)	604,584,554	382,510	7,229,446	116.65	1394.82	71.39%
Talbot County Energy	Pet (DFO)	812,446	720	9,716	163.37	1953.76	
McIntosh	Gas (NG)	35,571,054	29,372	555,139	116.64	1820.42	82.16%
McIntosh	Pet (DFO)	48,720,946	48,966	660,452	163.45	2215.71	
Robins	Gas (NG)	7,195,503	1,472	27,815	116.67	451.00	71.40%
Robins	Pet (DFO)	2,708,497	776	10,471	163.38	631.64	
MPC Generating	Gas (NG)	145,449,482	88,612	1,674,761	116.65	1343.12	71.38%
MPC Generating	Pet (DFO)	3,525,517	3,009	40,582	163.46	1881.63	

Q. DO YOU HAVE ANY OTHER CONCERNS?

A. Yes. The Updated IRP and associated data responses indicate that Georgia Power is considering extending the retirement dates of its coal plants. Specifically, the Updated IRP states that

> In the 2022 IRP Final Order, the Commission approved the retirement and decertification of Plant Scherer Unit 3 and Plant Gaston Units 1-4 and Unit A by December 31, 2028. With continuing increases to the projected load forecast and capacity needs following 2028, the Company will likely evaluate extending the operation of certain units, particularly Plant Scherer Unit 3, beyond 2028.[79]

Moreover, in response to Data Request No. STF-JKA-2-8 the Company witness states that:

> with the increase in capacity needs in 2028 and beyond, the Company is assuming Bowen Units 1-2 will retire at the end

[79] Updated IRP at 27.

of 2035 for planning purposes. Also, while the current assumed retirement date for Scherer Unit 3 and Plant Gaston Units 1-4 and Unit A are at the end of 2028, the Company will likely evaluate extending operation of certain units beyond 2028 in the 2025 IRP.

Q. WHY IS THIS CONCERNING?

A. Rather than evolving its system needs and looking to build a network that is future proof, the utility is looking backwards to continue operating plants that the affiliate-owner itself found are uneconomic and misaligned with the Company's goals. Georgia Power should be increasing its network capacity to procure resources that the Company and its customers want.

IV. RECOMMENDATIONS

Q. DO YOU HAVE RECOMMENDATIONS TO ADDRESS THE CONCERNS AND DEFICIENCIES THAT YOU HAVE RAISED ABOVE?

A. Yes. First and foremost, the Commission should require Georgia Power to refile the Updated IRP with proposed transmission solutions, and to include in that review both new and upgrade projects. While Georgia Power sweepingly declares that there is not sufficient time to incorporate transmission projects, it provides no data to back its claim. Further, the Company failed to study any GETS solutions and there is scant evidence of any reconductoring analysis—both of which are solutions that can be implemented over short timelines. In directing Georgia Power to conduct a more robust transmission analysis, the Commission should also require the Company to base its economic analysis on a life-cycle economic cost and benefit assessment which includes not only the capital

costs of new infrastructure, but also the efficiency, reliability, and generation access gains over the lifecycle of the proposed project.

Moreover, the Commission should require Georgia Power to consider federal financing options in its economic calculations. In its response to Data Request No. STF-PIA-7-1, Georgia Power explained that its "Transmission planning does not consider any assumptions, costs and benefits related to federal, state, and local tax incentives, grants, loan subsidies or other benefits in its analyses on transmission needs and investments."

But these incentives and subsidies can play a key role in making transmission solutions more economic. For example, the Department of Energy Loan Program Office's (LPO) Energy Infrastructure Reinvestment Program (EIR) helps finance projects that "retool, repower, repurpose, or replace" certain aging infrastructure, this includes "reconductoring transmission lines and upgrading voltage" and replacing retired power plants with "transmission interconnection to off-site clean energy."[80] And the Department of Energy's Grid Deployment Office offers several programs to finance the construction and upgrade of transmission lines including the Transmission Facilitation Program, Grid Resilience and Innovation Partnerships (GRIP) Program, and Grid Resilience Grants.[81]

[80] *See, e.g.* U.S. Department of Energy, *Title 17 Clean Energy Financing – Energy Infrastructure Reinvestment*, available at https://www.energy.gov/lpo/energy-infrastructure-reinvestment.

[81] *See, e.g.* U.S. Department of Energy, *Federal Financing Tools*, available at https://www.energy.gov/gdo/federal-financing-tools; *see also* Department of Energy, *Innovative Grid Deployment: Pathways to Commercial Liftoff*, Dec. 2023, available at https://www.energy.gov/sites/default/files/2023-12/Grid%20Liftoff%20Webinar%20Final.pdf.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. The Commission should continue to evolve its transmission planning processes and direct Georgia Power to conduct a proactive and multivalue, rather than reactive, planning analysis in concert with its three-year IRP filing. In making this recommendation, I also recommend the Commission adopt SACE's 2022 IRP recommendation to "[e]stablish a Transmission Planning Collaborative that includes opportunities for meaningful engagement by interested stakeholders to enable consideration of economic transmission and distribution system investments and alternatives."[82]

These process and planning improvements will aid both Georgia Power's own and the SERTP regional planning process. In the Commission's own words, "This type of transparency in transmission planning will facilitate better decision-making compared to the [information] that the Commission [is] currently receiv[ing]."[83]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

[82] Docket No. 44160, SACE and Southface Brief at 11-13.

[83] IRP Order at ¶ 11.

MR. JACOB: Finally, I would ask that Attachment 1 to Witness Patel's prefiled direct testimony be marked for identification as SACE Exhibit 1.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as SACE Exhibit 1.)

BY MR. JACOB:

Q Ms. Patel, did you prepare a summary of your testimony?

A I did.

Q Okay. And before you deliver that, did you also prepare a demonstrative handout to accompany that summary?

A I did.

MR. JACOB: I had pre-circulated that last week, and I have copies here today for anybody that does not have it.

Would you like me to distribute those?

CHAIRMAN SHAW: Yes, that would be good. We have got a lot of papers up here, so it would help to make sure we get the right --

MR. JACOB: I am sure you do. May we approach?

CHAIRMAN SHAW: Sure.

MR. JACOB: Okay. Mr. Chairman, with your

permission, I would like to ask Witness Patel to deliver her summary.

CHAIRMAN SHAW: Sure. You may proceed.

A Thank you. Good afternoon, Mr. Chairman and Commissioners; and I thank you for the opportunity to respond to Georgia Power Company's updated IRP filing. My testimony concerns the importance of examining the full spectrum of supply side solutions in an IRP and the lack of transmission modernization and expansion solutions in Georgia Power's IRP update.

To meet the unprecedented load growth that underpins the company's filing, Georgia Power should be presenting cost-effective solutions that minimize ratepayer impacts while maximizing reliability. The company is aware of transmissions' role as a supply side resource and that it is needed to both expand generation supply options, especially existing generation supply options.

But Georgia Power's proposed package fails to proactively consider whether transmission solutions such as reconductoring with high-performance conductors, installing grid enhancing technologies, or building new transmission could be used more cost effectively to meet the increased demand.

While Georgia Power claims that solutions other

than the ones it presented have long lead times, the evidence is to the contrary. Reconductoring with high-performance conductors, for example, can be completed in less than three years and even faster if using existing poles and infrastructure.

In addition to increasing carrying capacity from existing resources, high-capacity conductors increase resiliency, reduce transmission line losses, and offer benefits that outweigh the costs. The reconductoring time frame matches the timing of expected load additions to Georgia Power's system. And although I do not list them specifically in my testimony, based on the questions that both the Commissioners and others were asking yesterday, I do have examples of where these technologies have been used, if you are interested.

In offering only a limited set of generation solutions, Georgia Power is missing the moment to build a grid that is needed to reliably and economically serve customers now and in the future. As presented in Figures 4 and 1 of my testimony, which are provided for your convenience in the demonstrative, Georgia Power's existing system consists primarily of low voltage, 115 kV and below, lines concentrated in the northern end of its footprint.

It has a constrained system, and it

acknowledges that it is a constrained system. In its updated IRP, Georgia Power did not study any potential solutions that would unlock increased capacity within Georgia, including potential south-to-north transmission solutions that could provide significant access to the renewable potential in the southern portion of the state. Georgia Power's proposed solutions are out of sync with the challenges facing the energy system today.

For example, in addition to significant load growth, the region has been experiencing increasing severe weather patterns, which I know you have heard from other witnesses this week -- yesterday and today.

Figure 8 of my testimony provides data from the National Oceanic and Atmospheric Administration, or NOAA, depicting 40-plus years of disaster events that cost more than a billion dollars in Georgia. This is on the back page of the demonstrative.

As the graph shows, these events have been increasing in severity and frequency. During several of these events, including Winter Storm Elliott, resources within the southern balancing authority area and, in particular gas resources, were unable to perform when required. Power imports, mainly from Florida, helped keep the lights on in this region.

As weather patterns are bigger than any one

transmission footprint or utility footprint, it is important to maintain and build strong connections with neighbor balancing areas. But neither the updated IRP nor Georgia Power's transmission study, which was filed in the regular IRP docket, examined proactive transmission solutions.

Georgia Power's proposed solutions are also out of sync with the goals of its own parent company. As others have mentioned, Southern Company has a goal to reach net zero greenhouse gas emissions by 2050, with an interim goal of 50 percent reduction in emissions by 2030, compared to a 2007 baseline.

Southern's goals are similar to many of the large manufacturers who have announced plans to site plants within Georgia Power territory. Rather than looking to the future and identifying resources that are both more cost-effective and more aligned with its parent company and its customers' goals, Georgia Power has proposed to meet its increased need primarily by entering into PPA to support plants that the Mississippi utility commission has found to be uneconomic and has directed its utility retire.

In short, Georgia Power's failure to examine transmission development and upgrade solutions robs the Commission of the opportunity to conduct a thorough

analysis of whether there are transmission alternatives that would increase reliability, be more cost-effective in increasing the identified load growth.

SACE respectfully requests that the Commission direct Georgia Power to file supplemental testimony examining the cost and benefits of using high-capacity conductors, grid enhancing technologies, and new transmission as alternative mechanisms to serve the identified load growth, to include as part of its next three-year IRP filing a proactive and multivalue scenario analysis.

As mentioned by other witnesses, multi-value scenario analysis helps utilities and the Commission better address the uncertainty of the different load in generation retirement futures.

Thank you, again, for your time.

MR. JACOB: Mr. Chairman, the witness is available for questions from the Commission and cross-examination by the parties.

CHAIRMAN SHAW: All right. Thank you, Mr. Jacobs.

Commissioners, any questions from the panel?

(No response.)

CHAIRMAN SHAW: All right. We will start with cross. Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

(No response.)

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

(No response.)

CHAIRMAN SHAW: Mr. Jones, I think, was out, but he said he didn't have any more questions, any cross.

Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE -- well, Southern Renewable Energy Association.

MR. MAHAN: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. MCNUTT: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: All right. Georgia Power.

MR. HEWITSON: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Ms. Patel, good to see you.

A Good to see you, as well.

Q Steve Hewitson on behalf of Georgia Power. On page 6, line 20, you state that transmission is a supply side resource; right?

A Correct.

Q Okay. And I believe I understand your position that transmission plays a role, but would you agree with me that transmission assets, the poles, the lines, reclosers, transformers, substations, things like that, do not actually generate any power?

A They do not, but they allow the power to move from one location to the other, so you want to maximize your capability to move that power.

Q But they are not a power generator?

A They are not.

Q Now, on page 11, lines 3 to 15, your testimony implies that Georgia Power should be investing in more 500 kV transmission lines; right?

A What I say in my testimony is that it would be good to examine the options to increase the capacity of your system. When you have a lower voltage transmission line, you are limited in the amount of power you can carry. And when you have unprecedented load growth, like the way that you identified in this filing and that's going on around the country, we need higher-capacity lines in order to move power more effectively.

Q Now, your testimony does not provide any analysis of the cost of replacing existing transmission lines with 500 kV lines; right?

A It does not, because there was no transmission analysis done to see which lines could be appropriately replaced with a higher-capacity line or where you could build new transmission. That's why I asked for a transmission analysis or at least analysis of some GETs and reconductoring that could be done on existing lines.

Q Right. But there was no discussion of the actual costs of what it takes to reconductor to a 500 kV line or to build a 500 kV line, in general?

A Well, you could reconductor to similar voltage and increase capacity, because the higher advanced conductors are more effective at carrying capacity, so you don't necessarily need to reconductor to a 500 kV line. And, no, I did not include the cost, because that depends on where it's located and whether you have a right-of-way. That's dependent on a lot of different factors.

Q Do you agree with me that installing a 500 kV line is generally more expensive than a 230 or a 115 line?

A Well, it depends. As Witness Goggin provided yesterday, there is evidence to say that it is more

cost-effective to install a higher-capacity line. So I -- it depends on the pathway. It depends on what your need is. It is a hard question to answer whether it is more expensive or less expensive, because the cost and benefits are different.

Q Right. But I asked about the costs. The costs are higher; right?

A But costs can't be looked at in a vacuum. You have to look at what your need is and why you are installing that line. I mean, I could say do I want to buy a Tesla or do I want to buy a dinky $1,000 used car? Depending on what my need is, that higher cost may be justified. So it depends on what your needs are.

Q Well, let's talk about those costs. In your discussion of proactive planning, on page 13, lines 9 through 20, is it fair to say that you believe Georgia Power should build a higher-capacity grid to serve future growth?

A I think that's something that Georgia Power should be looking at, whether it is cost-effective and worthwhile and benefits customers to build a higher-capacity grid, yes.

Q There is a cost to that; don't you agree?

A There is, but there is also a cost keeping the status quo and keeping a system that is aging in place

and trying to meet your needs with one-off solutions. There is -- there is a cost to everything, and so you have to look at what the most effective cost is.

Q And one of the factors that the company needs to look at and this Commission needs to balance is what that cost is, in terms of what the company needs at the time, because customers will pay for it; right?

A Right. But you should -- the better planning looks at broad -- looks at multiple scenarios. Right now you have identified that there is going to be significant load growth in the region, but you don't know exactly how much of that is going to show up. There could be some that do end up installing their data centers and their manufacturing facilities, and there could be companies that don't show up. So it is the responsibility of the utility, and, ultimately, the Commission, to pick out solutions that cost effectively serve the public based on whatever uncertainties and risks there are.

So if you are picking solutions in a piecemeal manner and saying, Here is our need. We have, you know, the significant load growth that we have, and we are only going to look at these three solutions, which is basically what the company did, you only looked at generation solutions, then you are not necessarily figuring out what is the best option for ratepayers in

the long run. Ratepayers have to pay all the costs at the end of the line, so you want to pick out what is -- what is going to most cost effectively meet not only your identified need but also reliability and economic and other concerns.

Q Are you aware of the cost analysis that the company did in the 2022 IRP regarding transmission solutions for bringing load -- or bringing generation from South Georgia to up north?

A At a very high level. I was not involved in the IRP, so I did not look at every one of those documents. But, yes, at a high level.

Q All right. On page 22, lines 2 to 4, you say it is possible that if the company had conducted a multivalue analysis, the company could have found it more beneficial from a cost perspective to combine renewables with new transmission and transmission upgrades; right?

A Do you mind mentioning that line? That sounds familiar, but just...

Q 22, lines 2 to 4. Sorry, I kind of go quickly.

A Yeah. No, no, no, that's okay. Not a problem.

Q Now, you did not include in your testimony any analysis of the lifetime combined cost of new transmission plus renewables; right?

A I did not, because, again, it depends on where

the path is, what -- what is available. I don't have that data to conduct such an analysis.

Q Okay. On page 24 you highlight Michigan's integrated generation and transmission plant.

A Correct.

Q Are you aware of any of those Michigan IRP requirements, that you refer to, that Georgia Power does not already do?

A I believe the last one is the biggest one that was an issue about transmission upgrades resulting in increasing system efficiency and reducing line losses, that the transmission -- at least the public version, because I wasn't a party to the IRP, nor does SACE have discovery rights -- the public version of the transmission filing that was filed this February, that the Commission directed last year, was very oriented towards reliability analysis, which I believe a witness yesterday testified about, as well. And so it is not looking at, broadly, what are the needs that could help improve the system overall. It is looking at where the reliability violations and solving those needs.

A proactive multivalue analysis has a broader viewpoint where you are looking at multiple benefits beyond just reliability, and you are also looking at multiple scenarios, so that it is not just one future

scenario. Again, right now, we don't know -- there is a lot of uncertainty around this load growth. We know load growth is happening, but we don't know the exact number that's going to end up coming on the system.

So by conducting a multivalue analysis -- which is what Michigan has been directing its utilities, which FERC is asking utilities to do -- it helps us figure out what are the different solutions out there, and maybe there are ones that address all of the different options that would be more cost-effective in the long run.

So that's what Georgia is not doing right now. It is looking -- it is a traditional way of planning. There is nothing -- that's the way utilities have done it. But the energy environment is changing, as you have identified, unprecedented; right. That was in your filing -- in Georgia Power's filing multiple times. We are in unprecedented times, so we need to able to react to that.

Q But as you said, you haven't reviewed all of Georgia Power's planning materials?

A I reviewed the transmission analysis that was filed in February, which was supposed to be -- I believe, the company is supposed to file annually, now, a transmission analysis.

Q On page 41, line 6 to 7, this is about the

carbon goals, you testified regarding Southern Company's net zero goal, that, "Based on the utility's current trajectory, it is unlikely that Georgia Power will be able to meet the company's internal targets." Do you see that?

A Yes.

Q Now, you are aware that the internal targets you are referencing are set by Southern Company, which is Georgia Power's parent company; right?

A Yes.

Q Are you aware that, even though Georgia Power has not set a specific target, by working with this Commission through the IRP process, the company has already achieved a 60 percent reduction from the 2007 levels, which is well ahead of Southern Company target of 50 percent by 2050?

A Yes. But if you look on page 42, there is a graph that shows -- both the graph on page 41 and 42, which is Figure 2, 10 and 11, shows that there has been a flattening of the decrease in reductions. And so that's the concern is that there needs to be significant changes if you are going to continue on the pathway to carbon neutrality by 2050.

Q But you agree that, sitting here today, we are already ahead of schedule?

A I don't know the exact numbers offhand, but I -- I believe that's right, subject to check.

Q Thank you, Ms. Patel. That's all I have for you today.

A Okay. Thank you.

CHAIRMAN SHAW: Redirect?

REDIRECT EXAMINATION

BY MR. JACOB:

Q Mr. Hewitson asked you whether or not you had evaluated the costs of any of the significant transmission upgrades. And while they didn't file those -- the costs for the north-south transmission in this docket, and Mr. Hewitson asked you about a docket that you were not involved in, is there anything that you can add from reviewing the analysis that SERTP did of that same north-south transmission option?

A Not off the top of my head, but I am happy to file additional information, if necessary.

Q I wasn't sure if there was a way that we could get to the answer that I think he was looking for. Let's see.

A If I may, can I add one thing? The north-south transmission line, I believe, is to allow for power imports from the south, which would be largely renewable and are lower cost energy than some of the other plants.

So, presumably, although I don't know the costs for the transmission line offhand, the all -- our bills are generation, transmission, and distribution. So the generation, even if the transmission has cost, if it's bringing in lower cost power, the overall bill to customers ends up being more cost-effective.

Q Mr. Hewitson also asked you a lot of questions about the longer-term transmission upgrades, but is it fair to say that your testimony is a combination of both some short-term actions and some long-term actions?

A Yes, correct. Transmission generally takes quite a while to build. It's not a quick solution. But the advanced high-capacity conductors and GETs are very quick solutions. They can be used in the interim while transmission planning is taking place and larger transmission lines are being -- the construction process and the bidding and permitting and all of that is occurring.

Also, some of those solutions aren't just interim solutions. They can be paired with longer-term transmission solutions. So they are quite cost-effective in the long run.

Q Last thing, I think. Would the kinds of transmission enhancement that you are recommending enable the existing resources of Georgia Power to meet more of

the new large loads that we are talking about without defaulting to new capacity resources?

A Yes. And there has been other utilities that have used it for that purpose. To unlock capacity that was due -- that wasn't able to be delivered due to congestion, they were able to put in either reconductoring or GETs to increase the capacity availability of existing resources and maximize the use of the existing system.

Q Thank you.

MR. JACOB: That's all I have got. Let's see. I request that SACE Exhibit 1 be admitted into evidence. And just for clarification, the demonstrative handout is just duplicates of things that was already prefiled as part of the Witness Patel's testimony, so it shouldn't need to be introduced into evidence. But SACE Exhibit 1 would need to be.

CHAIRMAN SHAW: So marked.

(SACE Exhibit 1 was admitted into evidence.)

MR. JACOB: Thank you. And may the witness be excused?

CHAIRMAN SHAW: Yes, you may. Thank you.

MS. PATEL: Thank you.

CHAIRMAN SHAW: All right. Our next panel will

be Southern Renewable Energy Association.

MR. COX: Thank you, Mr. Chairman. My name is Whit Cox, and I am appearing on behalf of the Southern Renewable Energy Association. At this time, I will call the Southern Renewable Energy Association's panel of witnesses, Mr. Arne Olson and Mr. Jonathon Monken.

With your permission, I will swear in the witnesses.

Thereupon,

ARNE OLSON,
JONATHON MONKEN,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. COX:

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

A (Witness Olson) Yes, my name is Arne Olson. I am a senior partner with Energy and Environmental Economics, otherwise known an E3; and I lead our integrated system planning practice.

Q Thank you. Mr. Monken, please state your full name, employer, and responsibilities for the record.

A (Witness Monken) Yes. My name is Jonathon Monken. I am a principal at Converge Strategies.

Q Thank you.

Mr. Olson, did you cause 45 pages of testimony to be filed in this docket on February 15th?

A (Witness Olson) I did.

Q Did you also cause to be filed with your testimony a copy of your resume as your exhibit?

A (Witness Olson) Yes.

Q And are there any corrections that you need to make to your prefiled testimony or exhibit at this time?

A (Witness Olson) No.

Q If I were to ask you the same questions today, would your responses be the same?

A (Witness Olson) Yes.

MR. COX: At this time, I move to admit the prefiled direct testimony of Mr. Olson into the record.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Arne Olson follows:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's 2023	**)**	**Docket No. 55378**
Integrated Resource Plan Update	**)**	

DIRECT TESTIMONY OF ARNE OLSON

ON BEHALF OF

SOUTHERN RENEWABLE ENERGY ASSOCIATION

February 15, 2024

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1 Introduction

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

A. My name is Arne Olson. I am a senior partner at Energy and Environmental Economics, Inc. (E3), located at 44 Montgomery Street, Suite 1500, San Francisco, CA, 94104.

Q. PLEASE STATE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 30 years of experience in the electric utility business in consulting and state government. Since joining E3 in 2002, I have worked extensively in the areas of resource planning, asset valuation, transmission, market design, and energy policy. I currently lead E3's Integrated System Planning practice and contribute frequently to projects across many practice areas. Prior to joining E3 in 2002, I served for six years as an energy policy specialist at the Washington Department of Commerce.

I received my M.S. in International Energy Management & Policy from the University of Pennsylvania and B.S. degrees in Mathematical Sciences and Statistics from the University of Washington. The attached résumé further describes my qualifications, experience, and publications.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN FRONT OF THE GEORGIA PUBLIC SERVICE COMMISSION?

A. Yes. In 2022, I testified before the Georgia Public Service Commission (Commission) on behalf of the Georgia Large Scale Solar Association on the matter of Georgia Power Company's (Georgia Power or the Company) 2022 Draft

Integrated Resource Plan in Docket No. 44160. My testimony evaluated the extent to which the Company incorporated prior recommendations for methodological improvements, and to provide additional recommendations, as warranted. Specifically, I provided a summary of IRP Best Practices and assessed how well Georgia Power's IRP practices aligned with them. Some of the recommendations related to Georgia Power's calculation of its capacity needs and accreditation of candidate resources toward that need remain relevant and will be reiterated in this testimony.

Additionally, I testified before this Commission in 2019 and 2020 on behalf of the Georgia Large Scale Solar Association on several topics including recommendations to improve system planning processes in order to create a level playing field among different candidate resources, capacity and energy payments to cogenerators under PURPA, and Georgia Power's Green Energy Program.

I have also provided expert testimony in legal or regulatory proceedings in California, Oregon, Colorado, New Mexico, Alberta, Ontario, Nova Scotia, and South Carolina. Notably, I testified before the Public Service Commission of South Carolina in 2023 on behalf of the South Carolina's Clean Energy Business Association on the topic of Santee Cooper's 2023 IRP. Additionally, in 2019 I testified before the Public Service Commission of South Carolina on behalf of the South Carolina Solar Business Alliance regarding Duke Energy's 2019 Integrated Resource Plan.

Additionally, I have presented at dozens of workshops and stakeholder forums in support of utility IRP processes and industry events related to resource planning.

Q. DO YOU HAVE OTHER EXPERIENCE RELEVANT TO THIS PROCEEDING?

A. Yes. I have served as the lead investigator in developing integrated resource plans for utilities and state agencies around North America. Much of my resource planning work has focused on helping utilities analyze the impacts of higher penetrations of variable renewable resources on their operations and investment decisions. Some examples of current and past projects include:

1. I am a co-author of Report Number 6 of the Lawrence Berkeley National Laboratory's "Future Electric Utility Regulation Series," entitled "The Future of Integrated Resource Planning."
2. For Xcel Energy, I led an effort to support development of Northern States Power's 2018-19 IRP examining high renewable scenarios within the context of the company's stated goal of completely decarbonizing their electric resource portfolio by 2050. My team recently presented results to a company leadership group that included the Chief Executive Officer, Chief Financial Officer, and several senior Vice Presidents of Xcel Energy, the parent company to Northern States Power.
3. For a group of 13 utilities in the Pacific Northwest, I led studies in 2017 and 2018 that examined scenarios achieving 50% renewables and up to

100% carbon reductions across the region, focusing on policy mechanisms to achieve the goals at least cost and on the nature and quantity of complementary resources that are needed to maintain reliable electric service.

4. In 2018, I led a study of the value of partially- and fully-dispatchable solar and solar + storage power plants on the Tampa Electric Company (TECO) system. The study was funded by First Solar but it involved extensive participation by a wide range of TECO staff and included detailed TECO power system data. First Solar and TECO jointly received a 2018 Top Innovators award from Public Utilities Fortnightly in conjunction with the study.

5. For Nova Scotia Power, I led a team that provided comprehensive support for their 2020 IRP process including a survey of resource options, calculation of a planning reserve margin and the contribution of wind and solar toward meeting reliability needs, a study of the role of the electric utility in meeting provincial greenhouse gas goals, and capacity expansion modeling of the cost, emissions and reliability implications of retiring their existing coal resources and replacing them with a combination of wind, hydro and thermal generation.

6. I have led teams that supported IRP processes for utilities across the country including the Sacramento Municipal Utilities District, Puget

Sound Energy, the Salt River Project, El Paso Electric, Omaha Public Power District, Black Hills Energy, and others.

7. I lead a team at E3 that supports the California Public Utilities Commission staff in developing a Reference System Plan for California and designing and implementing integrated resource planning standards for California load-serving entities.

8. I have led teams that perform analysis and provide strategic advice to support utility procurement activities including for Hawaiian Electric Company, Puget Sound Energy, NorthWestern Energy, El Paso Electric, and others.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY?

A. I was retained by the Southern Renewable Energy Association (SREA) to evaluate Georgia Power's integrated resource planning (IRP) practices and associated resource procurement practices, as they relate to the 2023 IRP Update. Recognizing that this update was developed outside of the normal triennial cycle with specific and limited purpose, I focus my testimony on matters that are most appropriate and reasonable for addressing in an interim period. My testimony is organized as follows:

- First, I review relevant comments that I raised as part of my previous testimony for Georgia Power's 2022 IRP and reiterate certain recommendations related to best practices for resource planning and capacity accreditation.

- Second, I discuss best practices related to transmission planning and provide recommendations for improving Georgia Power's transmission planning process as it relates to resource planning and procurement.
- Third, I identify best practices for resource procurement, evaluate the extent to which Georgia Power's practices are consistent with them, and make recommendations to improve alignment.
- Finally, I conclude with a summary of the most significant concerns and recommendations for Georgia Power to improve its practices related to the 2023 IRP Update for the benefit of Georgia ratepayers.

2 Review of Best Practices for Resource Planning and Capacity Accreditation

Q. PLEASE BREIFLY SUMMARIZE INDUSTRY BEST PRACTICES FOR RESOURCE PLANNING.

A. Through extensive work with utilities across the United States and Canada, I have identified seven principles that represent best practices for resource planning. In brief, these best practices include: (1) Incorporate climate policy and impacts of climate change; (2) Include renewable energy and energy storage resources as candidate resources; (3) Determine capacity needs through robust, loss of load probability (LOLP) modeling; (4) Consider total resource cost (TRC) of demand-side resources; (5) Address operational flexibility and integration needs through detailed operational study; (6) Engage meaningfully with stakeholders; and, (7) Conduct all-source solicitations for procuring resource needs identified during

planning. While I have enunciated these first six principles in prior testimony in front of this Commission with regard to integrated resource planning best practices, I add here the seventh principle to highlight the importance for utilities to act on their plans by procuring resources in a fair and competitive "all-source" process that results in least-cost outcomes for ratepayers. I describe this principle in greater detail later in this testimony.

Q. HOW DOES GEORGIA POWER'S 2023 INTEGRATED RESOURCE PLAN UPDATE COMPARE TO THESE BEST PRACTICES?

A. Georgia Power is now including renewable and energy storage resources as candidate resource options in its capacity expansion modeling for the IRP and capturing the dispatch benefits associated with adding solar and storage separately and in combination. This is an improvement from the 2019 IRP. However, Georgia Power does not appropriately capture the increased capacity value of solar and battery storage when added in combination, relative to the standalone values, and thus continues to undervalue solar and storage resources relative to other types of generation. By only partially recognizing the reliability contributions of renewable energy and energy storage resources, Georgia Power will essentially over-build non-renewable capacity at a higher cost to ratepayers. With substantial resource additions projected in Georgia Power's 2023 IRP Update, it is critical for Georgia Power to employ a more accurate methodology for estimating the capacity contribution of these resources. I have identified this concern in prior testimony and detail my continued concerns later in this testimony.

Q. WHAT IS THE INDUSTRY BEST PRACTICE FOR CALCULATING THE CAPACITY VALUE OF RENEWABLE ENERGY AND ENERGY STORAGE RESOURCES?

A. Widely accepted best practice for capacity accreditation of renewable energy and energy storage resources is to use a rigorous, reliability-based model using loss of load probability (LOLP) to calculate Effective Load-Carrying Capability (ELCC). ELCCs are increasingly used throughout the industry to calculate a more accurate value of the capacity contribution of variable resources such as wind and solar, dispatch-limited resources such as energy storage or demand response, and hydroelectric resources that have characteristics of both variable and dispatch-limited resources.

In addition, an emerging best practice is to use ELCC to estimate the capacity contribution of "firm" resources such as natural gas. The ELCC of a gas unit may differ from its Unforced Capacity or UCAP value because loss-of-load events tend to occur during periods with an unusually high number of resource outages; that is, the combined outage rate of the fleet during loss of load hours tends to be higher than the expected loss-of-load for any individual resource, or the combined outage rate for the fleet during normal hours. This is due to the binary and asymmetric nature of the reliability challenge, where most resource outage states do not result in loss of load, but the "tail conditions" of a cumulative outage distribution that do result in loss-of-load represent conditions with higher-than-average resource outages. In addition, the generator may suffer from weatherization

or fuel availability issues which prevent it from performing at its highest capacity during critical events. The ELCC methodology allows the reliability contribution of various resources to be compared on a level playing field.

Q. WHAT ARE PORTFOLIO EFFECTS AS THEY RELATE TO SOLAR AND STORAGE ELCC VALUES?

A. The ELCC values of solar and storage have two key portfolio effects that must be captured accurately in IRP modeling in order to ensure selection of least-cost portfolios that minimize costs for ratepayers. First, solar and storage are subject to *saturation* effects – where the marginal capacity value of solar or storage declines as more of the resource is added. This phenomenon is well-understood and is captured by Georgia Power in its modeling. Second, there is a *diversity benefit* of adding solar and storage together. This diversity benefit accrues because as more solar capacity is installed, the summertime loss-of-load risk hours typically shift away from daylight hours when solar is generating into a shorter window in the evening hours between sundown and 10pm. These shorter loss-of-load events can more easily be avoided by limited duration (e.g., 4-hour) battery storage. Adding storage, in turn, improves the capacity value of solar by moving loss-of-load hours from the evening back into the shoulder hours, e.g., late afternoon, when solar production is low but non-zero.

Q. HOW IS THE DIVERSITY BENEFIT OF RENEWABLE ENERGY AND ENERGY STORAGE DETERMINED?

A. Figure 1 demonstrates the diversity benefits of installing both solar and storage in the Desert Southwest region, from a study that E3 completed for a consortium of the six largest electric utilities in the region.[1] The left-hand panel shows that the incremental capacity value from new solar in the region on top of the 3.6 GW of solar that is already installed, represented in the yellow area, is already very low. The second panel shows that incremental additions of four-hour lithium-ion battery storage, represented in the purple area, have very high capacity value, over 95% of the nameplate value, until approximately 8 GW are installed. The value for standalone 4-hour storage additions beyond 10 GW is very low, as another 10 GW of installations yields only 1 GW of capacity value. The third panel shows that when solar and storage are added in combination, the capacity value of the combined portfolio, represented in the purple hashed area, continues to grow without any noticeable saturation effects.

[1] https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf.

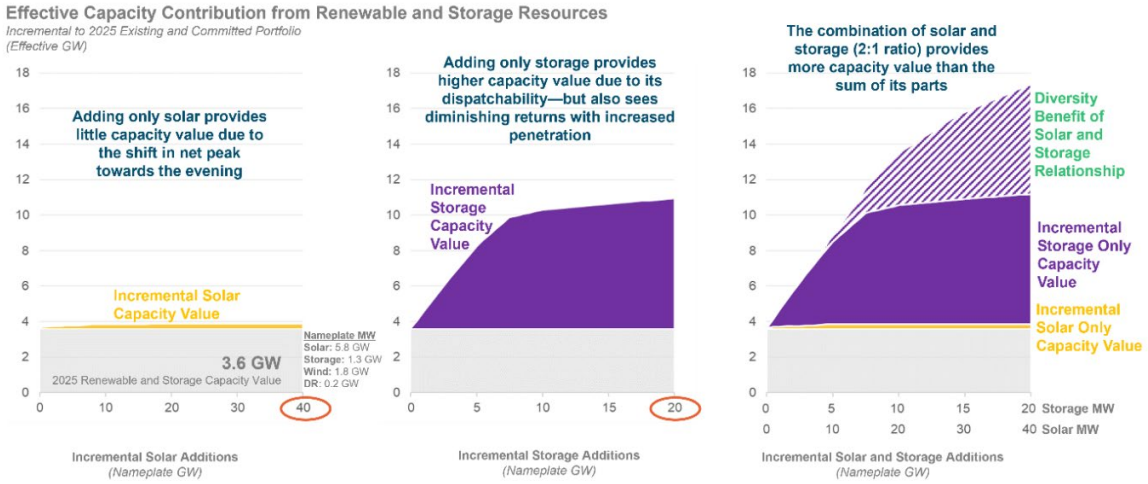
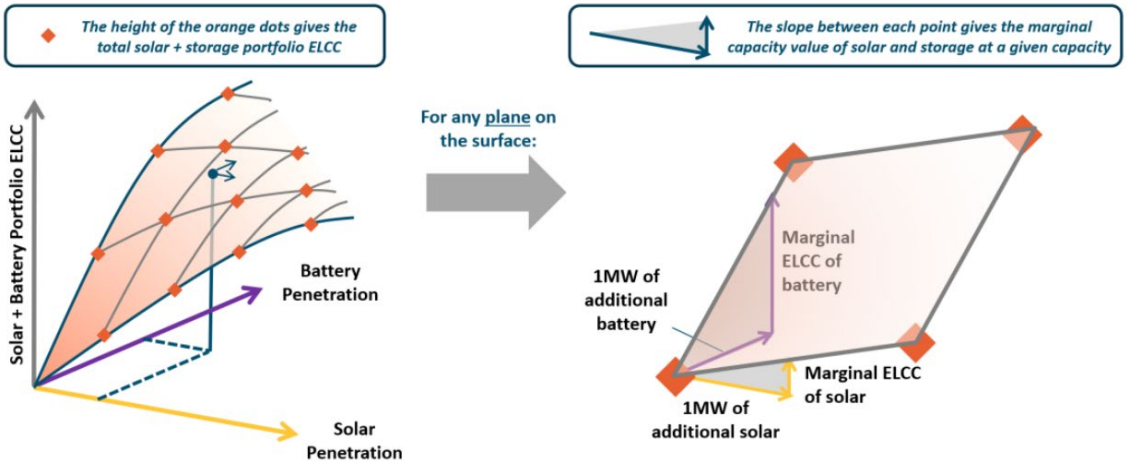


Figure 1. Solar and Storage Capacity Value with and without the Diversity/Interactive Benefit in the Desert Southwest

While many utilities have adopted single-resource ELCC curves for solar and storage, this practice only captures the *saturation* effect and not the *diversity benefit*. The complementary nature of solar and storage is best captured by a two-dimensional ELCC surface, as depicted in Figure 2 below. Georgia Power could take advantage of the functionality built into the SERVM model to calculate an ELCC surface that better captures the co-benefits of building both solar and storage.



Cumulative ELCC (MW)		Solar Cumulative Capacity (MW)							
		0	385	750	1,250	2,000	3,000	6,000	10,000
Storage Cumulative Capacity (MW)	0	0	208	303	324	330	335	336	338
	50	50	258	353	374	380	384	386	388
	200	199	407	504	523	530	535	536	538
	500	459	667	796	821	829	832	837	838
	1,000	656	864	999	1,135	1,215	1,244	1,264	1,270
	3,000	855	1,063	1,179	1,326	1,505	1,655	1,844	1,942
	5,000	920	1,128	1,254	1,403	1,605	1,806	2,096	2,312

Figure 2. Solar and Storage ELCC Surface from El Paso Electric's 2021 Integrated Resource Plan

Q. HOW ARE UTILITIES ADDRESSING THE CAPACITY VALUE OF HYBRID SOLAR + STORAGE PROJECTS?

A. Most utilities are now receiving bids from hybrid solar + storage projects with various levels of storage capacity and duration, in addition to standalone solar and standalone storage projects. If the utility does not use a two-dimensional solar and storage ELCC surface to reflect the combined contributions of projects that are not co-located, its calculations may unfairly favor co-located projects where synergies are more obvious. This would prevent the utility from achieving the least cost portfolio.

Q. ARE THERE EXAMPLES OF UTILITIES THAT UTILIZE THIS METHODOLOGY?

A. Yes, the most advanced utilities are using portfolio modeling approaches that are designed to consider variable renewable resources, energy storage, demand response, and other dispatch-limited resources alongside conventional generation such as natural gas. Specific utilities that use an ELCC methodology include Arizona Public Service,[2] NV Energy,[3] Xcel Energy,[4] and many others around the country.

To provide one concrete example, E3 supported El Paso Electric Company (EPE) in its 2021 IRP[5]. E3 utilized tools similar to the SERVM and Aurora models used by Georgia Power to select reliable resource portfolios. E3's RECAP model was used to establish a reliability target and to calculate a two-dimensional surface for solar and storage ELCC values. The surface was then used to select portfolios in capacity expansion modeling in PLEXOS LT to identify an optimal resource portfolio for EPE. This approach captures the portfolio effects of integrating higher levels of solar generation while also considering the diversity benefits of adding combinations of solar, wind and energy storage. EPE then used the PLEXOS model to evaluate bids received through an all-source RFP. This process enabled EPE to

[2] APS_IRP_2023_PUBLIC.pdf.
[3] 21-06 VOL3: NV Energy IRP TESTIMONY.
[4] HE_114-KLS-2-ELCC_Study_Report.pdf (xcelenergy.com); 2023 SPS-IRP Plan.pdf (xcelenergy.com); The-Resource-Plan-No-Appendices.pdf (xcelenergy.com).
[5] EPE 2021 Integrated Resource Plan.pdf (epelectric.com).

select a least-cost resource portfolio on behalf of its ratepayers in both the IRP and the procurement phases.

Q. HOW DOES GEORGIA POWER DETERMINE THE CAPACITY VALUE OF RENEWABLE ENERGY AND ENERGY STORAGE RESOURCES?

A. Georgia Power continues to treat renewable energy resources as standalone, energy-only resources, assigning them zero capacity value in its capacity expansion modeling.[6] Georgia Power models energy storage as standalone resources with energy arbitrage benefits and capacity benefits.[7] A capacity value equivalent to the full nameplate capacity of battery storage is credited to the earliest storage resources integrated into the system. Subsequent energy storage resources are progressively discounted as their ELCC is reduced due to saturation effects. Georgia Power accounts for this diminishing effect by parsing future energy storage assets into several different tranches, each with different capacity values, in the capacity expansion modeling.[8]

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[6] *See* Transcript of the January 17th, 2024 Hearing at p. 545, Georgia Power Economic Analysis of Capacity Resources, p. 2 (noting that the Company utilized the Aurora model to model the incremental costs and benefits of each resource it evaluated for the 2023 IRP Update); *See also* Georgia Power Supplemental Errata Filing, December 7, 2023; *See also* Transcript of the January 17th, 2024 Hearing at p. 193, Cross Examination by SREA Executive Director Simon Mahan ("(Witness Grubb) No. What Aurora – what the expansion plan model is doing is it is looking at solar from an energy production standpoint, and it is looking at storage from a capacity standpoint…it is looking at solar providing energy value and storage providing capacity [value]…Q Well, so does solar not get…some sort of an accredited value for Aurora, or is it set at zero? A (Witness Grubb) Not generic solar. Q It is set at zero in the model? A (Witness Grubb) It is set at zero.")

[7] *See* Georgia Power Supplemental Errata Filing, December 7, 2023.

[8] *See* Transcript of the January 17th, 2024 Hearing at p. 587 (A (Witness Grubb) "So once you have deployed a certain number of four-hour batteries, you need an eight-hour battery

Q. ARE THERE CAPACITY ACCREDITATION CONCERNS REGARDING THE COMPANY'S PROPOSED ASSETS IN THIS IRP?

A. Yes, the new Yates units are subject to transmission constraints that may restrict their capacity value. The new Yates units will only have the capability of providing 600 MW of output in both summer and winter until the transmission constraints are resolved by summer 2028.[9]

Further, the new Yates units and the BESS facilities at Robins and Moody AFB have all entered into the Southern Company generation interconnection queue as "Energy Resource Interconnection Service" (ERIS) requests.[10] ERIS-type service is a non-firm service that may be curtailed during system stress.[11] ERIS is a less robust transmission service, often requiring less study time and fewer physical upgrades as opposed to Network Resource Interconnection Service (NRIS). As described in a paper by the Nicholas Institute for Energy, Environment & Sustainability[12], FERC describes NRIS as follows:

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to give you an additional reliability impact. So those tranches are just changes in the capacity equivalents of those batteries, as you add more onto the system.").

[9] Transmission Screening Analyses Overview, pg. 1-2.

[10] Southern Companies' Transmission System Active OATT Generator Interconnection Requests. [https://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/Active-Gen-IC-Requests.pdf]

[11] Rao Konidena (July 21, 2023). What is the difference between Interconnection Service (e.g., NRIS) and Transmission Service (e.g. NITS)? [https://raokonidena.substack.com/p/what-is-the-difference-between-interconnection#:~:text=What%20is%20firm%20versus%20non,first%20to%20accommodate%20firm%20transactions.]

[12] Tyler Norris (August 2023). Beyond FERC Order 2023, Considerations on Deep Interconnection Reform. Duke Nicholas Institute for Energy, Environment & Sustainability. Pg. 3.

"Specifically, a transmission provider studying a generating facility for NRIS would study the transmission system at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility operating at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with reliability criteria and procedures"

With Georgia Power's 2022 capacity power purchase agreements approved by the PSC, firm network transmission service was required.[13] When asked about the ERIS/NRIS designation for the proposed self-own batteries, Company witness Grubb stated he did not know the difference between the two services.[14] The full 1.4 GW of capacity from the new units at Plant Yates and the 1 GW of new capacity from company-owned battery systems (some of which have not yet been identified

[https://nicholasinstitute.duke.edu/sites/default/files/publications/beyond-ferc-order-2023-considerations-deep-interconnection-reform.pdf].

[13] Monroe 1&2 Pro Forma Contract for the Purchase of Firm Capacity and Energy between Georgia Power Company and MPC Generating, LLC. 2022-2028 Capacity Pro Form PPA-CT. Section 5.1.4.3 pg. 30.

[14] *See* Transcript of the January 17th, 2024 Hearing at p. 588-589. ("Q The batteries that are being added, do you happen to know if they are going to be evaluated under a network resource interconnection service, or an NRIS, versus an energy resource interconnection service, or an ERIS? A (Witness Grubb) Are you talking about the batteries that we are proposing in this case? Q Yes. A (Witness Grubb) I don't know. Again, that's where I don't deal with transmission planning and interconnection agreements, but we have put native load reservations out there. Whatever, it will go through that process. I just don't know the difference between those two that you are mentioning. Q So you don't know the difference between NRIS versus ERIS? A (Witness Grubb) I don't. I would think the -- you said the NR is native load resource? Q Network. A (Witness Grubb) Network? I mean, I would assume it would be network. I don't know what the energy is, but again, we would have to get back with you on that. I believe there is a DR on that. We just haven't submitted it yet. But the point, Commissioners, is we will go through the process needed to make sure that those batteries are designated as native load resources to serve our customers.").

or potentially entered into the queue) effectively cannot provide firm capacity without sufficient transmission delivery capability. The NRIS transmission service is a firm transmission service in which upgrades needed for firm delivery are identified. In summary, GPC appears to be relying on transmission delivery capability that may not be available, which could materially impact those facilities' abilities to provide capacity during peak periods.

Q. DID GEORGIA POWER'S AVOIDED COST PROJECTIONS ACCURATELY SIGNAL ITS IMPENDING CAPACITY NEED?

A. No. In Georgia PSC Docket No. 4822, Georgia Power provides its avoided cost projections. On October 13, 2023, just two weeks prior to filing this IRP Update, the Company's projections show a $0/kW-yr Avoided Capacity Cost for qualified facilities until 2029.[15] These inconsistent signals to the market do not provide the clarity that developers need to structure products that are useful to the Company.

Q. ARE THERE OTHER TOPICS WORTHY OF REVISITING WITH RESPECT TO GEORGIA POWER'S MODELING OF RENEWABLE ENERGY AND ENERGY STORAGE RESOURCES?

A. Yes. It's worth revisiting Georgia Power's imposed limits on available renewable energy and energy storage capacity for selection in its IRP modeling, as well as its approach for determining the costs associated with renewable energy integration.

[15] Georgia Power Company, DKTs 4822 & 16573 - Avoided Cost Projections – Errata. [https://psc.ga.gov/search/facts-document/?documentId=215951].

Q. HOW DOES GEORGIA POWER DETERMINE THE LIMITS IMPOSED TO RENEWABLE ENERGY AND ENERGY STORAGE CAPACITY IN ITS IRP MODELING?

A. Arbitrary capacity limits, unsupported by technical or economic feasibility and not justified by Georgia Power,[16] are applied to the amount of renewable energy and energy storage resources that can be selected by the capacity expansion model, depending on year and resource type.[17]

Q. HOW DO THESE ARBITRARY CAPACITY LIMTIS AFFECT GEORGIA POWER'S SELECTED PORTFOLIO?

A. Arbitrary capacity limits have the effect of limiting the potential for certain resource types to enter the portfolio, even if those resources are lower cost than the resources that are selected and would have resulted in a lower-cost portfolio.

Q. IS IT APPROPRIATE TO ARTIFICIALLY LIMIT THE ENTRY OF CERTAIN RESOURCES INTO THE PORTFOLIO?

A. It can be, if there is evidence that the Company cannot physically connect these resources, e.g., cannot process applications, conduct studies, sign contracts, and build interconnection facilities fast enough. However, Georgia Power has presented no evidence that supports the limits applied. Moreover, while limits might be appropriate in the short term, in the longer term Georgia Power can augment its ability to add resources faster by hiring staff and dedicating more resources to the

[16] *See* Transcript of the January 17, 2024 Hearing at p.583-584.
[17] Georgia Public Service Commission, Docket 55378 Hearing. January 17, 2024. Transcript page 0583.

challenge. At a time of such unprecedented load growth, Georgia Power needs to be doing everything it can to accelerate its resource development process both for Company-owned and third-party resources. Old limits determined years ago by a rule of thumb are no longer appropriate in Georgia Power's 2023 IRP update.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR IMPROVING GEORGIA POWER'S IRP MODELING?

A. To address these issues, I recommend that Georgia Power assign solar a calculated ELCC value consistently across its modeling practices that is informed by its ELCC study. Ideally, Georgia Power should model renewable energy and energy storage resources together using a dynamic ELCC surface, rather than as standalone resources with fixed capacity values, to capture the diversity benefits that are known to exceed the sum of the individual resources.

However, as I had noted in prior testimony, to my knowledge, Aurora's capacity expansion software is not capable of implementing multi-dimensional ELCC surfaces. Therefore, Georgia Power should explore the solution space of the optimal combination of renewable energy and energy storage using other techniques. For example, modeling solar at higher levels of storage penetration and storage at higher levels of solar penetration. In addition, it should model hybrid resources with different duration batteries and corresponding ELCC values. Another solution could be conducting a sensitivity analysis that forces in different combinations of solar and storage with corresponding ELCC values for each

combination, again calculated by the SERVM model, to identify the near-optimal combination.

Additionally, Georgia Power should accurately reflect the impact of known transmission constraints that may prevent certain resources, specifically the new units at Plant Yates, from being able to deliver energy to load when it is most needed. If the resources are subject to curtailment during critical hours due to transmission constraints, this must be reflected in the accredited capacity value applied to these resources in Georgia Power's IRP modeling.

Finally, Georgia Power should remove the cap from its capacity expansion model to allow for a truly optimized portfolio to be developed without bias.

Q. GEORGIA POWER HAS ASKED FOR APPROVAL OF THE "FLEX CAPACITY" WHICH ALLOWS GEORGIA POWER TO ACQUIRE ADDITONAL CAPACIT AHEAD OF THE 2025 IRP IN THE EVENT THAT UPDATED LOAD FORECATS PROJECT ADDITIONAL CAPACITY NEEDS. SHOULD THE COMMISISON APRROVE THIS REQUEST?

A. No, Georgia Power already has the ability to acquire new resources under an "exception for supply-side capacity resources of extraordinary advantage that require immediate action."[18] The Company does not need additional authorization to procure resources that are needed for extraordinary load growth or due to fleeting opportunities.

[18] GA - GAC.

3 Transmission Planning

Q. BRIEFLY DESCRIBE THE ACTIVITIES THROUGH WHICH GEORGIA POWER IDENTIFIES TRANSMISSION NEEDS AND CONSTRAINTS.

A. Georgia Power maintains a ten-year transmission plan with updates for the trailing year provided annually to the Public Service Commission.[19] Additionally, FERC requires Georgia Power to participate in the Southeastern Regional Transmission Planning (SERTP) process, which is intended to provide stakeholders with an open and transparent transmission planning forum for the region. These transmission planning initiatives appear disjointed from each other and it is unclear how their results are incorporated into resource planning.

Historically, Georgia Power has performed reactionary transmission screening in response to resources as they are proposed. In its 2022 IRP, Georgia Power proposed to more proactively guide siting of resources through geographically targeted RFPs.[20]

Q. HOW DOES GEORGIA POWER INCORPORATE TRANSMISSION INTO ITS INTEGRATED RESOURCE PLANNING?

A. Georgia Power does not appear to consider any transmission planning information in its IRP process. The IRP model treats Georgia Power's system as a "copper sheet", where resources are not subject to explicitly defined transmission constraints that may inhibit their ability to deliver energy to load centers; nor are

[19] Document Detail (ga.gov).
[20] Georgia Power 2022 IRP. Chapter 14, Page 98.

any transmission costs added to individual candidate resources or resource groups to reflect transmission investments needed to deliver the energy to load. [21]

This requires transmission planners to react to the results of the resource plans, rather than coordinating mutual solutions. Because the resources are selected without regard to the potential transmission costs, transmission analysis can occur only for specific resources after they have been selected. This may result in the selection of seemingly lower-cost resources that require significant transmission upgrades (and are therefore higher-cost from a combined system perspective) over slightly resources that may have higher energy costs but require no transmission investments and are therefore ultimately lower-cost.

Q. WHAT ARE COMMON APPROACHES FOR BETTER INTEGRATING TRANSMISSION PLANNING WITH RESOURCE PLANNING?

A. Transmission planning, as it relates to resource planning and interconnection reform, is becoming more important as high-quality renewable resources are sited in areas farther from quickly growing load centers, requiring additional solutions to deliver that power to loads. As such, several new practices are emerging to better manage the influx of new resource additions needed to meet the significant load growth anticipated in the coming decades. Generally, I would highlight three common practices that are being embraced across the industry: (1) integrating transmission and resource planning as part of a more holistic planning process;

[21] *See* Transcript of the January 17, 2024 Hearing at p.582-583

(2) conducting more detailed analysis of transmission expansion opportunities; and (3) providing transparency of transmission constraints with resource providers.

Q. WHAT EXAMPLES CAN YOU PROVIDE FOR INTEGRATING MORE HOLISTIC TRANSMISSION AND GENERATION ANALYSES, AS SUGGESTED BY PRACTICE #1?

A. Several utilities, including Salt River Project in Arizona and Xcel Energy in Colorado, have begun transitioning from integrated *resource* planning (IRP), to a more holistic integrated *system* planning (ISP) framework.[22] Among other things, an ISP more proactively incorporates transmission planning, hosting capacity, and non-wires alternatives into the resource planning process.[23]

The topic of planning framework reform has also recently been taken up by the Task Force on Comprehensive Electricity Planning, which is sponsored by the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO). In its report, the Task Force underscored the need for planning reform, saying, in part, that a more comprehensive approach to electricity system planning is necessary to ensure that investments are cost-effective and meet the needs of the grid and its customers, as well as deliver against policy goals.[24] It can be more efficient to incorporate variables such as transmission congestion into the planning process than it is to react to them in the interconnection process.

[22] Integrated System Plan (ISP) | SRP (srpnet.com).
[23] https://rmi.org/insight/reimagining-resource-planning/.
[24] https://pubs.naruc.org/pub/154861E5-155D-0A36-3185-2E12B33288BC.

Within the southeast, Duke Energy has recognized that a more proactive approach to transmission planning and expansion is needed to meet load growth and clean energy policy targets in their 2022 Clean Energy Plan for the Carolinas. Duke has also adopted a new Integrated System & Operations Planning (ISOP) framework that optimizes capacity and energy resource investments across generation, transmission, and its distribution system. With respect to transmission, the utility brought over half a billion dollars of transmission projects to the North Carolina Transmission Planning Collaborative (NCTPC), detailing investments necessary to facilitate more solar interconnections in the near term. In its filing with the North Carolina Utilities Commission (NCUC), Duke notes that "a significant number of generator interconnection studies point to the same transmission constraints." Duke concludes "if the pathway for planning, development and construction of these transmission projects, which have repeatedly been shown to be needed to support renewable generation, is limited to the traditionally reactive generator interconnection process, the timeline… is likely to be adversely impacted."[25]

Q. WHAT EXAMPLES CAN YOU PROVIDE WHERE MORE DETAILED TRANSMISSION DATA IS DEVELOPED, AS IDENTIFIED BY PRACTICE #2?

[25] https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=2bb3f59d-c9a4-4f65-aace-567b38d51db2.

A. As transmission is integrated earlier and more comprehensively in the planning process, Practice #2 suggests that a more granular assessment of system constraints is necessary. Using a single zone transmission scheme to model resources is insufficient for coordinating resource siting with available transmission capacity, resulting in non-viable resources advancing further in the evaluation process than necessary. In ERCOT[26], dedicated transmission planning studies have been completed focused on defining designated renewable energy zones and identifying the transmission needs to deliver those remote renewable resources to load centers. This resulted in the creation of competitive renewable energy zones (CREZs) which drove substantial investment in renewable resources in the areas with the best resource potential and gave clear signals to developers about where to site their projects. This study spurred other CREZ-like studies across the country like Regional Generation Outlet Study[27] (RGOS) in the MISO territory and the Western Renewable Energy Zone (WREZ) study[28] in the West. These processes have identified long-term transmission investments that unlock generation resources that support a least-cost portfolio inclusive of both generation and transmission costs.

More recently the California Independent System Operator (CAISO) has been evaluating new reforms to their interconnection process, which includes development of transmission zones based on the available transmission capacity

[26] Outline for CREZ Analysis Report (ercot.com)
[27] Regional Generation Outlet Study (sd.gov)
[28] Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report (nrel.gov)

and least-cost major transmission buildout. For priority zones, generator interconnection requests will be ranked on their viability while projects not located in priority zones will be relegated to a separate, lower-priority study process. In 2023, CAISO also adopted a new strategic framework to coordinate transmission planning with the interconnection of new generation and energy storage, recognizing the interrelated nature of resource planning, transmission planning, the interconnection process, and resource procurement. CAISO's zonal planning framework prioritizes transmission expansion to regions where new clean energy resources can be built.[29] By communicating these transmission system limitations and working closely with integrated resource planners, California's organized market is working to interconnect projects more effectively and efficiently to the places on the system that offer the most value.

Q. HOW ARE ENTITIES WITHIN THE INDUSTRY ENSURING TRANSPARENCY OF TRANSMISSION CONSTRAINTS WITH RESOURCE PROVIDERS, AS SUGGESTED BY PRACTICE #3?

A. With a more comprehensive understanding of transmission capacity, as it relates to new resources, Practice #3 calls for the utility to work with external stakeholders. Transparency and clarity are what allow improvements in transmission planning to translate into efficient interconnection of viable resources. In support of this

[29]California's Progress in Advancing Transmission Planning and Permitting: A 2023 Review. Gridlab & CEERT. https://gridlab.org/wp-content/uploads/2023/11/GridLab_CEERT_CA-Progress-in-Transmission-Planning-and-Permitting-1.pdf

concept, FERC recently instituted improvements to standard transmission interconnection practices. In brief, FERC Order 2023 requires transmission providers, including RTOs and regulated utilities, to make several changes to the way generators are assessed in the interconnection process, including evaluating resources in clusters and publishing a heat map indicating hosting capacity across the system.[30] By sharing timely information about transmission capacity and deliverability by geographic area, new resources can be developed to target appropriate regions with minimal transmission needs and non-wires alternatives, such as storage sited as a transmission resource, can address constrained parts of the transmission grid.[31]

Q. DOES GEORGIA POWER'S USE OF GEOGRAPHICALLY TARGETED RFPS ADDRESS YOUR CONCERN ABOUT THEIR TRANSMISSION PLANNING PROCESS?

A. No. While targeted RFPs may be a useful way to address a specific need that can't be addressed in any other way, targeted RFPs by their nature seek a limited set of solutions that only address a portion of Company's needs. Targeted RFPs limit the solution space and may exclude resources that are strong "all-around performers" because they are not the best resource to meet the specified need. In particular, targeted RFPs that focus only on generation resources only would be unable to

[30] E-1 | Order 2023 | RM22-14-000 | Federal Energy Regulatory Commission (ferc.gov).
[31] Kahrl, Dr. Fredrich. All-Source Competitive Solicitations: State and Electric Utility Practices. March 2021.

address the tradeoffs between transmission and generation solutions to a location-specific need.

Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR GEORGIA POWER TO IMPROVE THE INTEGRATION OF TRANSMISSION PLANNING INTO RESOURCE PLANNING?

A. I recommend that Georgia Power more proactively integrate transmission planning into the early stages of a broader planning effort, identify more granular transmission constraints and communicate those to external stakeholders, include zonal transmission constraints in its capacity expansion modeling, and reflect those insights in its integrated resource plan. Sharing this information with independent power providers will encourage siting resources in more advantageous locations, possibly mitigating the need for investment in new transmission infrastructure and reducing costs for Georgia Power ratepayers.

4 Resource Procurement

Q. PLEASE DESCRIBE COMMON PRINCIPLES FOR BEST PRACTICES IN RESOURCE PROCUREMENT.

A. Resource planning and procurement are inherently linked, and the associated activities should be coordinated accordingly. Overall, procurement decisions should minimize ratepayer costs while managing demand, reliability, and long-term strategic goals of the utility, as overseen by the PSC. Specific principles that support this directive include: (1) transparency; (2) fair consideration; and (3) objective evaluation. Transparency of data and processes allows for information to be shared

effectively between the utility and stakeholders, which helps to improve the quality of decisions and compatibility of solutions. Fairness in considering candidate resources is necessary to understand all available options and is best accomplished through all-source competitive solicitations. Once resource bids are received, an objective evaluation can be conducted using accurate, impartial methods to select the most cost-effective solutions to address portfolio needs.

Q. WHAT SUPPORT DO YOU HAVE FOR THESE BEST PRACTICES?

A. Best practices in resource procurement are less established and continue to evolve; however, useful principles can be found in the "Edgar" standard, which was established in a 1991 FERC ruling.[32] The three specific components of FERC's Edgar standard provide for:

1. "a competitive solicitation process was designed and implemented";
2. impartial bid evaluation, "particularly with respect to non-price factors"; and,
3. resource selection "based on some reasonable combination of price and non-price factors."[33]

FERC later elaborated on these criteria, articulating four principles to determine whether an RFP satisfied the Edgar test:

[32] *Boston Edison Co. Re: Edgar Electric Energy Company*, 55 FERC ¶ 61,382 (1991) (Edgar).
[33] FERC Docket No. ER18-810-000, *Order Granting Authorization to Make Affiliate Sales*, 166 FERC ¶ 61,127, (2019) available at https://www.ferc.gov/sites/default/files/2020-07/02-2019-E-13.pdf (quoting Edgar at 62,167-69.)

a. Transparency: the competitive solicitation process should be open and fair;

b. Definition: the product or products sought through the competitive solicitation should be precisely defined;

c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders;

d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection."

It is important to note that these criteria were developed with specific regard for transactions between affiliates[34], in which extra care is required. While this federal standard is not binding for a state commission, I cite these principles as considerations for best practices that should be applied for all of Georgia Power's resource procurements.

Q. DO YOU HAVE AN EXAMPLE OF A STATE THAT DOES A GOOD JOB OF IMPLEMENTING THESE BEST PRACTICES FOR UTILITY-OWNED GENERATION OR AFFILIATE TRANSACTIONS?

A. The Colorado Public Utility Commission has embraced the concept of fairness in considering candidate resources through all-source solicitations. Like the Georgia

[34] *Id*. at 3 ("In *Edgar*, [FERC] stated that, in cases where affiliates are entering into market-based rate agreements, it is essential that ratepayers be protected and that transactions be above suspicion in order to ensure that the market is not distorted. Under Edgar, [FERC] has approved affiliate sales resulting from competitive bidding processes after [FERC] has determined that, based on the evidence, the proposed sale was a result of direct head-to-head competition between affiliated and competing unaffiliated suppliers.").

PSC, Colorado requires resource needs to be procured through a competitive solicitation; however, the Colorado PUC further stipulates all-source RFPs are preferred and utilities must provide specific reasons, supported by a cost-benefit analysis, to conduct an alternative solicitation.[35] This approach correctly recognizes that different resources offer combinations of benefits to the system; given the opportunity, renewable energy and energy storage resources can compete with alternatives and meaningfully contribute to a reliable and diverse portfolio as I discussed above. All-source solicitations ensure the diverse nature of candidate resources are evaluated together, and that the optimal blend of resources that meets a combination of system needs is selected, in contrast to solicitations for isolated system needs.

Arkansas,[36] California,[37] Illinois,[38] and Texas[39] are all examples of states with affiliate transaction rules for electric utilities. These rules are in place to ensure transparency and fairness to protect ratepayers, aligned with the intentions of the FERC's Edgar ruling and standard. In California, the California Public Utilities Commission has conducted independent audits of the large, regulated utilities in

[35] *See e.g.*, 4 CCR 723-3-3611(a) of Colorado Public Utilities Commission's Rules Regulating Electric Utilities, available at https://puc.colorado.gov/electricrules ("It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource plan (i.e., an all-source solicitation).")
[36] Public Service Commission (arkansas.gov).
[37] APPENDIX A (ca.gov).
[38] Title:83 Part:450 (ilga.gov).
[39] [1. INTRODUCTION] (texas.gov).

the State with respect to affiliate transactions. Other jurisdictions have various approaches to regulation.

Q. HOW DOES GEORGIA POWER'S PROCUREMENT PROCESS COMPARE WITH INDUSTRY BEST PRACTICES?

A. There are several occasions in which Georgia Power deviates from best practice in resource procurement in its 2023 IRP Update. For example, Georgia Power has failed to meet transparency and objectivity expectations in its expedited contracts with Mississippi Power and Santa Rosa.[40] The Commission should consider what standard to use for affiliate transactions, such as that which was executed on October 11, 2023,[41] given the FERC Edgar ruling was written with the intent to provide guidance around affiliate transactions. It is worth noting that other state public service commissions have rules regarding affiliate transactions that incorporate competitive bidding requirements and provide procedures for Commission review and approval of such affiliate transactions *prior* to execution.[42]

[40] Boston Edison Co. Re: Edgar Electric Energy Company, 55 FERC ¶ 61,382 (1991) (Edgar).
[41] *See* IRP Update Main Document at p. 17 (noting that Georgia Power executed a PPA with affiliate Mississippi Power for 750 MW on October 11, 2023.).
[42] *See e.g.*, Arkansas Public Service Commission, Affiliate Transaction Rules, available at affiliate_transaction_rules.pdf (arkansas.gov) ("The purpose of these rules is to ensure that all transactions among or between a public utility and any affiliates or divisions do not result in rates which are unreasonable and in violation of [state law]; to ensure that the rates charged by public utilities do not provide any subsidy to affiliates or divisions of the public utility which are involved in non-utility activities or which provide services to the public utility; to prevent anti-competitive behavior, and market manipulation or market power…").

In the absence of a competitive process, the resources proposed in Georgia Power's 2023 IRP Update should be benchmarked against comparable transactions to ensure that costs are prudent for Georgia ratepayers. Failure to comply with these standards may result in higher costs for Georgia Power ratepayers.

Q. DOES GEORGIA POWER TRADITIONALLY MAINTAIN A MINIMUM AMOUNT OF UTILITY-OWNED GENERATION?

A, Yes. Georgia Power's procurement process is subject to regulatory guidance from this Commission regarding the appropriate balance of Company ownership of resources versus third-party ownership. The specific amount is subject to PSC guidance, which has historically been 70%. The PSC requires the Company to notify the Commission when they exceed 30% for PPAs.[43] While Georgia Power maintains an independent evaluator for external bids, the Company is not required to justify its utility-owned generation projects by formalizing a bid or providing evidence of benchmarking costs.

Q. WHAT IS THE REASON FOR MAINTAINING A MINIMUM AMOUNT OF UTILITY-OWNED GENERATION?

[43] Transcript of the January 16, 2024 Hearing at 359-360, Cross Examination by Jennifer Whitfield ("Q… the last time I'm aware of the ownership percentage guidance this Commission has given being argued before the Commission is 2001…A (Witness Grubb)…So the issues that the Commission considered back then around reliability were a little bit different drivers. My understanding, it was more around market dynamics and the importance of reliability in third-party PPAs. But, again, today, reliability has got other drivers, but I would say it's just as important, even more important that it was then, and as much dynamics…But again, we have the obligation to notify the Commission when we exceed the 30 percent [for PPAs].").

A. Georgia Power cites reliability concerns as its main reason for supporting the PSC's prior guidance.[44] Specifically, Georgia Power cites superior performance during Winter Storm Elliott as an example of utility-owned generation exhibiting higher reliability than power sourced from independent providers[45]. Georgia PSC regulations leaves the specific threshold to be set by commission order and anticipates a need for this threshold to be suspended or lowered "from time to time" at the discretion of the commission. It is also worth noting that this rule makes no reference to reliability as a motivating factor[46].

Q. ARE THERE EXAMPLES OF UTILITIES THAT OPERATE WITH LESS THAN 70% SELF-OWNED GENERATION?

A. Yes, there are many examples of jurisdictions in which the vast majority, if not 100%, of generation is owned by independent power producers (IPPs) rather than utilities. For example, 13 states have fully restructured retail electricity markets in which consumers are able to choose from among many competitive power suppliers. States with fully restructured retail markets include Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Texas.

[44] *See* Transcript of the January 16, 2024 Hearing at p.84-85; 299-300

[45] Transcript of the January 16, 2024 Hearing at 364-365, Cross Examination by Jennifer Whitfield ("Q… Do you have any examples, Mr. Grubb, when PPAs have been unable to perform for Georgia Power, as they're contractually required to, in a way that has endangered customer load?…A (Witness Grubb)… We would have to look at those. I do know the company was able to perform better with company-owned resources in Winter Storm Elliott than PPAs did.")

[46] Georgia Public Service Commission Rule 515-3-4-.04(3)(f)7. https://rules.sos.state.ga.us/GAC/515-3-4.

In these states, all generation is typically owned by IPPs[47]. Nationwide, approximately 45% of total generation capacity is owned by IPPs[48].

Even among vertically-integrated utilities, many maintain a smaller percentage of utility-owned generation. Specifically, Xcel Energy in Colorado has less than 60% of its generation coming from utility-owned resources[49]. Additionally, Oklahoma Gas and Electric[50] as well as Puget Sound Energy[51] each maintain a portfolio with less than 50% of their power coming from utility-owned resources. In Colorado, the legislature sought to further limit the amount of utility-owned generation[52] by establishing an ownership target of 50%.

Q. IS THERE ANY EVIDENCE THAT THE JURISDICTIONS WITH HIGHER IPP OWNERSHIP HAVE OBSERVED LOWER RELIABILITY?

A. No. There is no evidence that suggests reliability is impacted due to a lower prevalence of utility-owned generation. Sourcing generation through independent power providers allows utilities to diversify their risk and could be considered a

[47] https://www.epa.gov/green-power-markets/power-market-structure.
[48] https://www.eia.gov/electricity/annual/.
[49] https://rmi.org/why-purchased-power-is-such-a-big-deal-to-better-understand-us-utilities-climate-impact/.
[50] EEI ESG/Sustainability Template – Quantitative Information for Oklahoma Gas and Electric Company (OG&E)
[51] https://www.pse.com/pages/energy-supply/electric-supply.
[52] *See* e.g., SB 19-236, Section 5(5)(V)(b), of the Colorado legislature, accessible at https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf ("The Commission shall allow the qualifying retail utility, inclusive of any ownership by its affiliates, to own a target of fifty percent of the energy and capacity associated with the clean energy resources and any other energy resources developed or acquired to meet the resource need, as well as all associated infrastructure, if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact.")

reliability benefit under certain conditions. Georgia Power has provided no data supporting its claim that higher proportions of utility-owned generation improves reliability.

During Winter Storm Elliot, Duke Energy Carolinas demonstrates higher percentage of utility-owned generation in its portfolio and exhibited lower reliability, as compared to Georgia Power. During this event in 2022, Duke was required to institute rolling blackouts in the Carolinas as several of its utility-owned assets experienced weather-related failures[53].

Georgia Power credited its resilience during Winter Storm Elliot to its diverse resource portfolio. In a hearing of the Energy Committee on February 2, 2023, Mr. Grubb specifically citing transmission interconnections, solar resources, and power purchase agreements as contributing to Georgia Power's stronger reliability performance, as compared to neighboring utilities like TVA or Duke Energy Carolinas.[54]

Q. WOULD IT BE IN THE PUBLIC INTEREST FOR THE COMMISSION TO REVISE ITS REGULATORY GUIDANCE TO ALLOW GEORGIA POWER TO PROCURE THAN 30% OF ITS GENERATION PORTFOLIO FROM PPAS?

[53] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/holiday-2022-winter-storm-raises-reliability-generation-diversity-questions-74685081.
[54] Public Hearing of the Energy Committee. Georgia Public Service Commission. February 2, 2023. 18:45.

A. Yes. Given the unprecedent level of load growth Georgia Power currently is experiencing, it is in the public interest for the Commission and Georgia Power to be working with as many parties as possible to meet increased demand, as aptly noted by Commissioner Echols during the Commission's February 1st administrative hearings. Georgia Power has continually placed limits on the quantity of solar and storage it allows into its resource portfolio. These limits are not based on assumptions about the IPP sector's ability to deliver the projects, but rather on the Company's ability to procure, contract, and interconnect the projects. It stands to reason that limitations on the Company's ability to mobilize labor and capital for interconnection of third-party resources would likely also affect the Company's ability to execute on self-owned projects on such a short time frame. Contracting with multiple IPPs would be a least-risk strategy for the Company to meet its near-term resource needs.

Q. WHAT METHODOLOGY DOES GEORGIA POWER USE FOR EVALUATING RENEWABLE ENERGY RESOURCE BIDS?

A. Georgia Power uses a "best cost" methodology based on a renewable cost benefits (RCB) framework to evaluate renewable energy resources. The RCB framework includes components like avoided energy costs, deferred generation capacity costs, avoided transmission losses, deferred transmission investment, and avoided distribution losses to fully assess the value of renewable resources. The best cost methodology is essentially an avoided cost method without a firm threshold for avoided costs that might limit resource selection.

Q. WHAT ARE THE LIMITATIONS OF GEORGIA POWER'S SELECTED METHODOLOGY?

A. Avoided Cost methodologies are simplified analyses based on a "snapshot" of the projected utility portfolio at a given moment in time. They are commonly used by utilities in lieu of more sophisticated portfolio analysis in specific instances where portfolio analysis is impractical or where benefits might be realized that are not captured in portfolio analysis. Marginal values are determined for each component based on that snapshot and are assumed not to change across the entire quantity of the resource being evaluated. For example, marginal energy values are typically based on either (a) a wholesale market price that is assumed to be independent of the addition of the resource being evaluated, or (b) the variable cost of the most expensive resource in a utility's dispatch stack in each hour of the year, which again is assumed not to change with the addition of the resource being evaluated. This framework is appropriate for evaluating relatively small quantities of resources in portfolio that is otherwise fixed. In general, conducting a more comprehensive portfolio analysis is better suited for evaluating the full range of costs and benefits of significant quantities of additional resources.

Avoided Cost methodologies are not well-suited to evaluating resources that can interact with other resources in the portfolio in complex ways, for example resources that can be dispatched in response to changing marginal energy costs. Most DERs cannot be dispatched by the system operator and in fact are not even visible to the system operator, and as a result an Avoided Cost framework is

appropriate for evaluating these resources. However, newer solar power plants have the capability to be optimally dispatched by system operators and to provide essential grid services. Valuation of these services is complex and may require dynamic modeling of system-wide production.

Furthermore, Avoided Cost methodologies are not well-suited to evaluating energy storage resources. Energy storage can provide significant value by displacing expensive peaking resources during high load hours and reducing the quantity of thermal generation required to meet system peaks. However, its energy value is dependent on the resources used for charging and its capacity contribution is complicated by considerations related to its limited duration and need to maintain a high state of charge. Valuation of energy storage may also require portfolio-level modeling.

Q. HOW SHOULD GEORGIA POWER EVALUATE RENEWABLE ENERGY AND ENERGY STORAGE RESOURCES IN PROCUREMENT?

A. As with many other utilities, Georgia Power uses avoided cost methodologies in bid evaluation. As long as the amount of new resources under consideration does not fundamentally change system conditions, this can be methodologically sound. However, because Avoided Cost methodologies develop individual, static valuations for each potential benefit stream, there is a risk that the method will double count, not count, or inappropriately count certain value streams if the values aren't combined in a way that preserves the appropriate portfolio-level value.

A better method for bid evaluation is to use portfolio optimization tools. These models are well suited for bid evaluation: when given a list of resource options, the models will select the economically efficient outcome, i.e., the least-cost outcome for ratepayers. Although it is important that the correct inputs be given to the model, the analytical framework has been vetted by the developers and other utilities, reducing the likelihood of errors that lead to inefficient outcomes. I recommend that Georgia Power use portfolio modeling tools for bid evaluation.

Q. HOW MIGHT GEORGIA POWER IMPROVE THEIR RESOURCE PROCUREMENT PROCESS TO ALLOW FOR MORE TIMELY RESOURCE ADDITIONS?

A. Georgia Power's experience with resource procurement is not altogether unique. Competitive solicitations are inherently time-intensive processes that are difficult to accelerate without negatively impacting the quality of the results. Georgia Power can maximize the effectiveness of these solicitations by issuing all-source RFPs on a more standardized periodicity, stemming from the needs identified in the IRP cycle. Implementing this regularity can avoid one-off, ad-hoc solicitations, such as the RFI issued on September 26, 2023 and the executed PPAs with affiliate Mississippi Power for 750 MW on October 11, 2023, and with Santa Rosa for 230 MW on October 22, 2023, respectively. While the results of the RFI indicated that Georgia Power could potentially meet its near-term needs with energy storage or

solar in the 2025-2028 period, including 1,200 MW by 2026[55], the lack of a standard, regular competitive bid solicitation process disallowed any opportunity for Georgia Power to explore the optimal solution to meet their needs by evaluating the Santa Rosa and Mississippi Power PPAs alongside bids from developers. Additionally, by ensuring the capacity expansion model can accurately optimize the desired portfolio, Georgia Power can fully leverage the time that is invested in the procurement process and eliminate the need to conduct resource-specific RFPs. Finally, by sharing zonal transmission data with resource developers, Georgia Power will improve the quality and viability of the proposals that are returned and eliminate the need to run location-specific RFPs. Increased transparency will also allow for a more streamlined transmission screening and eliminate the need for regionally focused RFPs.

5 Conclusion

Q. WHAT ARE YOUR KEY FINDINGS AND RECOMMENDATIONS?

A. In response to Georgia Power's 2023 IRP Update, I provide the following conclusions and recommendations:

- Georgia Power is arbitrarily limiting renewable energy and energy storage resources in its procurement plan by:

[55] Transcript of the January 17, 2024 Hearing at 654, Table 0-3-2 (indicating that 1,110 MW of capacity from the RFI PPAs would become available in 2026); *See also* Transcript of the January 16, 2024 Hearing at 354, Cross Examination by Jennifer Whitfield (" Q So looking at these tables, by my math it looks like you have about 3,000 megawatts of energy storage systems for batteries and battery-like things, for the laypeople like me, bid in for '26, '27, and '28. Would you agree with that? A (Witness Grubb) Right. In those calendar years, so, yes, the '25, '26, '27.")

- instituting unnecessary limits on how much the capacity expansion model can select;
- assigning solar resources a zero capacity value under the Aurora model; and
- failing to capture the diversity benefit of solar energy and battery storage in providing capacity.

Therefore, I recommend the Commission direct Georgia Power to update its treatment of renewable energy and energy storage resources in its capacity expansion analysis to do the following:

- remove any artificial limit for specific resources;
- assign solar resources a calculated capacity value in modeling, consistent with its 2022 IRP and the associated ELCC study; and
- ensure the diversity benefits of solar and energy storage resources are captured in modeling.

- Georgia Power's transmission planning is insufficient for allowing coordination with resource planning. To correct this, the Commission should:
  - direct Georgia Power to provide more transparency in its transmission constraints to allow stakeholders to better understand how resources are valued in various zones and allow for non-wire alternatives to be more easily and cooperatively developed; and

- incorporate transmission constraints and upgrade capacity information into its capacity expansion modeling to ensure that the resources selected can deliver energy to load when it is most needed.

- Georgia Power's procurement practices are inefficient and do not follow industry best practices. Therefore, the Commission should:
  - direct Georgia Power to follow industry best practices for resource procurement, including standards similar to the Edgar standards adopted by FERC, in its future resource procurement, including the upcoming 2025 IRP; and
  - direct Georgia Power to conduct all-source RFPs on a regular periodicity and develop a bid evaluation methodology that accurately captures the energy, capacity and transmission benefits and costs of candidate resources.
- The Commission should revise its guidance to reduce the amount of utility-owned generation that is required to be maintained by Georgia Power and direct Georgia Power to procure the optimal, most cost-effective mix of resources, regardless of ownership type.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MR. COX: And I also move to mark Mr. Olson's exhibit as SREA Exhibit 1 and request that it be admitted into the record.

CHAIRMAN SHAW: So marked.

(SREA Exhibit 1 was admitted into evidence.)

MR. COX: And would you like us to do Mr. Olson's summary now or go through that same process with Mr. Monken first? Does it matter?

CHAIRMAN SHAW: It doesn't matter.

MR. COX: Okay.

CHAIRMAN SHAW: However y'all want to do it. Just in the order that you prefer.

MR. COX: Okay. I will go ahead and go through that with Mr. Monken first.

BY MR. COX:

Q Mr. Monken, did you cause 14 pages of testimony to be filed on February 15th?

A (Witness Monken) I did.

Q Did you also cause to be filed with your testimony the following four exhibits as outlined on page 4 of your testimony: Exhibit JM-1, the HVDC Transmission: A National Security and Energy Resilience Imperative; Exhibit JM-2, Regulatory Considerations for Utility Investments and Defense Energy Resilience; Exhibit JM-3, Transmission Expansion for National

Defense, or TREND; and Exhibit JM-4, State of Georgia DoD Energy Fact Sheet?

A (Witness Monken) I did.

Q Thank you. Are there any corrections that you need to make to your prefiled testimony or exhibits?

A (Witness Monken) No.

Q If I were to ask you the same questions today, would your responses be the same?

A (Witness Monken) Yes.

MR. COX: At this time, I move to admit the prefiled direct testimony of Mr. Monken into the record.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Jonathon Monken follows:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's 2023	**)**	**Docket No. 55378**
Integrated Resource Plan Update	**)**	

DIRECT TESTIMONY OF JONATHON MONKEN

ON BEHALF OF

SOUTHERN RENEWABLE ENERGY ASSOCIATION

February 15, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, PRESENT POSITION, AND BUSINESS ADDRESS.

A. My name is Jonathon Monken. I am a Principal at Converge Strategies, LLC ("Converge") at 1301 K St NW, Washington, DC 20005.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree from the United States Military Academy and a Master's in Business Administration from Northwestern University. I have served in the United States Army for 22 years as an Armor Officer and I am currently assigned to the Cybersecurity and Infrastructure Security Agency ("CISA") at the US Department of Homeland Security ("DHS"). My civilian professional roles include serving as Director of the Illinois State Police from 2009-2011, Director of the Illinois Emergency Management Agency, Department of Nuclear Safety and Homeland Security Advisor to the Illinois Governor from 2011-2015, and Senior Director of System Resilience for PJM Interconnection from 2016-2020.

Q. WHAT IS CONVERGE STRATEGIES?

A. Converge Strategies, LLC ("CSL) is a professional services consulting company focused on the intersection of advanced energy, energy resilience and national security. We develop strategy and engage stakeholders on behalf of the Federal and State Governments including the U.S. Department of Defense ("DoD"), U.S. Department of Energy ("DOE"), and several National Laboratories to improve energy resilience planning and policy.

Q. WHAT IS YOUR ROLE AT CONVERGE STRATEGIES?

A. I advise clients in Federal and State Government, as well as the private sector, on the development and implementation of strategies designed to improve the energy resilience of critical infrastructure systems.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will provide an overview of the importance of including national security considerations into the Georgia Power Company ("GPC") Integrated Resource Plan ("IRP") to ensure the energy assurance needs of the DoD are met now and into the future.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

Exhibit JM-1 – *HVDC Transmission: A National Security and Energy Resilience Imperative*

Exhibit JM-2 - *Regulatory Considerations for Utility Investments in Defense Energy Resilience*

Exhibit JM-3 - *Transmission Expansion for National Defense (TREND)*

Exhibit JM-4 – *State of Georgia DoD Energy Fact Sheet*

II. THE IMPORTANCE OF ENERGY NEEDS TO NATIONAL SECURITY

Q. PLEASE PROVIDE AN OVERVIEW OF THE METHODOLOGY USED TO DETERMINE ENERGY NEEDS OF DOD.

A. CSL has engaged the DoD at all levels from the Office of the Secretary of Defense to individual installations to determine their needs for energy resilience to support mission assurance requirements. This includes developing and conducting assessments using the proprietary Regional Identification of Gaps in Operational Resilience ("RIGOR") method, the design and execution of Black Start Exercises, and the facilitation of a DoD-funded technical support program from installation energy managers. Using the knowledge gained from these activities, CSL reviewed the DoD processes for developing energy resilience requirements. According to the National Defense Strategy, DoD's primary energy program priority is to ensure the readiness of the armed forces by pursuing energy security and energy resilience. In 2016, DoD took a major step to address looming energy vulnerabilities by mandating all military installations create an

Installation Energy Plan ("IEP"). These plans serve as roadmaps for installations to meet DoD energy efficiency, renewable energy, and energy resilience goals. The 2016 mandate was codified in 2018 and installations were then mandated to incorporate long-range plans for energy resilience capabilities to ensure available, reliable, and quality power for critical missions and to consider cybersecurity requirements. These deliberate steps by the DoD to assess and address energy resilience requirements highlight the broader national security risk to critical infrastructure posed by our adversaries and the imperative to address them. We used that information to identify DoD energy needs specific to infrastructure availability, service delivery, and total energy demand for installations to assess the ability of electricity infrastructure and high voltage transmission to meet those requirements.

Q. WHAT SOURCES DID YOU RELY UPON FOR YOUR ANALYSIS?

A. I relied upon DoD Directive 4180.01, the National Defense Authorization Act ("NDAA"), and Section 215A of the Federal Power Act, among other resources at the DoD to establish a baseline of needs for national security. DoD took several proactive steps to codify the importance of energy resilience to mission assurance, starting with DoD Directive 4180.01 to establish the need to enhance the power resiliency of installations. This preceded the 2018 NDAA which defined energy resilience in law, making it a centerpiece in DoD planning. Additionally, Section 215A of the Federal Power Act describes Defense Critical Electric Infrastructure ("DCEI") to establish the role of private utilities to provide this electricity services to defense installations. These policy actions provide a foundation to support the energy needs of national security, but they must be expanded on by agencies such as the Federal Energy Regulatory Commission ("FERC") to include a comprehensive strategy for resilient transmission systems. I was also privy to Classified and Unclassified briefings and documents in my role as a member of the Defense Science Board

Task Force of Defense Critical Infrastructure from 2019-2020 identifying DoD vulnerabilities from disruptions to energy systems.

There is also a strong foundation of policy and federal law with regards to DoD energy. Under U.S. Code, the general energy policy of the DoD is to "ensure the readiness of the armed forces for their military missions by pursuing energy security and energy resilience.[1]" In 2021, Congress passed a law requiring DoD to attain a minimum level of 99.9% availability for energy loads that support critical missions by 2030.[2] DoD subsequently adopted guidance specifying even higher availability requirements for certain facility types. Missile fields, cyber operations facilities, and satellite control facilities, for example, must attain a minimum level of 99.9999% availability.[3] This availability requirement translates to a downtime of only 30 seconds per year. Each of the military departments have also set policy requiring that critical missions be able to operate independently from the grid. The Air Force's critical mission requirement is 7 days of independent operation, and the Navy and Army have each established 14-day requirements.[4] The Army has set an additional target to install microgrids at all of its installations by 2035.[5] DoD requires each installation to develop an energy resilience master plan, and encourages installations to pursue backup power and other onsite resilience investments using private capital and its own budget funds.[6] The DoD's $330 million dollar Energy Resilience and Conservation Improvement

[1] 10 U.S.C. 2911
[2] National Defense Authorization Act for Fiscal Year 2021
[3] Office of the Undersecretary of Defense for Acquisition and Sustainment. (2021). Metrics and Standards for Energy Resilience at Military Installations.
[4] Assistant Secretary of the Air Force for Installations, Environment and Energy. (2020). Air Force Policy Directive 90-17; Secretary of the Army. (2020). Army Directive 2020-03 (Installation Energy and Water Resilience Policy); Department of the Navy. (2020). Installation Energy Resilience Strategy.
[5] Office of the Assistant Secretary of the Army for Installations, Energy and Environment. (2022). United States Army Climate Strategy.
[6] Office of the Assistant Secretary of Defense for Sustainment (ASD(S). (2016). Installation Energy Plans; ASD(S). (2018). Policy on Energy Savings Performance Contracts and Utility Energy Service Contracts; Office of the Assistant Secretary of Defense for Energy, Installations and Environment. (2020). Fiscal Year 2026 Energy Resilience and Conservation Investment Program Guidance.

Program ("ERCIP"), for example, supports energy resilience, energy efficiency, and water conservation at installations.

Q. WHAT ARE THE CONCLUSIONS OF YOUR ANALYSIS?

A. U.S. national security is under threat, both domestically and internationally. While this issue traditionally has a purely militaristic connotation, the nature and source of threats have expanded beyond planes, tanks, and ships. Modern security risks now target extensions of those weapons platforms—the energy needed to execute essential missions. Energy is not a newcomer to the geopolitical landscape—it has underpinned many conflicts over the last century. Recent years, however, have seen the nexus between energy and national security come into sharper focus. DoD installations, numbering more than 500 across every region of the United States including 13 in Georgia alone, represent the single largest ratepayer in the country and the largest ratepayer on the Georgia Power Company (GPC) system. Within the state DoD is truly a unique energy consumer, and not simply due to the size of their energy bills. The missions supported by that electricity—the vast majority of which comes from GPC's privately owned and operated infrastructure—require uninterrupted service in the face of growing climate, physical, and cybersecurity risks. Meeting these needs will require physical infrastructure able to access and deliver geographically-dispersed electric generation resources across the country in a manner that meets the diverse needs of DoD missions and community resilience. Despite its focus on installation-level resilience, DoD remains heavily reliant on civilian infrastructure. Over 99% of DoD bases rely on the commercial electricity grid for power, and the majority of bases also use civilian natural gas, water, wastewater service, and telecommunications infrastructure.[7] In 2021,

[7] Stockton, P. & Paczkowski, J.P. (2019). Strengthening Mission Assurance Against Emerging Threats: Critical Gaps and Opportunities for Progress. Joint Forces Quarterly; U.S. Government Accountability Office. (2020). Climate Resilience: DOD Coordinates with Communities but Needs to Assess the Performance of Related Grant Programs;

DoD reported over 6,200 unplanned electric utility outages with a combined duration of close to 3,500 days.[8] Although many assume that DoD has sufficient backup power, military diesel generators, microgrids, and other resilience systems are generally not designed for longer duration power outages, or able to support the defense communities upon which DoD depends.[9] Additionally, a recent report by the National Renewable Energy Laboratory (NREL) states, "The Department of Defense realized the current electrical configuration was a vulnerability and tasked the NREL to study the effectiveness of backup power systems used on DoD sites. The study discovered well-maintained generators have a reliability of 80 percent after two weeks of run time. Based on this information, the study determined a single, well-maintained emergency generator cannot guarantee emergency power for critical loads over multi day outages."[10] As a result, ensuring energy resilience for DoD requires specific investments in both on-base solutions and grid resilience to adequately mitigate the risk to mission assurance. The status quo for transmission planning and design reflected in this IRP does not currently capture the energy resilience needed to support national security needs.

Samaras, C. & Willis, H.H. (2013). Capabilities-Based Planning for Energy Security at Department of Defense Installations. Santa Monica, CA: RAND Corporation.

[8] U.S. Department of Defense. (2022). Annual Energy Management and Resilience Report (AEMRR) Fiscal Year 2021.

[9] CNA Military Advisory Board. (2015). National Security and Assured U.S. Electrical Power. Arlington, VA: Center for Naval Analysis.; Narayana, A., Knopman, D., Powers, J.D., Boling, B., Miller, B.M., Mills, P., Van Abel, K., Anania, K., Cignarella, B., Jackson, C.P. Air Force Installation Energy Assurance: An Assessment Framework. Santa Monica: RAND Corporation.

[10] Marquesee, J., Ericson, S., & Jenket, D. (2020). Emergency Diesel Generator Reliability and Installation Energy Security. Golden, CO: National Renewable Energy Laboratory.

III. DOD ENERGY REQUIREMENTS SHOULD BE INCORPORATED INTO THE IRP UPDATE TO SUPPORT NATIONAL SECURITY AND PROMOTE THE PUBLIC INTEREST

Q. IN YOUR VIEW, SHOULD THE IRP IDENTIFY SPECIFIC PLANS TO ADDRESS DOD ENERGY NEEDS?

A. Yes. Central to this discussion are the tools and methods available to mitigate risks and ensure the resilient delivery of energy to DoD and the national security functions they perform. The electric grid is undergoing an unprecedented transition driven by the rapid proliferation of renewable energy resources, the electrification of transportation, and the increased automation of grid operation. Bridging the gap between the grid of today and the grid needed to meet this national security imperative will require a reimagining of how electricity is delivered at both a micro and macro-level. Previous GPC testimony confirmed that DoD is one of the largest (if not the single largest) customers on their system. Aggregating energy resilience requirements across the state can better leverage the redundancy and resilience of the bulk electric system rather than relying on individual distributed energy resources alone. While the DOE, DoD, and Southern Company committed to ensuring the prioritization of military installations in emergency restoration plans in the memorandum of understanding[11] referenced in GPC testimony, Southern Company subsidiaries should work with grid operators to ensure that the critical defense facilities are included as priorities for infrastructure design and investment. As an alternative, grid operators can work with DoD to develop specific programs to support national defense loads, using current planning processes such as black start as a precedent and guide. Such programs would support

[11] Office of the Assistant Secretary of Defense for Sustainment and Office of the Assistant Secretary for the Office of Electricity. (2020). Memorandum of Understanding Concerning a Collaboration to Enhance Energy Resilience.

critical installations with hardened and dedicated transmission cranking paths and capable generation assets to ensure energy delivery even during adverse operating conditions.

Presently, nine DoD installations in Georgia have a range of on-site Carbon-Free Energy (CFE) resources, with varying levels of coordination with GPC. However, these contracts and projects are not designed specifically with energy resilience in mind, in many cases leaving military installations without access to capacity generated on their own installations during a major outage event. The proposed IRP Update does not currently address this issue with planned energy storage projects at Moody Air Force Base ("AFB") and Robins AFB, where Georgia Power has proposed to develop, own, and operate up to 1,000 MW of Battery Energy Storage Systems (BESS) and/or BESS plus solar.[12] During testimony, when asked about the ability of the Air Force Bases to use those resources to support missions, witness Bush indicated the following:

> "We -- from a physical capability, these batteries are not located -- will not be located on the base themselves. So not -- they're not physically connected to the -- to the bases. Again, I -- if some mechanism were put together through a transmission system to allow that to happen, that can -- that could occur. But our current design is not for us to do that. Our current design is to have the batteries at those sites and fully controlled and operated by the operating companies. But if those -- the bases were to invest appropriately, then they -- that we could arrange the system to allow that. But it's my understanding that that has not occurred."[13]

This testimony highlights both the importance and the current lack of targeted transmission investment to support the proposed BESS installations for the DoD air force bases, and likewise the lack of critical investment to support DoD's mission assurance requirements.

Additionally**,** DoD energy requirements should be integrated into regional generation reserve margins across the Southern Company operating territory and supported by interregional

[12] Direct Testimony of Jeffry R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush on behalf of Georgia Power at p. 27.
[13] Transcript of the January 17, 2024, Hearing at p. 441 (PDF p. 50).

transfer minimums with neighboring balancing authorities and independent system operators. Current transmission planning and operational processes in the IRP don't explicitly take DoD energy loads into account so they cannot be directly supported with dedicated capacity or targeted transmission investment. The vulnerabilities to DoD energy assurance are a byproduct of historical planning processes that place an emphasis on generation reserves as the means to address adverse operating conditions and disruption events. However, transmission expansion can play an essential role in addressing these vulnerabilities in a number of ways.

Q. HOW CAN UTILITIES INCORPORATE DOD REQUIREMENTS IN RESOURCE AND TRANSMISSION PLANNING?

A. By using scenario-based planning where the DoD's goals are achieved, utilities can proactively prepare to serve the unique DoD energy requirements. This will require extensive coordination with military installations regarding existing and planned energy infrastructure investments (Exhibit JM-4 – *State of Georgia DoD Energy Fact Sheet)* to determine the mission-driven energy service delivery requirements for bases and their surrounding communities. Planned projects such as the previously mentioned battery storage resources near Moody AFB and Robins AFB must be evaluated for additional transmission investment to ensure their connectivity and availability to DoD during times of emergency. Given the Congressionally-mandated reliability requirements for critical defense missions, updated modeling and contingency analysis is needed to determine the ability of existing transmission, distribution, and generation to meet those requirements and identify improvements needed to address vulnerabilities in future IRPs.

Q. IN YOUR VIEW, DO DEFENSE CRITICAL ELECTRIC INFRASTRUCTURE (DCEI) INVESTMENTS PROMOTE THE PUBLIC INTEREST?

A. Absolutely. Successful infrastructure planning requires coordination across a variety of

stakeholders. These stakeholders range from individual landowners all the way up to multiple agencies across the federal government. The federal government can be the most complex stakeholder to engage with due to its size and the diversity of missions across agencies, but taking into account the needs of DoD, all stakeholders stand to gain from the incorporation of national security requirements into the GPC IRP. Military bases are not the only beneficiaries of increased access to energy resources. The communities that surround DoD installations and large customer centers in cities throughout the region are able to see the cost and resiliency benefits of infrastructure investments in four specific ways:

1) **Economics**. The average ratepayer's two largest concerns are often affordable and reliable electricity, and these are closely tied to economic stability. In fiscal year 2022, Georgia's economy benefited from $6.0B in defense contract spending and $7.2B in personnel spending responsible for 124,079 direct jobs as a result of its military installations, with defense spending makes up 1.8% of Georgia's GDP[14]. Meeting DoD's energy needs is not just a benefit to national security, it is vital to the economic health of the state and its residents.

2) **Personnel impacts**. Military installations are closely connected to and affected by the communities that surround them. More than 60% of military personnel live outside the fence line of the installation, along with nearly 100% of civilian personnel who work for DoD.[15] Power outages at the homes of personnel and their families can negatively impact military readiness. Additionally, DoD installations are not equipped to handle an influx of civilians seeking shelter during emergencies that disrupt services to the general population.

[14] https://oldcc.gov/sites/default/files/FY2022%20Defense%20Spending_GA.pdf.
[15] Bipartisan Policy Center. (2023). Housing America's Military Families.

3) **Interdependent utilities**. Most DoD installations rely on multiple civilian utilities including water/wastewater, communications, and transportation, each of which depend on the same electricity feeding the base. Since transmission outages can affect larger geographic areas, they increase the chance of cascading failures across utilities that will degrade or disrupt mission capability.

4) **Defense industrial base.** The Defense Industrial Base (DIB) is the network of facilities and organizations that provide defense-related materials, products, and services to the U.S. government.[16] This includes research, development, and manufacturing of weapons platforms and armaments, among many other activities that are energy-intensive. The DIB includes organizations with highly specialized capabilities that are important to national defense. The DIB is also important to state economies. In 2021, the defense industry employed 1.1 million Americans across 60,000 companies.[17] In 2023, DoD released its first National Defense Industrial Strategy, which highlights the risk that critical infrastructure vulnerabilities pose to critical defense-related components and technologies.[18]

IV. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. Based on my analysis and conclusions as outlined herein, the Commission should take the following actions to incorporate national security interests into the resource planning process for Georgia Power's 2023 IRP Update:

1. The Commission should direct Georgia Power to make targeted transmission investments

[16] https://crsreports.congress.gov/product/pdf/R/R47751.
[17] https://www.ndia.org/-/media/sites/ndia/policy/vital.signs/2023/ndia_vitalsigns2023_final_v3.pdf?download=1?download=1.
[18] https://businessdefense.gov/docs/ndis/2023-NDIS.pdf.

to support the battery systems to be installed near the Moody and Robins Air Force Bases, thereby supporting DoD's mission assurance requirements; and

2. The Commission should direct Georgia Power to incorporate the DoD's energy requirements into its 2023 IRP Update. More specifically, Georgia Power should be required to identify specific plans to address the DoD's energy needs in its 2023 IRP Update by using scenario-based planning where the DoD's reliability goals are achieved, including the identification of adequate capacity resources and associated transmission pathways; and

3. The Commission should direct Georgia Power to incorporate DCEI into the IRP process to inform long term planning in support of targeted infrastructure hardening and investment for military installations and their surrounding communities. Additionally, generation assets required to meet the CFE requirements of DoD and transmission and distribution assets to support U.S. Army microgrid requirements should be identified in its 2023 IRP Update and future IRPs.

MR. COX: And I also move to admit Mr. Monken's four exhibits into the record and request that they be marked as follows: I request that Mr. Monken's Exhibit JM-1 be marked as SREA Exhibit 2. I request that Mr. Monken's Exhibit JM-2 be marked as SREA Exhibit 3. And then I request that Mr. Monken's Exhibit JM-3 be marked as SREA Exhibit 4. And finally, I request that Mr. Monken's Exhibit JM-4 be marked as SREA Exhibit 5.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as SREA Exhibits 2, 3, 4, and 5.)

BY MR. COX:

Q And then, Mr. Monken, I understand that you have brought some additional copies of the SREA Exhibit 5, the State of Georgia Energy DoD Fact Sheet, to share as a demonstrative handout. Is this correct?

A (Witness Monken) It is.

MR. COX: Mr. Chairman, would I have permission for my colleague, Simon, to distribute these?

CHAIRMAN SHAW: Yes, go ahead.

BY MR. COX:

Q And let's proceed to the testimony summaries.

Mr. Olson, would you please provide your testimony summary?

A (Witness Olson) Yes. Mr. Chair and Commissioners, thank you for the opportunity to testify today on behalf of Southern Renewable Energy Alliance in the Georgia Power IRP. By way of background, I have over 30 years of experience in the energy industry, specializing in the areas of integrated resource planning; transmission planning; renewable energy planning, including renewable energy procurement, resource adequacy, renewable energy integration, transmission planning, rate and tariff design, wholesale market design, and energy policy analysis. I have testified as an expert in numerous proceedings, including before this Commission.

My direct testimony addresses best practices for evaluating renewable and energy storage resources in the context of Georgia Power's 2023 integrated resource plan update, and I focus on three primary components of their proposed plan: Number 1, on the capacity value of solar and storage resources; Number 2, on the linkage between transmission planning and generation planning; and, Number 3, on resource procurement.

So first, with respect to capacity accreditation, the approach used by Georgia Power in its IRP for capacity need determination and capacity value accreditation can be improved upon in several ways.

Georgia Power established its planning reserve margin requirement and calculated effective load carrying capability, or ELCC values, using a generic combustion turbine, CT, as a reference resource.

Georgia Power's IRP modeling represented solar and storage capacity values using a fixed value of zero for solar and declining values with successive traunches of energy storage. However, solar has a nonzero value, according to their own studies. And solar and storage resources can interact with each other in positive ways in their ability to provide capacity, such that the capacity value of the combined portfolio is greater than the sum of the contributions from each resource individually.

While Georgia Power incorporates some of these interactive effects by calculating storage ELCCs assuming that there is a handpicked quantity of solar energy on the system, this still doesn't allow the Aurora model to dynamically update those capacity values as it sorts through various combinations of solar and storage to find the least cost portfolio.

The better practice, as I describe in my testimony, is to use a two-dimensional ELCC surface that gives the capacity expansion model a more accurate view of the capacity contribution of solar alone, storage

alone, and solar and storage in combination.

An additional emerging best practice is to calculate both the planning reserve margin and ELCC for all resources relative to a perfect capacity equivalent. This practice recognizes that no resources are perfect and, therefore, that no resource should receive a capacity value of 100 percent.

Gas resources, in particular, can experience significant challenges operating reliably during very cold conditions, as seen during recent major winter storms.

Georgia Power is over crediting thermal generators by assuming that they are 100 percent reliable during extreme cold weather events. Moreover, the most stressful grid conditions tend to occur when there is an unusually large number of thermal plant outages. It is the performance of the thermal fleet during these events that really matters for reliability, and Georgia Power's modeling should reflect this by calculating the capacity contribution of thermal resources during these unusual events rather than during average conditions.

Secondly, with respect to linkage between transmission and generation planning, I note that Georgia Power's current processes for planning generation and transmission are disjointed and reactive and may not lead

to the lowest cost of serving load for Georgia Power ratepayers.

Georgia Power's transmission screening process is used primarily to determine the dates when some new resources are allowed to be available to provide capacity in the IRP. Meanwhile, Georgia Power's ten-year transmission planning process appears to primarily identify the transmission needed for reliability based on interconnection requests. Neither process proactively identifies the long-term transmission needs associated with major changes to the company's loads and resource mix.

Nor does the combination enable Georgia Power to select a least cost portfolio that considers both generation and transmission costs.

An emerging practice in the industry is to move from an integrated resource plan toward an integrated system plan, this approach where generation and transmission, distribution, and customer programs are considered within the same holistic planning framework.

Potential transmission upgrades for specific groups of resources are identified proactively and made available to the capacity expansion model for optimized selection along with the affected generation. Transparently engaging stakeholders while proactively

planning transmission needs will provide additional benefits to Georgia Power ratepayers by leading to higher quality bids into Georgia Power RFPs.

Then lastly, with respect to RFPs and procurement, my testimony describes the importance of engaging in regular All-Source procurements in which all cost and value drivers, energy, capacity, and transmission are considered. An All-Source procurement with dynamic modeling of resource selection is superior to the renewable cost-benefit framework employed by Georgia Power because it endogenously considers combinations of resources that interact in complex ways, such as solar and storage.

It will be especially important for a robust process to be used to evaluate company-owned generation and affiliate transactions. With respect to company-owned generation, I note that, while Georgia Power raises reliability-related concerns about its ownership share falling below 70 percent of total capacity, it has provided no evidence that independently-owned generation is less reliable than utility-owned generation.

Many regulated utilities rely on independently-owned generation for a much larger share than 30 percent of their total capacity. Thirteen states

have fully restructured retail markets where effectively 100 percent of generation is independently owned with no evidence that these utilities or states suffer from lower reliability.

Indeed, approximately 45 percent of all generation resources nationwide are independently owned. Given how much new capacity is needed to meet rapid load growth in Georgia, this is an "all hands on deck" moment, and Georgia Power should be working with as many parties as possible to develop the needed supply.

Thank you, again, for the opportunity to testify.

BY MR. COX:

Q Thank you, Mr. Olson.

Mr. Monken, will you also please provide a summary of your testimony?

A (Witness Monken) Yes, of course. Mr. Chair, Commissioners, thank you so much for the opportunity to be here with you today to talk about this vitally important issue.

My name is Jonathon Monken. I am a principal at Converge Strategies. I hold a Bachelor of Science degree from the United States Military Academy and a master's in business administration from Northwestern University.

I have currently served in the United States Army for the past 22 years as an armor officer, and I am currently assigned as a cyber and communications operations officer at the Cybersecurity and Infrastructure Security Agency, or CISA, at the U.S. Department of Homeland Security.

My civilian and professional roles include serving as director of the Illinois State Police from 2009 to 2011; director of the Illinois Emergency Management Agency and Department of Nuclear Safety, and Homeland Security adviser to the Illinois governor from 2011 to 2015; and, previously, as senior director of system resilience for PJM Interconnection from 2016 to 2020.

I advise clients in federal and state government, as well as the private sector, on the development and implementation of strategies designed to improve the energy resilience of critical infrastructure systems.

My testimony provides an overview -- excuse me -- over scroll. My testimony provides an overview of the importance of including national security considerations into the Georgia Power Company integrated resource plan to ensure the energy assurance needs of the Department of Defense are met now and into the future.

In 2021, Congress passed a law requiring DoD to attain a minimum level of 99.9 percent availability for energy loads that support critical missions by 2030. DoD subsequently adopted guidance specifying even higher availability requirements for certain facility types. Missile fields, cyber operations facilities, and satellite control facilities, for example, must attain a level -- a minimum level of 99.9999 percent availability.

This availability requirement translates to a downtime of only 30 seconds per year. The Army has set an additional target to install microgrids at all of its installations by 2035. DoD installations numbering 13 in Georgia represent the single largest ratepayer on the Georgia Power Company system.

The mission supported by that electricity, the vast majority of which comes from GPC's privately owned and operated infrastructure, require uninterrupted service in the face of growing climate, physical, and cybersecurity risks.

Meeting these needs will require physical infrastructure able to access and deliver geographically disbursed electric generation resources across the country in a manner that meets the diverse needs of DoD missions and community resilience.

The status quo for transmission planning and

design reflected in this IRP does not currently capture the energy resilience needed to support national security.

Aggregating energy resilience requirements across the state can better leverage the redundancy and resilience of the bulk electric system rather than relying on individually distributed energy resources alone.

While the DOE, the Department of Defense, and Southern Company committed to ensuring the prioritization of military installations and emergency restoration plans in a memorandum of understanding, GPC should work with grid operators to ensure that the critical defense facilities are included as priorities for infrastructure design and investment.

As an alternative, grid operators can work with the Department of Defense to develop specific programs to support national defense loads using current planning processes, such as Black Start, as a precedent and a guide. Such programs would support critical installations with hardened and dedicated transmission cranking paths and capable generation assets to ensure energy delivery, even during adverse operating conditions.

Presently, nine DoD installations in Georgia

have a range of on-site carbon-free energy resources with varying levels of coordination with GPC. However, these contracts and projects are not designed specifically with energy resilience in mind. In many cases leaving military installations without access to capacity that's generated on their own installations during a major event.

The proposed IRP update does not currently address the issue with planned energy storage projects at Moody Air Force Base and Robins Air Force Base where Georgia Power has proposed to develop, own, and operate up to 1000 megawatts of battery energy storage systems, plus potential resources for solar.

My testimony highlights both the importance and current lack of targeted transmission investment to support these proposed battery installations for the DoD Air Force bases and, likewise, the lack of critical investment to support DoD's Mission Assurance requirements.

Additionally, DoD energy requirements should be integrated into regional generation reserve margins across the Southern Company and Georgia Power Company territory and supported by interregional transfer minimums with neighboring balancing authorities and independent system operators.

Current transmission planning and operational response processes in the IRP don't explicitly take DoD energy loads into account, so they cannot be directly supported with dedicated capacity or targeted transmission investment.

The vulnerabilities to DoD energy assurance are a by-product of historical planning processes to place an emphasis on generation reserves as the means to address adverse operating conditions and disruptive events. However, transmission expansion can play an essential role in addressing these vulnerabilities in a number of ways. Planned projects, such as the previously mentioned battery storage resources near Moody Air Force Base and Robins Air Force Base, must be evaluated for additional transmission investment to ensure both their connectivity and availability to DoD during times of emergency.

Given the congressionally mandated reliability requirements for critical defense missions, updated modeling and contingency analysis is needed to determine the ability of existing transmission, distribution, and generation to meet those requirements and identify improvements needed to address vulnerabilities in future IRPs.

Based on the analysis and conclusions outlined in my testimony, I am recommending that GPC take the

following three actions to incorporate national security interests into their resource planning process for its 2023 IRP update:

Number one is to make targeted transmission investments to support the battery systems to be installed near both Moody and Robins Air Force bases.

Number two is to incorporate the DoD's energy requirements into the 2023 IRP update. More specifically, Georgia Power should be required to identify specific plans to address the DoD's energy needs by using scenario-based planning where the DoD's reliability goals are achieved, including the identification of adequate capacity resources and associated transmission pathways.

And number three is to incorporate defense critical infrastructure investments into the IRP process to inform long-term planning in support of targeted infrastructure hardening and investment for military installations and their surrounding communities.

Additionally, generation assets required to meet the CFE requirements of DoD and transmission and distribution assets to support the U.S. Army microgrid requirements, should be identified in its 2023 IRP update and future IRPs.

Thank y'all for your time.

Q Thank you.

MR. COX: Mr. Chairman, at this time, I submit the witnesses for questions from the Commission and cross-examination.

CHAIRMAN SHAW: Thank you, sir.

Mr. Monken, first of all, very impressive background. Thank you for your service to our country and to your state.

MR. MONKEN: Thank you, Mr. Chairman.

CHAIRMAN SHAW: Very impressive. On your exhibit, that would have been your exhibit, I guess, JM-4 and their Exhibit No. 5.

MR. MONKEN: Yes, sir, that's correct.

CHAIRMAN SHAW: The Department of Defense Energy Fact Sheet. Not trying to be too critical here, but on the Moody Air Force Base piece where you said it's a 2.5-megawatt solar array, I have a little local knowledge, because Moody is in my backyard literally.

MR. MONKEN: Yes, sir.

CHAIRMAN SHAW: But I think that solar array is -- it is either 49 or 50 megawatts, I believe.

MR. MONKEN: Yes, sir. It has been upgraded in recent years. That was the initial project and the first tranche of solar that was installed at the

base.

CHAIRMAN SHAW: Oh, okay. Thank you.

MR. MONKEN: But an important clarification for sure.

CHAIRMAN SHAW: Another interesting fact about the Moody piece is Moody is actually the only military installation in the state that is not directly served by Georgia Power. It is actually a Colquitt EMC wholesale customer.

MR. MONKEN: Yes, sir.

CHAIRMAN SHAW: But there is an MOU with Georgia Power to be able to use the renewables piece in the event of emergencies and national security, like you are concerned about, like we all are.

MR. MONKEN: Yes, sir.

CHAIRMAN SHAW: Thank you.

Any other questions?

COMMISSIONER PRIDEMORE: Mr. Monken, I have a request.

MR. MONKEN: Yes.

COMMISSIONER PRIDEMORE: So this DoD Energy Fact Sheet, it doesn't denote anywhere that this is yours or attached to the Southern Renewable Energy Association's intervenorship. I know it is in your group exhibits. But the fact that DoD is also an

intervenor in this case, could you submit this with some denotation so that Commissioners and staff know that this is, in fact, attached to Southern Renewable Energy Association and not DoD, since they are also an intervenor?

MR. MONKEN: Absolutely, Commissioner. No problem.

COMMISSIONER PRIDEMORE: Thank you.

COMMISSIONER JOHNSON: Thank you for your service. Appreciate it.

MR. MONKEN: Yes, sir.

CHAIRMAN SHAW: That's coming from another Army guy.

MR. MONKEN: Be Navy, sir.

CHAIRMAN SHAW: Any other questions from Commissioners?

(No response.)

CHAIRMAN SHAW: All right. We will move forward with cross.

Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. CARVER: Yes, Mr. Chairman.

CROSS-EXAMINATION

BY MR. CARVER:

Q Infrastructure and transmission lines get me all fired up, so I am glad -- glad of this panel, and I want to thank both of you here today. Dr. Olson, I know you well from previous testimony, and it is great to see you. I am also an Army officer, retired now, so I appreciate it. In fact, the Fort Rucker military project for Georgia Power was also something that's come up here before at our Commission. That was my last duty station. So I appreciate what you do for the service of our country.

I am Brad Carver. I represent the Advanced Power Alliance; and, Mr. Olson, from the last time you testified, we have absorbed the Georgia Large Scale Solar Association membership into our organization. And so I would like to talk to y'all today, in particular, about transmission infrastructure and how solar and battery storage can be paired together successfully.

I will start with, Mr. Olson, did you have the occasion to see the cross-examination of Mr. Goggin yesterday, particularly related to multiuse planning and transmission planning?

A (Witness Olson) I did.

Q In that testimony, we -- we heard about -- and I know in your testimony you reference -- what Duke Energy is doing, so I am going to get into some questions

about that in a moment. I will point you to page 13 of your testimony. You have some discussion around effective load carrying capability, ELCC, which can provide a more accurate value of the capacity contribution of variable resources like solar power; is that correct?

A (Witness Olson) Yes.

Q So on page 13, you say that, "While many utilities have adopted single-source ELCC curves for solar and storage, this practice only captures the saturation effect." And so you go on to recommend actually being able to do two-dimensional solar.

And on page 14, I will direct you to lines 11, 12 of your testimony. You say that, if -- that if you just do one-dimensional ELCC that, "This would prevent the utility from achieving the least cost portfolio." Can you explain why that's the case?

A (Witness Olson) Yes. And as I mentioned in my summary of my testimony at the beginning, it is because of the interactive effects between solar and storage when both of them are added onto the system. The solar interacts with storage by serving load during the middle of the afternoon and shortening the window in which a battery might need to dispatch in order to provide full capacity. But that shortened window, or shorter duration

of battery, can provide the same amount of capacity versus what might have taken a longer duration battery in the absence of the solar. So that's one example of how they interact with each other.

The way that this interaction interplays with the capacity value is that, as I said, the capacity contribution of the portfolio of solar and battery resources is greater than the sum of the parts. So if you just take the solar by itself and the storage by itself and you add them up, that doesn't get you to the total amount of capacity that the combined set of resources provide, because of these interactive effects.

And if your capacity expansion model that you are using in the IRP doesn't take that into consideration by modeling this dynamically, then it is going to miss that value that you get from adding both of them at the same time. And so it is going to under-invest in both of those resources.

Q Thank you very much. I want to turn you to page 21. On page 21 one you reference that Aurora, the Aurora model is not capable of being able to evaluate this appropriately; and so I want to dig into that for a second. Because it seems like to me that because of that, because we are not evaluating that appropriately, maybe we need to have a new model here in Georgia or

maybe a new way to look at this.

Could you explain? I mean, because, again, the Aurora model maybe doesn't have this capability. Could you explain that?

A (Witness Olson) Yes, and so that's correct. The Aurora model can only really look at one dimension of the problem at a time, and so what the company has done with that is they have, in effect, held solar constant, and they have modeled storage in traunches. So Traunch 1 has a certain ELCC value -- and I forget the number. It is up to 1000 megawatts or maybe it is 3000. For the second traunch, they say, Well, storage is starting to saturate a little bit, so we will give that second traunch a little bit of a lower value. And then there is a third traunch, which has an even lower value. So, in effect, they have got sort of a stair step one-dimensional curve for storage, which kind of, more or less, gets the answer right, but they are not incorporating, again, those interactive effects.

Now, you know, Aurora is a model that's used by a number of utilities across the country, so I am not going to say that it is not a model that's very useful for lots of purposes. I will say that we, in our company, have moved away from Aurora for, really, what the reason that it is not very good at addressing solar

storage variable resources.

So there are other models out there that could be adopted. PLEXOS is another model that is sold by the same vendor that sells Aurora. Energy Exemplar, that's a more advanced model. EnCompass is another model that's used. I think Duke uses that in North Carolina. I know Xcel uses it in Colorado.

So there are a number of other software packages that could better address the combined value of solar and storage, which is only going to increase in importance as more and more of those resources are added to the Georgia Power system. So I would, in the long run, recommend moving to a different model.

In the short run, what they could do, and haven't done, is just done some sensitivity analysis around, well, what if we had a lot of storage on the system. How would that change the value of solar? So the interactive -- interaction works both ways. The more storage that's on the system, the more capacity contribution you get from solar.

So what their ELCC study does is it models storage with a lot of solar, but it doesn't go the other way and say, if we had a lot of storage, what would that do to the ELCC of solar. So that would be one, just example, of a concrete step that I would recommend to

better explore this sort of solution space and get closer to the optimal solution, which their model can't get them to on its own.

Q I appreciate that very much. I am going to shift now because I want to, on -- you on page, let's see, 23 of your testimony, you talk about SERTP -- let me turn to that now. Actually, I'm sorry.

Before we get into that, let me do one other thing. Let's go to page 27 of your testimony. This is your testimony related to competitive renewable energy zones, CREZs, that you reference on line 9.

What I want to ask you about, we are seeing here in Georgia quite a bit of land use issues. We are seeing this across the APA footprint, but, in particular, we are having areas of the state where we have had an overconcentration of solar which is accompanied by transmission constraints. And there are plenty of other parts of Georgia that have been -- have had a dearth of projects, and that's because there are some transmission limitations in those places.

So you refer here to these competitive renewable energy zones, and one of the things we are looking at in the state -- and, particularly in South Georgia, and particularly in Chairman Shaw's district -- is that we have the overconcentration and

then under-concentration and that if we could spread those resources out more effectively -- and it could be done with small upgrades in transmission infrastructure -- that that might can spread this resource to other areas.

So can you talk about how being able to use something like competitive renewable energy zones in Georgia could be advantageous for our long-term planning here?

A (Witness Olson) Yes, I can try. So the competitive renewable energy zone process that the Commissioners might be aware originated in Texas a number of years ago, where they looked at the geography of the state, and it was pretty clear that the best wind was pretty far away from the load centers in the northwestern part of the state up in the Panhandle, which was going to require a lot of transmission to deliver that wind into the load centers in Dallas-Houston area. So they proactively identified a number of transmission investments that they could make that would unlock that resource on behalf of their customers.

So they went and said, this is where it looks like the good wind is, where there is going to be the most interest in developing that resource, and planned the transmission to see if it made sense to build that.

And it did in that case.

California has done -- did something similar a number of years ago where they looked at what is called the RETI process, Renewable Energy Transmission Initiative. They looked at where would it be a good place in California to locate solar, to locate wind, and what would be the transmission corridors to get from those locations into the load centers. Just, again, looking at and taking into consideration not just the quality of the resource but also things like land use considerations, environmental values of land, other types of siting challenges that you might see, just to get a sense of, we know there is going to some solar built. Where is it most likely to be built, and let's see if we can identify some transmission corridors and some lines that might, you know, assuming it is cost-effective, bring those resources to load.

Q And that would be similar to what we would be looking at in Georgia where we have the most valuable area of the state for utility scale projects would be South Georgia, and the load center is where we are sitting here in the capital of Atlanta, Metro Atlanta; is that correct?

A (Witness Olson) Yes. And some transmission would obviously be required to bring those resources from

where they are generated to the load center.

Q Yes. Okay. So now let's turn to that southern -- the Southeastern Regional Transmission Planning study, the SERTP process, which, please hand our witness that, as well. I have shown this to counsel. This is the -- this was -- this was asked about yesterday during Mr. Goggin's testimony, but this is a SERTP study. This is something that's undertaken by the company in the Southeast region. And I want to bring this to the attention and ask you about this. Because what we are hearing here is that if we had infrastructure upgrades in certain places that we --

MS. PRYOR: Objection. I am sorry. He hasn't established that the witnesses are familiar with the study to which he is referencing.

MR. CARVER: Very good point.

BY MR. CARVER:

Q Are you familiar with this SERTP study?

A (Witness Olson) Generally familiar, yes.

Q Okay. So you have here on pages --

MS. PRYOR: Objection. Was this part of Mr. Olson's testimony? You mentioned it was referenced yesterday, but I don't believe it was part of Mr. Olson's testimony.

MR. CARVER: It is not part of his testimony,

but he -- on page 23 of the testimony, he references Georgia Power participating in the SERTP process. And I just asked him if he was generally familiar -- or I asked him if he was familiar with this study, and he said he was generally familiar. So the reason I want to ask him about this is because this is --

CHAIRMAN SHAW: So you are saying this -- this handout is referenced in his testimony?

MR. CARVER: I am saying that the SERTP process is referenced in his testimony. And, Mr. Chairman, if I may --

CHAIRMAN SHAW: What are we looking at here? I am just --

MR. CARVER: Mr. Chairman, this is directly relevant, because this is a -- this is a study of how you could get 1.6 gigawatts of solar power from South Georgia to Metro Atlanta, to our load center; and I am asking him about this, because he is an expert in this area. And I wanted to ask him, because if we are able to do these transmission upgrades, we could be unlocking 1.6 gigawatts of very cheap power for North Georgia.

MS. PRYOR: Unfortunately, I am still going to have to object. Mr. Olson's testimony references

the SERTP process generally, that the Georgia Power participates in it. It does not reference this specific study, and that amounts to a friendly cross.

CHAIRMAN SHAW: Mr. Carver, if you can find a question that you can ask that's relevant to his testimony and to this document --

MR. CARVER: Okay.

CHAIRMAN SHAW: -- I will allow it. But if it is just pertaining to this and not in his testimony, then we are going to move on.

MR. CARVER: I understand. I understand. And I will connect the dots here. His testimony is dealing with about how we can look at using -- he just talked about the process that he has looked at in states like California and Texas to bring resource-rich generation resources to areas where there is demand, just like we have in the state of Georgia between South Georgia and North Georgia. And he has established he is generally familiar with this study.

And what I want to ask him about is, if we -- if we had and we could expend a reasonable sum of money to make these transmission upgrades to the tune of about $100 million, isn't that something

that we should probably be looking at in this 2023 IRP update?

MS. PRYOR: I am going to have to object again. Mr. Carver just made very clear that this study was not part of Mr. Olson's testimony.

CHAIRMAN SHAW: Let's move on.

MR. CARVER: All right.

BY MR. CARVER:

Q Let's move on. So I am going to turn you to page 26. Yesterday we heard, again, that Duke Energy has undertaken multiuse planning in its transmission planning process. And they are a utility here in the Southeast that's also not in an RTO, but that they are doing that, and you reference this on page 26. You spend an entire page talking about Duke Energy's proactive approach to transmission planning. Let me ask you this: If Georgia Power were to undertake planning similar to this, do you think that they could project and be able to put in place infrastructure upgrades to deliver needs like we are seeing in this IRP update right now?

A (Witness Olson) And I guess what I would say is, this is the type of process that's an emerging best practice among utilities that are looking out and seeing very significant changes to both their loads and to their resource mixes over a period of time that is relevant for

transmission developments.

Transmission takes a long time to develop. Many transmission plans have looked ten years out. That's really not far enough out anymore given how long it takes to build transmission and the big changes that we are seeing in portfolios all around the country. So a more proactive process, that looks farther out, that proactively anticipates where the best resources might be located, provides benefits. And if it is open and transparent and has lots of stakeholder participation, it provides more benefit.

How this type of information could be brought into a resource planning process is -- and I will just give a specific example of the way that we do it in California. So we run the IRP process for the State of California, and there we look at using the type of information I described earlier: Here is where the resources are; here is where the interconnection queue tells us that people are looking to locate. Here is the information about the cost of transmission upgrades to connect this location or that location. And there is several different zones, a dozen or more zones that we look at.

And the capacity expansion model then optimizes the portfolio over time, given that transmission cost and

the quality of the resource and the output shape of the resource, and finds the optimal portfolio. It is sort of transmission-informed capacity expansion modeling, which gives us then a least cost portfolio across both the transmission and the generation components.

Now, to do that you need high-quality information about what the potential transmission upgrades are to bring specific resources or groups of resources to load, and so it requires that transmission planning process to be done at the outset with this end in mind, that it is going to be used for resource selection in an IRP.

Q And wouldn't that be like this SERTP study that we just looked at that would be, here is $100 million of transmission upgrades you could do, and you could unlock 1.6 gigawatts of solar power from South Georgia?

A (Witness Olson) Yes. I would say, in particular, if it were combined with the type of on-the-ground GIS-type of information about the resource quality, the quantity of resource that might be available in a given location, and the quantity of land where it is suitable to site that resource. That's the additional piece that I didn't see in this study.

Q Okay. And so let me -- now we are to the finale. So now we are in this IRP update. This is

unusual. The first time I have ever experienced this during my career. We do have another IRP filing that's going to happen at the end of this year, and Georgia Power is going to be filing that.

CHAIRMAN SHAW: First of next year.

BY MR. CARVER:

Q First of next year. January of next year. And so what would you recommend, since we are sitting, you know, ten months out from their filing of that? What would be helpful that could be done in this window of time that could help guide us as we go into this next IRP?

A (Witness Olson) Yes. And I think I refer to this sort of at the end of my testimony in my recommendations. But in effect, I recommend a form of transmission-informed capacity expansion modeling where you take the resource information, and you gather it up, and you look at the transmission requirements. You add the cost of the transmission onto the resources and, from that, select a resource portfolio that minimizes cost, total costs, including generation and transmission.

Q Thank you very much, Mr. Olson.

MR. CARVER: Thank you to the panel.

No further questions.

COMMISSIONER PRIDEMORE: Mr. Olson, I have got

some questions to Mr. Carver's point. He brought up Duke yesterday and what they are trying to do since they -- since the State of North Carolina passed the carbon rule. Define multivalue transmission planning for us today.

MR. OLSON: I think we heard a lot about that yesterday. But it, you know, refers to the notion that a transmission project has a lot of different value propositions, a lot of different benefits that you get from adding a transmission line. So it enables you to bring resources to meet -- to load center to meet a capacity need. It allows the delivery of energy. It might help you meet a public policy goal. That's one of the benefits that FERC has identified in their transmission planning guidelines.

There are other benefits like resilience, optionality. It gives you the ability to move energy in ways that you might not have expected when you were planning the transmission line to begin with. These have very long lifetimes. And it is sort of a like a road. You don't necessarily know exactly how you are going to use it, but you know it will be useful for a variety of reasons.

So that's the notion behind it, multivalue

transmission planning, is that we need to do a holistic view of all the different values that you might get from a transmission project. And then, you know, the more proactively you can identify the specific needs in each of those areas -- energy, capacity, et cetera -- then, you know, the more proactively you can plan the transmission projects that might be required to achieve them.

COMMISSIONER PRIDEMORE: So it is my understanding that as Duke Carolinas defines it and as the FERC defines it is that it is the economic need, the public policy need, and the reliability need of the transmission system, or for new transmission lines to be built.

Are you suggesting that the State of Georgia does not oversee Georgia Power building transmission assets that are reliable, economic, and in the public policy interest?

MR. OLSON: I guess what I would say is that there are a variety of ways that you can go about meeting each of those requirements, and some of them might be more reactive, and some of them might be more proactive. And I have seen states and utilities that are kind of on both sides of that spectrum, and, to me, what we see in Georgia is more

on the reactive side; and what we see in North Carolina and other places where we work, like Salt River Project in Arizona, Xcel in Colorado, are more on the proactive side, where they are really doing more than just looking at, you know, where are our interconnection requests when they are planning the transmission system.

COMMISSIONER PRIDEMORE: Well, I think, to your Duke example, Duke filed their plan in the separate council that they put up with it, the NCTCP with the FERC, and the FERC denied the proposal back in December. I know a lot of the clean energy groups that have intervened in this case are supportive of that and are supportive of Duke changing the -- or modifying the petition to refile with the FERC.

But the fact that the FERC rejected it based upon cost and violation of Order 890, I think, to some extent, some of these recommendations -- and really a non-true comparison to the way that Georgia manages transmission projects. For kind of the new shiny object or the new catch phrase, because we all know this, we all work in this space, and so, you know, we kind of get wrapped around the axle about something for a little while, thinking it is like the panacea. And I am not saying that it is not.

I am just asking, should we not have a real evaluation of the way that Georgia manages transmission and the transmission assets that are put forward in this proposal, knowing that they have and have always been reviewed as being economic, reliable, and in the public policy interest?

MR. OLSON: Yeah. And again, I am not trying to say that -- propose anything that I think is a panacea, either. What I am trying to propose is incremental improvements to the process that already exist in Georgia, and I think we have discussed what those might be. More proactive, taking into consideration additional information beyond what is traditionally considered by transmission planners, including resource quality, GIS-type of information about resource potential, and those types of things.

COMMISSIONER PRIDEMORE: Thanks, Mr. Olson.

VICE CHAIRMAN ECHOLS: I just have one question. I don't know if you -- were you in here when Mr. Goggin was on the stand?

MR. OLSON: I was watching remotely yesterday. Yes.

VICE CHAIRMAN ECHOLS: I want to go back to this ERIS versus the IR -- the energy versus the network designation and Georgia Power's plans to use

the energy designation on Yates; right. You know what I am talking about?

MR. OLSON: Yes.

VICE CHAIRMAN ECHOLS: So I just wonder, you know, are we going to regret and wind up spending more money, in the future? In other words, if we are going to do the Yates units, do we need Georgia Power to go ahead and study the units, you know, in its network, you know, designation instead of how we have done it? We -- do you think that there is some urgency to that, or can that wait? What is your thoughts on that?

MR. OLSON: Well, as I understand it, those -- the company is saying those resources are needed to provide capacity in the 2029, someone will correct me I am sure, kind of time frame. So that's soon in the transmission world.

Now, I did hear yesterday that the company has submitted a request for native load service, transmission service for those units. But what was puzzling to me out of that exchange was, so if the company is going to acquire firm native load transmission service for those units, why would you go through the process of an energy-only interconnection request?

There is also an NRIS, which is a network interconnection request, where transmission upgrades are studied to be able to deliver that resource to the grid on a firm basis. Energy-only, ERIS, that's an energy-only designation. It explicitly says that that resource is subject to potential curtailment if the grid can't accommodate it.

So to go back to the analogy that Mr. Goggin used yesterday about the driveway and then getting onto the main road, if you can't get out of your driveway, then I don't know what good it does you to have service across all of the main roads. That's where I was confused by that exchange, and I do have that in my testimony, as well, about this -- my puzzlement about their selection of ER -- and my concern about their selection of the ERIS interconnection service for those units.

VICE CHAIRMAN ECHOLS: All right. Thank you.

MR. CARVER: Thank you. Thank you, gentlemen.

CHAIRMAN SHAW: All right. Moving on. Clean Energy Buyers Association.

MR. DUNBAR: No questions. Thank you.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: GAM.

(No response.)

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

MR. MORELAND: No questions.

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STRUM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. MCNUTT: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power.

CROSS-EXAMINATION

BY MR. PRYOR:

Q Good afternoon, gentlemen. Allison Pryor on behalf of Georgia Power Company.

A (Witness Olson) Good afternoon.

A (Witness Monken) Good afternoon.

Q Thank you for your service, Mr. Monken.

A (Witness Monken) Thank you.

Q I have a couple questions for you on your testimony.

A (Witness Monken) Sure.

Q You recommend that the company plan for and make targeted transmission investments, specifically for the Department of Defense at the Robins and Moody's battery projects; is that correct?

A (Witness Monken) It is.

Q And was your recommendation limited to those specific battery projects or more broadly towards DoD

installations across the state?

A (Witness Monken) Both.

Q Okay. And did you confer or collaborate with any of -- any Department of Defense representatives before making those recommendation?

A (Witness Monken) I did not.

Q Okay. And you are aware that Department of Defense is an intervenor in this case?

A (Witness Monken) I am.

Q Did you read their testimony?

A (Witness Monken) I did.

Q Did it surprise you to learn that they did not share the same recommendations that you made?

A (Witness Monken) Not necessarily, no.

Q Okay. You understand that Georgia Power's responsibility for generation and transmission planning is to all 2.7 million customers and not just a single customer like the Department of Defense; correct?

A (Witness Monken) Yes.

Q And you did not analyze the estimated cost associated with any of the targeted transmission investment that you recommended?

A (Witness Monken) No.

Q And just to be clear, your recommendation is that all of Georgia Power's customers be paying for those

targeted transmission investments; is that correct?

A (Witness Monken) No, that was not stated in testimony.

Q Okay. So your recommendation would be that the Department of Defense would pick up the tab for those transmission investments?

A (Witness Monken) It is actually -- the best path is a blended investment model, recognizing -- and this is actually something that Commissioner Echols had mentioned in the previous meeting on this particular subject, is there is no reason why you can't design and implement a technological solution that also supports defense communities that surround those installations, as well, recognizing that there is co-dependencies on other infrastructure systems and personnel that reside within those defense communities. So there is no reason to make it a single ratepayer benefit.

In fact, it would be preferred to support as many of those 2.3 million customers in Georgia as possible while making these targeted investments to support the Department of Defense.

Q Understood. Thank you very much.

A (Witness Monken) Thank you.

CHAIRMAN SHAW: Redirect?

MR. COX: No redirect. And, Mr. Chairman, may

our witnesses be excused at this time?

CHAIRMAN SHAW: Yes. Thank y'all, and you may be excused.

Go ahead and -- Department of Defense can go ahead and move forward with yours. Go ahead.

MR. MCNUTT: Good afternoon, Mr. Chairman. John McNutt on behalf of the Department of Defense and all other federal executive agencies. I have got Mr. Chris Walters and Mr. Colin Fitzhenry here as our witness panel.

Gentlemen, could you please raise your right hands.

Thereupon,

COLIN FITZHENRY,
CHRISTOPHER WALTERS,
having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. MCNUTT:

Q Mr. Walters, could you introduce yourself and your title and employer?

A (Witness Walters) Sure. My name is Christopher Walters. I am a principal at the firm Brubaker & Associates. I have been employed by BAI since January 2011.

Q Mr. Fitzhenry?

A (Witness Fitzhenry) Yes. My name is Colin

Fitzhenry. I am a senior consultant at Brubaker & Associates, and I have been employed there since 2013.

Q Mr. Walters, did you prepare and cause to be filed on February 15, 2024, 18 pages of direct testimony and two exhibits in this proceeding?

A (Witness Walters) Yes.

Q Since we filed it, did you have any technical corrections to that testimony?

A (Witness Walters) No technical corrections, though I do have some corrections that I would like to make.

Q Well, let's start. Do you have a correction on page 14 of your testimony, line 9?

A (Witness Walters) Yes.

Q What is your correction?

A (Witness Walters) Between the words "your" and "concerns," I would like to insert the word "other."

Q Great. And your other correction is page 15, line 20; correct?

A (Witness Walters) Yes.

Q And what is that correction?

A (Witness Walters) The word "required" should be struck and replaced with "considered."

Q Mr. Fitzhenry, did you have any corrections to your testimony?

A (Witness Fitzhenry) I do not.

Q Perfect.

MR. MCNUTT: Mr. Chairman, if it pleases the Commission, I would like to mark as Department of Defense Exhibit 1 the direct testimony of Mr. Walters and as Department of Defense Exhibits 2 and 3 Mr. Walters' two exhibits?

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as DOD Exhibits 1, 2, and 3.)

MR. MCNUTT: If it please the Chair, the Commission, I would also like to mark the testimony of Mr. Fitzhenry as Department of Defense Exhibit No. 4 and his two exhibits as Department of Defense Exhibits No. 5 and 6.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as DOD Exhibits 4, 5, and 6.)

BY MR. MCNUTT:

Q Mr. Walters, would you like to offer a summary of your testimony to the Commission?

A (Witness Walters) Yes, I would. Thanks. Mr. Chairman, Commissioners, thanks for having me today. This is my first time testifying here in Georgia. I appreciate you welcoming me here.

CHAIRMAN SHAW: Welcome.

A (Witness Walters) My name is Christopher Walters, and I am a principal at the firm Brubaker & Associates. I am testifying here today on behalf of the Department of Defense and all other federal executive agencies. The purpose of my testimony is to provide comments on Georgia Power Company's 2023 IRP update filing, discuss the objectives of the voluntary agreement entered into by the federal government and Georgia Power Company's parent, Southern Company, known as a memorandum of understanding, or an MOU, as well as discuss broader clean energy goals.

Further, I observe certain deficiencies I believe to be present in the IRP update filing and offer recommendations to potentially alleviate some of those concerns and mitigate certain risks.

This proceeding was filed with sense of urgency given the extraordinary economic growth that is expected in the Southeast in Georgia, leading to a projected capacity shortfall much sooner than previously expected. In general, a lack of time leads to rushed analyses and decisions which can ultimately have unwanted and expensive consequences. To that end, it is imperative that the Commission consider building in protections for existing customers so they are not left paying if new

customers and new loads do not materialize or do not sustain.

I recommend that the company require capital commitments from the new economic development projects and, in particular, those deemed of higher risk. I recommend the Commission consider implementing length of service contracts for the new higher risk customers. I also recommend that the Commission consider implementing annual reporting requirements to track the performance of newer loads with look back tests.

With regard to the 70 percent ownership requirement, given the significant advancements in energy and energy storage technology since that requirement was last considered in 2001, I recommend all relevant stakeholders revisit that requirement and study whether it would produce meaningful benefits to customers without jeopardizing rate affordability and service reliability.

Further, in order to help achieve the carbon pollution free energy objectives and needs of its current and new large customers, I -- I recommend the company should study the possibility of relaxing the existing limits of the CARES program and assess the demand for CARES and/or other CFE offerings.

The company should study the potential of expanding the amount of renewable resources procured

through the ongoing RFP process, as well as possibly making the program continuously available for letters of interest and keep a resource solicitation open on an ongoing basis so the program can grow alongside customer demand.

The Southeast, in general, and Georgia, specifically, has been presented a tremendous opportunity to see unprecedented economic growth over the next several years, from various industries. While there is great opportunity for continued economic growth, there is an equally great opportunity to get it wrong, burdening ratepayers with hundreds of millions in costs.

While the company's efforts to offer and expand CFE resources is significant, there is more to be done on that front and there is a tremendous demand for those resources. Some of Georgia Power's largest customers, including the federal government, have clean energy goals and objectives.

While the company has testified it will engage those customers in helping achieve those goals, it is imperative that the company follow through on its commitment to do so while also maintaining safe and reliable electric service. Engaging large customers in the public and private sectors to help achieve sustainability goals can be its own source of economic

development and should be pursued.

Thank you.

Q Thank you, Mr. Walters.

Mr. Fitzhenry, would you like to summarize your testimony, please?

A (Witness Fitzhenry) Yes, I would. Good afternoon, Mr. Chairman and Commissioners. Thank you for allowing me the time to summarize my testimony and recommendations. The primary purpose of my testimony was to address Georgia Power's modeling efforts to support its 2023 integrated resource plan update.

My conclusions and recommendations can be summarized as follows: The capacity accreditation of resource options the company includes in its integrated resource plan modeling does not accurately reflect the capacity contribution of either solar or thermal-generating resources.

Georgia Power should utilize the effective load carrying capability studies it perform for variable renewable resources and incorporate more appropriate analyses of thermal unit performance to correctly model the contribution of all potential generating resources being considered.

This will better inform the company's selection of resources in its plan. Georgia Power did not update

its reserve margin study for the 2023 IRP update, and the target reserve margin may not accurately reflect the company's capacity obligation.

In addition, Georgia Power's updated economic analysis of capacity resources was limited to only six capacity resources. As a result, Georgia Power potentially misses an opportunity to identify alternative lower cost generating resources to fulfill its capacity obligation.

And finally, Georgia Power has not demonstrated through rate impact studies that its proposed resource plan will put downward pressure on rates of its existing customers.

I recommend that Georgia Power take the following action: Update its reserve margin study to ensure that the 2023 IRP update accurately reflects the company's capacity obligations; utilize production cost modeling to compare potential resource expansion plans to ensure that the least cost resource plan is being proposed; utilize the existing or conduct a new effective load carrying capability study of potential generating resources so that the company is accurately reflecting the accredited capacity value of resources.

Thank you all for your time.

MR. MCNUTT: Mr. Chairman and Commissioners, I

believe that my witnesses are ready for cross-examination and examination.

CHAIRMAN SHAW: Thank you, sir. Any questions from the Commissioners?

(No response.)

CHAIRMAN SHAW: All right. We'll move on. Cross.

Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: No questions.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: GAM.

(No response.)

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power &

Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

(No response.)

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

MR. COX: No questions.

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions.

CHAIRMAN SHAW: Georgia Power.

MR. HEWITSON: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Gentlemen, good afternoon. Steve Hewitson on behalf of Georgia Power Company.

A (Witness Fitzhenry) Good afternoon.

Q Mr. Fitzhenry, if I could start with you?

A (Witness Fitzhenry) Sure.

Q On page 3, lines 15 to 24, you state that Georgia Power's resource mix study assigned a zero percent capacity credit for solar resources.

Do you see that testimony?

A (Witness Fitzhenry) I do.

Q Okay. And in support of that testimony you cite Mr. Grubb's testimony in January during the direct hearing; right?

A (Witness Fitzhenry) That's correct.

Q In that testimony, Mr. Grubb stated that generic solar gets an ELCC of zero percent but existing and known solar like that coming through an RFP is given a positive capacity credit.

Wasn't that his testimony?

A (Witness Fitzhenry) Yes. In fact, I do say that he says the company continued to model generic solar resources, assuming they have no capacity value, on lines 4 and 5.

Q Okay. So you understand that it is only the generic resources?

A (Witness Fitzhenry) Yes, absolutely, I understand the distinction. In fact, in the Georgia Power's territorial base case load verse existing capability study, that they present as a work paper, you can -- solar resources are demonstrated to have capacity both in the summer and winter.

Q Okay. And are you aware the system is projected to have about 14 gigawatts of solar by 2035?

A (Witness Fitzhenry) I am not aware of that specific number. I know that solar is growing within the service territory of Georgia Power.

Q In the resource mix study, the generic solar gets put on top of that already-planned-for solar; right? Is that your understanding?

A (Witness Fitzhenry) I am sorry. Could you repeat that question?

Q Yeah. In the resource mix plan, the -- any generic solar that is being studied would be on top of that 14 gigawatts. Is that your understanding?

A (Witness Fitzhenry) Yes. Any additional capacity installation would be above what they currently have.

Q So do you agree that the capacity credit of

solar declines with penetration?

A (Witness Fitzhenry) Yes, I would. Generally speaking -- I mean, there is a lot of other variables, but generally speaking, that's how it is modeled, correct.

Q Okay. Thank you.

Mr. Walters, you discussed the carbon-free energy goals of the federal government and other customers at Georgia Power. But you are aware Georgia Power has 2.7 million customers; right?

A (Witness Walters) Give or take, yes.

Q And Georgia Power's responsible for serving all of its customers and balancing their many needs, would you agree with that?

A (Witness Walters) Of course.

Q You discuss customer engagement on clean energy goals. And prior to filing your testimony, were you provided any information on the number of meetings or level of engagement between Southern Company and the federal government in support of the MOU?

A (Witness Walters) I was not.

Q Are you aware that there are monthly meetings between the General Services agency, the DoD, and Southern Company to collaborate on a roadmap to meet the requirements of Executive Order 14057 and implement the

MOU?

A (Witness Walters) Yes. I believe that was part of the requirements in the MOU that was laid out.

Q Are you aware that there were weekly calls between the company and the Department of Defense regarding the Fort Stewart BESS project?

A (Witness Walters) I think I knew that there was discussions. I don't know about the -- I don't think I was privy to the frequency.

Q Are you aware that there are biweekly calls between the company and DoD regarding the Robins Air Force Base solar project and resiliency needs?

A (Witness Walters) Again, I am not aware of the frequency.

Q Are you aware that there are monthly meetings between the company and the Army Secretariat of Office of Energy Initiatives, the Department of Naval Facilities Engineering Command, and as-needed meetings for the Air Force Office of Energy Assurance?

A (Witness Walters) Again, I was not aware of the frequency.

Q You are aware the meetings are happening, though; right?

A (Witness Walters) I am aware that they have had meetings, yes.

Q Are you aware, then, that in 2023 there were over 100 meetings or calls between Georgia Power and the Department of Defense to discuss and work through DoD's energy needs, including both resiliency measures for military bases in Georgia?

A (Witness Walters) I was not aware of the amount of meetings.

Q Are you aware of the projects that Georgia Power is currently working on with DoD, which include microgrids and BESS projects at military bases?

A (Witness Walters) Generally, yes.

Q Are you aware that there are resilience projects either in discussion or underway at every single DoD installation that Georgia Power serves?

A (Witness Walters) You said at every installation?

Q That Georgia Power serves.

A (Witness Walters) Yes, I think -- yes, I would agree with that.

Q And just to be clear, should your testimony be taken in any way as suggesting that Georgia Power and Southern Company have not engaged meaningfully with the DoD on the clean energy goals?

A (Witness Walters) It was my understanding -- you know, the purpose of my testimony was that the IRP

update filing and the resources sought was a departure from what was prescribed in the MOU. I am certain that the company has had several rounds of negotiations in helping the DoD meet its needs. In fact, that's why it entered the MOU is to help the DoD meet those needs, or the federal government meet those needs.

Q But, prior to this, you weren't -- it doesn't seem that you were made aware of the full engagement between Southern Company, Georgia Power, and the Department of Defense and its organizations?

A (Witness Walters) Yes, I was not made aware of the entirety of the engagement.

Q Thank you. That's all the questions I have for you.

CHAIRMAN SHAW: Redirect?

MR. MCNUTT: No, Mr. Chairman. I thought that went just fine.

CHAIRMAN SHAW: So glad you did.

MR. MCNUTT: Mr. Hewitson was quite kind.

With the indulgence of the Commission, I know it has been a long couple of days, I would move the testimony of Mr. Walters and Mr. Fitzhenry into evidence along with their prepared filed testimony and exhibits.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Christopher Walters and Colin Fitzhenry follows:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	**GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND MISSISSIPPI POWER COMPANY, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND SANTA ROSA ENERGY CENTER LLC, AND AMENDED CERTIFICATION OF THE RESIDENTIAL THERMOSTAT DEMAND RESPONSE DEMAND SIDE MANAGEMENT PROGRAM**	**)**	**DOCKET NO. 55378**

DIRECT TESTIMONY

AND EXHIBITS

OF

CHRISTOPHER C. WALTERS

ON BEHALF OF THE
THE UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES

FEBRUARY 15, 2024

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	**GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND MISSISSIPPI POWER COMPANY, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND SANTA ROSA ENERGY CENTER LLC, AND AMENDED CERTIFICATION OF THE RESIDENTIAL THERMOSTAT DEMAND RESPONSE DEMAND SIDE MANAGEMENT PROGRAM**	**)**	**DOCKET NO. 55378**

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Exhibit___(CCW-1) to Exhibit___(CCW-2)

DIRECT TESTIMONY OF
CHRISTOPHER C. WALTERS

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. Please state your name and business address.

A. My name is Christopher C. Walters. My business address is Brubaker & Associates, Inc., 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. What is your occupation and by whom are you employed?

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please describe your education and professional experience.

A. My education and professional experience are detailed in my Exhibit___(CCW-1).

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the Department of Defense ("DOD") and all other Federal Executive Agencies ("FEA").

B. Summary

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide comments on Georgia Power Company's ("GP" or "the Company") 2023 Integrated Resource Plan Update ("IRP Update") filing, discuss the objectives of the voluntary agreement entered into by the Federal Government and GP's parent, Southern Company, known as a Memorandum of Understanding ("MOU") and discuss broader clean energy goals. I observe certain deficiencies I believe to be present in the IRP Update filing and offer recommendations to potentially alleviate some of those concerns and mitigate certain risks.

C. Summary of the IRP Update and Initial Thoughts

Q. Please summarize your understanding of the circumstances that caused GP to file this IRP Update.

A. Updated demand projections relative to the Company's 2022 IRP indicate that GP will have a capacity deficiency to serve its customers by the winter of 2025/2026. The Company states that capacity deficiency may impair GP's ability to provide reliable firm service to its customers. As explained in the Direct testimony of the Company witnesses Mr. Grubb, Mr. Valle, Mr. Evans, and Mr. Bush (collectively the "Panel"), based on data and information at the time of GP's 2022 IRP, the Company was projecting less than 400 megawatts ("MW") of growth from the winter of 2023/2024 to the winter of 2030/2031.[1] At the time of the filing of the IRP Update, GP now expects load growth of approximately 6,600 MW through the same time period. This revised load growth has accelerated when GP is projecting a capacity deficiency to 2025/2026 from 2030/2031.

GP also opines that there is limited time to procure or construct the capacity resources that are needed to meet its capacity deficiency by the winter of 2025/2026. As such, GP maintains that it must acquire additional capacity resources, largely outside typical competitive solicitation processes, to meet the projected growing capacity and energy demands in order to support the tremendous economic growth opportunities expected in the Southeast in general, and Georgia specifically.

Q. Will you please briefly describe what is driving this change in the company's projected customers' demand and economic development to the Southeast in general, and in particular, Georgia?

A. At the hearing, the Panel testified that the overwhelming majority of the large economic development growth (approximately 80% of the total gigawatt hours) is going to come from data center load. In addition to data centers, the Panel also testified that the state is seeing an influx of manufacturing growth for the manufacture of electric vehicles, battery, and clean energy technology.

[1] Direct testimony of the Panel at page 8.

Q. How does this projected growth compare to historical growth in GP's load?

A. The Panel testifies that the Company was selected to serve approximately 100 MW of large load economic development projects on average per year prior to 2021. Through August 2023, GP was selected to serve more than 1,700 MW of large load economic development projects.

Q. In its IRP Update, what resources has GP proposed to meet the projected capacity needs as a result of the forecasted growth in the state of Georgia?

A. The Company has proposed the following resources to meet its projected capacity needs:

1. Execute a Power Purchase Agreement ("PPA") with Mississippi Power Company ("Mississippi Power") to procure power from generating assets that are owned, maintained, and operated by Mississippi Power.
2. Execute a PPA with Santa Rosa Energy Center LLC for capacity and energy from a natural gas-fired Combined Cycle ("CC") generating asset located in Pace, Florida.
3. Pursue potential acquisition of an additional ownership interest in an existing generating asset within the Southern Company footprint.
4. Expand the Company's implementation of Battery Energy Storage Systems ("BESS") by leveraging transmission interconnection resources at existing solar facilities, such as Company-owned facilities at military bases.
5. Invest in a new BESS co-located with a new solar facility at a site with existing transmission interconnection facilities.
6. Build simple-cycle Combustion Turbines ("CTs") to leverage the reliable and economical nature of this technology to meet peak capacity needs.
7. Add and expand Distributed Energy Resource ("DER") and Demand Response ("DR") programs to quickly meet and offset growing capacity needs.
8. Establish a framework within which the Company can procure additional capacity ("Flex Capacity") ahead of the 2025 IRP filing in the event there are additional capacity needs resulting from an update to the 2023 IRP Update load forecast.

Q. Do you have any initial thoughts on the Company's IRP Update filing and the resources it has requested to meet the forecasted capacity requirements?

A. The Company and the State of Georgia have a tremendous amount of economic development projects in the pipeline over the next several years. However, as I discuss later in this testimony, certain of GP's largest existing customers have internal required clean energy and emissions-reduction targets. It appears that some of the prospective new loads driving this interim IRP are subject to internal sustainability goals as well. These customers will need GP's assistance and support to engage with them and plan to help achieve their stated objectives. To that end, while the Company has proposed some expansion of its carbon pollution-free energy ("CFE") resources, it is unlikely to be enough to meaningfully help those customers achieve their goals given the significant amount of proposed capacity through the development of CTs, the PPAs with Mississippi Power and Santa Rosa Energy Center. Failing to meaningfully account for the needs of new and existing customers to help them achieve their clean energy goals may negatively impact the attractiveness of continued economic development in GP's service territory.

D. <u>Clean Energy Goals</u>

Q. Is GP required to achieve mandatory Renewable Portfolio Standards ("RPS") or other clean energy benchmarks set out by Georgia?

A. I am not aware of any State-mandated clean energy goals or benchmarks that are required of GP to achieve at this time.

However, I am aware of GP's parent, Southern Company, announcing in 2018 its own goals of a lower carbon energy future in its *Planning for a lower carbon future report.* In the 2018 report, Southern Company set an initial goal of achieving 50% reduction in GHG emissions by 2030 relative to 2007 levels. Southern Company updated and revised its goals in its *Implementation and action toward net zero report* issued in September 2020 where it announced that they would be updating their long-term GHG emissions reduction goal of net zero emissions by 2050, and would possibly achieve its 50% reduction target five years early in 2025.

As far as agreements or commitments with its large customers, the Company has implemented its Clean And Renewable Energy Subscription ("CARES") program which allows commercial and industrial ("C&I") customers to support their sustainability initiatives. As far as specific commitments, I am aware of the MOU it entered into with the Federal Government just a few months ago. I am not aware of additional specific customer commitments the Company has made. GP witness Grubb stated, during cross-examination on GP's Direct Testimony, that the Company regularly communicates with its customers to remain informed of their needs and objectives, however, so ostensibly the Company is familiar with individual customer sustainability goals.

Q. Please briefly describe what the CARES program is.

A. On behalf of participating C&I customers, GP will procure new renewable resources for subscription through the CARES Program. Participating customers are able to purchase a subscription for a pro-rata share of the production of renewable resources procured through the Company's utility-scale renewable Request for Proposal ("RFP") process. GP will retire the RECs on behalf of participating customers, allowing customers to receive the environmental benefits associated with their pro-rata share of the energy produced by the program resources.

Q. Are you aware of any of GP's customers having expressed clean energy goals?

A. Yes. The Federal Government entered into an MOU with GP for assistance to achieve its clean energy goals. Some of the largest companies in the world have set out clean energy objectives. For example, the Clean Energy Buyers Association ("CEBA") is an intervening party to this case, representing over 400 companies. Many of these companies are existing or are potential new customers in GP service territory. For example, as was discussed with the Panel on cross-examination by Walmart's counsel, Walmart has announced clean energy goals and is engaged in discussions with GP about its CFE needs and goals.[2] In addition, it is my understanding that a number of local

[2] Docket No. 55378, January 17, 2024, Transcript at 0650-0653.

governments in GP's service territory also have sustainability goals upon which they would lean on GP to help them achieve.[3]

Q. Please describe what the MOU is, what its objectives are, and the time horizon for which it is effective.

A. The MOU is a non-binding agreement entered into between the Federal Government and Southern Company, covering the Southern Company electric utility footprint in Alabama, Georgia, and Mississippi. It was effectuated on October 13, 2023. I have attached the executed MOU as Exhibit___(CCW-2).

The purpose of the MOU is to collaboratively and promptly create a plan for CFE. This plan, intended to be in effect by 2030, aims to ensure that 100% of electricity for Federal Government customers of Southern Company's electric utility subsidiaries is derived from CFE resources. These resources can be owned or contracted for by Southern Company subsidiaries, with at least 50% meeting the Federal Government's CFE objectives. The MOU was executed to meet Executive Order 14057 ("EO") and its corresponding Implementing Instructions issued in August 2022. The Federal Government has set a target to attain 100% CFE on a net annual basis by 2030, with half of it being hourly-matched on a 24/7 basis.

Importantly, the Implementing Instructions create a pathway for the Federal Government's pro rata share of CFE in a utility's existing grid mix to count toward the Federal Government's requirements; in other words, the level of CFE serving all customers on the broader grid is an important part of the equation, in addition to new CFE resources. Prior to this, Southern Company had already announced that it aims to achieve net-zero emissions by 2050 and reduce greenhouse gas emissions on its system by 50% by 2030, relative to 2007 levels. The MOU plan has four major areas of emphasis:

[3] For example, the City of Atlanta's *Clean Energy Atlanta* resolution that calls for City of Atlanta operations to achieve 100 percent clean energy by 2025 and communitywide 100 percent clean energy by 2035. https://www.100atl.com/cleanenergyatlanta

1. Developing a roadmap for the Federal Government's electricity needs served by the Southern Operating Companies to meet the targets set out in the CFE requirements of EO.
2. Designing a CFE tariff for identifying an applicable regulatory pathway that would provide the appropriate pricing and other terms needed to achieve the requirements of EO.
3. Subject to the Southern Operating Companies' respective resource planning and operation obligations, the construction and/or acquisition of the renewable and CFE resources needed to generate additional electricity and associated Renewable Energy Credits ("REC") which, in conjunction with Southern Operating Companies' existing and future nuclear, hydroelectric or other CFE resources would result in Federal Government operations using electricity that is 100% attributable to CFE resources by 2030.
4. In support of the requirements of the EO, the certification and reporting of the RECs and Scope 2 emissions accounting[4] to satisfy the requirements of the Federal Government, including hourly time matching of load and generation, as well as the certification of output of legacy CFE assets which are properly attributable to Federal Government customers.

Q. Does GP engaging its large customers on helping achieve their clean energy goals support the economic development of GP's service territory and the Southeast generally?

A. Yes. As a vertically integrated electric utility, GP plays an integral role in helping C&I customers achieve clean energy goals. Utilities are the experts in managing energy infrastructure, and are a valuable resource to large customers. While new large loads coming to the state have an opportunity to select suppliers, it is clear that GP has positioned itself as a preferred supplier for a substantial amount of new prospective load

[4] Scope 2 emissions are indirect Greenhouse Gas ("GHG") emissions associated with the purchase of electricity, steam, heat, or cooling. Although scope 2 emissions physically occur at the facility where they are generated, they are accounted for in an organization's GHG inventory because they are a result of the organization's energy use. https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance.

coming to Georgia. Notably, the Company has at least verbally committed to engaging its other large customers to achieve their clean energy goals. For example, at the hearing the Panel testified that it would "absolutely" and "always" work with its customers in the C&I sectors to help them meet their sustainability and renewable energy goals.[5]

Q. Are you aware of any examples of electric utilities engaging and partnering with its C&I customers to achieve clean energy goals and support economic development?

A. Yes. In 2023, Entergy Arkansas, LLC ("EAL") received approval to offer its Go Zero Emissions Resource Options ("Go ZERO") tariff which allows customers to acquire clean energy attributes associated with the output of EAL's existing emissions free resources, as well as additional renewable energy resources as they come online. It is my understanding that the Go ZERO tariff was developed in conjunction with an MOU entered into with the Federal Government and EAL. EAL's President and CEO, Laura Landreaux, has acknowledged the economic development potential of the Go ZERO tariff, stating that "In addition to price and reliability, companies are looking for clean energy sources, which EAL can offer to prospective customers seeking to locate in Arkansas. We believe Go ZERO helps set Arkansas apart as the place to do business."[6]

Another Example would be the Large Customer Renewable*Connect ("Large Customer R*C") program proposed by Southwestern Public Service Company of New Mexico ("SPS") that is currently pending approval before the New Mexico Public Regulation Commission ("NMPRC"). SPS developed and proposed the Large Customer R*C program in response to requests from its large C&I customers for a voluntary renewable energy purchase program that will facilitate their ability to meet their own renewable energy and sustainability goals. The R*C program will allow these customers the opportunity to purchase additional amounts of renewable energy that are in excess of

[5] Docket No. 55378, January 17, 2024, Transcript at 0602.
[6] https://www.entergynewsroom.com/news/entergy-arkansas-gets-green-light-for-commercial-customers-go-zero/

what is currently required under New Mexico's Renewable Energy Act and the applicable RPS requirements established in a Commission-approved tariff.[7]

In July 2022, Public Service Company of New Mexico ("PNM") and Meta announced commercial operation of the New Route 66 Solar Facility that was developed to help power the Meta Los Lunas Data Center. The plan for the New Route 66 facility was approved in 2018 by the NMPRC, and developed by NextEra Energy Resources. PNM's Chair and CEO, Pat Vincent-Collawn, stated that "We proudly support our customers in realizing their sustainable energy goals, whether it is our neighbors installing solar on their rooftops or businesses seeking renewable energy options" and that "The Route 66 solar facility aligns with our values at PNM. This project increases renewable energy, creates local jobs and brings investment into New Mexico."[8]

Finally, I am also aware of Evergy working with its large C&I customers at both its Missouri and Kansas utilities on developing tariff rate options to help achieve clean energy goals.

Q. Is the Federal Government hoping to engage and partner with GP to achieve its clean energy goals?

A. Yes, a major plan objective of the MOU is for GP - as a part of the broader Southern Company - to assist the Federal Government in achieving its goals to decarbonize its energy load. The Federal Government is one of the largest, if not the largest, existing customers served by GP, primarily through its major military installations.

[7] https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/2023%20Notice%20to%20SPS%20Customers%202300271.pdf

[8] PNM News, PNM and Meta Celebrate the New Route 66 Solar Facility, https://m.pnm.com/documents/28767612/29865400/PNM+and+Meta+Celebrate+the+New+Route+66+Solar+Facility.pdf/c5213b75-34fc-413f-3cb8-e043d3c97ec9?t=1659541518641

Q. Has GP previously partnered with the Federal Government?

A. Yes. As part of this IRP Update, GP is proposing to add 178 MW of 4-hour duration lithium-ion BESS to existing Company-owned solar facilities at Robins and Moody Air Force Bases and 200 MW of BESS plus 200 MW of solar at a new site. It is my understanding that the Federal Government supports these projects as well as the general approach to add storage to existing solar locations.

E. Deficiencies in the existing IRP Update filing

Q. Please highlight some concerns you have with the IRP Update filing.

A. Given the anticipated growth spurred by rapid economic development, the immediate necessity to secure additional capacity resources within a constrained timeframe may induce rushed analyses, decisions, and potential oversights in resource selection. The urgency to match the accelerated pace of growth may limit the availability of time for comprehensive assessments and thorough consideration of all relevant factors. In such circumstances, critical details might be overlooked, risks underestimated, and the Commission may find itself compelled to make decisions without the advantage of a comprehensive analysis vetted by all stakeholders. This heightened sense of urgency poses a risk to the decision-making process.

In addition, I have certain other concerns. They can be summarized as follows:

1. The Company's resource option/selection process should not be constrained based on a strict application of the 70/30 ownership rule, particularly in a time of exponential growth in the region.
2. While the current IRP Update does include certain expansions of CFE resources, it inadequately addresses customer-specific goals and needs.
3. The Company insists that there will be downward pressure on rates as a result of the projected sales growth. However, GP stops short of guaranteeing rates are going to realize that downward pressure.
4. Load forecast needs to be thoroughly vetted, including projected load growth for serving new at-risk large customers.

Q. Will you please briefly address some of your concerns with the 70% ownership requirement GP references?

A. Yes. GP makes reference to a precedent that was last litigated and decided by this Commission in 2001, requiring that an electric utility own a minimum of 70% of its capacity. The restriction requiring an electric utility to own and operate a minimum of 70% of its generation capacity, limiting alternative sources like PPAs to 30% or less, can be a concern for several reasons:

1. Cost Efficiency: Depending too heavily on owned generation capacity may limit GP's ability to benefit from potentially more cost-effective alternatives available through PPAs. It might result in higher costs for ratepayers if the utility is unable to secure the most economically favorable resources.
2. Technological Advances: Energy landscapes and technologies evolve over time. Relying heavily on owned generation facilities might hinder the utility's ability to swiftly adopt and integrate emerging, more efficient, and environmentally friendly technologies that could lead to cost savings.
3. Market Dynamics: Restricting the use of PPAs may limit the utility's flexibility to navigate market dynamics. Entering into agreements with external providers could offer better terms and pricing, contributing to more stable or even reduced rates for ratepayers.
4. Risk Mitigation: Owning and operating all generation capacity exposes the utility and, consequently, ratepayers to the risks associated with maintaining and upgrading these facilities. Sharing these responsibilities with external providers through PPAs may distribute risks and ensure more efficient risk management.
5. Renewable Energy Integration: Limiting alternative sources might impede the utility's ability to meet renewable energy goals or environmental commitments. PPAs for renewable energy sources, for example, could help the utility transition to a more sustainable energy mix.

The restriction on alternative capacity sources could potentially lead to missed opportunities for cost savings, hinder the adoption of new technologies, limit flexibility in

responding to market changes, increase risk exposure, and impede progress towards sustainability goals, all of which could impact ratepayers by potentially leading to higher costs and a less resilient energy infrastructure.

Q. Will you please briefly address your concern that the IRP Update inadequately addresses customer-specific goals and needs?

A. Yes. As I have explained earlier in this testimony, by way of the MOU, the Company has committed to helping the Federal government achieve its CFE goals for load that is served by GP. The Company's pursuit of additional capacity resources proposed in this interim IRP is significantly weighted in favor of non-CFE resources, which are counter to Southern Company's footprint-wide goals in general, and the objectives to which GP's parent company agreed in the MOU.

Q. The Company filed its IRP Update in October 2023. The MOU was effectuated in October 2023. Could GP have realistically accounted for the objectives of the MOU in its filing?

A. It is not clear, but subsequent updates should reflect the resources that GP needs to provide this support. The Company had most likely been preparing its IRP update for months prior to the effective date of the MOU; however, my understanding is that the MOU was also under consideration for a significant duration of time before it was effectuated. As such it is imperative that the Commission be made aware of the MOU's existence and the objectives that GP agreed to with the Federal Government. It is also important that the Company's commitment is reiterated and reaffirmed in this docket. That said, the precise mix and quantity of resources needed to fulfill the objectives under the MOU are still under consideration.

Q. Should the Commission and other stakeholders be concerned about the potential for increased costs on other rate classes should the MOU objectives be achieved?

A. Yes. I recommend that the Commission should always concern itself with cost-based rates, and fair rate setting treatment to all customers. With that in mind, the MOU clearly states that all costs of CFE programs developed under the MOU, including the net cost of

CFE generation and delivery, and the incremental cost of program administration shall be borne by the program participants, with no material cost increases without corresponding benefits to non-participating customers. In other words, the costs of any program eventually resulting from the MOU work should be carefully considered to ensure that other customers do not bear inequitable costs. This same rate setting principle can be applied to other customers that receive assistance from GP to achieve clean energy goals, and indeed the Commission has already considered these features. For example, in the aforementioned CARES program, it is my understanding that customers selecting to participate in the tariff pay renewable integration charges to avoid adverse cost impacts to other customers.

Q. Will you please briefly describe your concerns with the lack of commitment from GP to ensure rates are going to realize downward pressure?

A. Yes. A major focal point of the Panel's direct testimony, as well as testimony at the hearing on its direct case was their belief that the revenues from the new load will more than offset the costs to serve it. The Panel's direct testimony states as follows:

> All else being equal, we expect that the projected revenues associated with incremental load from these new customer projects will offset the costs of the resources requested in this filing and put downward pressure on our overall retail rates as we continue to provide clean, safe, reliable, and affordable power for all of Georgia Power's customers in the coming years.[9]

In response to questions from Commissioner Pridemore concerning what happens if there is upward pressure on rates by building for demand that doesn't come, the Panel admits that it "would not be beneficial for customers," but suggested that "the risk to the customers is that we don't move forward with this plan and we don't support new load

[9] Panel Direct Testimony, page 10.

growth and we don't put downward pressure on rates. These loads give us an opportunity to help all customers."[10]

At the hearing, the Company explained that it has attempted to mitigate some of the risk of rates potentially increasing through measures such as the Ratepayer Impact Measure Test ("RIM Test") and direct investments from the new customers.[11] However, the Company stopped short of committing to a guarantee that rates would see downward pressure.

Q. Will you please briefly describe your concerns with the lack of commitment from GP to ensure rates are going to realize downward pressure?

A. Yes. At the hearing the Panel testified that two of the economic development loads pursued by GP are what are considered to be "high risk" cryptocurrency projects. Stakeholders should be concerned that certain projected new customers with large loads at risk of either never materializing or abandoning operations prematurely, especially higher-risk load (i.e., cryptocurrency load) could have an undue impact on existing customer rates in the event of some unexpected consequences causing the operations to cease prematurely. Higher-risk operations such as cryptocurrency mining can introduce volatility and uncertainty into the utility's revenue stream. If the cryptocurrency market crashes or if the mining operation fails, GP may face significant financial losses, potentially impacting its ability to provide reliable service to other customers. If the utility's financial stability is compromised due to investments in high-risk ventures, it may result in increased costs for ratepayers. Ratepayers could end up bearing the burden of any financial losses incurred by the utility through higher electricity rates.

[10] Docket No. 55378, January 17, 2024, Transcript at 0485-0486.
[11] Docket No. 55378, January 17, 2024, Transcript at 0465.

F. Recommendations and Suggested Risk Mitigation Solutions to be Considered

Q. Do you have any recommendations for the Commission to consider in order to mitigate the potential consequences of new economic development projects being pursued by GP?

A. This proceeding was filed with a sense of urgency given the extraordinary economic growth that is expected in the southeast and Georgia, leading to a projected capacity shortfall much sooner than previously expected. In general, a lack of time leads to rushed analyses and decisions which can ultimately have unwanted and expensive consequences. To that end, it is imperative that the Commission consider building in protections for existing customers so they are not left paying if new customers and new loads do not come to fruition or do not sustain. In other words, the economic development loads being pursued by the Company needs to be thoroughly vetted and risk mitigation efforts should not be overlooked. Some potential solutions that should be studied and considered to help mitigate risk to existing customers from GP's pursuit of new economic development load (particularly for new higher-risk load) include but are not limited to the following:

1. Capital requirements and direct investments from the new large customers. It is my understanding that, according to Mr. Evans' testimony at the hearing, the Company has already employed this measure.[12]
2. Length of service contracts. Such contracts should be required by the Commission so that GP and its existing customers have some protection from the new higher-risk customers. Length-of-service contracts can include performance guarantees and penalties for non-compliance, ensuring that higher-risk customers adhere to agreed-upon terms and conditions. This provides additional assurances to the utility and existing customers that the higher-risk customers will operate responsibly and contribute positively to the overall reliability and stability of the utility's services. Similar commitments are currently part of the CARES program.
3. Annual reporting requirements tracking the performance of the newer loads with lookback tests. This will potentially allow the Company and the Commission to stay

[12] *Id.*

abreast of higher-risk load situations and be prepared should the load be in jeopardy to ensure they are not leading to increased costs for existing customers. The lookback tests will potentially get a better understanding of how accurate the Company's RIM test was.

The Company, Commission, and interested stakeholders should assess the possibility and reasonableness of such possible solutions.

Q. Do you have any suggestions to be considered in order to address the possible concerns outlined above as it relates to the 70% ownership requirement?

A. Yes. Given the significant advancements in energy and energy storage technology since that requirement was last considered in 2001, I recommend all relevant stakeholders revisit that requirement and study whether it would produce meaningful benefits to customers without jeopardizing rate affordability and service reliability.

Q. Do you have any suggestions to be considered in order to address customer-specific goals and objectives, particularly as it relates to CFE?

A. Yes. As described above, the Federal government and some of the largest businesses in the world, many of which are existing customers of GP, have stated CFE goals and objectives. In order to help achieve the CFE objectives and needs of its current and new large customers, the Company should study the possibility of relaxing the existing limits of the CARES program, and assess the demand for CARES and/or other CFE offerings. The Company should study the potential of expanding the amount of renewable resources MWs procured through the ongoing RFP process, as well as possibly making the program continuously available for letters of interest and keep a resource solicitation open on an ongoing basis so the program can grow alongside customer demand. So long as resources are available in the market, the demand for CFE exists, and costs are not being shifted to other customers, large customers should not be prohibited from achieving progress towards their sustainability goals by artificial limits on programs or procurement targets.

The Company should work with its existing and potential C&I customers in a multilateral stakeholder process to get a better understanding of the CFE needs and objectives for those customers, and review the Company's future planned system capacity and projected energy mix. The Company should study the possibility of ways to formalize a framework with those C&I customers to achieve their clean energy objectives. Together, GP and its C&I customers could study the possibility of on-site solar and BESS solutions, additional REC programs, as well as possibly working with third-party CFE developers to accelerate the ability to meet demand for those resources.

I recommend interested stakeholders study whether future IRPs should include an assessment of GP adding resources that will allow it to work with existing customers to achieve stated customer CFE goals. The Company should support C&I customers' use of on-site solar and BESS solutions, and study the potential benefit to GP in meeting its system-wide resource adequacy needs.

Q. Does expanding the availability of CFE resources offer other potential benefits besides helping customers achieve stated CFE objectives and goals?

A. Yes. Expanding the availability of CFE resources can potentially be its own driver of economic development. The Company acknowledges as much on its CARES program flyer where it lists "Fuel economic growth" through "supporting financial viability of renewable energy leads to job creation" under the "Key Benefits" section. This is reiterated through the MOU stating "[a]chieving these sustainability goals benefits the environment and enables the continued expansion of economic renewable and CFE generation, which creates and provides jobs while increasing the tax base for local and state economies."

G. Concluding Remarks

Q. Please provide your concluding remarks.

A. The Southeast in general, and Georgia specifically, has been presented a tremendous opportunity to see unprecedented economic growth over the next several years from various industries. While there is great opportunity for continued economic growth, there

is an equally great opportunity to get it wrong burdening ratepayers with hundreds of millions in costs.

Further, while the Company's efforts to offer and expand CFE resources is significant, there is more to be done on that front as there is a tremendous demand for those resources. Some of GP's largest customers, including the Federal government and the multitude of customers in the CEBA, have clean energy goals and objectives. While the Company has testified it will engage those customers in helping achieve those goals, it is imperative that the Company follow through on its commitment to do so while also maintaining safe and reliable electric service. Engaging large customers in the public and private sectors to help achieve sustainability goals can be its own source of economic development and should be pursued. In fact, by entering into the MOU, the Company and Federal Government agree that "[a]chieving these sustainability goals benefits the environment and enables the continued expansion of economic renewable and CFE generation, which creates and provides jobs while increasing the tax base for local and state economies."

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	**GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND MISSISSIPPI POWER COMPANY, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND SANTA ROSA ENERGY CENTER LLC, AND AMENDED CERTIFICATION OF THE RESIDENTIAL THERMOSTAT DEMAND RESPONSE DEMAND SIDE MANAGEMENT PROGRAM**	**)**	**DOCKET NO. 55378**

EXHIBITS

OF

CHRISTOPHER C. WALTERS

ON BEHALF OF THE
THE UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES

FEBRUARY 15, 2024

Qualifications of Christopher C. Walters

Q. Please state your name and business address.

A. Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. Please state your occupation.

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please summarize your educational background and work experience.

A. I received a Bachelor of Science Degree in Business Economics and Finance from Southern Illinois University Edwardsville. I have also received a Master of Business Administration Degree from Lindenwood University.

As a Principal at BAI, I perform detailed technical analyses and research to support regulatory projects including expert testimony covering various regulatory issues. Since my career at BAI began in 2011, I have held the positions of Analyst, Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my tenure, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory project work includes estimating the cost of equity capital, capital structure evaluations, assessing financial integrity, merger and acquisition related issues, risk management related issues, depreciation rate studies, and other revenue requirement issues.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services

through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q. Have you ever testified before a regulatory body?

A. Yes. I have sponsored testimony before state regulatory commissions including: Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony before the City Council of New Orleans and an affidavit before the FERC.

Q. Please describe any professional registrations or organizations to which you belong.

A. I earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

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MEMORANDUM OF UNDERSTANDING
BETWEEN
THE UNITED STATES GENERAL SERVICES ADMINISTRATION
AND
SOUTHERN COMPANY SERVICES, Inc.

This non-binding Memorandum of Understanding ("MOU") is made and entered into by and between the United States of America, acting by and through the Administrator of General Services ("GSA"), and Southern Company Services, Inc. ("SCS") (collectively the "Parties"). SCS is the authorized agent for The Southern Company ("Southern Company").

Parties: GSA is an agency in the executive branch of the United States Government that provides centralized procurement for the Federal Government, offering billions of dollars' worth of products, services, and facilities that federal agencies need to serve the public. Southern Company currently serves over 9 million electric and gas customers and is committed to sustainability as reflected in its goal of achieving net-zero greenhouse gas emissions company-wide by 2050 with an interim target of 50% reduction in emissions by 2030.

Effective Date and Term: This MOU will become effective upon execution by both Parties. The date of execution by the last Party to sign will be deemed to be the effective date of this MOU. This MOU will terminate two years from the effective date.

Authority: Pursuant to 40 U.S.C. 501(c), GSA is authorized to represent certain executive agencies in negotiations with public utilities. SCS is authorized to enter into this non-binding MOU on behalf of the Southern Company.

Purpose: The Parties will work collaboratively and expeditiously towards developing a non-binding carbon pollution-free electricity ("CFE") plan (the "Plan"). The Parties will seek for the Plan to be implemented by 2030 and result in electricity that is 100% attributable to CFE resources for Federal Government electricity customers of the electric utility subsidiaries of Southern Company ("Southern Operating Companies"). Resources can be either owned or contracted for by the Southern Operating Companies with at least 50% meeting the Federal Government's hourly matching objectives for 24/7 CFE. Further, by pursuing their respective sustainability goals, the Parties strive to provide benefits to the States of Alabama, Georgia, and Mississippi.

Background: In accordance with Executive Order 14057[1] and its associated Implementing Instructions,[2] the Federal Government established a goal to achieve 100% CFE on a net annual basis by 2030, including 50 percent 24/7 CFE. Southern Company's goal is net-zero emissions by 2050 and a 50% reduction in greenhouse gas emissions by 2030, as compared to 2007 levels.

Roles and Responsibilities: The Federal Government, as represented by GSA, strives to meet its sustainability goals while maintaining or improving affordability, reliability, and resilience of the electric power system. Achieving these sustainability goals benefits the environment and enables the continued expansion of economic renewable and CFE generation, which creates and provides jobs while increasing the tax base for local and state economies.

Southern Company (through the Southern Operating Companies) strives to provide and maintain excellent customer service, high reliability, and affordable electric prices. Southern Company has been building for the future of energy and developing a diverse portfolio of energy resources, including renewable and sustainable resources.

The Plan in General: In developing the Plan, the Federal Government, as represented by GSA, and SCS recognize the critical importance of the Southern Operating Companies' existing and future nuclear and other carbon pollution-free generation. The Parties will work together to ensure that these sources of CFE will be considered when reaching the annual and hourly matching CFE targets of Executive Order 14057. The Parties further recognize that the Plan should provide benefits to the Federal Government and to the Southern Operating Companies' other customers that Southern Operating Companies have an obligation to serve consistent with the regulation and oversight of their respective Public Service Commissions.

The Parties anticipate that under programs developed subject to the Plan, (1) SCS may match existing CFE to the Federal Government's load to ensure that the total share of CFE for all other SCS customers, namely non-participating customers, is not reduced on a load ratio basis by such programs; and (2) all costs of such programs, including the net cost of CFE generation and delivery, and the incremental cost of program administration shall be borne by the program participants, with no material cost increases without corresponding benefits to non-participating customers.

Four Major Emphasis Areas of the Plan: The Parties envision that the Plan would comprise four major emphasis areas to address the Federal Government's electricity needs served by the Southern Operating Companies:

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[1] Executive Order 14057, Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability (December 8, 2021), available at Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability - The White House.

[2] Implementing Instructions for Executive Order 14057 Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability, The White House Council on Environmental Quality (August 2022), available at E.O. 14057 Implementing Instructions (sustainability.gov).

1. Developing a roadmap for the Federal Government's electricity needs served by the Southern Operating Companies to meet the targets set out in the CFE requirements of Executive Order 14057.

2. Designing a CFE tariff or identifying an applicable regulatory pathway that would provide the appropriate pricing and other terms needed to achieve the requirements of Executive Order 14057.

3. Subject to the Southern Operating Companies' respective resource planning and operation obligations, the construction and/or acquisition of the renewable and CFE resources needed to generate additional electricity and associated Renewable Energy Credits (RECs), which, in conjunction with Southern Operating Companies' existing and future nuclear, hydroelectric or other CFE resources would result in Federal Government operations using electricity that is 100% attributable to CFE resources by 2030.

4. In support of the requirements of Executive Order 14057, the certification and reporting of the RECs and Scope 2 emissions accounting to satisfy the requirements of the Federal Government, including hourly time matching of load and generation, as well as the certification of output of legacy CFE assets which are properly attributable to Federal Government customers.

Additional Plan Elements: In addition to the four major emphasis areas, the Plan may include one or more of the following:

1. Subscribing to a Southern Operating Companies CFE time matching tariff.

2. Assessing the prospect of the Southern Operating Companies constructing, owning, and operating a CFE generation and/or energy storage system at Federal Government facilities.

3. SCS developing additional tariffs for renewable energy, dispatchable CFE generation and battery storage, and flexible demand response to achieve full 24/7 CFE.

4. As appropriate, evaluating energy efficiency measures for Federal Government facilities to make implementation of the Plan more effective and economical.

Schedule: The Federal Government, as represented by GSA, and SCS will endeavor to complete the work necessary to develop the Plan, including a proposed implementation schedule, by May 31, 2024.

Communications: SCS and the Federal Government, as represented by GSA, also believe it is appropriate to communicate periodically with respective appropriate customers, investors,

regulators, and other stakeholders regarding the MOU and its contents in order to consider feedback from such stakeholders.

Terms and Conditions:

a. This MOU is effective on the date signed by the Parties. The date signed by the last Party is the effective date of this MOU. This MOU remains in effect for a term of two years from the effective date unless terminated pursuant to Section c. below.

b. This MOU may be amended by the mutual written agreement of both Parties through issuance of a written supplemental agreement that is signed and dated by both Parties.

c. This MOU may be terminated 60 days after either Party provides written notice of such termination to the other Party.

d. This MOU is to be construed in a manner consistent with applicable laws and regulations and GSA policies and procedures. This MOU neither expands or detracts from those powers and authorities vested in the Parties by applicable laws, statutes, or regulations. All actions undertaken pursuant to this MOU are subject to, and will be carried out in compliance with, all applicable laws, regulations, and other legal requirements.

e. Any definitive agreement with a Southern Operating Company and/or tariff of a Southern Operating Company necessary to effectuate the Plan will be subject to applicable state laws, regulations, and approvals.

f. This MOU is for internal management purposes for each of the Parties. It is not legally enforceable and shall not be construed to create any legal obligations on the part of either Party. This MOU shall not be construed to provide a private right or cause of action for or by any person or entity.

g. This MOU in no way restricts either Party from participating in any activity with other public or private agencies, organizations, or individuals.

h. This MOU is neither a fiscal nor a funds obligation document. Nothing in this MOU authorizes or is intended to obligate the Parties to expend, exchange, or reimburse funds, services, or supplies, or transfer or receive anything of value.

i. All activities of GSA under or pursuant to this MOU are subject to the availability of appropriated funds and no provision herein shall be interpreted to require obligation or payment of funds in violation of the Anti-Deficiency Act, 31 U.S.C. § 1341.

j. To the extent that a Party incurs costs as a result of actions taken pursuant to this MOU, such Party shall bear sole responsibility for such costs.

IN WITNESS WHEREOF, the Parties have executed this MOU on the dates hereinafter identified.

UNITED STATES OF AMERICA, acting by and through the Administrator of General Services

By: Robin Carnahan

Robin Carnahan
Administrator
U.S. General Services Administration

Date 9/28/2023

SOUTHERN COMPANY SERVICES, INC.

By: Christopher C. Womack

Christopher C. Womack
President and Chief Executive Officer
Southern Company

10/13/23
Date

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	**GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND MISSISSIPPI POWER COMPANY, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND SANTA ROSA ENERGY CENTER LLC, AND AMENDED CERTIFICATION OF THE RESIDENTIAL THERMOSTAT DEMAND RESPONSE DEMAND SIDE MANAGEMENT PROGRAM**	**)**	**DOCKET NO. 55378**

DIRECT TESTIMONY

AND EXHIBITS

OF

COLIN T. FITZHENRY

ON BEHALF OF THE
UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES

FEBRUARY 15, 2024

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	**GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND MISSISSIPPI POWER COMPANY, CERTIFICATION OF THE POWER PURCHASE AGREEMENT BETWEEN GEORGIA POWER COMPANY AND SANTA ROSA ENERGY CENTER LLC, AND AMENDED CERTIFICATION OF THE RESIDENTIAL THERMOSTAT DEMAND RESPONSE DEMAND SIDE MANAGEMENT PROGRAM**	**)**	**DOCKET NO. 55378**

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DIRECT TESTIMONY
OF COLIN T. FITZHENRY

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. Please state your name and business address.

A. My name is Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. What is your occupation and by whom are you employed?

A. I am a Senior Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please describe your educational and professional experience.

A. My educational and professional experience are detailed in my Exhibit___(CTF-1).

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the Federal government (Department of Defense and all other Federal Executive Agencies, or "DoD-FEA").

B. Summary

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Georgia Power Company's ("Georgia Power" or "Company") modeling efforts to support it's 2023 Integrated Resource Plan Update ("2023 IRP Update). I will also address the resource selection process utilized by Georgia Power to develop its 2023 IRP Update resource plan.

The fact that I do not address certain aspects of the 2023 IRP Update proposals should not indicate agreement with any specific element of such proposals.

Q. Please summarize your recommendations and conclusions.

A. My conclusions and recommendations can be summarized as follows:

- The capacity accreditation of resource options the Company includes in its Integrated Resource Plan ("IRP") modeling does not accurately reflect the capacity contribution of either solar or thermal generating resources. Georgia Power should utilize the Effective Load Carrying Capability studies it performs for variable renewable resources and incorporate more appropriate analyses of thermal unit performance to correctly model the contribution of all potential generating resources being considered. This will better inform the Company's selection of resources in its resource plan.
- Georgia Power did not update its Reserve Margin Study for the 2023 IRP Update, and the target reserve margin may not accurately reflect the Company's capacity obligation. As a result, Georgia Power may be overstating its need for capacity resources.
- Georgia Power's proposed 2023 IRP Update resource plan presents risk of cost increases if new environmental regulation increases the cost of operating fossil fuel generating resources.
- Georgia Power's Updated Economic Analysis of Capacity Resources limited the Aurora production cost modeling to only six capacity resources.[1] As a result, Georgia Power potentially misses an opportunity to identify alternative lower cost generating resources to fulfill its capacity obligation.
- Georgia Power has not demonstrated through rate impact studies that its proposed resource plan will put downward pressure on the rates of its existing customers.

C. IRP Update Summary

Q. Please provide an overview of Georgia Power's IRP process.

A. Since the IRP Act of 1991, the Georgia Public Service Commission ("Commission") has overseen the resource planning process for Georgia Power. Georgia Power periodically updates its IRP to account for changes to forecasted load, generating resources, system reliability and environmental regulation.[2]

[1] Georgia Power, Updated Economic Analysis of Capacity Resources, 2023 Integrated Resource Plan Update, page 5.
[2] Georgia Power 2022 Integrated Resource Plan, Chapter 1, page 1.

The last full IRP filed with the Commission was the Georgia Power 2022 IRP (Docket No. 44160). In the 2022 IRP, Georgia Power updated its seasonal Target Reserve Margins for the short-term (2022-2024) and long-term (2025-2041) planning periods based on the Company's 2021 Reserve Margin Study.[3] In addition, the Company updated its supply-side strategy in its 2022 IRP to recommend the retirement of eleven of its coal and oil generating units between 2022 and 2028.[4] The Company chose to retire these resources because economic analysis did not support continued operation due to their forecast of low natural gas prices, modest load growth, environmental risk and substantial renewable penetration.[5] To accommodate the retirement of the coal and oil units, the Company proposed to add 2,356 megawatts ("MW") of capacity from natural gas power purchase agreements ("PPAs") procured through the Company's 2022-2028 Capacity Request for Proposal ("RFP").[6] The Company is also planning for an additional 6,000 MW of new renewable resources by 2035.[7] At the time of the 2022 IRP filing, Georgia Power determined that it did not need to procure additional capacity until 2029.[8]

Q. Do you have any concerns about how Georgia Power developed its capacity expansion plan in its 2022 IRP filing?

A. Yes. When Georgia Power used the Aurora production cost model to develop its capacity expansion plan it did not assign the appropriate level of accredited capacity to the modeled generating resources. According to Company witness Jeffrey Grubb, the Company used a 0% capacity accreditation for solar resources, and only modeled them as energy resources.[9] In addition, the capacity accreditation for thermal resources was modeled at 100%. This capacity accreditation does not accurately reflect the capacity contribution of either solar or thermal resources. With respect to solar, it is also inconsistent with the Company's own Effective Load Carrying Capacity ("ELCC") study provided in the 2022 IRP.

[3] Georgia Power 2022 Integrated Resource Plan, Chapter 1, page 2.
[4] Georgia Power 2022 Integrated Resource Plan, Chapter 1, page 5.
[5] Georgia Power 2022 Integrated Resource Plan, Chapter 11, page 73.
[6] Georgia Power 2022 Integrated Resource Plan, Chapter 1, page 5.
[7] Georgia Power 2022 Integrated Resource Plan, Chapter 1, page 6.
[8] Georgia Power 2022 Integrated Resource Plan, Chapter 10, page 68.
[9] Exhibit___(CTF-2), Docket No. 55378 Transcript, Wednesday January 17, 2024, pages 0584 & 0585.

Q. Do you have the same concerns regarding how the Company conducted modeling in the 2023 IRP Update?

A. Yes. Company witness Mr. Grubb indicated in the hearing addressing Direct Testimony that in the 2023 IRP modeling, the Company continued to model generic solar resources assuming they provide no capacity value.

Q. Did the Company perform a study to determine the appropriate accreditation value for solar resources?

A. Yes, in its 2022 IRP the Company provided a Study of Renewable Capacity Values using the ELCC Methodology in the Southern Company System ("ELCC Study") that indicated the accredited capacity contribution that wind, solar, and battery energy storage resources could be expected to provide at various levels of adoption in the market. That study showed that even in high adoption scenarios (where there was 3,000 MW of incremental solar installed), the accredited capacity value of solar would be expected to be 25% in non-winter months and 5% in winter.[10]

Q. How does modeling solar resources as an energy only resource limit Georgia Power's ability to develop a least-cost resource plan?

A. Solar resources provide significant contributions to offsetting the summer peak demand and provide limited, but non-zero, capacity contributions in the winter. By assigning a 0% capacity accreditation to solar resources in its modeling, the Company's modeling is both inaccurately valuing the resource and inconsistent with the Company's own ELCC study. In addition, assigning a 100% capacity accreditation for thermal resources does not accurately reflect the forced outage rates of thermal generators, which has the potential to reduce their availability during periods of peak demand. As a result, the model's economic evaluation of solar and thermal resources may be inaccurate and result in the selection of a resource plan that is not least-cost or the best possible fit for the needs of Georgia Power's customers.

[10] Table IV-2: "Wind and Solar Resource ICE Factors Using the CWFT," 2022 IRP ELCC Study, Technical Appendix 1, page 10.

Q. How would you recommend the Company improve its IRP modeling for future IRPs?

A. Georgia Power should be required to continue performing studies to determine the ELCC of potential generating resources being modeled, and be required to utilize the findings of those studies in its capacity expansion modeling. This will better inform the Company's selection of resources in its resource planning process.

Q. Has this recommendation been made before?

A. Yes, and in fact, the Company is now ordered to utilize ELCC in its IRPs. The 2022 IRP Order Adopting Stipulation mentions that "The Commission finds and concludes that ELCC is the industry standard…" and "In its next IRP, and any upcoming RFPs issued before the next IRP, the Company agrees to use the ELCC Methodology to determine the renewable resource capacity values."[11]

Q. Why did Georgia Power file a 2023 IRP Update?

A. The Company filed the update to respond to changes in its load forecast that have occurred since the 2022 IRP was approved by the Commission. More specifically, Georgia Power's updated load forecast includes the addition of numerous new large load customers that the Company has procured in the intervening months following the 2022 IRP.[12] Georgia Power claims that this extraordinary growth in load requires the Company to either procure or build new supply and demand-side capacity resources to meet the increases in customers' demand and energy. Georgia Power claims that the updated load forecast creates a winter capacity deficit of 1,875 MW as soon as December 2026.[13]

D. <u>Capacity Need</u>

Q. How did Georgia Power determine that it will have a capacity deficit?

A. In support of the 2023 IRP Update, Georgia Power prepared the 2023 IRP Update Load and Energy Forecast ("2023 IRP Update Load Forecast"). The 2023 IRP Update Load Forecast provides a twenty-year forecast of energy sales and peak demand to determine the

[11] Public Interest Staff's Proposed Order Adopting Stipulation" July 29, 2022. Fact No. 32.
[12] Direct Testimony of Grubb, Valle, Evans, and Bush, page 9 of 56, lines 8-10.
[13] Georgia Power, 2023 Integrated Resource Plan Update, Figure 4: Georgia Power Winter Capacity Needs.

energy and capacity needs of the Company. The summer and winter peak demands are then compared to the total available capacity of all resources to determine a net capacity position. Based on this analysis, the Company determined that it will experience a capacity deficit by the winter of 2026/2027.

Q. What is Georgia Power's current level of available capacity to meet its forecasted peak demand?

A. Georgia Power's available capacity is the sum of its owned generating capacity, purchased generating capacity, and dispatchable demand-side resources. In 2027, the Company's total available accredited capacity is about 21.8 gigawatts ("GW") in winter and 23.2 GW in the summer of 2027. The Company has 1.4 GW less available accredited capacity in the winter to meet its peak demand because Georgia Power has almost 2 GW less purchased generating capacity in the winter of 2027 than the summer. The Company's net capacity position, which is the difference between its planning reserve margin ("PRM") and available capacity, is shown in Table 1 below.

Table 1

Winter and Summer Net Capacity Position
(All Units in MW)

	Winter				Summer				Seasonal Change (Winter - Summer)			
Year	Peak Demand	25% Planning Reserve Margin	Available Capacity	Net Capacity	Peak Demand	15% Planning Reserve Margin	Available Capacity	Net Capacity	Peak Demand	Planning Reserve Margin	Available Capacity	Net Capacity
2024	15,283	19,104	19,980	877	16,757	19,271	19,871	600	(1,474)	(167)	110	277
2025	15,947	19,934	21,196	1,262	17,383	19,990	21,941	1,951	(1,435)	(56)	(745)	(690)
2026	17,256	21,570	21,296	(274)	18,804	21,624	22,080	455	(1,548)	(55)	(784)	(729)
2027	18,928	23,660	21,785	(1,875)	20,633	23,729	23,211	(518)	(1,705)	(69)	(1,425)	(1,357)
2028	19,751	24,688	22,088	(2,601)	21,561	24,796	23,234	(1,562)	(1,811)	(107)	(1,146)	(1,039)
2029	20,551	25,688	21,357	(4,331)	22,445	25,812	23,400	(2,412)	(1,895)	(124)	(2,043)	(1,919)

Source: 2023 IRP Update, Appendix, Georgia Power Territorial Base Case Load vs. Existing Capability Table

Q. Did Georgia Power procure more purchased generating capacity for the summer than the winter because it has a higher summer capacity obligation?

A. No, not according to the Company. Despite the fact that the Company experiences it's highest peak demand in the summer months, and is forecasting that it will continue to be

summer peaking,[14] the Company projects that it will require approximately the same amount of available capacity for both seasons. This is because the PRM, also referred to as the target reserve margin, is significantly higher in winter than summer. The Company proposes a summer target reserve margin of 15.28% over the long-term and 14.78% in the short-term. Its proposed winter target reserve margin will be 25.18% over the long-term and 24.69% over the short-term.

Q. How does the PRM impact the Company's seasonal net capacity position?

A. As shown on Table 1, in the year 2027, the forecasted peak demand is about 1,700 MW greater in the summer than the winter; however, the PRM, which informs the capacity obligation, is only about 70 MW greater. Because Georgia Power uses a higher PRM for the winter than the summer, the Company's capacity obligations end up nearly the same for both seasons. Table 1 illustrates the impact of the higher PRM and compares the net capacity position of Georgia Power in the winter to the summer. However, despite the fact that Georgia Power requires the same levels of capacity for both seasons, its winter net capacity position is a 1,875 MW deficit.

Q. Did Georgia Power update its Reserve Margin Study for the 2023 IRP Update?

A. No. Georgia Power is still relying on its 2021 Reserve Margin Study used in the 2022 IRP to determine the PRM for the summer and winter months.

Q. Was the Company's selected winter reserve margin explicitly endorsed in the 2022 IRP proceeding or its concluding Order?

A. No. In the Order approving the Stipulation in the 2022 IRP, the Commission noted that the matter was not fully settled; rather the Company was allowed to continue using the 26% winter reserve margin "until such time as a winter TRM is agreed to between PIA Staff and the Company and approved by the Commission," and that the "use of the 26% winter TRM for planning purposes is not an endorsement by Stipulating parties of

[14] 2023 IRP Update Load and Energy Forecast, pages 3-5.

that TRM, and no Stipulating Party is foreclosed from proposing an alternative winter TRM in a future case."[15]

Q. Is it clear to you why there was no explicit endorsement of a particular reserve margin in the Order?

A. I was not involved in the 2022 proceeding; however, the Order implies that there was no need to act on the TRM at the time because there were no near term capacity additions needed at the time. With the filing of the 2023 IRP Update this is obviously no longer the case, so the matter of whether a 26% winter reserve margin is appropriate seems to continue to be an open question.

Q. Would it have been best practice for the Company to update its reserve margin study in the 2023 IRP Update filing?

A. Yes. The appropriate reserve margin for a planning area is highly dependent on the magnitude and shape of load on the system at peak demand periods. Given that the Company is filing this IRP in anticipation of significant incremental load, much of which is attributed to high load factor customers, the shape of Georgia Power's overall load may be changing. This means that the 2021 study may no longer accurately reflect the appropriate capacity margin for the company to provide reliable service.

E. <u>IRP Update Modeling</u>

Q. What resources is the Company requesting approval for in its IRP Update?

A. In total Georgia Power is requesting approval for potentially up to 3,380 MW of supply-side capacity resources.[16] The Company's proposed resource plan consists of: (1) a PPA with Mississippi Power Company ("Mississippi Power") to procure power from its existing generating assets; (2) a PPA with Santa Rosa Energy Center LLC for capacity and energy from a natural gas-fired combined cycle ("CC") plant located in Pace, Florida; (3) potential acquisition of an additional ownership interest in an existing generating asset

[15] Public Interest Staff's Proposed Order Adopting Stipulation" July 29, 2022. Fact No. 16.
[16] Total Capacity = 750 MW (Mississippi Power PPA) + 230 MW (Santa Rosa PPA) + 1000 MW (BESS or BESS/Solar Hybrid) + 1,400 MW (3 Duel-Fuel CTs at Plant Yates) = 3,380 MW.

within the Southern Company footprint; (4) battery energy storage systems ("BESS") at existing solar facilities, such as Company-owned facilities at military bases; (5) a new BESS co-located with a new solar facility at a site with existing transmission interconnection facilities; (6) three simple-cycle combustion turbines ("CTs") at Plant Yates; and (7) expansion of distributed energy resource ("DER") and demand response ("DR") programs.

Q. Do you have any concerns about 2023 IPR Update resource plan?

A. Yes. The resource plan is heavily reliant on fossil-fuel fired generating resources, which are subject to fuel price volatility. In addition, there is added risk that new environmental regulation could impose additional cost on the operation of these resources. The Mississippi Power PPA is expected to be filled, at least in part, with coal-fired generating resources that would have otherwise been retired or remarketed outside of system reserve sharing[17] if not for this PPA with its affiliate company. Ostensibly, those resources were proposed for retirement because economic analysis determined they were no longer cost effective to keep online relative to Mississippi Power's needs.

Q. How did Georgia Power select these resources to meet its capacity and energy obligations?

A. Georgia Power relied on its internal knowledge of existing generating resources with available capacity and self-build options that could be built prior to the winter of 2026/2027. The Company also conducted a Request for Information ("RFI") to gather market information regarding the availability of existing and planned Capacity Resources for the capacity need identified for years 2026 through 2028, the timeframe being addressed in the Company's 2023 IRP Update.[18] However, there were limitations to the RFI; Georgia Power limited responses to existing facilities of 100 MW or greater. In addition, the Company did not conduct an all-resource RFP prior to filing the 2023 IRP Update to determine the alternative generating resources available. Lastly, as discussed in

[17] Georgia Power, 2023 Integrated Resource Plan Update, page 13.
[18] Georgia Power, 2023 Request for Information for Capacity Resources – Summary of Results, December 4, 2023.

greater detail in the testimony of my colleague, Christopher C. Walters, it did not appear to solicit broad-based customer feedback to determine the magnitude of renewable resources needed to fulfill customer sustainability goals.

Q. What modeling was performed by Georgia Power to support its 2023 IRP Update?

A. The Company prepared the 2023 IRP Update Load Forecast to account for the new load acquired by Georgia Power. Georgia Power continued to rely on models from its 2022 IRP filing in the 2023 IRP Update. The Company did not update its Reserve Margin Study or its ELCC Study for the 2023 IRP Update. In addition, Georgia Power utilized Aurora production cost modeling in its Updated Economic Analysis of Capacity Resources to evaluate the Net Present Value ("NPV") of six capacity resources under various sensitivities.

Q. How is the Aurora production cost model typically utilized in the Georgia Power IRP process?

A. In its 2022 IRP, Southern Company used Aurora to simultaneously model its three operating subsidiaries, and then assign capacity to individual subsidiaries depending on which operating area has a deficit. The combination of new resources assigned to each subsidiary is the utility's System expansion plan. The System expansion plan identifies the capacity and energy additions that inform the type of resources that are most economical within a particular timeframe for the given assumptions. In addition, the Aurora production cost model is used to evaluate the different generation technologies. The Aurora model considers all possible combinations of capacity additions, on a yearly basis, that satisfy the Company's target reserve margin constraints. The resulting combination of candidate resources with the smallest production and capital cost over the planning horizon represents a least-cost plan, given the assumptions used.[19] As a result of the modeling performed in the 2022 IRP filing, the Company determined that the most

[19] Georgia Power, 2022 Integrated Resource Plan, Chapter 10, page 63.

economical approach to long-term planning would be to retire approximately 3,500 MW of coal and oil generating resources and double the amount of renewables.[20]

Q. Does the modeling the Company provided directly correlate to what it is proposing in this resource plan?

A. It appears it does not. For example, the Mid-Gas Zero Carbon ("MG0") case forms the Base Case for the Company's Capacity Expansion Plan, but the resources the Company is actually proposing the Commission approve are not aligned with the resources included in that modeling. The Company speaks to this in the Direct Testimony hearing, where it says that it used the modeling to inform its proposed plan, but the plan is not directly a reflection of modeling. I would note that this is not uncommon; every planner must use their professional judgment in selecting a proposed plan based on modeling and other factors. However, it is clear that the proposed Plan deviates from the modeling and it is not clear that the Company performed a full assessment of costs and risks associated with the Plan it actually is proposing.

Q. What would a fulsome analysis include?

A. For customers and stakeholders to understand the costs and risks of the proposed plan more fully, the Company would present a Base Case set of estimated capital and operating costs (including both fixed and variable operations and maintenance costs); compare it to a set of sensitivities to reasonably assess the risk that the future of key inputs looked different than the Base Case (for example, high and low fuel prices, different technology price outlooks, different load levels, different capacity prices, or different future environmental costs); it would assess the selected plan's impact to customer rates and/or bills quantitatively; and it would assess the environmental impacts of the plan.

[20] S&P Global, Georgia Power's resource plan would retire 3,500 MW, double renewables, January 31, 2022.

Q. How can customers be assured the 2023 IRP Update resource plan is a least-cost best fit plan without a fulsome analysis of costs?

A. In my opinion, they cannot. In particular, it does not appear the Company conducted or provided a rate or bill impact analysis in the record of this IRP filing. The Company repeatedly stated in its Direct Testimony that the proposed plan will put downward pressure on rates for existing customers, due to increased load anticipated; however, it has not provided any analysis of expected rate impact on customers resulting from the plan.

Q. Do you have any additional concerns with the Company's modeling in this IRP?

A. Yes. In response to questioning during Direct Testimony, Company witness Mr. Grubb stated repeatedly that the Company has not performed an evaluation of how this plan affects the Company's overall energy mix.[21] Both Southern Company and its customers have ambitious sustainability goals that include decarbonization of their energy sources. Without an assessment of how this plan will affect the underlying mix of energy resources, neither Georgia Power itself, nor its customers, have a clear expectation of how this plan affects their ability to achieve these goals long-term. This proposed plan is also affecting the operations of its other operating companies, both from a cost and emissions perspective, in a way that should be assessed and reported transparently. In sum, the Company's alleged lack of modeling regarding the energy mix resulting from this plan is a significant weakness in its analysis, and, therefore, its ability to be responsive to customer cost, reliability and environmental needs.

F. Conclusion

Q. What are your recommendations?

A. I recommend that Georgia Power take the following actions: (1) update its Reserve Margin Study to ensure that the 2023 IRP Update accurately reflects the Company's capacity obligations; (2) utilize Aurora production cost modeling to compare potential resource expansion plans to ensure that the least-cost resource plan is being proposed; and (3) utilize the existing, or conduct a new, ELCC study of potential generating resources so that the

[21] Exhibit___(CTF-2), Docket No. 55378 Transcript, Wednesday January 17, 2024, pages 0552 & 0553.

Company is accurately reflecting the accredited capacity value the resource provides to Georgia Power and supports its ability to supply firm service to its customers.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	**GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE**	**)** **)** **)**	**DOCKET NO. 55378**

EXHIBITS

OF

COLIN T. FITZHENRY

ON BEHALF OF THE
UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER
FEDERAL EXECUTIVE AGENCIES

FEBRUARY 15, 2024

Qualifications of Colin T. Fitzhenry

Q. Please state your name and business address.

A. Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. Please state your occupation.

A. I am a Senior Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please summarize your educational background and experience.

A. I received a Bachelor of Science in General Engineering from the University of Illinois Urbana-Champaign, which provided a broad background in mechanics and control systems. Prior to joining BAI, I served as an Engineer Intern for Dynegy Inc., where I was involved with generation operation at both Vermilion Power Station and Tilton Power Station.

Since joining BAI in January 2013, I have provided assistance in several regulated utility matters. Some of these include resource planning, transmission planning, fuel cost recovery, environmental compliance plans, mergers, asset transfers, electrical and commodity price forecasting, and power procurement.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, finance, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm have participated in over 700 major utility rate and other cases and statewide generic investigations before

utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

Georgia Power Company's 2023 Integrated Resource Plan Update) Docket No. 55378

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Wednesday, January 17, 2024

The above-entitled matter came on for hearing pursuant to Notice at 9:30 a.m.

PRESENT WERE:
JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
TRICIA PRIDEMORE, Commissioner

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can it be grid charged?

A (Witness Grubb) It could be grid charged, if we needed that. There are some periods of time we expect it will be grid charged.

Q What percentage of Georgia Power's current energy mix is fossil gas?

A (Witness Grubb) I have that. We actually had it in the filing.

So it is 45 percent of capacity. I'm not sure energy -- it's slightly higher in 2022. I don't have --

Q Would you accept 48?

A (Witness Grubb) Yeah. On energy?

Q Yes.

A (Witness Grubb) Yes, 48.

Q That was from your 2023 Facts and Figures by the Numbers published online?

A (Witness Grubb) No. That's correct. I think that's what I have here, too.

Q All right. So if the Commission approves the resources proposed in this 2023 IRP Update, what will that percentage be for the winter of 2027-2028?

A (Witness Grubb) I don't have those numbers. I don't think I've run. Not that aspect of it. I don't have them here.

Q Will it increase or decrease Georgia Power's

reliance on gas?

A (Witness Grubb) This filing?

Q Yes.

A (Witness Grubb) So it depends on how much we can dispatch the CTs. And as Mr. Bush has said, if we do, it would be a more economic gas usage than what the system is now. So we don't have those numbers, but it won't drastically increase.

Q All right. Well, this kind of gets back to the conversation that was started earlier. Many, many times in the last two days we heard that this plan will put downward pressure on rates. But I think we got beyond that earlier today and we started talking about other bill impacts. Because people -- you know, customers ultimately pay a bill, not just a rate.

Is it true that over a quarter of residential customer bill is the fuel rider?

A (Witness Grubb) I haven't -- subject to check. I don't remember what the latest fuel rates are.

Q And another roughly 8 percent on the EECR?

A (Witness Grubb) Subject to check.

Q Thank you.

Have you analyzed the bill impacts from this request for -- especially for residential customers?

A (Witness Grubb) Not to bills because that

let you off the hook.

A (Witness Grubb) I believe we filed them in the DR. I just can't remember which DR since there has been 270 of them filed.

Q But there weren't any hybrid projects that were modeled as a resource in the capacity expansion model; right?

A (Witness Grubb) No. When you say "hybrid," I'm assuming you mean solar-plus storage?

Q Solar-plus storage, yes.

A (Witness Grubb) No. What Aurora -- what the expansion plan model is doing is it is looking at solar from an energy production standpoint, and it is looking at storage from a capacity standpoint. So it is not -- it is not dependent on location, if they are located together or not. It is looking simply at solar providing energy value and storage providing capacity model. Whether you model them as a hybrid or not, it wouldn't really change the outcome at all.

Q Well, so does solar not get a -- some sort of an accredited value for Aurora, or is it set at zero?

A (Witness Grubb) Not generic solar.

Q It is set at zero in the model?

A (Witness Grubb) It is set at zero. So if we -- once we know solar resources through an RFP, they

would get it, but a generic solar does not.

Q And so --

A (Witness Grubb) Because again, it is being added for energy value.

Q So the company performed an effective load carrying capacity analysis for solar, though; right?

A (Witness Grubb) To use on projects that we have project profiles for in evaluating RFPs, that's correct.

Q But you didn't include that evaluation in the model for capacity expansion?

A (Witness Grubb) That is my recollection because, again, it is looking at adding it for energy resources. And it does allow it to be added before we have a capacity need, so it does do that.

Q All the batteries that are added in the model -- well, all the resources in the model are modeled as company-owned resources; is that correct?

A (Witness Grubb) So as we have always done, Commissioners, not knowing the results of RFPs, we have always shown the avoided cost or the cost of a capacity is the company's cost to build, which is a standard utility practice.

So when you are talking about a generic expansion plan, you model that cost to build, because

(DOD Exhibits 1 through 5 were admitted into evidence.)

MR. MCNUTT: Thank you, Mr. Chairman.

CHAIRMAN SHAW: All right. Gentlemen, thank you for your time and y'all can be excused.

MR. FITZHENRY: Thank you very much.

CHAIRMAN SHAW: All right. Our next and last panel to be called is that of Walmart.

MS. EATON: Walmart calls Lisa Perry as its witness to the stand.

With your permission, I will swear in the witness.

CHAIRMAN SHAW: Please do.

MS. EATON: Please raise your right hand.

Thereupon,

LISA V. PERRY,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. EATON:

Q Can you please state your name and business address for the record?

A My name is Lisa V. Perry, and my business address is 2608 Southeast Jay Street, Bentonville, Arkansas, 72716.

Q For whom do you work and in what position?

A I am a director on the utilities team, regulatory, for Walmart, Inc.

Q And have you testified before this Commission in prior dockets?

A No, I have not.

Q On February 2nd -- I mean, on February 15th, 2024, did you cause to be filed in this docket the prefiled direct testimony in question-and-answer format consisting of 15 pages?

A Yes, I did.

Q Do you have any additions, updates, or corrections to your prefiled direct testimony?

A I do. I have one correction. And it is on page 15 of my testimony, line 8. Crossing out "Demand response plus energy credit program" and replacing that with "Curtailable Load Program."

Q Thank you.

If I were to ask you the same questions contained in your prefiled direct as you have amended them today, would your answers be the same?

A Yes, they would.

MS. EATON: I would move that the Commission accept Ms. Perry's prefiled direct testimony, as amended today orally from the stand, into the record as if given orally.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Lisa V. Perry follows:)

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's 2023	**)**	**Docket No. 55378**
Integrated Resource Plan Update	**)**	

DIRECT TESTIMONY AND EXHIBIT OF

LISA V. PERRY

ON BEHALF OF

WALMART, INC.

FEBRUARY 15, 2024

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Exhibits	**Description**
Exhibit LVP-1	Witness Experience

I. Introduction

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

A. My name is Lisa V. Perry. My business address is 2608 SE J Street, Bentonville, Arkansas 72716. I am employed by Walmart Inc. ("Walmart") as Director, Utility Partnerships - Regulatory.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of Walmart.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I received a J.D. in 1999 and a L.L.M. in Taxation in 2000 from the University of Florida Levin College of Law. From 2001 to 2019, I was in private practice with an emphasis from 2007 to 2019 in Energy Law. My practice included representing a large commercial client before the utility regulatory commissions in Colorado, Texas, New Mexico, Arkansas, and Louisiana in matters ranging from general rate cases to renewable energy programs. I joined the energy department at Walmart in September 2019 as Senior Manager, Energy Services. My Witness Qualifications Statement is attached as Exhibit LVP-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No, I have not.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes, I have submitted testimony with state regulatory commissions for Arkansas, Colorado, Connecticut, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, New York, Ohio, Oklahoma, South Carolina, Texas, Virginia, and Wyoming. I have also provided legal representation for customer stakeholders before the state regulatory commissions for Colorado, Texas, Arkansas, Louisiana, and New Mexico in the cases listed under "Commission Dockets" in Exhibit LVP-1.

Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibit listed in the Table of Contents.

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS IN GEORGIA.

A. As shown on Walmart's website, Walmart operates 213 retail units, 10 distribution centers, three fulfillment centers, and employs over 66,000 associates in Georgia. In fiscal year ending 2023, Walmart purchased approximately $24.8 billion dollars of goods and services from Georgia-based suppliers, supporting over 189,000 supplier jobs.[1]

[1] https://corporate.walmart.com/about/location-facts/united-states/georgia

Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN THE SERVICE TERRITORY FOR GEORGIA POWER COMPANY ("COMPANY" OR "GPC")

A. Walmart has 125 retail stores, three distribution centers, one fulfillment center, and related facilities that take service from GPC.

II. Purpose of Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the Company's proposed 2023 Integrated Resource Plan ("IRP") Update filed October 27, 2023, along with supporting testimony and documents, in which the Company is seeking, *inter alia*, approval of new generation resources, power purchase agreements ("PPAs"), new distributed energy resource ("DER") programs, and a new curtailable load, or demand response, program. Specifically, my testimony addresses the Company's proposed DER programs, its proposed commercial and industrial ("C&I") customer demand response program, and opportunities for customers to provide resources that can help the Company meet its increasing customer demand.

Q. PLEASE SUMMARIZE WALMART'S RECOMMENDATIONS TO THE COMMISSION.

A. Walmart makes the following recommendations to the Commission:

(1) require the Company to work with interested stakeholders to build upon the Company's proposed DER Co-Location Program, DER Customer Owned Program, and Demand Response Plus Energy

Credit Program by developing additional C&I programs that provide more options to customers and will capitalize on resources that customers can bring to the Company's system on both the supply-side and demand-side of the equation, such as those mentioned later in my testimony, and any other opportunities that help the Company provide affordable and reliable clean energy solutions that benefit all customers; and

(2) require the Company seek Commission approval of such program(s) as part of its next statutorily required 2025 IRP.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE WALMART'S SUPPORT?

A. No. The fact that an issue is not addressed herein should not be construed as an endorsement of, agreement with, or consent to any filed position.

III. Description of Proposed 2023 IRP Update

Q. CAN YOU PROVIDE A GENERAL DESCRIPTION OF THE PROPOSED 2023 IRP UPDATE?

A. Yes. Based on my understanding, the Company is experiencing substantial load growth since filing its currently approved 2022 IRP, and, as a way to address this growth, the Company filed the 2023 updated IRP to seek approval of additional resources.[2] Specifically, the Company is asking the Commission to approve

[2] *See* Direct Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush ("Grubb, *et al.* Direct"), p. 6, lines 2-7.

additional supply-side resources, including two PPAs, three simple cycle combustion turbine ("CT") resources, and Battery Energy Storage Systems ("BESS").[3] The Company is also seeking approval of two new DER programs, the DER Co-Location Program and the DER Customer Owned Program, along with a new Curtailable Load Program for C&I customers and expansion of an existing residential demand response program.[4]

Q. IN ADDITION TO SUPPLY-SIDE RESOURCES AND DEMAND-SIDE PROGRAMS, IS THE COMPANY SEEKING APPROVAL FOR ANYTHING ADDITIONAL AS PART OF ITS 2023 IRP UPDATE?

A. Yes, it is. The Company is also asking the Commission to allow the Company to seek approval of additional capacity prior to its 2025 IRP during instances when the Company's load forecast project interim additional capacity needs.[5] The Company refers to this as "Flex Capacity."[6] Furthermore, the Company is seeking Commission approval to update its transmission system, as needed, to integrate the resources requested in its 2023 IRP Update into the Company's system.[7]

Q. WHAT IS WALMART'S RESPONSE TO THE COMPANY'S PROPOSED 2023 IRP UPDATE?

A. Walmart understands that the Company is seeking approval of different resources to meet growing demand quickly and efficiently. Walmart also appreciates that the Company is putting forth various avenues that it can deploy in order to meet its

[3] *See id.*, p. 6, line 25 to p. 8, line 3.
[4] *See id.*, p. 41, lines 18-23.
[5] *See id.*, p. 50, lines 18-21.
[6] *See id.*
[7] *See* Grubb, *et al.* Direct, p. 52, lines 22-27.

customer needs that not only provide additional generation resources, but also manage the demand side of the equation. As I discuss in more detail below, Walmart's ongoing efforts to meet its sustainability goals have provided it with valuable experience and access to a variety of clean energy resources that can provide the Company with even more solutions to meet its growing customer demand. In short, Walmart sees customers as being a part of the solution by positioning themselves to provide not only demand-side resources such as demand response, but also generation capabilities that reduce the Company's need to purchase expensive centralized generation.

IV. Walmart's Sustainability Goals

Q. HAS WALMART ESTABLISHED CORPORATE SUSTAINABILITY GOALS THAT INCLUDE CLEAN ENERGY AND CARBON REDUCTION GOALS?

A. Yes, it has. Walmart has long had aggressive and significant company-wide renewable energy goals, and on September 21, 2020, Walmart announced new targets as a part of its sustainability goals, including: (1) to be supplied 100 percent by renewable energy by 2035 and (2) zero carbon emissions in its operations, including its transportation fleet vehicles, without the use of offsets, by 2040. Walmart has also set a goal to transition to zero emission buildings by deploying low-impact refrigerants for cooling and electric equipment for heating by 2040.[8] ***Additionally, on January 9, 2024, Walmart announced a goal to bring 10 GW of***

[8] https://corporate.walmart.com/news/2020/09/21/walmart-sets-goal-to-become-a-regenerative-company.

13 new clean energy projects online by the end of 2030, including 1 GW of new onsite solar plus storage, and enabling 2 GW of new community solar projects.[9]

To date, Walmart has contracted for or currently takes electricity from one or more renewable resources in at least 29 states, including Georgia, and Puerto Rico.

Q. WHAT CHANNELS DOES WALMART UTILIZE TO SECURE CLEAN ENERGY RESOURCES?

A. To meet its clean energy goals, Walmart utilizes three primary channels to secure resources:

- **Development of off-site resources:** These products are typically structured to replace other energy, both physically and on the bill. This mechanism allows Walmart to leverage its scale to drive the best project economics while simultaneously minimizing transaction time and costs. To date, Walmart has contracted for these resources in deregulated markets through Texas Retail Energy, LLC, a competitive electric supplier wholly owned by Walmart that serves as its electric supplier in most deregulated retail markets, to directly serve its load. Walmart has also entered into "Virtual PPAs" and "Renewable Energy Certificate ("REC") Agreements" in deregulated wholesale markets for clean energy assets. These contracts do not directly serve Walmart's load but allow it to bring new large-scale renewable resources to the market by entering into long-term financial agreements for clean energy power and environmental attributes. Walmart

[9] https://tech.walmart.com/content/dam/walmart-global-tech/documents/Walmart%20CES%20Keynote%20Script%20Transcript_1.9.24.pdf.

will also sign up its facilities for offsite community solar program subscriptions in jurisdictions where those programs are offered. Through these programs, Walmart sites will subscribe to an allocation of a shared offsite solar installation and receive bill credits based on their subscription size, facility power usage, and their eligible utility expenses. In addition to community solar program participation, Walmart is also working to make clean energy accessible and affordable for its customers and members, as part of its commitment to unlock 2 GW of new community solar projects around the United States. As an example, Walmart recently announced its investment in seven community solar projects in Illinois and New York, which will serve low-to-moderate income households, public schools, and religious institutions, among others.

- **Development of on-site resources:** Walmart is currently developing and will own on-site, behind the meter resources, and has also contracted resources through PPAs and leases that allow performance guarantees. These resources replace grid energy with the expectation that the operating costs for the site are reduced.
- **Utility partnerships:** Walmart works with its utility partners to develop useable commercial and industrial programs and economic structures targeted to function within the confines of the regulatory compact and with minimal impact to non-participating customers. When this option is pursued, Walmart works to ensure that programs it assists in developing can be used by broader groups of customers, not merely by Walmart. Walmart

is unique in the large commercial space because it has significant in-house rate and regulatory expertise that it is willing to leverage to create opportunities to move the entire industry forward. Walmart currently participates in programs with 20 utilities across the United States. The largest of these partnerships that have been executed to date include the development of and participation in Florida Power & Light Company's SolarTogether Program, Duke Energy Florida's Clean Energy Connection Program, ***and the Company's Renewable Energy Development Initiative Program***. While Walmart assisted in developing these opportunities, the opportunities are open to other interested large customers, not just Walmart.

V. Supply Side Opportunities

Q. YOU MENTIONED THAT THE COMPANY IS SEEKING APPROVAL FOR SPECIFIC CUSTOMER-SITED SUPPLY-SIDE RESOURCES THROUGH TWO NEW DER PROGRAMS. COULD YOU PLEASE PROVIDE MORE DETAIL ABOUT THESE DER PROGRAMS?

A. The Company is seeking to offer the DER Co-Location Program to large C&I customers, which would site a Company-owned dispatchable 10 MW or greater back-up generator at the customer's premises.[10] The back-up generator would be a system resource for the Company during normal grid operations, but would then switch to back-up power for the participating customer during a power outage.[11] The economics of the program is based on the cost of the back-up unit itself and

[10] *See* Grubb, *et al.* Direct, p. 42, lines 2-6.
[11] *See id.*, p. 42, lines 6-10.

the value that it brings to the Company's system as set forth in the accompanying DCL-1 tariff.[12]

Q. WHAT IS THE SECOND PROPOSED DER PROGRAM?

A. The second proposed DER program is the DER Customer Owned Program, which, as its name suggests, provides a credit to C&I customers who own a dispatchable back-up generator with a minimum of 1 MW and maximum of 10 MW capacity, either from one account or through the aggregation of multiple accounts, under the proposed DCO-1 tariff.[13] As with the DER Co-Location Program, the Company would operate the back-up generator as a system resource during normal operations and as back-up power for the participating customer during outages.[14]

Q. DOES WALMART SUPPORT THESE TYPES OF PROGRAMS?

A. Yes, Walmart supports the Company's proposed DER programs and, in fact, has supported a similar program through testimony filed with the Louisiana Public Service Commission for Entergy Louisiana LLC's Power Through program, which provides additional supply-side resources to the utility while giving participating customers resilient back-up power.[15] Walmart looks forward to continuing its conversation with GPC about the proposed DER programs and whether these programs are a good fit for Walmart and its operational needs.

[12] *See* updated tariff sheet for DCL-1 filed in this Docket on January 11, 2024, p. 12.60.
[13] *See* Grubb, *et al.* Direct, p. 43, lines 7-15.
[14] *See id.*, p. 43, lines 10-19.
[15] https://www.entergy.com/powerthrough/.

Q. DOES WALMART BELIEVE THERE ARE ADDITIONAL CUSTOMER-PROVIDED RESOURCES AND OPPORTUNITIES AVAILABLE TO THE COMPANY?

A. Yes, it does. As I mentioned above, as part of its sustainability efforts, Walmart is working to make clean energy accessible and affordable for its customers and members, and it has committed to unlocking 2 GW of new community solar projects around the United States.[16]

Q. HOW CAN PROJECTS SUCH AS COMMUNITY SOLAR HELP THE COMPANY UNLOCK ADDITIONAL CAPACITY RESOURCES TO MEET ITS GROWING CUSTOMER DEMAND?

A. The structure of a Community Solar project can vary depending on legislative authority, customer resources, and utility appetite for customer involvement. In some states, such as New Jersey, New York, Nevada, and other states, the legislature has promulgated statutes that allow third parties to install smaller community solar projects and re-sell the output from that facility to individual customers. In other states, such as Georgia, where third parties are generally prohibited from re-selling electricity from a solar installation, there are other opportunities for customers to support solar generation resources. For example, Walmart could invest its own capital in solar projects where the utility owns and operates the solar installation, with or without co-located energy storage, as a system resource. This type of arrangement not only provides the utility with access

[16] https://tech.walmart.com/content/dam/walmart-global-tech/documents/Walmart%20CES%20Keynote%20Script%20Transcript_1.9.24.pdf.

to a greater number of generation resources, but also provides cleaner power for all of its customers.

Q. ARE THERE ANY OTHER TECHNOLOGIES THAT WALMART BELIEVES CAN ACT AS A RESOURCE TO THE COMPANY'S GENERATION SYSTEM?

A. Yes, there are. As I briefly mentioned above with community solar, customer-owned or customer-financed BESS, similar to the technology that the Company is seeking approval of in this Docket, can also enable the Company to provide additional energy storage that can act as a balancing resource to renewable energy powered generation.

Another opportunity is leveraging customer-side generation that can provide benefits not only to the individual customer, but also to the utility's system and resource planning as a whole. As I mentioned earlier, Walmart is currently developing and will own on-site, behind the meter resources at its facilities. These resources can act primarily as replacement power for Walmart's operations with any additional power being made available to the utility or to third parties where allowed under community solar structures.

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION REGARDING DER PROGRAMS AND CUSTOMER PROVIDED SUPPLY-SIDE RESOURCES?

A. Walmart appreciates GPC's continued efforts to develop programs that leverage customer sites and resources as not only a way to meet increasing customer demand, but also as a means to provide cleaner power to all customers. To continue

this initiative and to leverage new and evolving technology and customer resources, Walmart recommends that the Commission:

(1) require the Company to work with interested stakeholders to build upon the Company's proposed DER Co-Location Program and DER Customer Owned Program by developing additional C&I programs that provide more options to customers and will capitalize on resources that customers can bring to the Company's system on the supply-side such as those mentioned earlier in my testimony and any other opportunities that help the Company provide affordable and reliable clean energy solutions that benefit all customers; and

(2) require the Company seek Commission approval of such program(s) as part of its next statutorily required 2025 IRP.

VI. Demand Side Opportunities

Q. YOU MENTIONED THAT THE COMPANY IS SEEKING APPROVAL IN THIS DOCKET FOR SPECIFIC DEMAND SIDE RESOURCES, SUCH AS A NEW CURTAILABLE LOAD PROGRAM FOR C&I CUSTOMERS. IS WALMART INTERESTED IN THESE TYPES OF PROGRAMS?

A. Yes, it is. The Company is seeking approval of its proposed Curtailable Load Program and corresponding DCL-1 tariff for C&I Customers in addition to its currently approved Demand Response Plus Energy Credit Program.[17] Although Walmart is continuing to evaluate its interest in the Curtailable Load Program, at

[17] *See* Grubb, *et al.* Direct, p. 47, lines14-21.

present, Walmart has over a thousand stores participating in demand response initiatives throughout the United States. These programs span multiple Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"), including: ISO New England Inc., New York Independent System Operator, PJM Interconnection, LLC, Electric Reliability Council of Texas, Midcontinent Independent System Operator, and California Independent System Operator. Walmart also participates in dozens of demand response programs and, at utility or government request, has provided emergency responses outside of formal programs.[18]

However, to maximize customer engagement and system benefit, Walmart recognizes that multiple demand response programs may be needed to meet the needs of most customers. The benefits of load reduction through these types of programs have been demonstrated time and time again through extreme weather events such as 2021 Winter Storm Uri and excessive heat during summer months. Additionally, demand response resources can potentially delay and/or reduce the need to develop new generation facilities, saving money for the Company's customers.[19] In order to maximize the benefits of supply-side management through a robust suite of program offerings, Walmart supports approval of the Company's

[18] Walmart currently participates in utility demand response programs either directly with the utility or through an aggregator of retail customers, including, among other programs, (i) SRP's Business Demand Response Program found at https://www.srpnet.com/assets/srpnet/pdf/energy-savings-rebates/business/rebates/BDR-Fact-Sheet.pdf, (ii) Public Service Company of New Mexico's ("PNM") Peak Saver Commercial & Industrial Demand Response Program found at https://www.pnm.com/peaksaver, and (iii) Evergy's Business Demand Response Program found at https://www.evergy.com/ways-to-save/incentives-link/demand-response.

[19] *See, e.g.,* Michigan Agency for Energy Report, "Michigan Capacity Resources Assessment," p. 9 (analyzing the impact of declining reserve margins in Michigan and retirement of coal plants, particularly during high load emergency conditions, stating that energy efficiency and demand response "could delay the need for peaking capacity under the high demand scenarios") (Jan. 31, 2017) *available at* https://www.michigan.gov/documents/energy/Michigan_EGEAS_Report__01_31_2017_550217_7.pdf.

proposed Demand Response Plus Energy Credit Program and requests that the Company continue to work with C&I customers to develop additional programs that can meet the needs of the most number of customers.

Q. WHAT IS WALMART'S RECOMMENDATION TO THE COMMISSION REGARDING DEMAND SIDE MANAGEMENT PROGRAMS?

A. Walmart recommends that the Commission:

(1) require the Company to work with interested stakeholders to build upon the Company's proposed Demand Response Plus Energy Credit Program by developing additional C&I programs that provide more options to customers and will capitalize on resources that customers can bring to the Company's system on the demand side and any other opportunities that help the Company provide affordable and reliable clean energy solutions that benefit all customers; and

(2) require the Company seek Commission approval of such program(s) as part of its next statutorily required 2025 IRP.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's 2023	**)**	**Docket No. 55378**
Integrated Resource Plan Update	**)**	

EXHIBIT OF

LISA V. PERRY

ON BEHALF OF

WALMART, INC.

FEBRUARY 15, 2024

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GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
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EXHIBIT LVP-1 OF

LISA V. PERRY

ON BEHALF OF

WALMART, INC.

FEBRUARY 15, 2024

Lisa V. Perry

Director, Utility Partnerships - Regulatory
Walmart Inc.
Business Address: 2608 SE J Street, Bentonville, Arkansas 72716
Business Phone: (479) 274-0238

EXPERIENCE

September 2023 – Present
Walmart Inc., Bentonville, AR
Director, Utility Partnerships - Regulatory

September 2019 – September 2023
Walmart Inc., Bentonville, AR
Senior Manager, Energy Services

November 2017 – September 2019
Oram & Houghton PLLC, Round Rock, TX
Of Counsel, Energy Law

February 2016 – November 2017
Ray Quinney & Nebeker, P.C., Salt Lake City, UT
Of Counsel, Energy Law

September 2007 – February 2016
Welborn, Sullivan, Meck & Tooley, P.C., Denver, CO
Partner, Energy Law

EDUCATION

2000	University of Florida Levin College of Law	LL.M., Taxation
1999	University of Florida Levin College of Law	J.D.
1996	University of South Florida	B.A., Criminology
1993	University of South Florida	B.A., Psychology

FILED TESTIMONY

2024

Public Service Commission of South Carolina Docket No. 2023-369-E: In re: S.C. Code Ann. Section 58-37-60 Independent Study to Evaluate the Integration of Renewable Energy and Emerging Energy Technologies into the Electric Grid for the Public Interest.
Issue: Evaluation of integrating renewable generation and related technologies into the grid.

2023

Public Service Commission for the State of Maryland Case No. 9702: In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy
Issue: General rate case.

Public Service Commission for the State of New York Case No. 23-E-0418: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; and Case No. 23-G-0419: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas and Electric Corporation for Gas Service.
Issue: General rate cast for electric and gas service.

Indiana Utility Regulatory Commission Cause No. 45933: Petition of Indiana Michigan Power Company, an Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service Through a Phase In Rate Adjustment; and for Approval of Related Relief Including: (1) Revised Depreciation Rates, Including Cost of Removal Less Salvage, and Updated Depreciation Expense; (2) Accounting Relief, Including Deferrals and Amortizations; (3) Inclusion of Capital Investment; (4) Rate Adjustment Mechanism Proposals, Including New Grant Projects Rider and Modified Tax Rider; (5) a Voluntary Residential Customer Powerpay Program; (6) Waiver of Declination of Jurisdiction with Respect to Certain Rules to Facilitate Implementation of the Powerpay Program; (7) Cost Recovery for Cook Plant Subsequent License Renewal Evaluation Project; and (8) New Schedules of Rates, Rules and Regulations.
Issue: General rate case.

Public Utilities Commission of Ohio Case No. 23-301-EL-SSO: In the Matter of the Application of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.
Issue: Approval of the Company's proposed Electric Security Plan.

Louisiana Public Service Commission Docket No. U-36697: Application of Entergy Louisiana, LLC for Approval of an alternative market-based mechanism process seeking to secure up to 3,000 MW of solar resources, including certification of those resources, expansion of the Geaux Greem Option Rider, and approval of a new renewable tariff.
Issue: Approval of a voluntary renewable program backed by utility-owned solar assets.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2023-00101: Application of Virginia Electric and Power Company for a 2023 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia.
Issue: Biennial review of rates.

Commonwealth of Kentucky Public Service Commission Case No. 2023-00159: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric

Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) a Securitization Financing Order; and (5) all other Required Approvals and Relief.
Issue: General rate case.

Louisiana Public Service Commission Docket No. U-36625: Application of Entergy Louisiana, LLC for Approval of the Entergy Future Ready Resilience Plan (Phase I)
Issue: Recovery of costs to upgrade transmission and distribution systems.

Colorado Public Utilities Commission Proceeding No. 23A-0242E: In the Matter of the Application of Public Service Company of Colorado for Approval of its 2024-2026 Transportation Electrification Plan.
Issue: Seeking approval of utility's second transportation electrification plan.

Indiana Utility Regulatory Commission Cause No. 45919: In the Matter of the Petition of Indiana Michigan Power Company for Approval of (1) an Electric Vehicle Fast Charging Rate and Tariff and (2) Deferred Accounting Treatment for the Costs of Certain Company-Owned Electric Vehicle Fast Charging Stations and the Revenue from the Electric Vehicle Fast Charging Tariff.
Issue: Approval of an EV charging tariff for utility-owned public EV chargers.

Oklahoma Corporation Commission Cause No. PUD 2023000038: In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Preapproval of New Generation Capacity Pursuant to 17 O.S. Section 286(C).
Issue: Approval to construct two CT units and recovery of costs through a rider.

State Corporation Commission of the State of Kansas Docket No. 23-EKCE-775-RTS: In the Matter of the Joint Application of Evergy Kansas Central, In., Evergy Kansas South, Inc., and Evergy Metro, Inc. for Approval to Make Certain Changes in their Charges for Electric Service.
Issue: General rate case.

Michigan Public Service Commission Case No. U-21389: In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.
Issue: General rate case.

Public Service Commission of Wyoming Docket No. 20000-633-ER-23 (Record No. 17252): In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $140.2 Million Per Year or 21.6 Percent and to Revise the Energy Cost Adjustment Mechanism.
Issue: General Rate Case.

Public Utility Commission of Texas Docket No. 54634, SOAH Docket No. 473-23-14020: Application of Southwestern Public Service Company for Authority to Change Rates.
Issue: General Rate Case.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2023-00002: Application of Appalachian Power Company for a 2023 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia.
Issue: Triennial review of rates.

Michigan Public Service Commission Case No. U-21297: In the matter of the Application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
Issue: General rate case.

Indiana Utility Regulatory Commission Cause No. 45816: Investigation of the Indiana Utility Regulatory Commission Regarding the Public Utility Regulatory Policies Act Section 111(d) Standards as Amended by the Infrastructure Investment and Jobs Act.
Issue: Electric vehicle charging programs and tariffs.

Illinois Commerce Commission Docket No. 23-0055: Commonwealth Edison Company Petition for Approval of a Multi-Year Rate Plan under Section 16-108.18 of the Public Utilities Act.
Issue: Multi-Year Rate Plan rate case.

Illinois Commerce Commission Docket No. 23-0082: Ameren Illinois Company d/b/a Ameren Illinois Petition for Approval of a Multi-Year Rate Plan pursuant to 220 ILCS 5/16-108.18.
Issue: Multi-Year Rate Plan rate case.

Illinois Commerce Commission Docket No. 23-0067: Ameren Illinois Company d/b/a Ameren Illinois Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service. (Tariff filed January 6, 2023).
Issue: Gas general rate case.

Illinois Commerce Commission Docket No. 23-0066: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service. (Tariff filed January 3, 2023).
Issue: Gas general rate case.

Indiana Utility Regulatory Commission Cause No. 45843: Verified Petition of Indianapolis Power & Light Company d/b/a AES Indiana for Commission Approval of an Electric Vehicle Portfolio, Including: (1) A Public Use Electric Vehicle Pilot Program Pursuant to Ind. Code Ch. 8-1-43; and (2) Time-Varying and Other Alternative Pricing Structures and Tariffs Pursuant to Ind. Code §8-1-2.5-6(3); and for Approval of Associated Accounting and Ratemaking.
Issue: Electric vehicle charging programs and tariffs.

Arkansas Public Service Commission Docket No. 22-065-U: In the Matter of the Application of Southwestern Electric Power Company for a Certificate of Public Convenience and Necessity to Operate the John W. Turk, Jr. Power Plant to Supply a Public Service to its Arkansas Customers and for Approval of a Generation Cost Recovery Rider to Recover its Costs in Arkansas Rates.
Issue: Cost recovery from customers of an existing generation resource.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2022-00166: Petition of Appalachian Power Company for consideration of the appropriate framework for cost recovery, the allocation of costs net of benefits pursuant to Code § 56-585.5 F, and class and jurisdictional cost allocation.
Issue: Recovery methodology and cost allocation of VCEA-related costs.

Oklahoma Corporation Commission Cause No. PUD 202200093: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma and to Approve a Formula Base Rate Proposal.
Issue: General rate case.

Oklahoma Corporation Commission Cause No. PUD 202200121: Application of Public Service Company of Oklahoma (PSO) for Approval of the Cost Recovery of the Selected Wind and Solar Facilities (Renewable Resources); a Determination there is a Need for the Renewable Resources; Approval for Cost Recovery of Prudent Costs Incurred by PSO for the Renewable Resources; Approval of a Temporary Cost Recovery Rider; Approval of Certain Treatment of Federal Production Tax Credits; and Such Other Relief the Commission Deems PSO is Entitled.
Issue: Acquisition of renewable generation and recovery through a rider.

Arkansas Public Service Commission Docket No. 22-061-U: In the Matter of an Application into Potential Cost Shifting Associated with Net Metering.
Issue: Net metering tariff and any potential cost shifting between participating and non-participating customers.

2022

Commonwealth of Virginia State Corporation Commission Case No. PUR-2022-00124: Petition of Virginia Electric and Power Company for approval of its 2022 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests.
Issue: Approval of 2022 RPS Plan, new renewable projects, PPAs, and cost recovery mechanism, Rider CE, pursuant to the VCEA.

Public Service Commission of South Carolina Docket No. 2022-254-E: In re: Application of Duke Energy Progress, LLC for Increase in Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and Request for an Accounting Order.
Issue: General rate case.

Public Utility Commission of Texas Docket No. 53719, SOAH Docket No. 473-22-04394: Application of Entergy Texas, Inc. for Authority to Change Rates.
Issue: General rate case.

Louisiana Public Service Commission Docket No. U-36350: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and Related Relief
Issue: Recovery costs related to Hurricane Ida.

Illinois Commerce Commission Docket No. 22-0432 and 22-0442 (cons.): Commonwealth Edison Company Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX and Illinois Commerce Commission on its own Motion vs. Commonwealth Edison Company Investigation into Commonwealth Edison Company's Beneficial Electrification Plan Filing pursuant to 20 ILCS 627/45
Issue: Approval of Beneficial Electrification Plan.

Illinois Commerce Commission Docket No. 22-0431 and 22-0443 (cons.): Ameren Illinois Company d/b/a Ameren Illinois Petition for Approval of Beneficial Electrification Plan pursuant to Section 45 of the Electric Vehicle Act and Illinois Commerce Commission on its own Motion vs. Ameren Illinois Company d/b/a Ameren Illinois Investigation into Ameren Illinois Company's Beneficial Electrification Plan Filing pursuant to 20 ILCS 627/45
Issue: Approval of Beneficial Electrification Plan.

Florida Public Service Commission Docket No. 20220010-EI: In re: Storm protection plan cost recovery clause
Issue: Seeking approval of the cost allocation and recovery methodologies used for storm protection plan cost recovery clause.

Michigan Public Service Commission Case No. U-21224: In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.
Issue: General rate case.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2021-00156: *Ex Parte*: Establishing a proceeding concerning the allocation of RPS-related costs and the determination of certain proxy values for Virginia Electric and Power Company.
Issue: Allocation methodology for VCEA-related costs and benefits.

Michigan Public Service Commission Case No. U-20836: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
Issue: General rate case.

Oklahoma Corporation Commission Cause No. PUD 202100164: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.
Issue: General Rate Case.

Louisiana Public Service Commission Docket No. U-36190: Application of Entergy Louisiana, LLC for Certification and Approval of the 2021 Solar Portfolio, Rider Geaux Green Option, Cost Recovery and Related Relief.
Issue: Approval of a voluntary renewable program backed by utility-owned solar assets.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2021-00135: Petition of Appalachian Power Company For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests.
Issue: Seeking approval of RPS Plan and recovery mechanisms for related costs.

Commonwealth of Kentucky Public Service Commission Case No. 2021-00481: Electronic Joint Application of American Electric Power Company, Inc., Kentucky Power Company and Liberty Utilities Co. for Approval of the Transfer of Ownership and Control of Kentucky Power Company.
Issue: Acquisition of Kentucky Power Company by Liberty Utilities Company.

Public Utility Commission of Texas Docket No. 52451, SOAH Docket No. 473-22-0816: Application of Southwestern Public Service Company for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fee.
Issue: Approval to implement AMS and recover costs through an additional surcharge.

Arkansas Public Service Commission Docket No. 21-070-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.
Issue: General rate case.

Arkansas Public Service Commission Docket No. 21-087-U: In the Matter of Oklahoma Gas and Electric Company's Request to Extend its Formula Rate Plan Rider.
Issue: Seeking extension of formula rate plan.

2021

Louisiana Public Service Commission Docket No. U-36105: Application for Certification to Deploy Natural Gas-Fired Distributed Generation and Authorization to Implement Rider UODG.
Issue: Approval to implement a distributed generation program and rider recovery.

Public Utility Commission of Texas Docket No. 52389, SOAH Docket No. 473-22-0009: Application of Southwestern Electric Power Company for Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees.
Issue: Approval to implement AMS and recover costs through an additional surcharge.

Louisiana Public Service Commission Docket No. U-35991: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricanes Laura, Delta, Zeta and Winter Storm Uri and for Related Relief.
Issue: Securitization of system restoration costs due to extreme weather conditions.

Oklahoma Corporation Commission Cause No. PUD 202100076: Application of Public Service Company of Oklahoma ("PSO") for Approval of a Financing Order for the Collection of Increased Costs Caused by the Extreme Winter Weather and Contained in the Regulatory Asset Authorized by Order 717625, Including an Appropriate Carrying Cost, and Such Other Relief as the Commission Deems PSO is Entitled.
Issue: Securitization of excessive fuel costs due to extreme weather conditions.

Colorado Public Utilities Commission Proceeding No. 21A-0141E: In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan.
Issue: Seeking approval of utility's plan to meet legislative renewable and carbon reduction goals.

Arkansas Public Service Commission Docket No. 21-054-TF: In the Matter of the Application of Entergy Arkansas, LLC for a Proposed Tariff Revision Regarding a Green Promise Tariff.
Issue: Seeking approval for a voluntary renewable energy tariff.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2021-00058: Application of Virginia Electric and Power Company for a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia.
Issue: General Rate Case.

Public Utility Commission of Texas Docket No. 52040, SOAH Docket No. 473-21-2607: Application of El Paso Electric Company for Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees.
Issue: Approval to implement AMS and recover costs through an additional surcharge.

Oklahoma Corporation Commission Cause No. PUD 202100072: In the Matter of the Application of Oklahoma Gas and Electric Company for a Financing Order Pursuant to the February 2021 Regulated Utility Consumer Protection Act Approving Securitization of Costs Arising from the Winter Weather Event of February 2021.
Issue: Securitization of excessive fuel costs due to extreme weather conditions.

Public Utility Commission of Texas Docket No. 51802, SOAH Docket No. 473-21-1892: Application of Southwestern Public Service Company for Authority to Change Rates.
Issue: General rate case.

Oklahoma Corporation Commission Cause No. PUD 202100055: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.
Issue: General rate case.

Louisiana Public Service Commission Docket No. U-35441: Application of Southwestern Power Company (SWEPCO) for Approval of a Change in Rates, Extension of Formula Rate Plan and Other Related Relief.
Issue: General rate case and extension of formula rate plan.

Michigan Public Service Commission Case No. U-20963: In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.
Issue: General rate case.

Florida Public Service Commission Docket No. 20210010-EI: In re: Storm protection plan cost recovery clause
Issue: Seeking approval of the cost allocation and recovery methodologies used for storm protection plan cost recovery clause.

Arkansas Public Service Commission Docket No. 19-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.
Issue: Seeking approval for amortization period and carrying costs for extraordinary fuel costs related to Winter Storm Uri.

Public Utility Regulatory Authority of Connecticut Docket No. 17-12-03RE11: PURA Investigation into Distribution System Planning of the Electric Distribution Companies – New Rate Designs and Rates Review.
Issue: Investigation into low-income rates and economic development rates.

Public Utility Commission of Texas Docket No. 51415, SOAH Docket No. 473-21-0538: Application of Southwestern Electric Power Company for Authority to Change Rates.
Issue: General rate case.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2020-00170: Petition of Virginia Electric and Power Company for approval of a rate adjustment clause, designated Rider RPS, under § 56-585.1 A 5 d of the Code of Virginia.
Issue: Seeking approval of a Rider RPS to recover costs associated with REC purchases made to comply with the Virginia Clean Economy Act.

Commonwealth of Kentucky Public Service Commission Case No. 2020-00350: Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit.
Issue: General rate case.

Commonwealth of Kentucky Public Service Commission Case No. 2020-00349: Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit.
Issue: General rate case.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2020-00164: *Ex Parte*: Allocating RPS costs to certain customers of Virginia Electric and Power Company.
Issue: Determining which costs and benefits of Virginia Clean Economy Act-related assets should be allocated to non-utility customers and seeking approval of a Rider NBC to recover/credit some of those costs and/or benefits.

Oklahoma Corporation Commission Cause No. PUD 202000097: Application of Public Service Company of Oklahoma ("PSO") for Approval of the Cost Recovery of Facilities to be Located at Ft. Sill; a Determination there is a Need for the Facilities; Approval for Future Inclusion in Base Rates for Cost Recovery of Prudent Costs Incurred by PSO for the Facilities; Approval of a Temporary Cost Recovery Rider; and Such Other Relief the Commission Deems PSO is Entitled.
Issue: Seeking approval to acquire a solar facility and gas facility sited at Fort Sill.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2020-00134: *Ex Parte*: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company.
Issue: Seeking approval of a Renewable Portfolio Standard Plan and rider pursuant to the Virginia Clean Economy Act (VCEA).

2020

Commonwealth of Virginia State Corporation Commission Case No. PUR-2020-00135: *Ex Parte*: Establishing 2020 RPS Proceeding for Appalachian Power Company.
Issue: Seeking approval of a Renewable Portfolio Standard Plan pursuant to the Virginia Clean Economy Act (VCEA).

Public Service Commission of South Carolina Docket No. 2019-209-E: In re: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to Dominion Energy South Carolina, Incorporated and S.C. Code Ann. Section 58-41-30 Related to Electrical Utilities and Their Current Voluntary Renewable Energy Program, and Such Other Proceedings Required By the Commission.
Issue: Seeking approval of a Voluntary Renewable Energy Rider.

Public Service Commission of South Carolina Docket No. 2020-125-E: In re: Application of Dominion Energy South Carolina, Incorporated for Adjustment of Rates and Charges.
Issue: General rate case.

Arkansas Public Service Commission Docket No. 16-036-FR: In the Matter of Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.
Issue: Seeking five-year extension of Formula Rate Plan.

Colorado Public Utilities Commission Proceeding No. 20A-0204E: In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021-2023 Transportation Electrification Plan.
Issue: Seeking approval of utility's plan to encourage EV adoption in its service territory.

Commonwealth of Kentucky Public Service Commission Case No. 2020-00174: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief.
Issue: General rate case.

Oklahoma Corporation Commission Cause No. PUD 202000021: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Approving a Recovery Mechanism for Expenditures Related to the Oklahoma Grid Enhancement Plan.
Issue: Seeking approval of a rider that allows for interim recovery of costs associated with expenditures made to enhance the grid.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2020-00015: Application of Appalachian Power Company For a 2020 Triennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.
Issue: General Rate Case.

Michigan Public Service Commission Case No. U-20697: In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.
Issue: General rate case.

Florida Public Service Commission Consolidated Docket Nos. 20200067-EI, 20200069-EI, 20200070-EI, 20200071-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company *et al.*
Issue: Seeking approval of Storm Protection Plans submitted by Tampa Electric Company, Duke Energy Florida, LLC, Gulf Power Company, and Florida Power & Light Company.

Arkansas Public Service Commission Docket No. 20-027-U: In the Matter of the Application of Walmart Inc. for Approval to Bid Demand Response into Wholesale Electricity Markets Through an Aggregator of Retail Customers.
Issue: Seeking approval to bid demand response into MISO through a third-party aggregator.

Public Utility Commission of Texas Docket No. 49737, SOAH Docket No. 473-19-6862: Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Acquisition of Wind Generation Facilities.
Issue: Seeking approval to acquire a wind generation facility located in Oklahoma.

Louisiana Public Service Commission Docket No. U-35324: Application of Southwestern Power Company (SWEPCO) for Certification and Approval of the Acquisition of Certain Renewable Resources in Accordance with the MBM Order and the 1983 and 1994 General Orders.
Issue: Seeking approval to acquire a wind generation facility located in Oklahoma.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2019-00201: Application of Virginia Electric and Power Company for approval of its 2019 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia.
Issue: Seek approval to implement eleven new demand-side management programs, to extend existing programs - some with updated parameters and cost/benefit results, and to continue three rate adjustment clauses.

2019
Oklahoma Corporation Commission Cause No. PUD 201900048: Application of Public Service Company of Oklahoma for Approval of the Cost Recovery of the Selected Wind Facilities; A Determination there is a Need for the SWFs; Approval for Future Inclusion in Base Rates Cost Recovery of Prudent Costs Incurred by PSO for the SWFs; Approval of a Temporary Cost Recovery Rider; Approval of Certain Accounting Procedures Regarding Federal Production Tax Credits; and Such Other Relief the Commission Deems PSO in Entitled.
Issue: Seeking approval to acquire a wind generation facility located in Oklahoma and Wind Facility Asset Rider.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2019-00094: Application of Virginia Electric and Power Company for Approval of a 100 Percent Renewable Energy Tariff, Designated Rider TRG, Pursuant to §§ 56-577 A 5 and 56-234 of the Code of Virginia.
Issue: Seek approval of a 100 percent renewable energy tariff.

Public Service Commission of South Carolina Docket No. 2019-239-E: In re: Dominion Energy South Carolina, Incorporated's Request for Approval of an Expanded Portfolio of Demand Side Management Programs, and a Modified Demand Side Management Rate Rider.
Issue: Seeking approval of an expanded Demand Side Management Plan and modified Demand Side Management Rate Rider.

Arkansas Public Service Commission Docket No. 19-035-U: In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire Wind Generating Facilities Pursuant to the Arkansas Clean Energy Development Act.
Issue: Seeking approval to acquire a wind generation facility located in Oklahoma and Wind Facility Asset Rider.

Commonwealth of Virginia State Corporation Commission Case No. PUR-2019-00154: Petition of Virginia Electric and Power Company for approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and condition applicable to electric service.
Issue: Seeking approval of certain expenditures relating to grid improvement and grid hardening.

COMMISSION DOCKETS (Appearing as Attorney of Record)
2019
Public Utility Commission of Texas Docket No. 49421: Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates.
Issue: General rate case

Public Utility Commission of Texas Docket No. 49494: Application of AEP Texas Inc. for Authority to Change Rates.
Issue: General rate case

Public Utility Commission of Colorado Docket No. 19AL-0268E: In the Matter of Advice Letter No. 1797 Filed by Public Service Company of Colorado to Reset the Currently Effective General Rate Schedule Adjustment ("GRSA") as Applied to Base Rates for all Electric Rate Schedules as well as Implement a Base Rate kWh Charge, General Rate Schedule Adjustment-Energy ("GRSA-E") to Become Effective June 20, 2019.
Issue: General rate case, Phase I

2018
Public Utility Commission of Texas Docket No. 48371: Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates.
Issue: General rate case

Public Utility Commission of Colorado Docket No. 18M-0074EG: In the Matter of the Commission's Consideration of the Impact of the Federal Tax Cuts and Jobs Act of 2017 on the Rates of Colorado Investor-Owned Electric and Natural Gas Utilities.
Issue: Commenced by the Commission to consider the impacts of the Tax Cut and Jobs Act of 2017 on the revenue requirements and rates of all Colorado investor-owned electric and natural gas utilities.

2017

Public Utility Commission of Texas Docket No. 47461: Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Wind Catcher Energy Connection Project in Oklahoma.
Issue: Purchase of a wind generation facility and generation tie line.

Public Utility Commission of Texas Docket No. 47527: Application of Southwestern Public Service Company for Authority to Change Rates.
Issue: General rate case

Public Utility Commission of Colorado Docket No. 17A-0462EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its Electric and Gas Demand-Side Management Plan.
Issue: Seek Commission re-examination and approval of the overall objectives and structure of Public Service's DSM initiatives to guide the Company in designing future DSM plans.

Public Utility Commission of Colorado Docket No. 17AL-0649E: In the Matter of Advice Letter No. 1748-Electric Filed by Public Service Company of Colorado to Revise its PUC No. 8-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective on Thirty Days' Notice.
Issue: General rate case, Phase I

Arkansas Public Service Commission Docket No. 17-038-U: In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line.
Issue: Purchase of a wind generation facility and generation tie line.

Louisiana Public Service Commission Docket No. U-34619: Application for Expedited Certification and Approval of the Acquisition of Certain Renewable Resources and the Construction of a Generation Tie Pursuant to the 1983 and/or 1994 General Orders.
Issue: Purchase of a wind generation facility and generation tie line.

2016

Public Utility Commission of Colorado Docket No. 16AL-0048E: In the Matter of Advice Letter No. 1712-Electric Filed by Public Service Company of Colorado to Replace Colorado PUC No. 7-Electric Tariff with Colorado PUC No. 8-Electric Tariff.
Issue: General rate case, Phase II

Public Utility Commission of Colorado Docket No. 16A-0055E: In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program.
Issue: Implement a voluntary solar program offering participating customers the ability to offset their current supply of energy from the Public Service system with solar energy produced at a dedicated facility or facilities.

New Mexico Public Regulation Commission Docket No. 16-00276-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 533.
Issue: General rate case

INDUSTRY TRAINING

- 2020 Practical Regulatory Training for the Electric Industry, Center for Public Utilities, New Mexico State University College of Business
- 2020 IPU Accounting and Ratemaking Course, Michigan State University
- 2016 and 2022 Western NARUC Utility Rate School
- EUCI Courses on the utility industry, cost allocation, and rate design.

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's 2023	**)**	**Docket No. 55378**
Integrated Resource Plan Update	**)**	

CERTIFICATE OF SERVICE

I do hereby certify that I have served the following parties with the foregoing **DIRECT TESTIMONY AND EXHIBIT OF LISA V. PERRY OF WALMART INC.** via electronic mail as follows:

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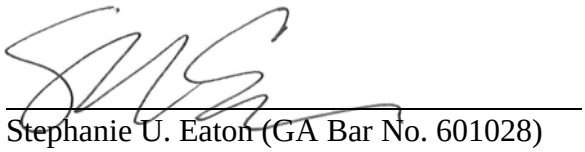

Stephanie U. Eaton (GA Bar No. 601028)

Dated: February 15, 2024

BY MS. EATON:

Q Did you also cause to be prepared and filed in this docket, one exhibit to your prefiled direct testimony identified as LVP-1?

A Yes, I did.

Q Do you have any additions, updates, or corrections to LVP-1 to your prefiled direct testimony?

A No, I do not.

MS. EATON: Commissioners, we've provided the court reporter with an updated copy of Ms. Perry's direct exhibit. And that was marked as Walmart 1, and I would ask that that be marked as the next hearing exhibit.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as Walmart Exhibits LVP-1 and LVP-2.)

BY MS. EATON:

Q Ms. Perry, have you prepared a summary of your prefiled testimony?

A Yes, I have.

Q Would you please read the summary to the Commission and the parties and counsel?

A Good morning, Commissioners -- or good morning.

COMMISSIONER JOHNSON: It's a long morning.

A Good afternoon on a Friday, being the last

witness.

The focus of my testimony is on three programs the company is proposing in Docket 55378, including the two distributed energy resources programs, DER co-location program and the DER customer-owned program. And a new demand response program, the Curtailable Load Program, along with additional opportunities for customers like Walmart to provide resources to the company that can help manage the anticipated additional load growth.

Walmart has 213 super centers, Neighborhood Markets and Sam's Clubs, plus ten distribution centers and three fulfillment centers in Georgia. Within Georgia Power's service territory, there are 125 facilities, three distribution centers and one fulfillment center. Collectively, Walmart's facilities currently purchase approximately 475-million-kilowatt hours annually from the company.

Like other businesses, Walmart has sustainability goals that include being powered 100 percent by clean energy by 2035, and zero carbon emissions in its operations by 2040.

In addition to its sustainability goals, Walmart recently announced, in January of this year, that it plans to bring its own resources on-line, including

one gigawatt of new on-site solar and two gigawatts of new community solar projects.

In addition to its own resources, Walmart relies on its utility partners like Georgia Power to meet its sustainability goals through utility scale renewable programs such as the company's renewable energy development initiative, along with other types of programs such as demand response programs to which Walmart is compensated to reduce its demand during critical times.

In addition to needing clean energy, Walmart also anticipates significantly increasing its load across the U.S. and in Georgia through electrification of its buildings, installing automated equipment, providing thousands of public EV chargers over the next several years and de-carbonizing its fleet.

In short, Walmart is asking its utility partners to provide substantially more electricity while keeping the electricity reliable, affordable, and increasingly clean. To accomplish these needs, Walmart sees interested customers as being an integral part in navigating this energy transition by using economies of scales and available customer resources to provide customer-based solutions that can help Georgia Power meet its increasing load through solutions that can, one,

reduce the need to build new generation assets; and, two, to provide a more diverse pool of cleaner resources for when additional generation capacity is needed.

Specifically, on the supply side, Walmart is interested in working with the company to explore ways that Walmart can help the company bring cleaner, cost-effective resources to its mix through technologies like community solar and energy storage.

Additionally, to enhance reliability, Walmart supports the company's proposed DER programs as a way to provide additional capacity to the grid.

On the demand side, Walmart is interested in continuing to work with Georgia Power to build upon its existing and proposed demand response programs to ensure that the company is offering a robust suite of programs that are attractive to a large number of diverse customers.

To that end, Walmart's recommendation to the Commission is to direct Georgia Power to work with interested stakeholders, to continue its efforts towards finding solutions that leverage customer resources in a way that can help maintain reliability as load continues to grow while keeping the power it provides to its customers affordable and increasingly clean. Walmart also recommends that the company seek the Commission's

approval of these programs in its next 2025 IRP filing.

Thank you.

MS. EATON: Mr. Chairman, Ms. Perry is available for cross-examination by the Commission and by the parties. Thank you.

CHAIRMAN SHAW: Commissioners, any questions?

COMMISSIONER PRIDEMORE: I have one. It is more clarification.

Do you have -- you can go.

VICE CHAIRMAN ECHOLS: I have one. Is Walmart considering building SMRs behind the meter at any facility now or in the future that you talked about? I will remind you, you are under oath. No, just teasing.

MS. PERRY: You know, honestly -- we are looking for cleaner forms of energy. And we are -- our goal is to be technology neutral. I don't know that we have discussed SMRs in particular. I think -- I don't know that we have a single site facility that would need something quite that powerful, to be honest with you.

But, like I said, you know, everything is on the table; and I think as technology continues to evolve and emerge, you know, we will certainly consider, you know, nuclear and what other

technology may come in the future.

VICE CHAIRMAN ECHOLS: The new scale units are 50 megawatts, so they are --

MS. PERRY: I am sorry. What?

VICE CHAIRMAN ECHOLS: They are 50 megawatts; they are not giant.

MS. PERRY: Okay. Thank you.

VICE CHAIRMAN ECHOLS: Thank you so much for coming down.

CHAIRMAN SHAW: Commissioner?

COMMISSIONER PRIDEMORE: Hi, there. I just want to clarify. Towards the bottom of page 9 of your testimony, you have a DER one recommendation. The next page, DER two. When you are talking about these DERs, are you talking about gas DERs?

MS. PERRY: So we use both a combination of gas and diesel.

COMMISSIONER PRIDEMORE: Okay. And I -- for what it's worth, I agree with you at the bottom of page 10, about the Louisiana program on DERs. It's a good program. Thank you.

CHAIRMAN SHAW: All right. Any other questions?

(No response.)

CHAIRMAN SHAW: All right. We will move

forward with cross.

Georgia Public Service Commission.

MR. THOMAS: No questions.

CHAIRMAN SHAW: Advanced Power Alliance.

(No response.)

CHAIRMAN SHAW: Clean Energy Buyers Association?

MR. DUNBAR: No questions.

CHAIRMAN SHAW: Heelstone.

MR. GALLOWAY: No questions.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

(No response.)

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

(No response.)

COMMISSIONER JOHNSON: Georgia Interfaith Power & Light.

MR. SHERRIER: No questions.

CHAIRMAN SHAW: Georgia Solar Energy Association.

(No response.)

CHAIRMAN SHAW: Georgia WAND.

MS. SCOTT: No questions.

CHAIRMAN SHAW: Georgia Watch.

(No response.)

CHAIRMAN SHAW: MARTA.

MS. STURM: No questions.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: No questions.

CHAIRMAN SHAW: Sierra Club.

MR. FABISH: No questions.

CHAIRMAN SHAW: SACE.

MR. JACOB: No questions.

CHAIRMAN SHAW: Southern Renewable Energy.

MR. COX: No questions.

CHAIRMAN SHAW: Department of Defense.

MR. MCNUTT: No questions.

CHAIRMAN SHAW: Georgia Power.

CROSS-EXAMINATION

BY MS. PRYOR:

Q Good afternoon, Ms. Perry. Allison Pryor for Georgia Power.

A Good afternoon.

Q You are aware that Georgia Power has regularly

worked with Walmart in the past regarding the company's C&I programs; is that right?

A Yes.

Q And if the company were willing to commit to meet with Walmart in advance of the '25 IRP to discuss the expansion or the creation of additional C&I customer programs, would that alleviate the concerns in this case for you?

A It would alleviate the concerns specific to Walmart, yes.

Q Okay, great. Thank you. No further questions.

CHAIRMAN SHAW: Any redirect?

MS. EATON: No, thank you, not needed. We would request that Walmart 1 be entered into the record.

CHAIRMAN SHAW: So marked.

Walmart Exhibit LVP-1 and 2 was admitted into evidence.)

MS. EATON: And we would request that Ms. Perry be excused.

CHAIRMAN SHAW: Ms. Perry, thank you for being here. You can be excused.

MS. PERRY: Thank you.

MS. EATON: Thank you very much for having us in the docket.

CHAIRMAN SHAW: Thank you. Thanks for all that Walmart does for Georgia.

Well, y'all, as we conclude, any housekeeping matters to take up before we adjourn?

MR. HEWITSON: Yes, Mr. Chair. I'd just ask that Georgia Power Exhibits 10 through 14 be moved into the record. I just wanted to wait until after the witnesses to get them all in at once.

CHAIRMAN SHAW: So marked.

(Georgia Power Company Exhibits 10 through 14 were admitted into evidence.)

CHAIRMAN SHAW: Any other housekeeping matters to take up?

MS. SCOTT: Mr. Chairman, I wanted Ms. Durand's testimony to be moved into the record.

CHAIRMAN SHAW: Okay. Yes, ma'am, Ms. Scott. So marked.

(Whereupon, the prefiled direct testimony of Patty Durand was previously inserted into the record:)

CHAIRMAN SHAW: Anything else?

MR. THOMAS: I think that to the extent that any of our exhibits weren't moved into the record...

CHAIRMAN SHAW: I will ask the court reporter

at this time to make all exhibits a part of the record. So --

Before we conclude, though, and on behalf of the Commission and the Commissioners and our staff, just want to thank everyone for taking part in this very important proceeding. Thank you for your patience with us. And thank you for sticking with us late last night so that we could get out of here at a decent hour on a Friday. So we wish everyone safe travels and have a good weekend. Thank you again.

That concludes this hearing. Until the next round, we are adjourned.

(Hearing was concluded at 3:03 p.m.)

C E R T I F I C A T E

We, Kelley M. Nadotti and Debbie Eickhoff, Certified Court Reporters, 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.

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5090-9084-2699-3664