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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION
STATE OF GEORGIA

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

Hearing Room 110
244 Washington Street
Atlanta, Georgia
Wednesday, March 27, 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
LAUREN "BUBBA" MCDONALD, Commissioner
TRICIA PRIDEMORE, Commissioner

ATHENS REPORTING, LLC
490 N. Thomas Street
Athens, Georgia 30601
(770) 225-7663
www.athensreporting.com

1 **APPEARANCES:**

2 On behalf of Georgia Public Service
3 Commission:

4 PRESTON THOMAS, ESQUIRE
5 GINNY DAVIS, ESQUIRE
6 Georgia Public Service Commission
7 244 Washington Street
8 Atlanta, Georgia 30334

9 On behalf of Georgia Power Company:

10 STEVEN HEWITSON, ESQUIRE
11 BRANDON MARZO, ESQUIRE
12 ALLISON PRYOR, ESQUIRE
13 Troutman Sanders
14 600 Peachtree Street
15 Suite 5200
16 Atlanta, Georgia 30308-2261

17 On behalf of Advanced Power Alliance:

18 WILLIAM BRADLEY CARVER, SR., ESQUIRE
19 Hall Booth Smith, P.C.
20 191 Peachtree Street, NE
21 Suite 2900
22 Atlanta, Georgia 30303

23 On behalf of Clean Energy Buyers Association:

24 SCOTT DUNBAR, ESQUIRE
25 Keyes & Fox, LLP
26 1580 Lincoln Street
27 Suite 1105
28 Denver, Colorado 80203

29 On behalf of Heelstone Renewable Energy, LLC:

30 NEWTON M. GALLOWAY, ESQUIRE
31 TERRI M. LYNDALL, ESQUIRE
32 DAVID E. PENLAND, ESQUIRE
33 Galloway & Lyndall, LLP
34 406 North Hill Street
35 Griffin, Georgia 30223

1 **APPEARANCES (continued):**

2 **On behalf of Georgia Association of**
3 **Manufacturers:**

4 **CHARLES B. JONES, III, ESQUIRE**
5 **Georgia Association of**
6 **Manufacturers**
7 **50 Hurt Plaza**
8 **Suite 985**
9 **Atlanta, Georgia 30303**
10 **-and-**
11 **LLOYD AVRAM**
12 **JEFFRY POLLOCK**

13 **On behalf of Georgia Center for Energy**
14 **Solutions:**

15 **PETER HUBBARD**
16 **Georgia Center for Energy Solutions**
17 **55 Leslie Street SE**
18 **Atlanta, Georgia 30317**

19 **On behalf of Georgia Coalition of Local**
20 **Governments:**

21 **ALICIA BROWN**
22 **City of Savannah, Office of**
23 **Sustainability**
24 **801 E. Gwinnett Street**
25 **Savannah, Georgia 31401**

26 **On behalf of Georgia Interfaith Power &**
27 **Light and Partnership for Southern Equity:**

28 **JENNIFER WHITFIELD, ESQUIRE**
29 **BOB SHERRIER, ESQUIRE**
30 **Southern Environmental Law Center**
31 **Ten 10th Street**
32 **Suite 1050**
33 **Atlanta, Georgia 30309**

1 APPEARANCES (continued):

2 On behalf of Georgia Solar Energy
3 Association:
4 DONALD MORELAND
5 Georgia Solar Energy Association
6 1199 Euclid Avenue
7 Atlanta, GA 30307

8 On behalf of Georgia WAND Education Fund,
9 Inc:

10 KIMBERLY SCOTT
11 250 Georgia Avenue
12 Suite 202
13 Atlanta, GA 30312

14 On behalf of Georgia Watch:

15 LIZ COYLE - Executive Director
16 55 Marietta St NW
17 Atlanta, Georgia 30303's

18 On behalf of Metropolitan Atlanta Rapid
19 Transit:

20 KIMBERLY "KASEY" A. STURM, ESQUIRE
21 Weissman
22 One Alliance Center, 4th Floor
23 3500 Lenox Road
24 Atlanta, Georgia 30326

25 -and-

PETER ANDREWS

On behalf of Microsoft Corporation:

21 CRAIG DOWDY, ESQUIRE
22 Taylor English Duma LLP
23 1600 Parkwood Circle
24 Suite 200
25 Atlanta, GA 30339

1 **APPEARANCES (continued):**

2 **On behalf of Resource Supply Management:**

3 JIM CLARKSON
4 Resource Supply Management
5 135 Emerald Lake Road
6 Columbia, SC 29209

7 -and-

8 ROBERT B. BAKER, ESQUIRE
9 Robert B. Baker, PC
10 2480 Briarcliff Road, NE
11 Suite 6
12 Atlanta, Georgia 30329

13 **On behalf of Sierra Club:**

14 ZACHARY FABISH, ESQUIRE
15 CURT THOMPSON, ESQUIRE
16 Sierra Club
17 50 F. Street NW, 8th Floor
18 Washington, D.C. 20001

19 **On behalf of Southern Alliance for Clean
20 Energy, Inc.:**

21 BRYAN JACOB
22 Southern Alliance for Clean Energy
23 1455 Hampton Hill Drive
24 Alpharetta, Georgia 30022

25 **On behalf of Southern Renewable Energy
Association:**

 SIMON MAHAN
 WHIT COX
 Southern Renewable Energy
 Association
 11610 Pleasant Ridge Road
 Suite 103 #176
 Little Rock, Arkansas 72223

1 **APPEARANCES (continued):**

2 On behalf of The United States Department of
3 Defense and All Other Federal Executive
 Agencies:

4 JOHN JOSEPH McNUTT, ESQUIRE
5 Regulatory Law Counsel General
6 U.S. Army Legal Services Agency
 Office of The Judge Advocate
 General

7 9275 Gunston Road
8 Suite 4300
 Fort Belvoir, VA 22060-4446.

9

10 On behalf of Walmart:

11 STEPHANIE U. EATON, ESQUIRE
12 CARRIE H. GRUNDMANN, ESQUIRE
13 STEVEN W. LEE, ESQUIRE
 Spilman Thomas & Battle, PLLC
14 110 Oakwood Drive
 Suite 500
 Winston-Salem, NC 27103

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P R O C E E D I N G S

CHAIRMAN SHAW: All right. Good morning, everyone. Thanks for making it down here on a rainy day in Georgia. I'm glad to see a packed room.

This is Docket No. 55378: Georgia Power Company's 2023 Integrated Resource Plan Update.

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. HEWISTON: Good morning. Steve Hewitson, Brandon Marzo, Allison Pryor on behalf of Georgia Power Company.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. CARVER: Brad Carver on behalf of the Advanced Power Alliance.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: Good morning, Mr. Chairman. Scott Dunbar on behalf of Clean Energy Buyers Association.

CHAIRMAN SHAW: Heelstone Renewable Energy.

1 MR. PENLAND: Good morning, Mr. Chairman.
2 David Penland, Newton Galloway and Terri Lyndall on
3 behalf of Heelstone Renewable Energy.

4 CHAIRMAN SHAW: Georgia Association of
5 Manufacturers.

6 MR. JONES: Clay Jones on behalf of GAM,
7 Mr. Chairman.

8 CHAIRMAN SHAW: Georgia Center for Energy
9 Solutions.

10 Georgia Center for Energy Solutions.

11 (No response.)

12 CHAIRMAN SHAW: Georgia Coalition of Local
13 Governments.

14 MS. BROWN: Good morning. Alicia Brown on
15 behalf of the Coalition.

16 CHAIRMAN SHAW: Georgia Interfaith Power &
17 Light.

18 MR. SHERRIER: Good morning, Mr. Chairman,
19 Commissioners. Bob Sherrier and Jennifer Whitfield
20 on behalf of Georgia Interfaith Power & Light.

21 And we have a request to make at the
22 appropriate time.

23 CHAIRMAN SHAW: Okay. I'll call on you at
24 the appropriate time.

25 Georgia Solar Energy Association.

1 Georgia Solar Energy Association.

2 (No response.)

3 CHAIRMAN SHAW: Georgia WAND Education Fund.

4 Georgia WAND Education fund.

5 (No response.)

6 CHAIRMAN SHAW: Georgia Watch.

7 Georgia Watch.

8 (No response.)

9 CHAIRMAN SHAW: Metropolitan Atlanta Rapid

10 Transit Authority.

11 MS. STURM: Good morning, Commissioners.

12 Kasey Sturm on behalf of MARTA.

13 CHAIRMAN SHAW: Microsoft Corporation.

14 MR. DOWDY: Good morning, Mr. Chairman and

15 Commissioners. Craig Dowdy on behalf of Microsoft.

16 CHAIRMAN SHAW: Resource Supply Management.

17 MR. BAKER: Good morning, Mr. Chairman.

18 Robert Baker on behalf of RSM.

19 CHAIRMAN SHAW: Sierra Club.

20 MR. FABISH: Good morning. Zach Fabish and

21 Curt Thompson on behalf of Sierra Club.

22 CHAIRMAN SHAW: Southern Alliance for Clean

23 Energy.

24 MR. JACOB: Bryan Jacob on behalf of Southern

25 Alliance for Clean Energy.

1 CHAIRMAN SHAW: Southern Renewable Energy
2 Association.

3 MR. COX: Good morning. Whit Cox and Simon
4 Mahan on behalf of Southern Renewable Energy
5 Association.

6 CHAIRMAN SHAW: United States Department of
7 Defense and All Other Federal Executive Agencies.

8 MR. McNUTT: Good morning, Mr. Chairman.
9 John McNutt on behalf of the DoD.

10 CHAIRMAN SHAW: Walmart.

11 MS. EATON: Good morning, Mr. Chairman.
12 Stephanie Eaton here on behalf of Walmart.

13 CHAIRMAN SHAW: Good morning.

14 All right. We'll take up housekeeping
15 matters at this time. Is there any matters to be
16 taken up?

17 Mr. Sherrier.

18 MR. SHERRIER: A few minutes ago a
19 stipulation was filed in this docket between Staff
20 and Georgia Power. And since Intervenorors have not
21 had a chance to review it, we would like to request
22 a delayed start to the proceedings today so that
23 folks have a chance to process what's in it.

24 CHAIRMAN SHAW: We're going to have -- we've
25 got approximately 12 public witnesses signed up.

1 We are going to go ahead and move forward with
2 that.

3 And I'll take that under consideration.

4 MR. SHERRIER: Thank you.

5 CHAIRMAN SHAW: All right. And -- yes, sir,
6 Mr. Carver.

7 MR. CARVER: Mr. Chairman, I have talked to
8 counsel for Georgia Power. We're going to be
9 reviewing the stipulated agreement, too, and like a
10 lot of what we're hearing, and certainly in terms
11 of going into the next IRP at the end of this -- in
12 a year.

13 As you know, the last hearing we attempted to
14 introduce the SERTP. We filed that -- the SERTP
15 study, transmission study. We filed that. We have
16 served all parties. And, again, we would like to
17 at least get a determination now whether that study
18 can be used as -- for purposes of
19 cross-examination.

20 But in light of the settlement, I think it's
21 going to be a much more, you know, friendly
22 cross-examination from that standpoint. But I just
23 want to at least get -- this is a preliminary
24 matter. So I thought I would bring it to the
25 attention of the Chair.

1 CHAIRMAN SHAW: When did you file that?

2 MR. CARVER: We filed it last night.

3 CHAIRMAN SHAW: I'm going -- I'm going to
4 take -- see if there's any other housekeeping
5 matters. And I'm going to have a conversation with
6 Mr. Bond and we'll let you know.

7 MR. CARVER: Okay. Thank you.

8 CHAIRMAN SHAW: Any other housekeeping
9 matters?

10 (No response.)

11 CHAIRMAN SHAW: All right. We'll start with
12 public witnesses.

13 First of all, I appreciate everybody for
14 coming, particularly public witnesses. I look
15 forward to hearing from you.

16 We'll start. We're going to go down the list
17 with -- and if I pronounce your name wrong, just
18 plan on saying your name when you get up to the
19 microphone in case I do mess it up.

20 Starting with John Reidelbach.

21 MR. REIDELBACH: That's a pretty good call
22 out there. You got that right.

23 CHAIRMAN SHAW: Oh, good.

24 MR. REIDELBACH: I'm John Reidelbach from
25 Coweta County.

1 CHAIRMAN SHAW: Well, thank you for having
2 good handwriting that I could read.

3 MR. REIDELBACH: Well, they told me to do it
4 that way, so...

5 So it's an honor and a privilege to address
6 you in this important topic area, the importance of
7 reliable energy. My name is John Reidelbach and
8 I'm proud to serve as the Chairman of the Coweta
9 County Board of Commissions. And I'm guessing, not
10 unlike your various paths to elected office, my
11 journey, interwoven with working in the defense
12 industry, healthcare, and community services, has
13 engrained me in the significance of building
14 resilient and sustainable and reliable energy.

15 I understand that this body is considering an
16 additional natural gas powered unit at the existing
17 Plant Yates in marked County Coweta. On behalf of
18 myself and my colleagues and other county
19 commissioners, we unanimously support this proud
20 continued legacy of hosting energy infrastructure
21 for our state. And our community will also benefit
22 both by jobs and taxes. And so we've had a very
23 good relationship with Georgia Power and we would
24 like to continue that relationship with them.

25 With over 12 years of experience working in

1 the defense industry, and subsequently moving into
2 the healthcare industry, as a consultant for the
3 past 26 years, I've witnessed firsthand how
4 critical reliable energy is to our national
5 security, our health services systems, and our
6 local businesses.

7 My wife, who's a medic with the City of Hope,
8 also understands the need of having uninterrupted
9 power. So that's a big benefit for the healthcare
10 sector.

11 My involvement in the community service is
12 notably in Coweta. I served as their Chairman for
13 the Coweta County American Red Cross, which we did
14 a lot of disaster relief, things of that nature.

15 Again, the Newnan/Coweta Boys and Girls Club
16 and then I was co-founder for the Newnan/Coweta
17 Citizens Emergency Response Team. Again, these are
18 rescue organizations or relief organizations. So
19 we understand the need to have power and a good
20 relationship with our power suppliers.

21 Timely investing in reliable energy means
22 investing in our natural security, in our
23 healthcare, education, and communities. In Coweta,
24 we stand ready to host and expand the
25 infrastructure of Plant Yates that will help

1 empower Georgia's continued quality growth.

2 Thank you all for your time today and thank
3 you so much for your service as an elected --

4 CHAIRMAN SHAW: Thank you for your service.

5 MR. REIDELBACH: Thank you.

6 CHAIRMAN SHAW: Next is Melinda Lemmon.

7 Melinda, good morning.

8 MS. LEMMON: Good morning.

9 CHAIRMAN SHAW: After her is Keaton Kramer --
10 Kramer.

11 MS. LEMMON: Good morning.

12 CHAIRMAN SHAW: Good morning.

13 MS. LEMMON: I'm the executive director of
14 the department of economic development for
15 Cartersville in Bartow County. My name is Melinda
16 Lemmon. Thank you for having me today.

17 It's been my pleasure to serve in this
18 profession for 32 years and 20 years specifically
19 in Cartersville in Bartow County. My department is
20 the primary point of contact for economic
21 development projects. And, of course, our
22 community is just 45 minutes north of here.

23 My board and our stakeholders have
24 intentionally tried to align our economic
25 development strategies with those of the state.

1 And we've seen successes together first,
2 experiencing some pressures together, too,
3 especially our utility partners, which is why I'm
4 here today.

5 I have heard people call this time frame that
6 we're in: Georgia's extraordinary economic growth
7 period. And I would agree with that. I think
8 that's our Bartow's story, as well.

9 In 2022 and '23, Bartow's story was impacted
10 by three very special stories and some expansions
11 and some other milestones. You may know some of
12 those milestones, Hyundai Motor Group SK On's joint
13 venture, which is an electric vehicle battery
14 manufacturing facility. Hanwha Qcells, Hanwha
15 Qcells USA, and Hanwha Advanced Materials Georgia,
16 which is the first -- the nation's first fully
17 integrated solar panel manufacturing campus.

18 Yakult Japanese probiotic beverage
19 manufacturer, Switch KEEP 2.0 Atlanta, which is a
20 data center project, several existing industry
21 expansions. And all of those projects since '22
22 have added or will add nearly 6,900 manufacturing
23 jobs over the next eight years. It's \$9.2 billion
24 invested over that same time frame.

25 So we're so grateful for that success. Those

1 goals that we've worked on for 20 years are being
2 accomplished.

3 Additionally, to speak to the pressures that
4 we're going to see as we implement all of this is
5 utility pressures. Of course, it's workforce
6 pressures. But here's some things to come. Also
7 during that time frame was 7.3 million square feet
8 of speculative industrial space. Those are ready
9 to go for customers to -- some have been absorbed,
10 but customers could walk in. They could be
11 high-demand utility customers at any moment.

12 And, also, as a final note on this growth
13 trajectory I'm talking about, in May of '22, the
14 family behind the Aubrey Corporation let it be
15 known that their company and the 19,500 acres that
16 belong to that company are on the market. Most of
17 those acres are in Bartow with some in Cherokee
18 after nearly a century of ownership. That was a
19 difficult decision for them to make, but it will
20 impact the growth of our community and the northern
21 portion of Metro Atlanta for awhile to come.

22 So I think that we can all agree
23 extraordinary economic growth is certainly what
24 we're experiencing, just as many others throughout
25 the state. I've witnessed 20 years of hard work

1 that have -- that deserve thanks to a lot of
2 different stakeholders for the growth that we're
3 experiencing now. But I'm also a witness to the
4 pressures of the pace and capacity that we're
5 experiencing, particularly our utility partners.

6 So I'm here today to please ask your support
7 for those utility partners through this significant
8 time in Georgia's history and beyond as we prepare
9 for the imminent growth ahead.

10 Thank you.

11 CHAIRMAN SHAW: Thank you, ma'am.

12 VICE-CHAIRMAN ECHOLS: Melinda, I wanted to
13 say on July 11th, my Clean Energy Road Show in its
14 13th year will be at the Savoy Car Museum in your
15 town.

16 MS. LEMMON: Fantastic.

17 VICE-CHAIRMAN ECHOLS: Which, of course,
18 Cartersville, the museum capital, really, of
19 Georgia.

20 MS. LEMMON: That's right.

21 VICE-CHAIRMAN ECHOLS: So that is an
22 incredible car museum and we're so excited to be
23 there. I hope you'll come out and maybe say a
24 word.

25 MS. LEMMON: Thank you.

1 VICE-CHAIRMAN ECHOLS: Great. Thank you.

2 CHAIRMAN SHAW: You probably need to warn
3 your hotels because he's like Taylor Swift. They
4 jack up the rates.

5 MS. LEMMON: Noted.

6 COMMISSIONER PRIDEMORE: I was actually going
7 to say something directed at Melinda, y'all.

8 But, Commissioner Echols, if Bartow had a
9 Mount Rushmore, your face would be on it. Thank
10 you.

11 MS. LEMMON: Wow.

12 COMMISSIONER PRIDEMORE: Along with Governor
13 Harris'. The work that you've done there, you have
14 such a -- the esteem of your community and -- so,
15 thank you.

16 MS. LEMMON: Wow. Humbled. Thank you,
17 ma'am.

18 VICE-CHAIRMAN ECHOLS: And the father of the
19 IRP process in Georgia that we're discussing here
20 was a Cartersville's legislator, Boyd Pettit, who
21 quarterbacked that. And so Cartersville definitely
22 has a big role in that, as well.

23 MS. LEMMON: Thank you so much.

24 CHAIRMAN SHAW: Thank you again.

25 Keaton Kramer.

1 Next is Bob James.

2 DR. KRAMER: Good morning, everyone.

3 CHAIRMAN SHAW: Good morning.

4 DR. KRAMER: My name is Dr. Keaton Kramer.

5 I'm a physical therapist and board-certified
6 orthopedic specialist. I work at Emory Hospital in
7 Lithonia and I live in Atlanta.

8 I come here speaking as a member of Georgia
9 Clinicians for Climate Action. And I strongly
10 oppose the IRP fossil fuel expansion. The only
11 safe energy for the health of all Georgians is
12 clean and renewable energy.

13 I see myself as a healer. I see my hospital
14 as a community of healers. I see my church as a
15 sacred group trying to mend spirits and mend souls.

16 As I was preparing this, I experienced a lot
17 of feelings. I see the yearning of my friends
18 here. I feel troubled, I feel disillusioned, I
19 feel angry, but I also feel vulnerable and often
20 helpless.

21 Dr. Jaggy, Dr. Birdsong, and all of our team,
22 here today and past meetings -- all of us really
23 know the connections: The wildfires, the methane
24 and how they cause strokes and heart attacks and
25 asthma attacks. The diesel buses poisoning our

1 children's minds. Just last night, there was a
2 tornado in Valdosta. All of this suffering.

3 Yesterday, I treated a 42-year old mother who
4 suffered a stroke. Her speech is slowed. She's
5 fallen multiple times a week and she's reduced to
6 using a walker. She has two young children. She
7 comes in for three hours of therapy and she works,
8 but she will always be a shadow of what she used to
9 be and it breaks my heart.

10 Too often I spend my hours trying to help my
11 patients crawl back from the damage that will never
12 be undone. All this striving, all of the
13 heartache, all the effort after, not before.

14 Here in this room, though, I am the patient
15 and you four are the doctor. It is before the
16 tragedy. I am desperate and you are not hearing
17 me. You are not hearing us.

18 Put down your pen and look in my eyes. See
19 my suffering. I'm asking you: Please, will you
20 help me?

21 You five -- you four here are the protectors
22 of this land. You four are the healers of this
23 land. When is the last time you felt so helpless
24 you cried?

25 I'm asking you: Please go home and pray

1 deeply about this. I'm asking you to change your
2 minds. Please help us because we need you.

3 CHAIRMAN SHAW: Thank you, sir.

4 Bob James.

5 Next is Ed Caines.

6 Good morning.

7 MR. JAMES: Good morning. Good to see you
8 again.

9 CHAIRMAN SHAW: You, too.

10 MR. JAMES: So I am a resident of Atlanta and
11 I am retired from CDC Federal Credit Union. And
12 I've spoken twice before.

13 Today I'd like to focus on the time-of-use
14 plan. I know we have some in place, but I really
15 think this is an important consideration. And I
16 appreciate what Tim has posted recently on social
17 media about virtual aspects.

18 Let me just share a little bit of what a
19 friend of mine here in Georgia said. He said: You
20 know, Minnesota does it, why can't Georgia? He
21 said: Minnesotans are so familiar it's like
22 drinking water to them. It's so engrained in their
23 everyday conversation and has been for decades.

24 Everyone in Minnesota knows that they pay for
25 electricity and when. They just assume the grid

1 operator is going to shut off certain things in
2 their house during certain times of the day and no
3 one complains. They act like they are proud of it.
4 It is truly remarkable to watch. It is so
5 non-political. It's a breath of fresh air to see.

6 So I -- I went ahead and I asked my friend
7 who lives in Minnesota. I said: Is this true?
8 How is it for you?

9 And he says: Yes. Time-of-use rate plans
10 are in place in Minnesota through Xcel Energy, peak
11 hours being between 12 p.m. to 6 p.m.

12 And, in addition, in my area anyway, one can
13 opt for energy from local solar farms. General
14 energy and solar are separate bills. The general
15 energy bill is reduced significantly by the use of
16 solar, resulting in an overall reduction in the
17 cost of energy.

18 So my hope for us is that we can improve our
19 rate -- time-of-use rate plans and promote it and
20 encourage it for the very reasons like Keaton was
21 saying. We do need to take consideration of our
22 stewardship.

23 So my question for you and Georgia Power:
24 Can we not optimize renewables in Georgia with
25 battery use, usage of time-of-use plans to increase

1 power needed during new anticipated load times?

2 I wish you the best. I realize you guys have
3 a lot to deal with. I thank you for the
4 opportunity.

5 CHAIRMAN SHAW: Thank you, sir.

6 Ed Caines.

7 Next is Mike Giles.

8 Good morning.

9 MR. CAINES: Good morning. Morning, y'all.

10 My name is Ed Caines and I'm a business
11 manager for Operating Engineers Local 926. Now,
12 this is my first time speaking before you, but I'm
13 sure you've heard from labor leaders like myself
14 time and time again.

15 You're well versed in hearing how
16 important -- important it is to have this work and
17 afford our members the opportunity to earn a decent
18 living and the dignity that that brings and the
19 transferable credits.

20 And you've probably heard it so often that
21 you can probably deliver the speech. And I'll save
22 you and the others from repeating all of that. I
23 think what I have is a unique version, a unique
24 story that I would like to share with you. I think
25 it will offer a twist to it.

1 But, first, I want to explain to those who
2 aren't informed what the operating engineer does.
3 Operating engineers are the men and women in
4 Georgia who operate the heavy machinery and bring
5 the technology that brings these buildings that we
6 see that line in the skyline out of the ground.
7 All the tower cranes that you see and all of the
8 bulldozers that move the earth. All of those are
9 operating engineers who quietly go about doing our
10 job, you know, providing the services and the
11 infrastructure to build things that everybody
12 benefits from.

13 Thousands of operating engineers in this area
14 are represented by me and others. And, you know,
15 we're proud to do what we do. Like I said, I've
16 got a unique twist on this story. And I'll get to
17 that in just a moment.

18 But I would like to share some other
19 thoughts. As you see how Georgia is growing, there
20 is an obvious need for additional energy. One of
21 my big concerns as business manager is getting
22 caught ill-prepared for the growth that we're
23 experiencing.

24 We've got data centers that are coming up.
25 And I can name a dozen without thinking of it.

1 We've got car plants. If you go along I-16 heading
2 towards Georgia, a mammoth project that's going
3 there.

4 I'd rather not have Georgia be in a position
5 where we're playing catch up, you know. This a
6 great place to work and we've got a reputation.
7 I'd just like to maintain that.

8 The short story I would like to share with
9 you is: While I was born in New York and
10 uninterrupted power is just what we expect. My
11 parents moved the family, my siblings and I, down
12 to the Virgin Islands and -- culture shock, yeah.

13 But things that you don't think about, like
14 reliable power. You know, there are times when you
15 just come to expect the power is going to go out.
16 And it's usually the most inopportune time. We
17 can't afford that here in Georgia.

18 And that's just one of the things that I
19 would like to share with you. When we're down
20 there, the water and power authority are combined.
21 They call it WAPA, Virgin Islands Water & Power
22 Authority.

23 And unreliable power is so common that
24 there's a saying down there that says: And the
25 Lord said, "Let there be light." And WAPA said,

1 "Not on a regular basis."

2 That's just the way things go. We come to
3 accept it. But we can't afford that here in
4 Georgia.

5 So, I mean, there's a lot to be said. You
6 have a heavy docket. I understand that.

7 Thanks for allowing me to share my time. And
8 I just wanted to bring a few bits of information to
9 you.

10 VICE-CHAIRMAN ECHOLS: What was that again?

11 And the Lord said, "Let there be light," and
12 what was WAPA's response?

13 MR. CAINES: Okay. So there's a heavy
14 dialect down there. And literally the way they say
15 it --

16 VICE-CHAIRMAN ECHOLS: Can you say it in the
17 Island vernacular?

18 MR. CAINES: In the Island vernacular, it
19 would be: Nutting tal go so. That loosely
20 translates to: Not hardly, not regularly. They
21 speak a heavy dialect. And it's English, but it
22 takes some understanding. Well, yeah, not a
23 regular basis.

24 VICE-CHAIRMAN ECHOLS: Yeah. Thank you.

25 MR. CAINES: Thank you for your time,

1 everybody.

2 VICE-CHAIRMAN ECHOLS: Thank you.

3 CHAIRMAN SHAW: Thank you.

4 All right. Next, Mike Giles.

5 Good morning.

6 MR. GILES: Good morning. Good morning,
7 Mr. Chairman, Commissioners. Thank you for the
8 opportunity to provide comments this morning.

9 My name is Mike Giles. I'm president of the
10 Georgia Poultry Federation, which is a trade
11 association that represents poultry growers,
12 processors, and allied businesses in Georgia, which
13 is the nation's leading broiler-producing state.

14 Poultry is the largest segment of agriculture
15 and agrobusiness in Georgia, representing an annual
16 economic impact of about \$45 billion. And the jobs
17 of almost 170,000 Georgians depend on the poultry
18 industry either directly or indirectly.

19 A reliable source of electricity is
20 critically important at every stage of production
21 in the poultry industry; from the farm level to
22 processing -- to processing -- to further
23 processing of the byproducts that are generated by
24 the industry.

25 At the farm level, poultry growers depend on

1 electricity to provide ventilation and lighting for
2 the houses and the automated systems that feed the
3 birds. Fertilized eggs are hatched in highly
4 specialized climate control hatcheries. And feed
5 mills throughout the state produce billions of
6 pounds of feed annually.

7 The machinery and poultry processing plants,
8 which will become even more advanced and automated
9 in the future, is powered by electricity. Finished
10 poultry products are stored in large freezer
11 facilities on their way to consumers in the United
12 States and through the world.

13 So that no valuable resources are wasted,
14 byproducts from our processing plants are converted
15 into proteins for our animal and pet foods using
16 electricity.

17 While we in the poultry industry are very
18 cognizant of how critically important electricity
19 is to the modern poultry industry, sometimes mother
20 nature has a way of reminding us just how important
21 it is. From ice storms and tornadoes, to
22 hurricanes, which can have even more widespread and
23 long-lasting effects, weather events and even
24 relatively short-terms disruptions in the
25 distribution of electricity can have tremendous

1 impacts on the overall production, processing, and
2 supply chains that the poultry industry depend on.

3 There are a number of critical nodes in the
4 overall poultry production and processing
5 infrastructure, which, if disabled even for
6 relatively short periods of time, can have
7 significant negative impacts on the industry's
8 ability to operate efficiently.

9 The citizens in Georgia and the United States
10 depend on the food that we produce on a daily
11 basis. It's about 30 million pounds of chicken
12 daily. And a significant portion of Georgia's
13 economy in communities throughout the state depend
14 on poultry and agriculture in general for their
15 economic well-being.

16 As you consider Georgia's future energy
17 demands, we ask that you place a priority on the
18 needs of the agribusiness and poultry sectors which
19 depend heavily on a reliable energy supply from a
20 variety of fuel sources.

21 Thank you.

22 CHAIRMAN SHAW: Thank you, Mr. Giles.

23 MR. GILES: Thank you.

24 CHAIRMAN SHAW: Please give our best to
25 Mr. Abbott --

1 MR. GILES: I will.

2 CHAIRMAN SHAW: -- if you will.

3 MR. GILES: I will. Thank you.

4 CHAIRMAN SHAW: He's a true legend and a
5 great American.

6 MR. GILES: Yes, he is. Thank you.

7 CHAIRMAN SHAW: Dan May.

8 Good morning.

9 MR. MAY: Good morning. My name is Dan May.
10 I have lived in Georgia since 1972. And I am 85
11 years old and I realize that I won't be around long
12 enough to see the worst effects of fossil fuels.

13 I feel sad, even guilty, thinking of my four
14 grandkids. I fully expect them to ask -- someday
15 to ask why we didn't do enough or more to keep the
16 climate from getting worse.

17 You four -- you five, whichever, have the
18 authority to do something substantial, something
19 that can save the lives of many, many Georgians and
20 many others by avoiding or postponing or preventing
21 deaths and illness due to air pollution and
22 excessive heat, even wildfires and storms, all the
23 other bad stuff that comes with climate change.

24 And as a side benefit, you -- you might not
25 get embarrassing questions from your kids and

1 grandkids, like I probably will. I wonder, how
2 would you -- how would you-all answer their
3 questions about how and why we've let the planet
4 get so dangerous? Or, will you be able to tell
5 them how you did something significant to turn it
6 around?

7 Thank you.

8 CHAIRMAN SHAW: Thank you, Mr. May.

9 Alan Hendry.

10 Next is Ms. Coronado.

11 MR. HENDRY: Good morning. Mr. Chairman, I'm
12 Alan Hendry, a concerned citizen and Georgia Power
13 bill payer.

14 It's my first meeting. I'm here to learn. I
15 don't intend to take any more of y'all's time
16 today.

17 CHAIRMAN SHAW: Well, thank you for coming
18 down.

19 Lisa Coronado, followed by Neil Sardana.

20 MS. CORONADO: Good morning.

21 CHAIRMAN SHAW: Good morning.

22 MS. CORONADO: The Fifth National Climate
23 Assessment came out last November. It states that
24 without rapid and deep reductions in global
25 greenhouse gas emissions severe climate risks and

1 harmful climate impacts will continue to grow.

2 Quote: Future climate change impacts depend upon
3 choices made today.

4 But not all choices have the same
5 significance. For example, cities and counties
6 across Georgia with the support of the overwhelming
7 majority of their residents are choosing to set
8 clean energy goals. Thousands in those communities
9 are actively choosing to invest their time, energy,
10 and financial resources to reach those goals.

11 But they won't be able to if just five people
12 -- the five of you -- choose to allow Georgia Power
13 to increase its reliance on fossil fuels, instead
14 of requiring them to provide cities with
15 electricity generated by cheaper, clean, and
16 renewable energy sources.

17 And if you choose to allow Georgia Power to
18 increase its reliance on fossil fuels and other
19 utility regulators follow your lead, then the U.S.
20 won't be able to meet critical 2035 greenhouse gas
21 reduction targets for the utility sector. Of
22 course, failing to meet those goals, the U.S. would
23 lose its opportunity to be a world leader and
24 influence other countries to take critical climate
25 action.

1 Quoting again from the Nation Climate
2 Assessment: In addition to reducing risk to future
3 generations, rapid emission cuts are expected to
4 have immediate health and economic benefits. At
5 the national scale, the benefits of deep emission
6 cuts for current and future generations are
7 expected to far outweigh the costs.

8 Let's just talk about a few of those costs
9 for Georgians. More days of increased heat means
10 higher utility bills for cooling. Extreme weather
11 events impact crops, often devastating farmers, but
12 also leading to higher costs for healthy fruits and
13 vegetables for all Georgians. Outdoor workers,
14 many paid hourly, will have to choose between
15 getting paid or risking their short- and long-term
16 health in extreme heat.

17 Massive rainfall events, such as occurred in
18 Atlanta last September, will lead to damaging
19 floods. And then more frequent and intense
20 hurricanes will impact large swathes of people.
21 Many will incur large expenses as they flee their
22 homes. Some will lose their homes and their
23 livelihoods. Hourly workers and business owners
24 will lose significant income as shops and
25 businesses shutter.

1 Honestly, it is so difficult to listen to
2 Georgia Power continually talk about downward
3 pressure on rates that if occurring would -- at all
4 would be measured in dollars and cents. Any
5 potential savings is dwarfed by the costs that we
6 know Georgians will incur if Georgia Power is
7 allowed to increase its reliance on fossil fuels.

8 But it's not just economic cost. You've
9 heard from your constituents, over 50 publicly
10 speaking here, hundreds more writing written public
11 comments, pointing you to the science and saying
12 how there will be many more additional deaths, more
13 disease, more destruction, more displacement of
14 large numbers of people, if people like you, the
15 ones who make the enormous consequential choices,
16 fail us. In your case, if you choose to listen to
17 Georgia Power, which, like other utilities and
18 fossil fuel companies, has known for decades about
19 the climate impacts, but use vast amounts of
20 customer money to deny the science, spread
21 misinformation, and delay action.

22 Thank you for listening to me and thank you,
23 Commissioner Echols, for reaching out to the
24 climate scientists and meeting with them. Before
25 you make your enormous, consequential decisions, I

1 really strongly encourage the other Commissioners
2 to reach out to the climate scientists, as well.

3 Thank you.

4 CHAIRMAN SHAW: Thank you, Ms. Coronado.

5 Neil.

6 And followed by Larry Heiman.

7 Good morning.

8 MR. SARDANA: Good morning. Thank y'all for
9 having me today. My name is Neil Sardana here.
10 I'm represent Georgia Conservation Voters as an
11 organizing manager.

12 Yeah, I wanted to come and speak to y'all.
13 Very much concerned about the proposal from Georgia
14 Power at the IRP Update that they've presented, you
15 know, with a -- again, another massive expansion of
16 polluting fossil fuels for the state of our -- for
17 our state.

18 And, you know, I -- I just want to say, you
19 know, I just recently had a child. You know, her
20 name's Mira. She's about six, seven months now.
21 And, you know, it's been like one of the greatest
22 joys of my life that I've experienced.

23 But in -- in this situation that we're in in
24 our world and this climate crisis, you know, I
25 recently realized by the time she's 26 years old in

1 2050, we'll really know by then whether she'll
2 actually have a future and whether my family and
3 all -- you know, the future of all these children
4 that right now do not have a voice in this
5 situation will actually have a future.

6 You know, we know -- and the decisions y'all
7 make today and the next few weeks on this IRP
8 Update will have a direct impact on that. You know
9 that this is going to have an accelerating effect,
10 you know, as a part of our state to, you know, blow
11 us well past some of the goals that we need to
12 meet, in terms of achieving more renewable energy
13 and bringing, you know, climate emissions off --
14 you know, out of our air.

15 But, you know -- you know, I remember, you
16 know, Commissioner Echols, when I first met you,
17 you told me: You know, don't come to the
18 Commission with concerns about climate. That's not
19 what's going to move us.

20 But we know that the vast majority of people
21 in this state, including a growing majority of
22 people in your -- in your political party are now
23 becoming concerned about this. But we've also seen
24 now that y'all have been provided two more years on
25 your terms in your seats as Commissioners. You

1 know, this -- many people see this as a major
2 defeat for our democracy.

3 But it is an opportunity for you to say:
4 Maybe I can be independent for Georgia Power for
5 maybe at least two more years. Maybe you don't
6 need to listen to them for these few more minutes
7 and actually listen to the public and actually
8 take -- you know, these are the concerns people are
9 coming to you with. This is what they're asking
10 you to do, in terms of representing the public's
11 needs and public interests.

12 So let's -- let's tell Georgia Power: You
13 know, this is not necessary. The PSC staff have
14 said that. Although, for some reason it looks like
15 they're completely collapsing on that. I can't
16 understand why.

17 I don't understand if that's what -- if
18 that's now what they're suggesting how they can
19 claim to represent the public's interest. And I
20 think if you go ahead and approve this proposal, I
21 don't think you can go ahead and claim to represent
22 the public's interest in any way.

23 And we've seen, because of the previous
24 decisions, not only a lack of movement on these
25 issues, massive increases in people's bills. So

1 this is an economic issue and an environmental
2 issue. But, in the long run, it's an issue for all
3 our futures. So I hope you make the right
4 decision.

5 Thank you.

6 CHAIRMAN SHAW: Thank you, sir.

7 Larry Heiman, followed by Makayla Peebles.

8 VICE-CHAIRMAN ECHOLS: And just to be clear,
9 what I said way back then was: Don't be lecturing
10 me about climate change if you yourself aren't
11 going to take personal responsibility driving an
12 electric car, putting solar on your house. Don't
13 come in here and lecture me if you're not going to
14 personally do anything about it. Just FYI.

15 CHAIRMAN SHAW: Good morning.

16 MR. HEIMAN: Good morning, Commissioners. My
17 name is Larry Heiman, resident of Dunwoody. I came
18 in here last month and made a public comment. And
19 I enjoyed my time here so much that I thought I
20 would come back again.

21 And last time I mentioned that I watched the
22 previous hearing on the YouTube channel and --
23 well, I did it again. This time I asked my wife if
24 she wanted to join me in watching it and she
25 politely declined, as you might understand why.

1 So I just wanted to share a few thoughts.
2 First of all, I do echo all of the thoughts of the
3 people that have commented before, especially
4 Mr. May, about the future and how he feels about,
5 you know, his grandchildren and what they're going
6 to experience, and what our responsibilities are
7 towards them.

8 But based on what I heard after watching the
9 last hearing, I just wanted to give a few thoughts.
10 And one was just -- I'm glad I wasn't here at that
11 time because I may have -- my ears may have fallen
12 out or my eyes may have fallen out of my head. But
13 I think I remember a Georgia -- a Georgia Power
14 representative saying that -- to one of the
15 witnesses for the Department of Defense that
16 Georgia Power's emissions have fallen 60 percent
17 since 2007. And I think that's a very disingenuous
18 statement.

19 That might be true if you look just at carbon
20 dioxide coming out of power plants due to the
21 switch from coal to natural gas. But as we all
22 know, and I'm sure that you know, natural gas leaks
23 all over the place upstream; from the wells to the
24 compressor stations, everywhere, all the way down
25 to the power plant. And those methane emissions

1 get in the atmosphere. They're extremely powerful,
2 you know, greenhouse gases. And they really offset
3 almost all of the gains you get from switching from
4 coal to natural gas, if not more.

5 As you may know, a satellite has now been
6 launched and is going to be providing, like,
7 realtime data on methane leaks in all production
8 basins around the world, including the U.S. And I
9 think that we're all going to be completely shocked
10 when we see that the estimates for methane leaks
11 have been completely underestimated for years and
12 years. And it's really going to, you know, bring
13 it home the reality of how gas is not a solution.

14 So, you know, Georgia Power and other
15 regulated IOUs in the southeast are getting some
16 bad reviews from the press for plans to deal with,
17 you know, load growth with fossil fuels. So just
18 wouldn't it be great if we, as Georgia residents
19 and Georgia Power customers, could wake up and see
20 just good news that the Public Service Commission
21 really put pressure on Georgia Power to take
22 advantage of all the great new technologies
23 available to help it continue to serve the load and
24 even serve the growing load, while also reducing
25 emissions and avoiding the risk of -- excuse me --

1 of stranded assets in the future that would not
2 help anyone?

3 Thank you.

4 CHAIRMAN SHAW: Thank you. All right.

5 VICE-CHAIRMAN ECHOLS: Larry, thank you --
6 thanks for coming back, by the way.

7 You know, as we sit and talk about grandkids
8 here, I think probably the best thing we can do to
9 our grandkids is tell them to get off social media
10 and not use ChatGPT. Because a ChatGPT prompt uses
11 ten times more power than a normal Google search.

12 So if we can just get our kids to turn off
13 our phones, then we're probably going to save quite
14 a bit of power. But I don't think we're going to
15 have any luck with that. I think -- I think that
16 train's left the station.

17 CHAIRMAN SHAW: Ms. Peebles, good morning.

18 MS. PEEBLES: Good morning.

19 CHAIRMAN SHAW: I didn't see any more on the
20 list so -- but if there others that have come in
21 since we began taking the comments, we'd be glad to
22 give you an opportunity.

23 Good morning.

24 MS. PEEBLES: Good morning. Honorable
25 Chairman Shaw and esteemed Commissioners, my name

1 is Makayla Peebles. I am a graduate student at UGA
2 College of Public Health. I'm pursuing a master's
3 in public health with a concentration in disaster
4 management, as well as certificates in social
5 determinants of health and global health. My
6 studies focus on the intersection of public health
7 and disaster management.

8 Over the next few minutes, I hope to share my
9 journey, my aspirations, and how pivotal this
10 Commission's role is shaping the future that the
11 public health infrastructure is robust and
12 resilient.

13 Growing up in a family, I was intimately
14 connected with the healthcare system. Both my
15 mother and father were first responders and have
16 both served on the front lines of medical
17 emergencies. I've witnessed firsthand the
18 fragility of our healthcare infrastructure.

19 My experiences, both personal and through my
20 academic studies, have highlighted a stark reality:
21 Our healthcare system is designed to serve citizens
22 on the worst days of human life.

23 It's a system when timeliness and reliability
24 of services are not just conveniences, but matter
25 of life and death. Statistics from the American

1 Hospital Association show that even a minute's
2 delay in emergency services can decrease survival
3 rates by 7 to 10 percent in cases of acute medical
4 conditions, like heart attacks and strokes. This
5 underscores the critical nature of an uninterrupted
6 healthcare service delivery system.

7 However, our healthcare extends far beyond
8 the walls of hospitals and emergency rooms. It
9 also includes dialysis centers, pharmacies,
10 refrigeration units for medications, and other
11 medical delivery offices, each a critical node in
12 the intricate web of public health infrastructure.

13 The advancements in the sector have been
14 monumental, contributing to dramatic increases in
15 life expectancy. For instance, in the last century
16 global health life expectancy has more than doubled
17 largely due to improvements in public health
18 infrastructure. Yet, underlying this vast network
19 is a fundamental necessity for reliable
20 electricity.

21 The World Health Organization highlights that
22 nearly 1 billion people worldwide lack access to
23 healthcare facilities with reliable power, severely
24 impeding the delivery of critical medical services.
25 Dr. Curt Harris from our UGA's Institute for

1 Disaster Management recently shared here the dire
2 consequences faced by other states who do a lack of
3 foresight in energy planning. The conflict of
4 healthcare demands in power outages has lead to
5 catastrophic outcomes in several instances,
6 emphasizing the necessity of preemptive planning
7 and investment in energy infrastructure.

8 Now, this does include an innovative mix of
9 renewable energy, nuclear power and natural gas,
10 ensuring that energy reliability underpins our
11 healthcare system, rather than being an
12 afterthought. Such strategic planning has
13 positioned Georgia as a leader in energy
14 reliability, directly contributing to the
15 resilience of our healthcare services.

16 As the Commission contemplates the future of
17 Georgia's energy policy, I urge you to consider the
18 profound implications of your decisions on the
19 public health. The adoption of a balanced energy
20 portfolio is not merely an environmental or
21 economic issue, but a public health imperative. A
22 diversified energy mix is crucial in ensuring the
23 uninterrupted operation of our healthcare system.

24 In closing, I stand before you not as an
25 energy expert, but as a committed student of

1 emergency response and healthcare systems, aspiring
2 to dedicate my career to enhancing public health
3 resilience.

4 Thank you for the opportunity to share my
5 perspective and contribute to this conversation.

6 CHAIRMAN SHAW: Thank you, ma'am.

7 Were there any other public witnesses that
8 came in after we began?

9 (No response.)

10 CHAIRMAN SHAW: All right. That will
11 conclude that portion.

12 And at this time, I will respond to some of
13 the requests that were made starting with Mr.
14 Sherrier.

15 I certainly agree with Mr. Sherrier that this
16 -- this stipulation that we've all got here was
17 just hot off the press.

18 Let's see. It's 10:15 now. I know you've
19 had some chance to look at it and we all kind of
20 want to look at this some more. But, at the same
21 time, we have a lot of people that are here and
22 ready to go.

23 So we're -- I'm going to give you, like,
24 20 minutes. So that will be at 10:35. We'll begin
25 with the first witness panel.

1 And, in the meantime, you know, I'm just
2 thankful that at least we've got this in front of
3 us now. Because a stipulation could happen at any
4 time, and at least we've got some time so that the
5 parties can ask questions.

6 Mr. Mahan.

7 MR. MAHAN: Yeah. Mr. Chair, is it possible
8 we could get printed copies?

9 CHAIRMAN SHAW: Yeah. And that's the other
10 thing I was going to mention.

11 MR. MAHAN: Thank you.

12 CHAIRMAN SHAW: Mr. Thomas had mentioned
13 there are some hard copies of the stipulation
14 sitting at the table where you walk in the hearing
15 room.

16 MR. MAHAN: Thank you. I appreciate it.
17 Thank you.

18 CHAIRMAN SHAW: Yeah. Actually, I'll do 25.
19 Let's go -- we're going to start back at 10:40.

20 And Mr. Carver had a request also regarding
21 his filing last night. I'll treat that as an
22 exhibit.

23 Mr. Carver, has he -- he stepped out?

24 MR. TURNER: He did, sir.

25 CHAIRMAN SHAW: And assuming that can be

1 handled as an exhibit and the panels have a chance
2 to familiarize themselves with that, we will allow
3 some questions on that, as long as the panel has
4 had a chance to familiarize themselves with the --
5 with the exhibit.

6 COMMISSIONER PRIDEMORE: Mr. Chairman,
7 printed copies of the exhibit for the Commissioners
8 prior to testimony, please.

9 CHAIRMAN SHAW: Okay.

10 MR. MARZO: Mr. Chairman, I just want to be
11 sure that I understand your ruling. We would like
12 to preserve our right to object how -- based on
13 what questions are asked. We don't know what the
14 questions are going to be.

15 So as long as -- as long as that doesn't
16 foreclose us making a legal objection should the
17 questions require that.

18 CHAIRMAN SHAW: Yeah. That -- I agree with
19 you there, Mr. Marzo. As long as you're able to
20 answer the questions and -- but at the same time,
21 we'll just treat this as a cross for a normal
22 exhibit.

23 So we'll all -- we definitely do want to get
24 copies of that. I don't know where Mr. Carver
25 stepped out, but I know you're representing him.

1 So we need to get those ASAP.

2 MR. BAKER: Mr. Chairman --

3 CHAIRMAN SHAW: Mr. Baker.

4 MR. BAKER: Could I -- I don't have a
5 computer and I know -- I thank you for the copies.
6 But could every party who needs one get a copy of
7 the stipulation?

8 Because it's highly unusual to present a
9 stipulation at the eleventh plus hour and have it
10 being considered at this time. And 25 minutes
11 is -- I'm a slow reader. And it's probably not
12 even enough to even skim through that.

13 CHAIRMAN SHAW: Well --

14 MR. BAKER: I mean, I appreciate -- I
15 appreciate the copy. I just need a copy to look
16 at, please.

17 CHAIRMAN SHAW: Yeah. We'll make sure that
18 everyone has copies. If we run out of copies,
19 we'll print some more.

20 I tell you what we'll do, we're going --
21 we're going to convene at -- at 10:45 is when we'll
22 ask them to call up their first panel.

23 Mr. Carver.

24 MR. CARVER: Yes, sir.

25 CHAIRMAN SHAW: We need to get copies of that

1 and we will --

2 MR. MARZO: We have them.

3 CHAIRMAN SHAW: -- allow the company to
4 object if they're not familiar with the -- with
5 the -- we're going to treat this as an exhibit as
6 normal cross for that. But we'll be -- we'll be --
7 I'll just say we'll be highly scrutinizing these
8 questions to make sure there's something that
9 witnesses have had a chance to become familiar with
10 enough to answer.

11 MR. CARVER: Understood.

12 CHAIRMAN SHAW: All right. Any other
13 housekeeping matters?

14 All right. We will go ahead and just stop
15 right here and we'll start back and call up the
16 first panel at 10:45.

17 (A recess was held from 10:22 a.m. until 10:45 a.m.)

18 CHAIRMAN SHAW: Okay. Thanks for your
19 patience. We'll go ahead and get started back with
20 the -- with the hearing. Again, it's Docket
21 No. 55378.

22 I hope everyone's had a chance to review the
23 stipulation. Did everybody -- was there anyone
24 that didn't get a copy?

25 (No response.)

1 CHAIRMAN SHAW: Okay. We'll go ahead and let
2 you go ahead and call up your first panel.

3 MR. HEWITSON: Well, it's a panel of one.
4 But before I get to that, I do want to announce,
5 and I'm happy to announce, that the Public Interest
6 Advocacy Staff, Georgia Power, and the Georgia
7 Association of Manufacturers have executed a side
8 letter agreement whereby the company and staff
9 agree to work with the Georgia Association of
10 Manufacturers to work on the language of the
11 tariffs that were filed as part of this -- of this
12 2023 Update. Specifically, the DER co-location
13 program, the curtailment -- curtailable load
14 program, and the DER customer-owned program
15 tariffs.

16 And in exchange for that agreement to work
17 collaboratively to work -- between those parties to
18 get to language that we all can agree with that the
19 Georgia Association of Manufacturers will agree to
20 the stipulation. So I'm very happy to announce
21 that.

22 CHAIRMAN SHAW: Okay. Thank you,
23 Mr. Hewitson.

24 Mr. Jones.

25 MR. JONES: May I just briefly comment. We

1 have executed the stipulation and support it fully.
2 We believe that there's work that can be done on
3 those tariffs to make them a little better.

4 We've been trying to work on that. It wasn't
5 something we could get all the language worked out
6 before the stipulation. But we're going to -- we
7 have signed the letter agreement, willing to work
8 with staff, the company, any other parties to bring
9 back some revised language to you before it's time
10 for you to vote on the stipulation.

11 CHAIRMAN SHAW: Okay. Thank you. Thank you,
12 sir.

13 Go ahead.

14 MR. HEWITSON: All right. Georgia Power
15 calls Mr. Abramovitz.

16 Would you please raise your right hand.
17 Thereupon,

18 AARON ABRAMOVITZ,
19 having been duly sworn, testified as follows:

20 MR. ABRAMOVITZ: I do.

21 DIRECT EXAMINATION

22 BY MR. HEWITSON:

23 Q Mr. Abramovitz, would you please state your
24 full name, your employer, and your responsibilities for
25 the record.

1 A Yes. Aaron Abramovitz. I work for Georgia
2 Power Company. I'm Georgia Power Company's executive
3 vice-president, chief financial officer, and treasurer.

4 Q On March 18th of this year, did you prefile
5 or cause to be prefiled 16 pages of rebuttal testimony in
6 question-and-answer format in Docket No. 55378?

7 A Yes.

8 Q Are there any corrections you need to make to
9 your prefiled rebuttal testimony?

10 A Not at this time.

11 Q If I were to ask you the same questions today
12 under oath, would your answers be the same as are set
13 forth in that prefiled rebuttal testimony?

14 A Yes, they would.

15 MR. HEWITSON: Chairman Shaw, the court
16 reporter has been provided a copy of the prefiled
17 rebuttal testimony of Mr. Abramovitz and I ask that
18 the rebuttal testimony be copied into the record as
19 if given here today.

20 CHAIRMAN SHAW: So marked.

21 (Whereupon, the prefiled rebuttal testimony
22 of Mr. Aaron Abramovitz follows:)

23

24

25

STATE OF GEORGIA

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

In Re:

Georgia Power Company's	)	Docket No. 55378
2023 Integrated Resource Plan Update	)	

REBUTTAL TESTIMONY OF

AARON P. ABRAMOVITZ

MARCH 18, 2024

**REBUTTAL TESTIMONY OF
AARON P. ABRAMOVITZ**

**IN SUPPORT OF GEORGIA POWER COMPANY'S
2023 INTEGRATED RESOURCE PLAN UPDATE
DOCKET NO. 55378**

I. INTRODUCTION

1
2 **Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

3 A. My name is Aaron P. Abramovitz. I am the Executive Vice President, Chief
4 Financial Officer, and Treasurer for Georgia Power Company ("Georgia Power" or
5 the "Company"). My business address is 241 Ralph McGill Boulevard N.E.,
6 Atlanta, Georgia 30308.

7 **Q. MR. ABRAMOVITZ, PLEASE SUMMARIZE YOUR EDUCATION AND**
8 **PROFESSIONAL EXPERIENCE.**

9 A. I graduated from the University of Georgia with a Bachelor of Business
10 Administration in Finance and Management Information Systems. I joined
11 Southern Company as a contractor in the Financial Strategy and Decision Support
12 organization. This position was followed by a series of Financial Analyst roles in
13 various disciplines that included Financial Planning, Financial Analysis, and
14 Regulatory Support. From there I transitioned to Georgia Power to serve as the
15 Coordinator for Forestry and Right of Way services. In 2008, I was assigned to the
16 Kemper Project in Mississippi, where I served in financial leadership roles of
17 increasing responsibility, eventually serving as the Project's Finance Director,
18 where I was responsible for governance, reporting, regulatory support, and
19 communications to Executives and the Board of Directors. In 2015, I returned to
20 Atlanta to serve as the Director of Investor Relations for Southern Company, where

1 I was responsible for Southern Company’s communications and relationships with
2 the investment community. In 2018, I was named the Southern Nuclear Vogtle
3 Units 3 and 4 Vice President of Business Operations. In this role, I had
4 responsibility for Southern Nuclear’s Project Controls, Risk Management,
5 Budgeting and Reporting, and Commercial Analysis & Controls. I moved to my
6 current role as Executive Vice President, Chief Financial Officer, and Treasurer for
7 Georgia Power in September 2021. I now oversee all accounting and finance
8 functions for the Company including financial reporting, regulatory accounting,
9 financial planning, analysis, and enterprise risk management.

10 **Q. MR. ABRAMOVITZ, HAVE YOU PREVIOUSLY TESTIFIED BEFORE**
11 **THE GEORGIA PUBLIC SERVICE COMMISSION (“COMMISSION”)?**

12 A. Yes. I testified in the Vogtle Construction Monitoring (“VCM”) proceeding,
13 Docket No. 29849, regarding the Nineteenth, Twentieth/Twenty-first, Twenty-
14 second, Twenty-third, and Twenty-fourth Semi-annual VCM Reports and in
15 support of the Company’s Application to Adjust Rates to Include Reasonable and
16 Prudent Plant Vogtle Units 3 and 4 Costs in Docket No. 29849 (“Vogtle Prudence
17 Proceeding”); the Plant Vogtle Unit 3 and Common Rate Adjustment proceeding
18 in Docket No. 43838 (“Unit 3 Rate Adjustment”); and the Company’s 2022 base
19 rate case proceeding in Docket No. 44280 (“2022 Rate Case”).

20 **Q. DID YOU PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF**
21 **OF GEORGIA POWER IN THIS PROCEEDING?**

22 A. No.

23 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

24 A. My testimony (i) explains why Georgia Power projects the 2023 IRP Update to
25 place downward pressure on rates for customers, and (ii) addresses specific
26 accounting aspects of the Company’s request.

1 **Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

2 A. As outlined in the direct testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans,
3 and Michael A. Bush (the “Company Direct Panel”), the Company is requesting,
4 among other things, 3,300 MW of capacity resources in the form of Power Purchase
5 Agreements (“PPAs”), three simple cycle combustion turbine (“CT”) resources at
6 Plant Yates, and battery energy storage system (“BESS”) resources. These capacity
7 resources are necessary to meet the substantial energy needs being driven by the
8 extraordinary pace and magnitude of economic development in Georgia.
9 Importantly, the Public Interest Advocacy (“PIA”) Staff and other parties to this
10 case acknowledge that this growth is very real. As further explained by the
11 Company Direct Panel, based on our forecast and in-depth understanding of our
12 customers’ energy needs and plans, we are confident that this growth will
13 materialize in the 2026-2028 timeframe, and the capacity resources requested in the
14 Company’s 2023 IRP Update will ensure Georgia Power can continue to reliably
15 serve our customers and support Georgia’s growing economy.

16 The 2023 IRP Update will provide substantial benefits to customers, and we expect
17 that the revenues associated with energy sales from incremental large load
18 customers will put downward pressure on rates for all customers, including
19 residential and small business customers. If approved, the 2023 IRP Update is
20 projected to provide approximately \$168 million of levelized net benefit annually
21 for customers for 2026 through 2028, or more than \$500 million of net benefit on
22 a cumulative basis for the three years. This benefit would put estimated downward
23 pressure on total retail rates of approximately 1.6% as a key variable in our next
24 base rate case filing. The Company expects that the projected revenues associated
25 with energy sales from large load customers will exceed the revenue requirement
26 associated with the incremental resources requested to serve the forecasted increase
27 in peak demand materializing in 2026-2028. Downward pressure on rates would be
28 achieved for all retail customers when, as a part of our next base rate case, Georgia

1 Power would use the net excess revenues resulting from the 2023 IRP Update to
2 decrease the impact of other revenue requirements when calculating the requested
3 rate adjustments.

4 The regulatory asset deferrals and additional sum requested by the Company in this
5 case are appropriate and should be approved. The deferrals will allow the costs and
6 benefits from the proposed resources to be concurrently recognized in the year the
7 resources are needed. Consistent with existing regulatory assets and regulatory
8 liabilities previously approved by this Commission, the costs related to the 2023
9 IRP Update stem from unforeseen circumstances that could not have been
10 accounted for during our last base rate case. These costs could not have been, nor
11 were they, contemplated when the Commission established the Company's current
12 base rates. The additional sum requested by the Company in this case is appropriate
13 and consistent with the amount per kW recently approved by the Commission.

14 As acknowledged by Staff, the Company considered a wide array of federal
15 incentives made available by the Inflation Reduction Act ("IRA") as part of its
16 request. (Tr. 519-521.) This includes considering the IRA's Domestic Content
17 Bonus Credit and Energy Community Bonus Credit as part of the selection of
18 resources and identifying specific BESS projects that incorporate the benefits of the
19 IRA. The Company will continue to pursue additional opportunities to leverage
20 these and other federal incentives to lower costs for customers.

21 If the Commission approves the Company's request and load growth materializes
22 as the Company expects, Georgia Power will be able to serve all of its customers—
23 both current customers and anticipated future customers—while supporting
24 Georgia's growing economy and related energy needs. If load growth does not
25 materialize as expected, both the Company and the Commission have multiple
26 levers available to manage the timing and extent of generation resources and related
27 costs to customers.

1 In this request, Georgia Power has sought to balance the need created by projected
2 growing peak energy demands with the timing of the generation resources
3 necessary to support Georgia's extraordinary growth and economic development.
4 This Commission's long-standing history of forward-thinking and constructive
5 regulation is highly correlated to Georgia's continued ability to attract and retain
6 businesses – ranging from technology and manufacturing to small business – and
7 without approval from the Commission to acquire these necessary capacity
8 resources, Georgia Power would be unable to serve its existing and growing
9 customer base with the reliability customers value and expect.

10 At Georgia Power, our customers are at the center of everything we do, and we are
11 unwavering in our commitment to provide them with clean, safe, reliable, and
12 affordable energy. Approval of our 2023 IRP Update will preserve and protect the
13 reliability and quality of service our customers expect and support the continued
14 economic development of our state, while placing downward pressure on rates for
15 the benefit of all customers.

16 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

17 A. In Section II of my testimony, I explain how the 2023 IRP Update will put
18 downward pressure on rates for all of Georgia Power's customers through the
19 projected changes to the Company's revenue requirement associated with this
20 request. In Section III, I address several accounting matters raised by intervenors,
21 including the appropriateness of regulatory asset treatment for certain costs, the
22 additional sums associated with the MPC and Santa Rosa PPAs, and the federal
23 incentives associated with the Company's BESS resource requests. Section IV sets
24 forth my concluding remarks.

25 **II. DOWNWARD PRESSURE ON RATES FOR ALL CUSTOMERS**

26 **Q. PLEASE EXPLAIN HOW, IF APPROVED, THE 2023 IRP UPDATE WILL**
27 **PUT DOWNWARD PRESSURE ON RATES.**

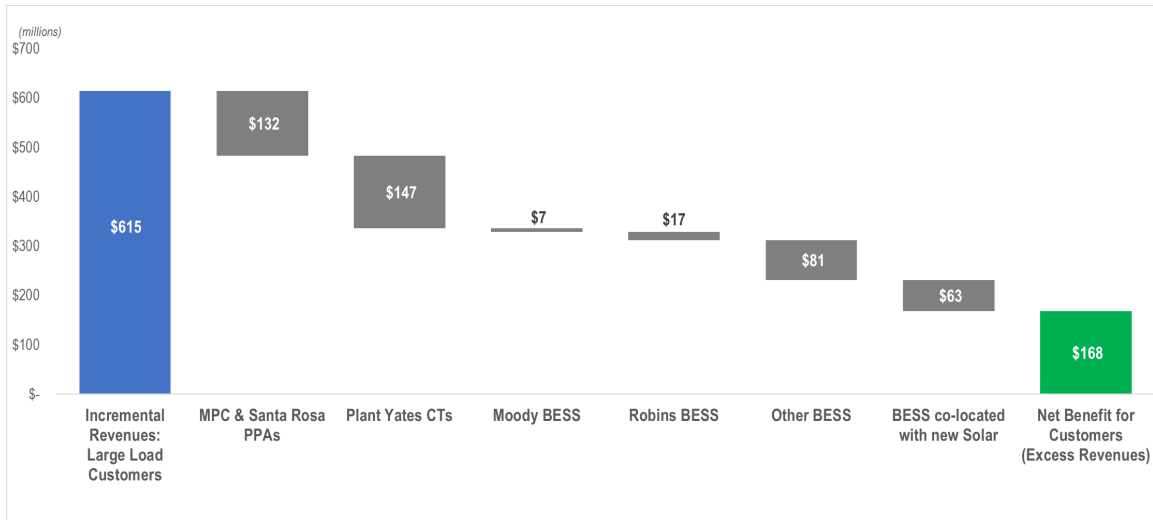
1 A. The incremental forecasted load projected in the 2023 IRP Update would result in
2 additional revenues that will benefit all retail customers in future rate adjustments.
3 When those revenues exceed the revenue requirement, or costs, this creates excess
4 revenues that helps to offset other costs in the computation of rate adjustments.

5 Georgia Power filed its 2023 IRP Update to serve the extraordinary energy demand
6 of Georgia's economic growth. Although there is a cost to serve this increased and
7 accelerated demand, there is also a benefit that materializes through increased
8 energy sales and revenues. In this case, with this request, the incremental revenue
9 benefits outweigh the costs. Downward pressure on retail rates occurs when the
10 costs associated with the resources requested in the 2023 IRP Update are more than
11 offset by the projected energy sales' revenues associated with the large load
12 customers.

13 **Q. HOW DOES THE 2023 IRP UPDATE IMPACT THE COMPANY'S**
14 **REVENUE REQUIREMENT?**

15 A. As shown in Figure 1 below, in the context of Georgia Power's upcoming 2025
16 base rate case, and assuming a three-year Alternate Rate Plan for the years 2026,
17 2027, and 2028, the revenues from the incremental large customer loads projected
18 by the Company are expected to exceed the revenue requirement associated with
19 the capacity resources requested in the 2023 IRP Update. Consistent with the
20 Company's typical practice, Georgia Power would include both the projected
21 revenues and the costs associated with these resources when calculating the rate
22 adjustments in our next base rate case and would use the net excess revenues related
23 to these resources to reduce the impact of other revenue requirements, placing
24 downward pressure on rates for all retail customers.

**Figure 1: 2023 IRP Update: Levelized Revenue Requirement Impact
(2026 - 2028)**



Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT COMPONENTS IN FIGURE 1.

A. The amounts presented in Figure 1 represent projected net revenue requirements for 2026 through 2028 on a levelized basis. The projected retail base revenues for incremental large load customers in Figure 1 are consistent with the revenues presented in the Company's response to STF-DEA-3-6. These projected revenues include estimated energy sales growth of nearly 9% over the next three to five years, with data centers representing more than 80% of that growth based on our most recent data. The revenue requirement blocks represent the projected revenue requirements of the capacity resources proposed in the 2023 IRP Update. As depicted in Figure 1, the projected result of the incremental revenues and the revenue requirement associated with the capacity resources is a levelized net benefit to customers of approximately \$168 million, which would equate to a cumulative three-year net benefit of more than \$500 million attributable to the Company's request in the 2023 IRP Update. This \$500 million net benefit would help to offset other costs and mitigate, or lessen, rate adjustments for customers. Figure 1 clearly

1 demonstrates the basis for the Company's expected downward pressure on
2 customer rates.

3 **Q. WHAT GIVES YOU CONFIDENCE THAT THE LOAD FROM THESE**
4 **LARGE LOAD CUSTOMERS IS GOING TO MATERIALIZE IN THE**
5 **2026-2028 TIMEFRAME?**

6 A. As Mr. Valle will explain further, Georgia Power's confidence is founded on robust
7 forecasting methodologies, strong economic development activity, customer
8 activity data, and customer commitments. The 2023 IRP Update is informed by
9 current economic trends and utilizes established forecasting methods to predict the
10 likelihood, scale, and timing of the projected load increases. Notably, PIA Staff and
11 the Intervenors submitting testimony on the issue have not challenged the
12 Company's organic load forecast and the statistical approach for anticipating
13 growth from new large load customers. (Tr. 89, lines 10-11; Tr. 1190, lines 8-9.)

14 Georgia Power's forecast is realistic and appropriately risk adjusted. With a long-
15 term economic development pipeline capacity of 21,000 MW in committed and
16 potential projects by the mid-2030's, our near-term winter 2028/2029 economic
17 development pipeline capacity is now estimated at nearly 14,200 MW, up from the
18 11,600 MW at the time of our initial filing in October 2023. Consistent with our
19 past practices, we are estimating that Georgia Power will ultimately serve just a
20 portion of all anticipated economic development projects, and the 2023 IRP Update
21 forecasts Georgia Power's winter of 2028/2029 peak demand will be approximately
22 5,260 MW higher than the winter peak of 2023/2024.

23 At the time of our initial filing, Georgia Power was chosen by fourteen large load
24 customers, securing agreements accounting for 3,612 MW of load, with 2,810 MW
25 anticipated by winter 2028/2029. Nine of these projects have initiated construction,
26 four are pending construction, and one 66 MW project is delayed. The trend of
27 robust economic activity has continued, and since our initial filing, Georgia Power

1 has secured an additional 2,602 MW from committed customers contributing 1,647
2 MW by winter 2028/2029. This information clearly indicates that these large load
3 customers are materializing and will need to be served sooner rather than later.

4 All signs, including direct input from customers, support Georgia Power's
5 expectation for continued robust economic growth in Georgia and the timing of
6 new large customers, and further my confidence that the load from these large load
7 customers will indeed materialize in the 2026-2028 timeframe.

8 **Q. DOES THE COMPANY'S ANALYSIS IN FIGURE 1 INCLUDE AN**
9 **ADDITIONAL SUM AND THE DEFERRALS THE COMPANY**
10 **REQUESTED IN 2024 AND 2025?**

11 A. Yes, our analysis includes the cost recovery of an additional sum for all five years
12 (2024-2028), the deferral and subsequent three-year recovery of capacity and non-
13 fuel expenses associated with the MPC and Santa Rosa PPAs, and a credit for the
14 off-System sale of that capacity during 2024 and 2025. Importantly, Georgia Power
15 is proposing that any additional sale of the capacity from the PPAs mentioned above
16 would increase the net benefit to customers reflected during this period, which
17 would further contribute to the downward pressure on rates.

18 **Q. HOW WOULD THE NET BENEFIT TO CUSTOMERS FROM THE 2023**
19 **IRP UPDATE IMPACT TOTAL RETAIL RATES?**

20 A. Based on the current estimate, the net benefit to customers illustrated in Figure 1
21 from the 2023 IRP Update would be equivalent to a decrease in total retail rates of
22 1.6%.

1 **Q. HOW HAS THE COMPANY TRADITIONALLY FILED FOR RATE**
2 **ADJUSTMENTS IN BASE RATE CASES?**

3 A. In previous base rate cases, the Company filed base tariffs whereby the adjustment
4 was applied to each traditional base rate on an equal percentage basis.

5 **Q. HOW WOULD THE BILL FOR A TYPICAL RESIDENTIAL CUSTOMER**
6 **BE IMPACTED IF THE NET BENEFIT TO CUSTOMERS PRESENTED IN**
7 **THIS FILING WAS ALLOCATED TO ALL RATE GROUPS ON AN**
8 **EQUAL PERCENTAGE BASIS?**

9 A. The Company estimates that the net benefit to customers from the 2023 IRP Update
10 would be equivalent to a decrease of \$2.89 per month to the typical residential
11 customer using an average of 1,000 kWh per month.

12 **Q. WILL RATES CHANGE AS PART OF THIS PROCEEDING?**

13 A. No. The Company is operating under the three-year Alternate Rate Plan approved
14 in the 2022 Base Rate Case and is not requesting a change in rates in connection
15 with the 2023 IRP Update. As explained above, the Company expects the increased
16 revenues associated with the 2023 IRP Update to more than offset the cost of the
17 resources requested in this case, and that impact would be addressed in the
18 Company's next base rate case.

19 **Q. WHAT IS THE ESTIMATED IMPACT TO RETAIL RATES AFTER 2028**
20 **AS A RESULT OF THE 2023 IRP UPDATE?**

21 A. With the 2023 IRP Update, the Company expects continued downward pressure on
22 rates for all retail customers beyond 2028. If approved, the cost of the proposed
23 resources requested in this filing would be more than offset by the revenues from
24 the forecasted incremental load beyond 2028. Since the revenue requirement
25 associated with the Company-owned resources is expected to decline over time, the
26 forecasted revenues from the incremental large customer loads included in this

1 request are expected to continue to exceed the total revenue requirement of the
2 resources included in the 2023 IRP Update.

3 **Q. WHAT LEVERS ARE AVAILABLE TO THE COMPANY AND THE**
4 **COMMISSION TO MITIGATE THE RISK OF RATE PRESSURE IF THE**
5 **LOAD GROWTH DOES NOT MATERIALIZE AS PROJECTED?**

6 A. Let me first reiterate that we are confident the load will materialize as projected and
7 that the requested resources will be critical to ensuring Georgia Power is able to
8 serve its existing and growing customer base with the reliability customers value
9 and expect. However, even if the forecasted load does not materialize as we expect,
10 there are multiple levers in place to mitigate the risk of upward pressure on rates.

11 The IRP framework provides ample opportunities to adjust our resource plan in
12 subsequent IRP cycles by reducing future investments in generation resources.
13 First, the framework allows us to adjust procurement plans for the resources
14 requested in this proceeding based on the most recent load forecast at the time
15 resources are submitted for certification. For example, the Company could reduce
16 the capacity procured for 2029 through 2031 through the All-Source Capacity RFP,
17 which was approved in the 2022 IRP. Second, the Company can make sales in the
18 wholesale market for any capacity above its target reserve margin to reduce the cost
19 obligation for customers, just as we did to secure off-System sale related to the
20 MPC PPA. Third, the Company could slow, reduce, or halt the development of
21 BESS resources if load growth is slower than expected or fails to materialize. .

1 **III. ACCOUNTING MATTERS**

2 **A. *Deferrals***

3 **Q. WHY IS THE COMPANY'S REQUEST TO DEFER CERTAIN COSTS TO**
4 **REGULATORY ASSETS APPROPRIATE?**

5 A. The Company is seeking regulatory asset treatment for the following: (i) capacity
6 and non-fuel energy payments made under the MPC and Santa Rosa PPAs in 2024
7 and 2025 (including additional sum and net of amounts remarketed to third parties);
8 (ii) non-useful and non-transferable development costs associated with the
9 requested BESS systems and Yates Units 8-10 CTs if the Commission denies these
10 requests; and (iii) the development costs associated with the Flex Capacity
11 framework that would otherwise be expensed for recovery in the next base rate
12 case. The deferral of these costs to a regulatory asset is appropriate because both
13 the costs and benefits from these capacity resources should be concurrently
14 recognized in the year the resources are needed. Like existing regulatory assets and
15 regulatory liabilities that were previously approved by this Commission, the costs
16 related to the 2023 IRP Update stem from unforeseen and extraordinary
17 circumstances. These costs could not have been, nor were they, contemplated when
18 the Commission established the Company's current base rates.

19 **Q. HAS THE COMMISSION ROUTINELY GRANTED DEFERRAL**
20 **REQUESTS OUTSIDE OF A BASE RATE CASE?**

21 A. Yes. The Commission has approved deferrals to regulatory assets numerous times
22 in an IRP. For example, in the 2019 IRP, the Commission approved deferrals for
23 Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant
24 Langdale Units 5-6, and Plant Riverview Units 1-2. In the 2016 IRP, the
25 Commission approved a deferral associated with Plant Mitchell Unit 3. In the 2013
26 IRP, the Commission approved a deferral for Plant Branch Units 3-4 and Plant

1 Boulevard Units 2-3. In the 2011 IRP Update, the Commission approved deferrals
2 for Plant Branch Units 1-2 and Plant Mitchell Unit 4C.

3 In addition to deferrals granted in the Company's IRPs, the Commission approved
4 cost deferrals in 2020 related to the COVID-19 pandemic, as well as the deferral
5 and subsequent disbursement of hundreds of millions of dollars in customer refunds
6 during 2018 and 2019 resulting from the Tax Cuts and Jobs Act. Notably, these
7 deferrals were approved during the three-year ARP periods for items that were not
8 contemplated in the respective base rate cases.

9 **Q. DO THE DEFERRALS REQUESTED BY THE COMPANY IN THIS CASE**
10 **PLACE UPWARD PRESSURE ON RATES?**

11 A. No. As previously mentioned, when the incremental revenues from the additional
12 large customer load presented in this filing are properly considered in conjunction
13 with the total revenue requirement of the capacity resources requested in this filing,
14 including the cost of the deferrals, the revenues are expected to exceed the revenue
15 requirement, putting downward pressure on rates for customers.

16 These deferral requests are directly associated with the capacity resources
17 necessary to serve our customers. Absent the efforts taken by the Company to
18 secure these resources to serve peak demand starting in 2026, Georgia Power would
19 be unable to serve its existing and growing customer base with the reliability
20 customers value and expect.

21 **Q. CAN THE COMPANY WAIT UNTIL THE 2025 BASE RATE CASE TO**
22 **MAKE A DEFERRAL REQUEST?**

23 A. No. The costs being deferred will be incurred in 2024 and 2025, and the Company
24 will need to account for those costs in that time period. Without Commission
25 approval to defer the costs, the Company will be required to expense these costs in
26 the Company's financial statements during that period. The Company cannot wait

1 to request deferral treatment in the 2025 Base Rate Case because, even if the
2 Commission were to grant the deferral in that case, the Company could not
3 retroactively reflect the deferral treatment in its financials for the periods when the
4 costs were incurred.

5 **B. Additional Sum**

6 **Q. ARE POWER PURCHASE AGREEMENTS REQUIRED TO BE**
7 **PROCURED THROUGH AN RFP TO QUALIFY FOR AN ADDITIONAL**
8 **SUM?**

9 A. No. The IRP Act authorizes an additional sum on any long-term power purchase,
10 and only instructs the Commission to consider lost revenues, if any, changed risks,
11 and an equitable sharing of benefits between the utility and its retail customers
12 when setting the additional sum. The purpose of the additional sum is to provide an
13 incentive to the Company to encourage long-term power purchases in lieu of
14 building or buying generation assets on which it can earn a return. Contrary to
15 Georgia Association of Manufacturers Witness Pollock's assertion that the
16 statutory criteria for the Company to recover an additional sum is unmet, it is not a
17 requirement that the Company procure the purchased power through an RFP for it
18 to be eligible for an additional sum. More importantly, the additional sum incents
19 the Company to act for the benefit of its customers to secure capacity, whether
20 Company-owned or power purchases, when that capacity is needed. This is exactly
21 what the Company has done in this case.

22 **Q. WHY IS IT APPROPRIATE FOR THE COMPANY TO RECOVER THE**
23 **ADDITIONAL SUMS ASSOCIATED WITH THE MPC AND SANTA ROSA**
24 **PPAS?**

25 A. The MPC and Santa Rosa PPAs are needed to serve Georgia Power customers.
26 Commission Staff acknowledges this fact. (Tr. 248, lines 11-12; 297, line 10; 298,
27 lines 1-3.) The Company's request for an additional sum in this case is consistent

1 with the treatment of other Georgia Power long-term power purchases needed to
2 serve our customers' capacity needs. Further, the amount per kW-year requested is
3 consistent with what was approved by the Commission for the six capacity PPAs
4 certified in the 2022 IRP, of which, five were affiliated PPAs. Although some
5 Intervenors have argued that the Company should not receive an additional sum for
6 a PPA with an affiliate (Tr. 939, lines 21-23), there is no statutory restriction on the
7 Company's ability to receive an additional sum for a long-term power purchase
8 with an affiliate. To the contrary, Commission practice has been to routinely allow
9 additional sums for affiliate PPAs.

10 **C. Federal Incentives**

11 **Q. WHAT FEDERAL INCENTIVES DID THE COMPANY CONSIDER AS**
12 **PART OF ITS REQUEST?**

13 A. The Company considered a wide array of federal incentives as part of its request.
14 As stated by Staff Witnesses Smith and Deitchman in their testimony, "the
15 Company was aware of and considered many of the tax incentives that have been
16 made available by the IRA." (Tr. 484, lines 19-20.) Witnesses Smith and
17 Deitchman also acknowledged this during the February 28 hearing. (Tr. 624, lines
18 13-15.) They note that the Company considered the IRA's Domestic Content Bonus
19 Credit and Energy Community Bonus Credit as part of the selection of resources
20 and identified the BESS projects that incorporate the benefits of the IRA (Tr. 520-
21 521.) Specifically, these projects, some of which include co-located solar projects,
22 qualify for certain investment tax credits and production tax credits, the benefit of
23 which were included in the Company's economic evaluation for the 2023 IRP
24 Update.

1 **Q. WILL THE COMPANY PURSUE ADDITIONAL OPPORTUNITIES TO**
2 **LEVERAGE FEDERAL INCENTIVES?**

3 A. Yes. The Company is continually pursuing new and evolving opportunities to
4 leverage federal incentives, including financing through DOE Loan Guarantees, tax
5 incentives, and other credits to lower costs for customers.

6 **IV. CONCLUSION**

7 **Q. WHY SHOULD THE COMMISSION APPROVE THE COMPANY'S**
8 **REQUEST AS FILED?**

9 A. At Georgia Power, the customer is at the center of everything we do. We are
10 unwavering in our commitment to provide our customers with clean, safe, reliable,
11 and affordable energy. Our request in this 2023 IRP Update seeks to continue
12 delivering on our customer commitment, as the forecasted load growth and
13 resulting need for additional capacity presents a significant opportunity to continue
14 to reliably serve our customers. Approval of our 2023 IRP Update will preserve
15 and protect the valuable reliability and quality of service both our current and future
16 customers expect and will support the continued economic development of
17 Georgia, while placing downward pressure on rates for the benefit of all customers.

18 Georgia's continued ability to attract and retain businesses - ranging from
19 technology and manufacturing to small business - is highly correlated to the
20 Commission's long-standing history of forward-thinking and constructive
21 regulation, which facilitates Georgia Power's ability to provide customers with
22 clean, safe, reliable, and affordable energy. We respectfully request that the
23 Commission approve the Company's 2023 IRP Update without modification.

24 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

25 A. Yes.

1 MR. HEWITSON: And with your permission, I'll
2 ask Mr. Abramovitz to provide a summary of his
3 testimony, as well as the stipulation.

4 CHAIRMAN SHAW: Yes, sir. Go ahead.

5 MR. ABRAMOVITZ: Good morning, Chairman Shaw
6 and Commissioners. I thank you for the opportunity
7 to be here today to discuss some of the points and
8 questions raised during the direct hearings for
9 Georgia Power's 2023 IRP Update and I'd like to
10 provide you a brief summary of the constructive
11 stipulated agreement reached between Georgia Power,
12 PIA Staff late last night, and Georgia Association
13 of Manufacturers this morning.

14 As discussed in our testimony and filings
15 throughout this proceeding, Georgia is in the midst
16 of a period of extraordinary economic development.
17 The capacity resources we are requesting in our
18 2023 IRP Update will ensure that we can continue to
19 serve our existing and growing customer base with
20 the reliability our customers value and expect,
21 while continuing to support Georgia's growing and
22 thriving economy.

23 PIA staff and other parties to this case
24 acknowledge that this growth is real. Based on our
25 forecast and in-depth understanding of our

1 customers' energy needs, we are confident that our
2 request in this case is necessary to serve load
3 beginning in the 2026 to 2028 time frame.

4 Since our initial filing in October of 2023,
5 Georgia Power has been selected to serve an
6 additional 2600 megawatts from committed customers.
7 This clearly indicates that these customers are
8 coming, that significant load will materialize, and
9 that the need to serve the -- that load will occur
10 sooner, rather than later.

11 My testimony focuses on the substantial
12 benefits that Georgia Power's request in the 2023
13 IRP Update will provide to our customers.
14 Specifically, we expect that the revenues
15 associated with energy sales from incremental
16 large-load customers will put downward pressure on
17 rates for all customers, including residential and
18 small business customers.

19 The company's request in the 2023 IRP Update
20 is projected to provide approximately \$168 million
21 of levelized net benefit annually for customers for
22 2026 through 2028, or more than \$500 million of net
23 benefit on a cumulative basis for those three
24 years.

25 While there is a cost to serve this increased

1 and accelerated energy demand, there is also a
2 benefit that materializes through increased energy
3 sales and revenues. And in this case, the
4 incremental revenue benefits outweigh the costs.

5 Downward pressure on rates would be achieved
6 when, as part of our next base rate case, Georgia
7 Power would use these net excess revenues to
8 decrease the impact of other revenue requirements
9 when calculating any requested rate adjustment.

10 This cumulative \$500 million of net benefit
11 would put annual downward pressure on retail rates
12 of approximately 1.6 percent as a part of our next
13 base rate case, which translates to approximately
14 \$2.89 per month for a typical residential customer
15 using an average of 1000 kilowatt-hours per month.
16 Said simply, approval of our 2023 IRP Update
17 request as amended by the stipulated agreement will
18 not increase rates for our customers.

19 As I said before, we are confident in our
20 forecast. As our direct panel will address later
21 today, Georgia Power's projections are founded on
22 robust forecasting methodologies and ongoing
23 evidence of strong economic development activity,
24 including information directly from our customers.

25 When we made our initial filing last October,

1 Georgia Power had been chosen by 14 large-load
2 customers to serve over 3600 megawatts of load. Of
3 these projects, nine have started construction,
4 four are pending construction, and only one small
5 66-megawatt project has been delayed. This is
6 evidence that the overwhelming majority of the load
7 Georgia Power has already been chosen to serve is
8 moving forward as planned.

9 As I mentioned earlier, robust economic
10 activity has continued. We have now been selected
11 to serve an additional 2600 megawatts from 11
12 committed customers. This clearly demonstrates
13 that these large-load customers are materializing
14 and will need to be served sooner, rather than
15 later. All signs, including direct input from
16 customers, support Georgia Power's projection of
17 continued economic growth and load that will
18 materialize in the 2026 to 2028 time frame.

19 Before I conclude my prepared remarks, let me
20 briefly describe several highlights of our
21 constructive stipulated agreement with the PIA
22 staff and the Georgia Association of Manufacturers.
23 This agreement provides substantial customer
24 protections and ensures that Georgia Power has the
25 needed capacity resources to preserve and protect

1 the valuable energy reliability that our customers
2 expect, and Georgia's growing economy must have.

3 First, the incremental revenue forecast
4 presented in the 2023 IRP Update and in Figure 1 in
5 my rebuttal testimony that is associated with
6 Georgia's extraordinary economic growth will be set
7 as a minimum estimate for the years 2026, 2027, and
8 2028 in Georgia Power's next base rate case. This
9 will ensure the incremental revenue from new
10 large-load customers has downward pressure of at
11 least \$2.89 per month to the typical residential
12 customer using an average of 1000 kWh per month.

13 Second, the stipulation agrees to the
14 certification of the MPC and Santa Rosa PPAs with
15 several modifications; that include eliminating the
16 regulatory asset deferral treatment and the
17 additional sums requested for the years 2024 and
18 2025.

19 Third, the stipulation agrees to grant the
20 company authority to develop, own, and operate
21 500 megawatts out of the 1000 megawatts of Battery
22 Energy Storage Systems it requested in its filing
23 and approves the Robins and Moody projects as
24 requested. For the remaining 500 megawatts that
25 are needed to serve customers during the winter of

1 2027 and 2028, the company agrees to issue an RFP
2 on an expedited schedule.

3 Fourth, the stipulation agrees to the
4 approval of the Plant Yates Units 8, 9, and 10
5 expansion as a part of the company's 2023 IRP
6 Update. The company agrees that if the
7 certification application is granted, Georgia Power
8 will not seek recovery of any project construction
9 costs that exceed the proposed project construction
10 cost in the company's application for
11 certification, absent a showing that such costs are
12 the result of circumstances beyond the company's
13 reasonable control.

14 Fifth, the stipulation agrees that the
15 company's flex capacity framework filed in the 2023
16 IRP Update should not be approved.

17 Sixth, the stipulation agrees that the
18 transmission projects necessary to accommodate the
19 loads and resource portfolio approved in the 2023
20 IRP Update should be approved, and Georgia Power
21 agrees to continue to investigate opportunities to
22 use distributed energy resources and grid-enhancing
23 technologies to reduce or defer the need for
24 transmission upgrades necessary to accommodate
25 future load growth or proposed generation

1 additions.

2 Finally, Georgia Power will investigate
3 additional behind-the-meter opportunities for
4 demand-side management, distributed energy
5 resources, energy storage systems, and related
6 funding opportunities that have been enabled under
7 the Inflation Reduction Act and the Title 17 Energy
8 Infrastructure Reinvestment Clean Energy Financing
9 Program.

10 At Georgia Power, our customers are at the
11 center of everything we do, and we are unwavering
12 in our commitment to provide them with clean, safe,
13 reliable, and affordable energy. Our request in
14 this 2023 IRP Update, along with the stipulated
15 agreement reached with the PIA Staff and Georgia
16 Associations of Manufacturers seeks to continue on
17 Georgia Power's commitment to customers, as the
18 forecasted load growth and resulting need for
19 additional capacity presents a significant
20 opportunity to continue to reliably serve our
21 customers.

22 The stipulated agreement benefits all
23 customers, and approval of this agreement will
24 preserve and protect the reliability and quality of
25 electric service our customers expect, and it will

1 support the continued economic development of our
2 state, all while placing downward pressure on rates
3 for all customers.

4 Georgia has continually been ranked the
5 number one state in the country to do business.

6 This Commission's long-standing history of
7 forward thinking and constructive regulation has
8 literally powered Georgia's continued ability to
9 attract and retain businesses, ranging from
10 technology and manufacturing to small businesses.
11 Our state's leadership in economic development is
12 fueled by the constructive regulation of this
13 Commission and the proactive steps that have been
14 taken to prepare Georgia for growth.

15 On behalf of the stipulating parties, we ask
16 that the Commission approve our request as amended
17 by the stipulated agreement as a reasonable
18 resolution of Georgia Power's 2023 IRP Update case.
19 With the Commission's approval of the stipulated
20 agreement, Georgia will continue to lead the way
21 with support of this extraordinary growth in
22 economic development, and Georgia Power will
23 continue to deliver on its commitment to serve our
24 existing and new customers with the reliability
25 they value and expect.

1 Thank you for your time and consideration.

2 MR. HEWITSON: Mr. Chairman, Mr. Abramovitz
3 is ready for questions from the Commission, as --
4 as well as cross-examination.

5 CHAIRMAN SHAW: Thank you, sir.

6 Commissioners?

7 Go ahead, Commissioner Echols.

8 VICE-CHAIRMAN ECHOLS: Hey, good morning.

9 MR. ABRAMOVITZ: Good morning.

10 VICE-CHAIRMAN ECHOLS: So glad to see this
11 solar plus battery project in this. We talked a
12 lot about this in the hearing.

13 What -- what do you think that's going to
14 look like?

15 Do you have any -- any concept of what that
16 would be in this next IRP?

17 MR. ABRAMOVITZ: Sure, Commissioner. So,
18 obviously, Mr. Bush and the other panel has much
19 more expertise than I do, but let me see if I can
20 address.

21 That solar plus battery energy storage
22 project, one, we want to co-locate, right, those
23 two resources so that the battery is charged by the
24 solar, right, not just off the grid. And then it's
25 independent. It can function independently.

1 And we have a good site that can be used, as
2 well. And it's an economic project. And that's
3 also why we've agreed to allow that to go through a
4 request for proposal, a competitive bidding
5 process. But we have confidence that it's economic
6 and it -- it will -- it can likely succeed in that
7 process, but it should go through the process.

8 VICE-CHAIRMAN ECHOLS: And in Paragraph 17
9 you mentioned the residential, small commercial
10 solar plus battery.

11 MR. ABRAMOVITZ: Uh-huh.

12 VICE-CHAIRMAN ECHOLS: Will -- do you
13 anticipate the utility having visibility into that
14 and maybe controlling -- a partial control like we
15 do with the smart thermostats?

16 MR. ABRAMOVITZ: That's definitely the
17 vision, Commissioner. To do that, we do need other
18 types of investments, like distributed energy
19 resource management systems that we talked about in
20 the last rate case. So it takes that kind of
21 investment and commitment, but then also the
22 infrastructure around that to manage that. And
23 obviously the next panel can probably get into that
24 a little bit more.

25 But that is the vision, that -- that is

1 available. And it also would put, if you will,
2 downward pressure on the capacity needs of the
3 utility and to help us to where we -- if we don't
4 have to build, we can forego maybe building another
5 asset or whatnot.

6 VICE-CHAIRMAN ECHOLS: Are you thinking in
7 the hundreds of homes or thousands of homes? Any
8 idea on that?

9 MR. ABRAMOVITZ: I personally don't know. It
10 really just depends on how large the program is and
11 if we want to do a pilot or a full-blown project.
12 I would say let's just see how it plays out and see
13 what we can put in the next Integrated Resource
14 Plan.

15 VICE-CHAIRMAN ECHOLS: Next question: Does
16 relinquishing the additional sum on the Santa Rosa
17 project and -- and Mississippi Power, too; right?

18 MR. ABRAMOVITZ: That's correct.

19 VICE-CHAIRMAN ECHOLS: And the deferrals,
20 does it provide ratepayer protection in the 2025
21 rate case?

22 And if so, how?

23 MR. ABRAMOVITZ: So how that will work in the
24 2025 rate case is these assets, if certified, will
25 serve need in '26, '27, '28. So there will be a

1 cost there.

2 With the company foregoing the ability to
3 defer those costs, that amortization of that
4 deferral will no longer be a part of our rate case.
5 So it actually lowers the request. And if we just
6 go by the math, the -- my exhibit, Figure 1, that
7 \$2.89, that \$168 million of net benefit, it
8 actually increases that benefit because the
9 customers will no longer be obligated to pay us
10 back for that deferred cost of that asset.

11 VICE-CHAIRMAN ECHOLS: So that \$2 figure
12 doesn't include the -- the deferral?

13 So it is --

14 MR. ABRAMOVITZ: That's correct, yeah. So
15 the number gets higher.

16 VICE-CHAIRMAN ECHOLS: Regarding the -- the
17 price protection at the Yates Plant, I heard the
18 language act of God type of -- type of things. And
19 I know God doesn't want any rate increases right
20 now. So -- that's a joke.

21 What kind of additional expenses would
22 ratepayers be protected from that God would be out
23 of; right?

24 Is there -- can you give me an example of
25 something that would be an expense that could

1 happen; you know, supply chain, labor pool?

2 You know, what -- what kind of things don't
3 fit under God?

4 MR. ABRAMOVITZ: Sure. So let me start first
5 with the way that we have agreed to this portion of
6 the stipulation is highly consistent with what any
7 other winner of a request for proposal in a
8 competitive bidding process would also agree to.
9 So it's the same kind of protection. So we're not
10 agreeing to anything that's different, if you will,
11 or unique here, outside of what would normally
12 happen in a competitive bidding process.

13 So what kind of protection does that offer
14 customers? We have an estimate to build the three
15 Yates CTs. And we have an estimate to, if you
16 will, build a small gas lateral from the location
17 to a larger pipeline.

18 If we have underestimated that cost, that's
19 on the company. If the materials to build that
20 pipe are more expensive, that's on the company.
21 If, for some reason, through the management of
22 building the facility -- now, granted, we have a
23 highly reputable consortium building the facility.
24 But if, for some reason, we just -- we're just not
25 on time and we're behind schedule and it's because

1 we just didn't manage appropriately, that's on the
2 company.

3 So anything that is related to project
4 execution that is -- my words -- normal course of
5 business that would be expected for the company and
6 the consortium to perform on, we hold -- well, we
7 are putting our money where our mouth is that we
8 will not come back and ask customers to pay for any
9 more than what we've asked for in the certification
10 filing.

11 VICE-CHAIRMAN ECHOLS: Last question. These
12 latter paragraphs about the company will continue
13 to investigate opportunities to use distributed
14 energy resources, the company will investigate
15 funding opportunities under the Inflation Reduction
16 Act, how is that meaningful?

17 You know, how is it meaningful here and
18 different than what you've been already doing as
19 you have your people look at this and explore that?

20 Does it mean that -- that you're going to
21 embed things into the IRP, that you're going --
22 that it's going to be a more aggressive look?

23 What does it mean?

24 MR. ABRAMOVITZ: So, Commissioner Echols, you
25 hit on a really good concept here. A lot of things

1 that are listed here are things that Georgia Power
2 does every day and doesn't need to sign an
3 agreement to do. But some parties in these
4 proceedings, whether it's this proceeding or rate
5 case proceedings, don't believe that we will.

6 So we want to put it in writing to say we
7 will commit to do this. So, one, we're committing
8 to do something that we do every day to make sure
9 we have the lowest cost and most reliable service
10 for our customers.

11 With that, with a written agreement, it does
12 up the ante, if you will, to where parties that
13 sign on to this stipulation and when we make this
14 commitment and put this in writing and we sign
15 this, people will expect it in the next Integrated
16 Resource Plan that there is some movement here and
17 there is some change.

18 And as the next panel can probably elaborate
19 on, we're going to need to do that anyways because
20 we're -- as this load is coming, this extraordinary
21 amount of development is here, we're going to have
22 to find -- we're going to have to continue to
23 provide new ways and inventive ways to serve that
24 capacity for the benefit of all of our customers.

25 VICE-CHAIRMAN ECHOLS: Thank you so much.

1 MR. ABRAMOVITZ: You're welcome.

2 CHAIRMAN SHAW: Commissioners, any other
3 questions?

4 Commissioner McDonald.

5 COMMISSONER McDONALD: Referring to your
6 docket in page 6 -- I believe it's page 6. Let's
7 see.

8 Yes. At lines 5 through 12, you talk about
9 incremental revenues benefit outweigh the costs.
10 Downward pressure on retail rates will occur --
11 will occur when costs associated with the resources
12 requested are more than offset by the project of
13 energy sales.

14 In other words, there's no guarantee there.
15 You're looking at the fact that the revenue coming
16 in off that, when it exceeds the cost of the
17 program, that's when you're going to have some rate
18 relief; is that correct?

19 MR. ABRAMOVITZ: That's correct.

20 COMMISSONER McDONALD: And where are the --
21 where are the guarantees that you know that the
22 revenue is coming there?

23 MR. ABRAMOVITZ: So, Commissioner McDonald,
24 you're correct. And as filed, that's what that
25 means. There is no guarantee.

1 As we've just stipulated to, Georgia Power is
2 guaranteeing that that assumption, that those
3 numbers that we've put in, if you will, on Figure
4 1, in my rebuttal testimony, that big -- I will use
5 simple -- simple terms. That big blue bar that has
6 a 615 in the middle of it, we're guaranteeing that
7 will be a key variable in our next rate case.

8 If, for some reason, a year from now, we file
9 our next rate case and we're wrong and this load
10 isn't here and our forecasts don't match that,
11 that's on the company. And we've -- we have
12 committed that we will ensure that that credit,
13 that revenue benefit for customers, will be in our
14 next rate case.

15 To your point, though, if you think about the
16 visual here on Figure 1, when this load does occur
17 and when these energy sales do occur, we have to be
18 able to serve it reliability. And so the boxes in
19 the middle, the gray boxes that represent the
20 revenue requirement for incremental peaking
21 generation capacity also need to be available.
22 They need to be built, they need to actually come
23 to fruition, they need to be on the ground, to
24 ensure this blue bar shows up.

25 But what we've done here and with the

1 stipulated agreement saying: We have the ability
2 to go procure these generation assets with the
3 ability to go get this peaking capacity, we are now
4 even more confident that this blue bar, this
5 revenue benefit for customers, this revenue credit,
6 will materialize. So we're committing to it for
7 our next rate case. That's --

8 COMMISSONER McDONALD: That's in your
9 forecasting?

10 MR. ABRAMOVITZ: It's in our forecasting.

11 COMMISSONER McDONALD: In your forecasting in
12 '25 rate case, do you anticipate a request for a
13 rate increase?

14 MR. ABRAMOVITZ: So I don't know. And I
15 truly wish I had a crystal ball. That way we could
16 make this all easier for us in the next year and a
17 half. I don't know.

18 There's a lot of other factors that go into
19 rate making, as you know, Mr. Commissioner, that
20 are over and above this 2023 IRP Update, and our
21 next IRP case that we'll file the first part of
22 next year in '25. So there's a lot of moving
23 pieces.

24 So I wish I had a better answer. The best
25 answer I have to today is I'm not sure.

1 COMMISSONER McDONALD: So your forecasting
2 doesn't run into that; is that correct?

3 MR. ABRAMOVITZ: Say that one more time
4 because it sounded like --

5 COMMISSONER McDONALD: Your -- your
6 forecasting does not anticipate what the decision
7 will be on that at this time?

8 MR. ABRAMOVITZ: That's correct,
9 Mr. Commissioner.

10 COMMISSONER McDONALD: Thank you.

11 MR. ABRAMOVITZ: You're welcome.

12 CHAIRMAN SHAW: Any other questions?

13 (No response.)

14 CHAIRMAN SHAW: I just want to make sure I
15 understand. As far as the -- the minimum downward
16 pressure on rate that you're committing to, the
17 \$2.89 per month, so if your load forecasts don't
18 hit and your -- these loads don't mature, then
19 you're still guaranteeing that \$2.89 at minimum to
20 downward pressure on the rates?

21 MR. ABRAMOVITZ: That's correct,
22 Commissioner. And I'll -- I'll say it a different
23 way.

24 As Mr. McDonald and I just kind of talked
25 about here, each rate case has multiple variables;

1 increases in costs to serve, credits, decreases,
2 things get less expensive, some things get more
3 expensive. What we're guaranteeing here is when we
4 present our next case and when we make a request
5 for our next case, whether it's a rate adjustment
6 up or a rate adjustment down, there will be, if you
7 will, a chart very similar to this that will
8 represent a fixed amount of downward pressure that
9 we have committed to in the next case.

10 And so all else being equal, let's say
11 everything else nets out and there's -- and our
12 numbers say there's zero change. If that's the
13 case, then approval of this case here would mean
14 that customers would see rates go down by \$2.89 per
15 month. That's all else being equal and nothing
16 else changes and, for some reason, all of our math
17 washes out and it's a zero request.

18 That's a very extreme scenario. I'm just
19 trying to be very clear on what this means and the
20 commitment we've made.

21 CHAIRMAN SHAW: So also I want to ask you --
22 so if these load forecasts do mature and -- and
23 possibly exceed -- the revenues exceed what you're
24 expecting from these -- this -- this new load, so
25 there is a chance that we'll see more downward

1 pressure on rates than this minimum amount that
2 you're committing to in the '25 rate case?

3 MR. ABRAMOVITZ: Yes, Commissioner Shaw. And
4 that is why the language in the stipulation is
5 worded very intentionally to call it a floor.

6 CHAIRMAN SHAW: Yeah.

7 MR. ABRAMOVITZ: And just so we all
8 understand, when we file our 2025 IRP, there will
9 be a load forecast and an energy forecast
10 representing a long-term view for the state and the
11 company of energy needs and capacity needs, but
12 also a short-term view.

13 Once that IRP is decided upon, whatever is --
14 gets decided upon from an energy and load forecast
15 gets moved right to our rate case. So we're going
16 to have wonderful insights the first part of next
17 year of: Is this blue bar going to be the floor or
18 is it going to be higher?

19 So to simply answer your question, if there's
20 more revenues in from new large-load incremental
21 customers, then the blue -- then the 2.89 is higher
22 and then we will definitely pass that through to
23 customers.

24 CHAIRMAN SHAW: All right. Thank you.

25 Any other questions?

1 (No response.)

2 CHAIRMAN SHAW: All right. We'll move on,
3 starting with cross with Georgia Public Service
4 Commission.

5 MR. THOMAS: No questions, Commissioner.

6 CHAIRMAN SHAW: No questions.

7 Advanced Power Alliance.

8 And, Mr. Carver, I just want to remind you,
9 on -- when you -- when we got this exhibit, I --
10 honestly, I didn't realize it was 58 pages. So I
11 just want to --

12 MR. CARVER: I'm going to make it easy for
13 you, Mr. Chairman. We are in discussions to sign
14 on as a stipulated party with Georgia Power at this
15 time. You know, we have been reviewing the
16 stipulated agreement and certainly, as you-all
17 know, we were pushing very heavily for a
18 competitive RFP for the battery storage. And that
19 is part of this agreement.

20 And then our second biggest issue is
21 transmission planning, which is exactly what this
22 SERTP Study that you see here is.

23 So we -- we are in discussions with Georgia
24 Power how APA can play a role in that process and
25 be a constructive partner with Georgia Power.

1 Because we all know we've got to integrate 10
2 gigawatts of solar to keep us the number one state
3 to do business and to keep drawing customers to our
4 state that demand that clean energy.

5 APA wants to be part of that solution, along
6 with your staff and the Georgia Power Company. So
7 we do not have any questions today.

8 We just ask that this SERTP Study, which we
9 have marked as APA Exhibit 1, be entered into the
10 evidence.

11 MR. HEWITSON: No objection.

12 MR. MARZO: No objection.

13 CHAIRMAN SHAW: All right. So marked.

14 Thank you, Mr. Carver.

15 (ADA Exhibit 1 was admitted into evidence.)

16 MR. CARVER: Thank you, Mr. Chairman.

17 CHAIRMAN SHAW: All right. Next, Clean
18 Energy Buyers Association.

19 MR. DUNBAR: No questions for this witness,
20 Mr. Chairman. Thank you.

21 CHAIRMAN SHAW: Okay. Heelstone Renewable
22 Energy.

23 MR. GALLOWAY: No questions of this witness,
24 Mr. Chairman.

25 CHAIRMAN SHAW: Georgia Association of

1 Manufacturers.

2 MR. JONES: No questions, Mr. Chairman.

3 CHAIRMAN SHAW: Georgia Center for Energy
4 Solutions.

5 Mr. Hubbard?

6 (No response.)

7 CHAIRMAN SHAW: Georgia Coalition of Local
8 Governments.

9 MS. BROWN: No questions.

10 CHAIRMAN SHAW: Georgia Interfaith Power &
11 Light.

12 MS. WHITFIELD: We've got some.

13 CHAIRMAN SHAW: Come on up, Ms. Whitfield.

14 CROSS-EXAMINATION

15 BY MS. WHITFIELD:

16 Q Okay. Good morning, Mr. Abramovitz.

17 A Good morning, Ms. Whitfield. How are you?

18 Q I'm good. I'm trying to become a speed
19 reader.

20 MR. HEWITSON: It's not that long.

21 MS. WHITFIELD: It's dense.

22 And, Commission, with apologies, I tried
23 really hard during the time you allocated to update
24 my questions to be more appropriate, in light of
25 this stip. But I don't know how effective I was at

1 that. So I'm going to try to do it on the fly.

2 COMMISSONER McDONALD: Pull that mike down a
3 little bit towards you.

4 There you go.

5 MS. WHITFIELD: Is that helpful?

6 BY MS. WHITFIELD:

7 Q Okay. Mr. Abramovitz, Commissioner McDonald
8 asked you if Georgia Power could commit to rates going
9 down in the 2025 rate case. And you said: I don't -- you
10 weren't -- you're not sure at this time; correct?

11 A That's correct.

12 Q As of today, does Georgia Power expect
13 residential bills to decrease in 2025?

14 A Just like I told Commissioner McDonald, I
15 can't -- I don't know. I don't see that. I don't see
16 them going up or down because I'm not sure what the
17 outcome is of our filing.

18 Q I assume that's the same answer for small
19 businesses, as well?

20 A Yes, it is.

21 Q Will Georgia Power commit to recommending a
22 decrease in residential bills and small businesses in the
23 2025 rate case?

24 A Until I know what our revenue sufficiency or
25 deficiency is, I can't make any commitments.

1 Q As a result of the new large load coming to
2 Georgia, does Georgia Power expect residential bills to
3 decrease?

4 A As a result of what this case, if you will,
5 applies to, if you just take this case in isolation,
6 residential bills should go down. But there's other costs
7 associated with serving our customers and the rest of the
8 business.

9 And so applying that with a broad brush
10 across the next rate case wouldn't be appropriate today
11 for today. But for the 2023 IRP, all else being equal,
12 rates should go down for customers.

13 Q So that would include then the transmission
14 costs for the large-load customers --

15 A That's correct.

16 Q -- that are being served?

17 A That's correct.

18 Q Would that also include accounting for rates
19 and other riders, like fuel?

20 A No. It's only with the 2023 IRP Update. So
21 this is a resource proceeding, not a fuel proceeding.

22 Q Right. What -- what I'm trying to understand
23 you just said yes with respect to the IRP Update. So how
24 do you define that?

25 What does that mean -- what does that mean to

1 you?

2 A Sure.

3 Q What -- what is part of the bucket that will
4 lead to what you anticipate to be a downward -- a decrease
5 in residential bills?

6 A So if we use Figure 1 as the example, the
7 simplest way to explain it, it's incremental revenues in
8 from new customers and large loads coming to the state
9 with this extraordinary economic development, to ensure
10 that we can ensure peaking reliability capacity and the
11 need in our peaking periods, like the winter and summer,
12 we need to procure new generation assets. And the costs
13 of that are the gray boxes in Figure 1. And the net is
14 the green at the very end.

15 That's what all this includes. It's the --
16 we have increased sales, increased revenue, because we
17 have increased capacity coming to the state and to our
18 customers. And so that has a benefit, but you have to --
19 we have to build resources to serve that. That has a
20 cost.

21 Q Sure. So one question. This is blue bar,
22 green bar, gray bars. We like it, too.

23 This blue bar is the revenue bar that you're
24 talking about?

25 A That is the revenues from incremental

1 large-load customers, that's correct.

2 Q The gray bars are the costs that are
3 associated with the assets that you've asked for as part
4 of the IRP?

5 A Yes. That is the capacity cost. The revenue
6 requirement capacity cost for those assets.

7 Q And this green bar is how you're coming up
8 with the savings number?

9 A That's correct.

10 Q Okay. Is this -- and I believe you mentioned
11 earlier that you expect to show the Commission a similar
12 chart to this in the IRP or rate case?

13 A In the rate case.

14 Q One of them.

15 Okay. Is this how you traditionally allocate
16 rates to large-load customers?

17 A And so also what's in my testimony is when we
18 do make rate requests, we do take not only the cost, but
19 also incoming revenues, and we equally allocate that cost
20 or, if you will, revenue across all customer classes. So
21 it's equally allocated. Very similar to what we've done
22 in previous rate cases.

23 Now, there will be a cost of service study
24 filed, as well, like any other rate case. And that
25 provides very valuable directional input of where parity

1 is for different rates. And Mr. Evans in the next panel
2 can definitely dive into that more than I can.

3 Q Okay. So the answer I heard is, no, you
4 don't plan to allocate rates like this?

5 A No. The answer you heard is it's -- that is
6 an all-in 100-percent view of revenue requirement. And we
7 will -- like I said in my testimony, we will allocate that
8 equally across rate classes.

9 Q Do these costs in these gray bars -- will
10 they be allocated to the large-load class?

11 A There will be a portion to the large load,
12 there will be a portion to residential, and a portion to
13 all of other tariffs.

14 Q How many of -- how much of these gray bars
15 will be apportioned to the RTP portion of the large load?

16 A So RTP is a variable rate. The large load
17 has a fixed component, as well. So they will also get
18 their share based on their -- the size of that customer
19 class or rate class. But Mr. Evans can definitely get
20 into more detail on that.

21 Q So for the RTP piece of that rate, the answer
22 is none; right?

23 A I didn't say that.

24 Q Well, is that the answer?

25 A No. I said it will be allocated based on the

1 size of the class and the tariff.

2 Q For the RTP usage, are you committing to
3 allocate capital costs for these assets to the
4 RTP customers for their usage under the RTP rate?

5 A I'm not sure I understand your question.

6 Q Okay.

7 A Maybe that's why --

8 Q Let's -- let's break it down.

9 A Maybe that's why we're talking past each
10 other.

11 Q Yes. Let's break it down.

12 So the customers involved here, they're
13 all -- I think there's 51 in the pipeline; right?

14 Of the ones with whom you've signed
15 contracts, there are -- a hundred percent of them are on a
16 RTP rate; correct?

17 A To the best of my knowledge.

18 Q Okay. And an RTP rate has two groups; right?

19 It has two kinds of rates; one is incremental
20 and one is a base rate?

21 A That's correct.

22 Q And is it fair to say that about 50 percent
23 of the energy sold to these large customers is under the
24 incremental rate?

25 A There is --

1 Q At least 50 percent?

2 A So if, in your example, the fixed portion of
3 an RTP customer's rate -- and, again, Mr. Evans in the
4 next panel can get into a lot of detail with you guys on
5 this.

6 The fixed portion, depending on what is
7 decided upon between the customer and the customer, is
8 fixed. So it could be 10, 20, 50, 60, 70, 80, 99,
9 whatever is left is the variable portion that gets priced
10 on a realtime pricing basis on a day ahead or an hour
11 ahead.

12 Q Right.

13 A So it all depends on what is agreed upon
14 between the company and the customer. There's no fixed
15 hard and fast rule.

16 Q Okay. So for that incremental piece --

17 A Uh-huh.

18 Q -- that could vary, will any of these costs
19 be attributed to the energy used under that piece of the
20 rate, the incremental piece of the rate?

21 A So, again, Mr. Evans will --

22 Q Mr. Abramovitz, yes or no?

23 A Just -- I'll answer your question. I'm
24 making sure that you get the answer you need.

25 Q Okay.

1 A So Mr. Evans can probably elaborate more, but
2 the way I understand it will work is the variable piece of
3 that rate is based on the marginal cost of energy, which
4 includes both energy and capacity.

5 So it is very likely that the gray bars here,
6 which are peaking and marginal energy resources, pieces of
7 that cost may actually materialize. But it all depends on
8 the forecasted cost of energy and capacity in the future.

9 So it's very hard to diff- -- to answer your
10 question in a straight manner. I apologize for that.

11 Q So Mr. Evans is the one who's able to answer
12 that question in a direct manner?

13 A He should be.

14 Q Okay. So -- but what we can establish here,
15 based on the chart in your testimony, is that this is not
16 how they're allocated to the customers?

17 This is a company-wide perspective, not a
18 reflection of how rates will actually be made; right?

19 A That's correct.

20 Q Okay. So these costs, the gray bars, there
21 is a cite in your testimony that they are from a response
22 to a data request, DEA-3-6, I believe. And that
23 particular request indicates that the figures here do not
24 include, quote: Transmission projects that may be
25 identified and placed in service due to load growth.

1 A That's correct.

2 Q So what is that cost expected to be?

3 A I'm not sure. We have to see how the load
4 growth materializes and what the customers need as they
5 come on the system.

6 But what I'll tell you is: Every time we add
7 a new customer to our system, and large-load customers
8 especially, the rate that they pay ensures that there is
9 no upward pressure on rates to any -- any existing
10 customer. Day one it puts downward pressure on rates.

11 And that's what we've done almost
12 historically when we attract any new loads, when we sign
13 any customer choice loads to Georgia Power, especially
14 when we think about new loads coming to the state and the
15 investment it takes these customers, these new large loads
16 agree to that price.

17 And so whether it's transmission, incremental
18 generation, or other pieces that cost, if you will, to
19 serve that next megawatt-hour of load that the customer
20 brings in, the way we price the product is to ensure that
21 over the long term of the contract customers are
22 economically benefited. And most recently, as recently as
23 last summer, the way we price it now is day one. So on a
24 nominal basis, customers are benefited, whether it's a
25 transmission cost, a distribution cost, or an incremental

1 natural gas plant or battery energy storage system or
2 whatnot.

3 Q So, Mr. Abramovitz, I have a question about
4 the stipulation, Paragraph 19. This stipulation -- this
5 paragraph reads: The transmission projects necessary to
6 accommodate the loads and resource portfolio approved in
7 the 2023 IRP Update are approved.

8 Does that include the figure that has been
9 exempted from these costs?

10 A What we're trying to ensure is if we are
11 going to -- if we're going to grow this state and new
12 customers come to the state and we build generation, we
13 have to be able to also hook them up. So we need approval
14 to actually build the wires or build the additional
15 substations or the additional switch gear to hook them up.
16 That's what that paragraph represents.

17 Q Sure.

18 A And today I'm not sure what that cost is.

19 Q Okay. So just to be clear, Paragraph 19 is
20 approving costs that we can't quantify?

21 A It's approving costs that we can't quantify.
22 But what I will remind you and the Commission is, just
23 because it's approved in an IRP doesn't mean it doesn't go
24 through a process in a rate case to say: Are these costs
25 reasonable and prudent for recovery?

1 So it's not a blanket approval. This still
2 has an extreme level of oversight and discretion by this
3 Commission when the -- when we actually do know the costs
4 of these projects.

5 Q So the company won't interpret this provision
6 then as indicating that there has been any finding of
7 reasonableness or prudence with respect to transmission
8 costs to accommodate the load and resource portfolio
9 approved in the 2023 IRP Update?

10 A I didn't say that. I said that we have
11 approval to build these -- these costs, but we still are
12 held to the same standard as every other dollar we spend
13 on behalf of our customers. That when reviewed by the
14 staff and the Commission, they have to be deemed
15 reasonable and prudent. But when we spend a dollar, we do
16 assume that they are reasonable and prudent because that's
17 how we act on behalf of our customers; in a reasonable and
18 prudent.

19 Q So what I'm -- sure. But what I'm trying to
20 understand is that this forecloses future review by this
21 Commission as to whether a cost you can't quantify that's
22 been approved here and that isn't included here on the
23 chart that's the whole basis of your saying that there are
24 savings -- that that cost can be approved and considered
25 by this Commission later?

1 A Ms. Whitfield, that's not what I said.

2 Q That's what -- I know. That's what I'm
3 asking.

4 Can they -- can -- will they have an
5 opportunity to consider the reasonableness and prudence of
6 the transmission costs for large-load customers that
7 haven't yet been identified?

8 A As I previously answered, that's the function
9 of each and every rate case every time we make an
10 investment. Yes, of course, the staff and the Commission
11 will have every opportunity to review that and make a
12 decision.

13 Q Okay. I think that answers my question.
14 That they can review --

15 A Yes.

16 Q -- these costs for reasonableness and
17 prudence?

18 Okay. This blue bar, the revenue, does it
19 include for the -- again, talking about the CBL piece and
20 the incremental piece.

21 A Uh-huh.

22 Q So maybe we call it -- I don't know what the
23 best way -- the best words are to use. But maybe CBL and
24 RTP or CBL and incremental for the two rates that make up
25 these customers?

1 A I think the common term would be "fixed" and
2 "incremental."

3 Q Okay.

4 A So there is a fixed component in the rate no
5 matter what is used, and there's an incremental based on
6 the energy usage.

7 Q Okay. Has the company taken out fuel costs
8 from the fixed rate --

9 A There -- there --

10 Q -- as part of this incremental revenue bar?

11 A There is no fuel cost in a base rate.

12 Q Okay. And same for the incremental rate.
13 Has the -- that lambda piece of that rate, has that been
14 removed from this blue bar?

15 A It has. That's an energy piece.

16 Q Okay. Thank you.

17 So you said before that this -- I think
18 the -- what I wrote down is that the gray boxes will need
19 to be available to make sure the blue bar shows up.

20 Are you aware that the gray boxes are based
21 on the company's very aggressive P95 forecast of load and
22 the blue box is based on P50, the most likely development
23 of load?

24 A Yes, I am.

25 Q So you would also be aware then that for this

1 blue bar to show up, some of these resources, namely Plant
2 Yates, are not necessary for that blue box to show up?

3 A I disagree. The blue bar is made up of
4 customers' nets -- revenues and energy sales from
5 customers that are coming to this state that sign up with
6 Georgia Power to ensure they have the highest level of
7 reliability. That is a commitment we've made as they
8 signed up.

9 That's why we're here today in this 2023 IRP
10 Update is to ensure that we can maintain the commitment to
11 both existing and new customers to serve them reliably.
12 And so all of the assets in the gray bars, including Plant
13 Yates, ensure that we can, if you will, honor that
14 commitment to the companies that are represented in that
15 blue bar.

16 There is a commitment we've made. There's a
17 commitment they expect that we will be reliable at all
18 times. The lights will come on, their plants will run,
19 their data centers will work at all times.

20 That is the commitment we made. That is what
21 the gray bars provide.

22 Q So as for reliability, the company forecasts
23 reliability using a reserve margin study; correct?

24 A That's correct. As approved by this
25 Commission in the 2022 IRP.

1 Q Correct.

2 And as a part of that reserve margin study,
3 Southern Company, who completed the study for Georgia
4 Power and its other subsidiaries, uses the one-in-ten
5 industry standard risk threshold for reliability or for
6 loss of load.

7 Are you aware of that?

8 A I am loosely aware of that. I would say
9 if -- the farther you go, you may want to ask the next
10 panel.

11 Q Okay, okay. Well, in that case, I will just
12 ask you: Is it your position that customers are willing
13 to pay any amount to never lose power ever once?

14 A No. And I think we've testified to that as a
15 company in multiple IRP proceedings. It's a balance of
16 economics and reliability and there's a cost benefit. And
17 that's why we have a 26 percent target planning reserve
18 margin.

19 MS. WHITFIELD: Okay. Thank you.

20 No further questions.

21 CHAIRMAN SHAW: Okay.

22 All right. Next is Georgia Solar Energy
23 Association.

24 MR. MORELAND: No questions.

25 CHAIRMAN SHAW: Georgia WAND.

1 Georgia WAND.

2 (No response.)

3 CHAIRMAN SHAW: Georgia Watch.

4 (No response.)

5 CHAIRMAN SHAW: MARTA.

6 MS. STURM: No questions.

7 CHAIRMAN SHAW: Microsoft Corporation.

8 MR. DOWDY: No questions, Mr. Chairman.

9 CHAIRMAN SHAW: Resource Supply Management.

10 CROSS-EXAMINATION

11 BY MR. BAKER:

12 Q Good morning, Mr. Abramovitz.

13 A Good morning, Mr. Baker.

14 Q I just have a clarification question
15 regarding the stipulation.

16 A Okay.

17 Q And I -- I know that you've been asked a few
18 questions about this, but with the understanding that
19 right now residential customers are served, I believe, by
20 the R-28 tariff, and that goes into effect, I believe,
21 effective April 1st of this year -- based on the provision
22 of the stipulation, Paragraph 2, is that 2.89 per month
23 reduction going to translate into reducing the current
24 R-28 residential rate by 2.89 a month?

25 A No. The result of -- this proceeding is a

1 resource proceeding. It's not a rate-making proceeding.
2 So no rates will be adjusted until the next rate case.

3 Q I understand that. I understand that. I'm
4 trying to find out how reliable that 2.89 figure is for
5 the future for the rate case.

6 Let me give you a hypothetical. If the 2025
7 rate case is filed, hypothetically, if rates -- Georgia
8 Power seeks a rate increase, and in this particular case
9 that might result in a 3 percent increase to residential
10 rates, does that mean, based on the provision of this
11 stipulation, that instead of the full 3 percent base rate
12 increase going to residential customers, that will be
13 reduced down to 1.5 percent approximately?

14 A That's a very simple mathematical way to
15 discuss this. That's the value of the commitment that
16 we've made as part of this stipulation, Mr. Baker. It is
17 a -- obviously, this is going to -- what we've committed
18 to is -- it's the method that we make our request; right?

19 It's when we present our case, we want to
20 ensure that the value that we presented in the 2023 IRP
21 Update and that net benefit to customers, that includes
22 that \$2.89 equivalent to residential customers, is taken
23 into account in our next base rate case.

24 So when we present our case in 2025, the rate
25 case, now with this stipulated agreement, if approved by

1 the Commission, we are committed to ensure that there is
2 at least \$2.89 of downward pressure on rates for
3 residential customers.

4 Does that answer your question?

5 Q It does. And that also -- that means,
6 though, that there could be -- even with the downward 2.89
7 and the downward pressure, that could mean rate increases
8 because of the fact that the company's rate case requests
9 will exceed or be greater than the 2.89 amount; is that
10 correct?

11 A That is a possible outcome.

12 MR. BAKER: Okay. All right. Thank you,
13 sir. I appreciate it.

14 MR. ABRAMOVITZ: You're welcome.

15 COMMISSONER McDONALD: That also would be
16 that if there was no rate increase in the '25 rate
17 case, then it would be a rate reduction for the
18 consumer?

19 MR. ABRAMOVITZ: That's correct, Commissioner
20 McDonald. That is also a possible outcome.

21 COMMISSONER McDONALD: Let's work for that;
22 okay?

23 MR. ABRAMOVITZ: We will do everything we
24 can.

25 VICE-CHAIRMAN ECHOLS: And following up on

1 that -- on Mr. Baker's question, you know, I asked
2 you about the Santa Rosa and I asked you about the
3 Mississippi Power and the deferral and not taking
4 the additional sum.

5 Is that also like money in the bank against a
6 possible rate increase in '25?

7 So it -- we take the \$2 and then we've got --
8 we've got that that we've kind of banked away if
9 there is an increase; is that -- is that correct?

10 MR. ABRAMOVITZ: Commissioner Echols, are you
11 asking me that because we have foregone the request
12 to defer the costs of those -- of these PPAs and
13 the additional sum that is included in that in '24
14 and '25 -- because we've foregone that request, the
15 fact that that regulatory asset won't be part of
16 our request in the next rate case, that -- that is,
17 if you will -- I guess that's a bank, if you will,
18 that lowers the cost of our request in the 2023 IRP
19 Update, which, obviously, if we lower the cost,
20 that increases the benefit of the IRP Update.

21 VICE-CHAIRMAN ECHOLS: Okay. All right.
22 Thank you for explaining that.

23 MR. ABRAMOVITZ: You're welcome.

24 CHAIRMAN SHAW: All right. Sierra Club.

25 MR. FABISH: No questions for this witness.

1 CHAIRMAN SHAW: Southern Alliance For Clean
2 Energy.

3 CROSS-EXAMINATION

4 BY MR. JACOB:

5 Q Good morning, Mr. Abramovitz. Bryan Jacob
6 for Southern Alliance for Clean Energy.

7 A Good morning, Mr. Jacob.

8 Q Just a few things.

9 Let's see. You testified about actions the
10 company and the Commission could take if the new load ends
11 up being lower than you're forecasting. You said on
12 page 11 of your -- the prefiled rebuttal testimony that
13 the company could reduce the capacity procured for 2029
14 through 2031 through the All-Source Capacity RFP, which
15 was approved in the 2022 IRP.

16 Are you following me?

17 A I'm with you.

18 Q That's kind of a mouthful.

19 A I'm with you.

20 Q All right. Could other RFPs that have
21 already been approved, like the current or futures CARES
22 RFP, also be reduced in that scenario?

23 A Yes. We have flexibility there. And the
24 concept here is -- the flexibility is, one, we want to
25 make sure we can reliably serve our customers, but we also

1 want to make sure that we don't overbuild and we maintain
2 affordability.

3 And so when we go out and we make requests
4 for proposals, whether it's from CARES, CRSP, All-Source
5 RFPs, we get a signal and we get offers from the market.
6 And there is no obligation that we take all of those
7 offers in if they're not needed. So that's where the
8 flexibility comes in.

9 Now, hopefully the market does come and the
10 market offers competitive bids and it's all economically
11 competitive for our customers. But if we don't need the
12 capacity, then there's no reason to take it.

13 Now, CARES and CRSP is a little different.
14 That is very -- that's solar and renewables and that's
15 very -- pointing to a very large set of our customer base.
16 And so some of that is subscribed to, so we have a
17 commitment there if it's already subscribed to.

18 So there is a balance there. It can't just
19 be an all or nothing. So we have to make sure that we
20 honor all of our commitments.

21 Q If it were to be reduced in that scenario,
22 would it be reduced by its ELCC equivalent capacity?

23 A So you're asking will it be reduced based on
24 the economic levelized carrying cost capacity?

25 So what -- what it actually means to the

1 system, meaning if I have 100 megawatts of solar, it's not
2 attached to a battery, then the capacity value is
3 obviously lower; is that what you're asking me?

4 Q Exactly.

5 A Yeah. It would be reduced by what the
6 equivalent would be.

7 Q Okay.

8 A Because we plan to the equivalent, not -- not
9 to what the actual generator is because of the value of
10 that capacity.

11 Q Okay. Can you assure us here today that the
12 total amount of renewable procurement would be the same or
13 even higher if the stipulation is approved?

14 A I'm not sure I can guarantee that today
15 because I can't predict the market or the demand from
16 customers on that one.

17 Q Okay. Different topic.

18 Page 15 of your prefiled rebuttal -- I'll let
19 you get there. You ask and answer a question of what
20 federal incentives did the company consider as part of its
21 request?

22 A Yes.

23 Q And your answer relies heavily, or almost
24 exclusively, on what staff testified as -- about the
25 Georgia Power filing, as opposed to what Georgia Power

1 itself had testified.

2 You reference -- or it references the
3 Inflation Reduction Act. It talks about the domestic
4 content bonus credit, the energy community bonus credit,
5 eligibility of battery storage for the investment tax
6 credit.

7 What about funding for transmission projects
8 that are administered through the Department of Energy,
9 were those also considered?

10 A So they're not part of the economic analysis
11 we've done, but we're always on the lookout in trying to
12 consider those. That's part of the reason I answered in
13 my testimony the way I did.

14 While we may not have included that in the
15 economic analysis, that doesn't mean we're trying to --
16 we're not trying to go after and actually secure that for
17 the benefit of the customers. What we want to make sure
18 is that everybody in the case, all the stakeholders and
19 parties involved in the case, understand what we did
20 include.

21 But understanding that we're not going to
22 leave any stone unturned, if there's a benefit out there,
23 especially a federal tax benefit or loan guarantee or a
24 grant, we're going to do whatever we can to procure that
25 for the benefit of our customers.

1 Q Yeah. And I'm trying to figure out whether
2 that stone has already been turned or it's to be turned.

3 A It's a -- it's not as -- it's not as
4 straightforward of a process as folks would like. It's --
5 sometimes it's application. Sometimes it's competitive
6 bidding. I wish it was more straightforward and it was
7 the first-come, first-serve model, but often it is not.

8 Q I did not see in the prefiled testimony, but
9 today in the stipulation and in your opening remarks, you
10 referred to the Energy Infrastructure Reinvestment
11 Program, which is different than the Inflation Reduction
12 Act.

13 A That's right.

14 Q But you say -- the way the stipulation reads
15 is that the company will investigate a number of things,
16 including that Title 17 Energy Infrastructure
17 Reinvestment.

18 So is that a situation where it has not yet
19 been investigated, but will be?

20 A No. It's just a commitment that we will as
21 in -- even though we may have already done it or we
22 have -- we are doing it, we're just ensuring that
23 everybody understands that we will continue to do that.

24 Q Okay.

25 A As we talked earlier about with the

1 Commissioners.

2 Q My read of the language of the stipulation
3 doesn't clarify the time frame for it -- for that point
4 No. 21 in the stip.

5 Will this be in time for the 2025 IRP filing?

6 A I hope it will because it will lower costs
7 for our customers if we can secure the -- the benefit.

8 Q Will there be an opportunity for either staff
9 or other intervenors to engage in any way in that process
10 of evaluation?

11 A I'm not sure I understand your question.

12 Which evaluation are you --

13 Q Point No. 21. The company will investigate a
14 variety of things. In some parts of the stipulation you
15 say that staff and stakeholders will be involved in the
16 process. This one doesn't say that. It's silent.

17 So I want to know whether that's envisioned
18 as part of this.

19 A You know, I'm sure as a part of either just
20 open dialogue that we have with all of our customer groups
21 and stakeholders, we can always have a conversation of
22 what we're doing and what we're trying to look at from an
23 incentive perspective. Nothing -- nothing even in the
24 stipulation would forbid that.

25 Q True. Nothing would forbid it, but I'm

1 trying to figure out if -- if it can be an affirmative
2 part of this process.

3 A While I would love to edit the stipulation
4 from the stand, I'm not sure that's appropriate, Mr.
5 Jacob.

6 Q Okay.

7 A I think -- you know us well. If you call us,
8 we will pick up the phone and we will talk with you. Just
9 like all of our other customer groups and stakeholders,
10 I'm sure we can find a way to constructively work together
11 on this, or at least inform each other of where we are and
12 what we're doing.

13 Q Okay. That provision is also silent on
14 another DoE programs. So you explicitly talk about the
15 Energy Infrastructure Reinvestment Clean Energy Finance
16 Program. You don't say anything about the DoE Grid
17 Resilience and Innovation Partnership, the GRIP program,
18 which also was not part of the Inflation Reduction Act.
19 It was part of the bipartisan infrastructure law,
20 otherwise known as IIJA.

21 A That's right.

22 Q Yeah. So will that be considered as a part
23 of the stipulation, as well?

24 A It probably doesn't need to be because we're
25 already looking at it. I mean, that's -- as we talked

1 about earlier this morning, there's a lot of things in the
2 stipulation that commit us to do things that we already
3 do. And any federal incentive, whether it's from the Tax
4 Cut and Jobs Act, Inflation Reduction Act, even incentives
5 that are decades old that still exist, we do what we can
6 to go secure those for the benefit of customers.

7 A stipulation doesn't mean that we -- if it's
8 not in the stipulation, it doesn't mean we're not doing
9 it. We always go down and look and try to find every way
10 possible to lower the cost of our product and improve our
11 service for our customers.

12 MR. JACOB: Okay. That's it. No further
13 questions.

14 CHAIRMAN SHAW: All right. Thank you, sir.
15 Southern Renewable Energy Association?

16 CROSS-EXAMINATION

17 BY MR. MAHAN:

18 Q Good morning. Simon Mahan for the Southern
19 Renewable Energy Association. I just have a few kind of
20 clarifying questions.

21 So on Figure 1 of your testimony, the one
22 that Ms. Whitfield was holding up with the blue bars and
23 the gray bars and the green bars, y'all filed this
24 testimony before the stipulated agreement was released.

25 And so you include a cost here for the

1 battery and co-located use solar facility. That's been
2 stripped out with the stipulation. And so how -- how does
3 pulling that specific project out impact Figure 1, the
4 \$168 million of net benefits for the customers?

5 A So just on the surface, it would make the
6 green bar, the \$168 million net benefit larger. But my
7 caution would be it doesn't mean we still don't need the
8 200 megawatts of capacity there. So that will be
9 competitively bid.

10 And so depending on what the market presents
11 and who wins that bid, there is a cost. Obviously, it
12 will be the lowest cost for customers, just like
13 everything we've presented here in this case.

14 So on the surface, if you take out that last
15 gray bar, obviously, the green bar increases. The very
16 end of the chart gets more valuable. But we still do need
17 200 megawatts of resources there.

18 Without -- without the solar piece and it's
19 just battery -- and, again, Mr. Bush can hit this in the
20 next panel if you need more detail. Obviously, if it's
21 not a co-located battery and solar facility and it's just
22 a battery facility, that will be less expensive. So if we
23 just take that scenario into play, then, obviously, the
24 green bar is going to be higher.

25 Q And -- so the procurement of that additional

1 capacity will be through the capacity RFP or the battery
2 RFP or some mixtures of these RFPs that we've got coming
3 up; is that --

4 A That's correct.

5 Q Okay. And then also in the stipulation
6 there's an Attachment B. It's titled: "2023 IRP Update
7 Estimated Incremental Review."

8 And you've got numbers here for '26, '27, and
9 '28. Are those cumulative on an annual -- or are they on
10 an annual basis?

11 A They're on an annual basis.

12 Q Okay. So you could add them all up and get
13 something close to one and a half billion dollars or close
14 to \$2 billion?

15 A That's correct. I think it rounds to about
16 1.8 or \$1.9 billion.

17 Q Okay. So how do these figures then on
18 Attachment B relate to the blue bar on Figure 1?

19 A They're just like we're referencing in --
20 it's a data -- from a data request response previously in
21 the hearings. And in Figure 1, they are the same numbers.
22 That's how the blue bar was created.

23 And so the math on this is you take the
24 annual amounts for '26, '27, '28, you total them up, and
25 then you discount it back to make a levelized number. And

1 what's important here is -- the reason why we chose the
2 levelized discounted amount to have one number is because
3 that is typically how Georgia Power Company makes its rate
4 request in every base rate case. Because it is the
5 lowest-cost option economically for customers.

6 So when we ask for base rate case
7 adjustments, we present that in a levelized manner.
8 Historically, though, through stipulated agreements, that
9 levelized treatment is broken out to a more step function.
10 But the reason why we chose levelized is because -- so it
11 will be consistent with how we request our next adjustment
12 in the base rate case.

13 One, so we all can be aware of what we should
14 expect, but, two, when we get into the base rate case,
15 we're using apples and apples, if you will, from a graph
16 perspective. We're not trying to confuse people.

17 MR. MAHAN: Okay. That's all I have. Thank
18 you.

19 CHAIRMAN SHAW: Thank you, sir.

20 Department of Defense?

21 MR. McNUTT: No questions, Mr. Chairman.

22 CHAIRMAN SHAW: Walmart?

23 MS. EATON: One second.

24 CROSS-EXAMINATION

25 BY MS. EATON:

1 Q Good morning.

2 A Good morning.

3 Q Mr. Abramovitz, I just have a few questions
4 and really clarifications on the stipulation. And I, like
5 everybody else, tried to read it really quickly.

6 So I just wanted to make sure we were all on
7 the same page before additional witnesses testify. And if
8 some of the questions I'm asking really are better asked
9 for somebody else, please just let me know.

10 A Okay.

11 Q I wanted to clarify. In Paragraph 7 of your
12 stipulation that the originally planned 1000 megawatts of
13 BESS that the company was going to own and operate is kind
14 of split into two. And Paragraph 7 addresses the 500
15 megawatts of BESS that the company will own and operate.

16 And then Paragraph 9 addresses the additional
17 500 megawatts of BESS originally in the -- in the
18 application.

19 A Yes. And, you know, just some color there.
20 It is purposeful that we split this. Because in order for
21 us to maintain that reliability that's so valuable to our
22 customers, there's a time component with this load and
23 these customers coming to the state and coming to our
24 service territory and signing up for Georgia Power's
25 service.

1 And so Paragraph 7 states that the company
2 can build, own, or procure, if you will, 500 megawatts of
3 battery energy storage to serve the capacity needs in '26
4 and '27, the winter of '26 and '27. We've agreed to, if
5 you will, execute or provide an accelerated RFP in
6 Paragraph 9 for the remaining 500 megawatts because we
7 have more time to secure those resources.

8 But the split is intentional to where
9 accelerated RFP in Paragraph 9 ensures that we have the
10 appropriate resources to serve customer needs in the
11 winter of '27 and '28. And then in Paragraph 7, to ensure
12 that we also have the right resources and the appropriate
13 resources to serve customer needs in the winters of '26
14 and '27.

15 Q Okay. Thank you.

16 Paragraph 9 also states that the RFP will
17 follow the solicitation, product requirements, regulatory
18 accommodations and schedule found in Attachment C to the
19 stipulation. And I've looked at Attachment C to the
20 stipulation and there are some solicitation requirements
21 listed there.

22 Are you aware of whether or not there are any
23 current or prospective customers who qualify under the
24 solicitation requirements?

25 A I'm -- I'm not aware. And if I'm not aware,

1 I'm sure that the next panel can answer them in a more
2 full manner.

3 Q Okay. Also had a couple of questions on
4 paragraphs, I guess, 13, 14, and 15 of the stipulation. I
5 believe I heard earlier today that the company is working
6 with Georgia Association of Manufacturers on the specific
7 language for these tariffs; is that correct?

8 A That's correct.

9 Q And so that the -- it was -- from what I
10 could tell in a quick reading, the tariffs that are
11 attached to the stipulation were the ones from the
12 original filing.

13 They're not edited yet; is that right?

14 A To the best of my knowledge, but Mr. Evans
15 can definitely dive into that with you from the next
16 panel.

17 Q Okay. And to the extent there are changes to
18 these tariffs that are -- are done after today, would the
19 company be willing to provide those revisions to
20 customers, like Walmart, before the Commission is asked to
21 approve those tariffs so they can also weigh in or see
22 what that language is and ask any questions or get
23 additional clarification?

24 A That's a perfectly reasonable request.

25 Q I was also wanting to ask you about

1 Paragraph 17, where it states that the company will
2 evaluate and develop a residential and small commercial
3 solar and battery pilot program that will provide grid
4 reliability and capacity benefits and submit the pilot
5 program for approval as part of the company's 2025 IRP
6 filing.

7 Do you have any more information on the
8 potential size of the program or whether or not it would
9 be at more than one location or any more information you
10 could provide?

11 A Today I don't have any more details there.
12 The commitment is we're going to evaluate and work with
13 folks to put something in there. So I think that point is
14 probably in its infancy still.

15 Q Sure. And here again, would this be the kind
16 of program with which the company would be willing to
17 Walmart -- work with Walmart to try to develop such a
18 program?

19 A I'm sure we would be.

20 Q You were asked about whether or not the
21 company was planning to provide its investigation in
22 Paragraph 25 in connection with the 2025 IRP filing. And
23 I think you said you hope so.

24 I wanted to ask the same question with
25 respect to Paragraph 20 where it speaks to the company and

1 investigating opportunity to use distributed energy
2 resources and grid-enhancing technologies.

3 Will -- will the company plan to present that
4 information, the conclusion of its investigation, in the
5 2025 IRP?

6 A You know, I'm not sure today. But I'm sure
7 it's going to be a topic that comes up in the 2025 IRP.
8 So it will be, if you will, talked about.

9 Again, especially when it comes to individual
10 customers, whether it's a national brand or a local
11 company -- I mean, anytime a customer has a question,
12 we're here to work with them and answer those questions.
13 So it doesn't have to be something written in the
14 stipulation to have that discussion.

15 Q Sure. And I was just wondering whether or
16 not the company was actually planning to include the
17 investigative information in the 2025 IRP.

18 A Probably too soon to tell since we're still
19 working on getting through these proceedings, but then
20 also when we file our 2025 IRP Update.

21 Let's -- let's just see how it plays out.

22 MS. EATON: Sure.

23 Okay. That's all the questions I have about
24 the stipulation. Thank you so much.

25 MR. ABRAMOVITZ: You're welcome.

1 CHAIRMAN SHAW: Redirect?

2 How much time do you need?

3 MR. HEWITSON: Thirty seconds.

4 CHAIRMAN SHAW: All right.

5 REDIRECT EXAMINATION

6 BY MR. HEWITSON:

7 Q Mr. Abramovitz, Ms. Whitfield asked you some
8 questions regarding transmission costs for new large-load
9 customers.

10 Do you remember those questions?

11 A I do.

12 Q Okay. Is it correct to say that the
13 transmission costs for those large-load customers are
14 built into the rate the customer will pay so that the
15 cost-causing customer pays for those transmission costs?

16 A Yes. I think I tried to explain that in one
17 of my responses to where the way we price new loads and
18 new customers when we win that load from a customer choice
19 process is to ensure that the marginal cost of that energy
20 that we're providing that company is covered -- more than
21 covered and puts downward pressure and benefits customers
22 day one. That includes transmission, distribution, and
23 incremental generation. So, yes, transmission would be in
24 there.

25 Q Okay. And Mr. Jacob asked if the company can

1 reduce RFP targets for other RFPs, other than the
2 All-Source.

3 Do you remember that -- that question?

4 A I don't. But I will --

5 Q Well, let me ask it this way then. Nothing
6 in the company's request or the stipulation seeks to
7 change the target capacity sought in any
8 Commission-approved RFP; is that correct?

9 A It does not.

10 MR. HEWITSON: Thank you, Mr. Abramovitz.

11 That's all I have, Mr. Chairman.

12 And unless there are any further Commissioner
13 questions, I would ask that Mr. Abramovitz be
14 excused.

15 CHAIRMAN SHAW: Any -- Commissioners, any
16 further questions?

17 (No response.)

18 CHAIRMAN SHAW: All right. Well, this is a
19 great stopping point right at noon. So we're going
20 to take a full hour and give everybody some more
21 time to digest the stipulation.

22 So, Mr. Abramovitz, you can be excused.

23 We'll see everybody back in here at -- let's
24 just say five minutes after 1:00.

25 (A lunch break was held from 12:06 p.m. until 1:05 p.m.)

1 CHAIRMAN SHAW: Thank you for being back
2 again. This is Docket 55378. We'll pick up where
3 we left off this morning.

4 Mr. Marzo, you can go ahead and swear in your
5 next panel.

6 MR. MARZO: Thank you, Mr. Chairman. At this
7 time Georgia Power Company calls the rebuttal panel
8 of Mr. Jeff Grubb, Mr. Francisco Valle, Mr. Lee
9 Evans, Mr. Mike Robinson, and Mr. Mike Bush.

10 With your permission, Mr. Chairman, can I
11 swear the panel in?

12 CHAIRMAN SHAW: Yes, sir.

13 Thereupon,

14 JEFFREY R. GRUBB,
15 FRANCISCO VALLE,
16 LEE EVANS,
 Michael Robinson,
 Michael Bush,

17 having been duly sworn, testified as follows:

18 DIRECT EXAMINATION

19 BY MR. MARZO:

20 Q. With the exception of Mr. Robinsaon, you all
21 previously testified in the IRP update docket; is that
22 correct?

23 A. (Witness Grubb) That's correct.

24 A. (Witness Bush) Correct.

25 Q. Mr. Grubb, would you, once again, please

1 state your full name, your employer, and your
2 responsibilities for the record?

3 A. (Witness Grubb) Yes. I'm Jeffrey R. Grubb.
4 I'm the director for resource policy and planning with
5 Georgia Power Company, where I am fortunate enough to lead
6 the team who leads the company's efforts in generation
7 planning, resource planning, including development of the
8 IRPs and this IRP update.

9 Q. Thank you, Mr. Grubb.

10 Mr. Valle, would you do the same?

11 A. (Witness Valle) Sure. Francisco Valle,
12 director of forecasting and analytics for Southern
13 Company, and responsible for the load forecast for Georgia
14 Power.

15 Q. Mr. Evans, would you do the same?

16 A. (Witness Evans) Yes. Lee Evans, director of
17 economics and load flexibility for Southern Company,
18 responsible for the design, planning, and implementation
19 of load flexibility programs, the planning around them,
20 and the system costing function and economic analysis.

21 CHAIRMAN SHAW: Speak up just a little bit.

22 BY MR. MARZO:

23 Q. Mr. Robinson, would you do so, as well?

24 A. (Witness Robinson) Good afternoon. Mike
25 Robinson, vice president of grid transformation,

1 responsible for planning and policy for transmission and
2 distribution, data analytics, fiber strategy, and
3 compliance.

4 MR. MARZO: Is that loud enough,
5 Mr. Chairman?

6 CHAIRMAN SHAW: Yes, sir.

7 MR. MARZO: Okay.

8 BY MR. MARZO:

9 Q. Mr. Bush, would you do so, as well?

10 A. (Witness Bush) Good afternoon, Commissioners.
11 Mike Bush. I'm director of generation planning and
12 development for Southern Company. I am responsible for
13 the development of all new generation implementation of
14 new generation for the Southern electric operating
15 companies.

16 Q. Thank you, gentlemen.

17 Mr. Grubb, on March 18th of this year, did
18 you and the panel cause to prefile, or cause to be
19 prefilled, 53 pages of rebuttal testimony in
20 question-and-answer format, in both trade secret and
21 public disclosure form in this docket?

22 A. (Witness Grubb) Yes, we did.

23 Q. And at that time, did you also prefile three
24 exhibits, with Exhibit 2 being filed both in trade secret
25 and public disclosure form?

1 A. Yes.

2 Q. Were those exhibits prepared under your
3 supervision and direction?

4 A. (Witness Grubb) Yes.

5 Q. Are there any corrections that need to be
6 made to your prefiled rebuttal testimony or exhibits?

7 A. (Witness Grubb) There are not.

8 Q. If I were to ask you the same questions today
9 under oath, would your answer be the same as set forth in
10 your prefiled rebuttal testimony?

11 A. (Witness Grubb) Yes, they would.

12 MR. MARZO: Mr. Chairman, the court reporter
13 has been provided a copy of the prefiled rebuttal
14 testimony. I now ask that the rebuttal testimony
15 of the panel be copied into the record as if given
16 orally here today.

17 CHAIRMAN SHAW: So marked.

18 MR. MARZO: For the record, Mr. Chairman, I
19 would also like to identify the prefiled trade
20 secret rebuttal testimony of this panel as Georgia
21 Power Company Exhibit 15; Exhibit 1 to the rebuttal
22 panel's testimony is GPC Exhibit 16; Trade Secret,
23 Exhibit 2, as GPC 17; Public Disclosure, Exhibit 2
24 as GPC 18; and Exhibit 3 to the rebuttal panel as
25 GPC 19; and have each of them admitted into the

1 record, subject to cross-examination.

2 CHAIRMAN SHAW: So marked.

3 (The documents referred to were marked for
4 identification as GPC Exhibits 15 through 19.)

5 (Whereupon, the prefiled rebuttal testimony
6 of Jeffrey R. Grub, Francisco Valle, Lee Evans,
7 Michael B. Robinson and Michael A. Bush follows:)

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STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's
2023 Integrated Resource Pl

)

Docket No. 55378

Brenda P. Elwell

REBUTTAL TESTIMONY OF

JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS,

MICHAEL B. ROBINSON, AND MICHAEL A. BUSH

MARCH 18, 2024

**REBUTTAL TESTIMONY OF
JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS,
MICHAEL B. ROBINSON, AND MICHAEL A. BUSH**

**IN SUPPORT OF GEORGIA POWER COMPANY'S
2023 INTEGRATED RESOURCE PLAN UPDATE
DOCKET NO. 55378**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. My name is Jeffrey R. Grubb. I am the Director of Resource Policy and Planning for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Francisco Valle. I am the Director of Forecasting and Analytics for Southern Company Services ("SCS"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Lee Evans. I am the Director of Economics and Load Flexibility for SCS. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Michael B. Robinson. I am the Vice President of Grid Transformation, Power Delivery for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is Michael A. Bush. I am the Generation Development Director for SCS. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

1 **Q. DID YOU PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF**
2 **OF GEORGIA POWER IN THESE PROCEEDINGS?**

3 A. Yes, other than Mr. Robinson, we all filed Direct Testimony in this docket on
4 December 4, 2023.

5 **Q. MR. ROBINSON, PLEASE SUMMARIZE YOUR EDUCATION AND**
6 **PROFESSIONAL EXPERIENCE.**

7 A. I graduated from Auburn University in 1993 with a Bachelor of Electrical
8 Engineering. I began my career as a cooperative education student with Georgia
9 Power working in distribution and marketing. After leaving the Company to serve
10 in the United States Navy, I worked for an electric municipality in Texas, the
11 Kerrville Public Utility Board, for five years where I was responsible for all
12 distribution and substation facilities. In 1999, I returned to Southern Company as
13 an engineer on the Enhanced Power Quality team with Alabama Power.
14 Throughout my career at Southern Company, I have served in a variety of positions,
15 including as principal engineer in Transmission Planning; supervisor of the
16 transmission maintenance center in Albany, Georgia; supervisor of the transmission
17 control center in Valdosta, Georgia; transmission planning manager; South Georgia
18 area transmission manager; Metro South distribution manager; and general
19 manager of Transmission Planning and Operations.

20 From 2017 through 2020, I served as the Power Delivery Operations General
21 Manager for Georgia Power. I served as Planning, Operations, and Policy Vice
22 President until January 2024, when I transitioned into my current role as Vice
23 President of Grid Transformation, Power Delivery. In my current role, I lead an
24 organization responsible for distribution and transmission planning, administration
25 of the Georgia Integrated Transmission System (“ITS”), data analytics and fiber
26 strategy, and Power Delivery compliance. I work with multiple organizations to
27 identify the Company’s long-term transmission and distribution strategies to

1 address our future needs. I also actively engage with System and industry partners
2 to appropriately identify industry-wide solutions, alternatives, and emerging
3 technologies.

4 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

5 A. Yes, I testified before this Commission in Georgia Power’s 2022 and 2019 base
6 rate cases in Docket Nos. 44280 and 42516, respectively, as well as in Georgia
7 Power’s 2022 Integrated Resource Plan (“IRP”) in Docket No. 44160.

8 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

9 A. The purpose of our testimony is to respond to the testimony of the Georgia Public
10 Service Commission (“Commission”) Public Interest Advocacy Staff (“PIA Staff”)
11 and various Intervenor filed in Docket No. 55378. Due to the number of Parties
12 filing testimony in this case and the limited time available to file rebuttal, our
13 testimony focuses on several key issues without attempting to address every issue
14 raised in PIA Staff or intervenor testimony. The fact that the Company may not
15 respond to a particular position of PIA Staff or an intervenor should not be
16 construed as acceptance of such position.

17 **Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL**
18 **TESTIMONY?**

19 A. Yes. In response to PIA Staff’s request that the Company file a Cost-of-Service
20 Study (Tr. 241, lines 12–15) or something similar that shows the cost impact across
21 rate groups (Tr. 672, lines 16–20), we have attached Exhibit 1, which shows Net
22 Income and Return on Investment as presented in the 2022 Rate Case Test Year,
23 distributed across each of the eight customer rate groups. Additionally, a sensitivity
24 is included with the addition of the 2028 costs and revenues associated with
25 investments and new loads presented in this 2023 IRP Update. Finally, a difference

1 between the two is calculated to represent the impact of such additional costs and
2 revenues on each of the eight customer rate groups.

3 In addition, Exhibit 2 is a revised Attachment D to the Yates Certification
4 Application updating the comparison of the proposed Yates Units 8-10 to other
5 similar projects. Finally, Exhibit 3 is an excerpt from Lazard's 2023 Levelized Cost
6 of Energy Analysis¹ identifying publicly available capital cost information for
7 various generation technologies, including gas peaking technologies. Exhibits 2
8 and 3 provide evidence of the reasonableness of the costs for the Yates CTs as
9 proposed.

10 **Q. PLEASE SUMMARIZE THE REBUTTAL TESTIMONY OF THE PANEL.**

11 A. As demonstrated by the load forecast in the 2023 IRP Update, Georgia is
12 experiencing extraordinary economic growth that has significantly impacted the
13 magnitude and timing of Georgia Power's capacity needs. A substantial portion of
14 this rapid economic growth is expected to occur over the next five years. The
15 Company must act expeditiously to address the significant energy needs associated
16 with this economic growth and to ensure it continues to maintain an electric System
17 that can reliably meet the needs of customers and our thriving state.

18 Between the conclusion of the 2022 IRP and the filing of the 2023 IRP Update,
19 Georgia Power was selected to serve more than 3,350 megawatts ("MW") of new,
20 large load customers, representing approximately 34 years of traditional customer
21 choice growth in just over one year. While substantial, this growth represents only
22 a fraction of the potential load growth from Georgia's economic development
23 pipeline. In fact, since the 2023 IRP Update was filed in October of 2023, the
24 economic development pipeline has continued to grow and has now expanded to

¹ <https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/>

1 more than 21,000 MW. In addition, the Company has now been selected to serve
2 an additional 2,602 MW since its initial filing in this proceeding. What's more,
3 several customers representing 2,173 MW of the new large load included in the
4 2023 IRP Update Forecast have now accelerated their load ramps, which would
5 incorporate their entire load by 2031. These changes since October 2023 evidence
6 the continued economic growth we are seeing in Georgia, continued customer
7 interest in being served by Georgia Power, and the need to act now to reliably meet
8 our customers' demand for energy as it continues to grow and accelerate. Moreover,
9 it underscores the need to plan for a P95 load forecast, a load level supported by
10 PIA Staff, to ensure the Company has sufficient resources to serve Georgia's
11 substantial energy needs that are being driven by economic growth.

12 No party has reasonably challenged that the overall increase in demand is real and
13 coming to the state. The only point of disagreement is the magnitude of the increase
14 and the timing in which the projected large loads will materialize. PIA Staff and
15 Intervenors alike agree with the Company's proposed methodology to account for
16 the increase in unexpected large load customer additions and only take issue with a
17 few assumptions, the impact of which lessens the magnitude of the growth and
18 assumes a slower pace for load realization.

19 With the 2023 IRP Update, Georgia Power is seeking approval of approximately
20 3,300 MW of generation capacity resources to serve its immediate growing
21 customer demand. Specifically, the Company has requested certification of
22 (i) 750 MW from the Mississippi Power Company ("MPC") Power Purchase
23 Agreement ("PPA"), (ii) 230 MW from the Santa Rosa PPA, and (iii) 1,300 MW
24 from three proposed combustion turbines ("CTs") at Plant Yates Units 8-10. The
25 Company has also requested approval to build 1,000 MW of battery energy storage
26 systems ("BESS"), including the Robins, Moody, and 200 MW BESS plus
27 200 MW solar projects. In addition, the Company has proposed two new distributed
28 energy resource ("DER") customer programs, a demand response program, and an

1 expansion of its existing residential thermostat demand program. Each of these
2 essential capacity resources will provide an economical and reliable supply of
3 electric power or valuable demand response for the Company's customers.
4 Significantly, these resources are in addition to and complement the resources the
5 Company is authorized to procure through competitive RFPs, which includes the
6 CARES Utility Scale ("US") RFPs, All-Source Capacity RFP, and 500 MW Energy
7 Storage System ("ESS") RFP.

8 Our rebuttal testimony addresses PIA Staff and Intervenor challenges to the
9 Company's load forecast assumptions, the procurement of resources outside of a
10 competitive RFP process, and the Company's proposed mix of capacity solutions.
11 Although PIA Staff and Intervenors made several recommendations regarding
12 Georgia Power's long-term generation and transmission planning processes, none
13 of those recommendations need to be decided in this case. The focus of this
14 proceeding should remain on how Georgia Power can best address the significant
15 near-term customer demand for electric power and the corresponding capacity need
16 between 2026 and 2028. Accordingly, much of our rebuttal testimony appropriately
17 focuses on those pressing issues. Other matters, including the balance of PIA Staff
18 and Intervenor recommendations, can be addressed more fully in Georgia Power's
19 2025 IRP or a subsequent proceeding.

20 Georgia Power's 2023 IRP Update establishes a plan that ensures the Company can
21 preserve and protect the reliability and quality of service our customers expect and
22 continue to reliably serve Georgia's growing capacity needs corresponding to
23 robust economic growth while also lowering rates for all retail customers by
24 spreading the cost of electric service across a larger customer base. The Company's
25 plan provides substantial economic and reliability benefits to the state and our
26 customers. As such, we respectfully request the Commission approve the
27 Company's request without modification.

1 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

2 A. The remainder of our testimony is structured as follows:

- 3 • Section II discusses the timing of the 2023 IRP Update and the need to act
4 now, before the 2025 IRP, to request Commission approval of the new
5 capacity resources.
- 6 • Section III addresses critiques of the Company's 2023 IRP Load Forecast
7 and assumptions incorporated into the Load Realization Model, which was
8 used to adjust the forecast for the projected addition of large load customers
9 to Georgia Power's System.
- 10 • Section IV discusses the Staff and Intervenor feedback and
11 recommendations regarding the Company's ability to expedite or modify
12 the RFPs approved in the 2022 IRP.
- 13 • Section V discusses Staff and Intervenor challenges to the Company's
14 Target Reserve Margin.
- 15 • Section VI responds to Staff and Intervenor recommendations and critiques
16 of the resources requested in this case.
- 17 • Section VII addresses the Company's transmission requests in the case and
18 responds to calls from Staff and Intervenors to alter its long-term
19 transmission planning process.

20 In addition to our testimony, the testimony of Aaron Abramovitz (i) explains why
21 Georgia Power expects the 2023 IRP Update to place downward pressure on rates
22 for customers, and (ii) addresses specific accounting aspects of the Company's
23 request.

II. THE COMPANY'S REQUEST

Q. WHY IS THE 2023 IRP UPDATE NECESSARY?

A. As discussed in our direct testimony, the 2023 IRP Update is necessary to preserve and protect the reliability and quality of service our customers expect, address the extraordinary economic growth taking place in Georgia, and to ensure that Georgia Power can continue to reliably meet the rapidly growing energy needs of our customers and our state.

Q. WHAT CAPACITY RESOURCES ARE NEEDED TO ENSURE THAT GEORGIA POWER CAN CONTINUE TO MEET THIS RAPID ECONOMIC GROWTH?

A. The 2023 IRP Update seeks approval of approximately 3,300 MW of additional capacity resources so that the Company can meet the state's energy needs for the period of December of 2025 through November of 2028. Specifically, the Company has requested certification of (i) 750 MW from the MPC PPA, (ii) 230 MW from the Santa Rosa PPA, and (iii) 1,300 MW from three CTs proposed at Plant Yates, Units 8-10. The Company has also requested permission to build 1,000 MW of BESS and proposed two new DER customer programs, approval of a new demand response program, and an amendment to the certificate to expand the existing residential thermostat demand response program. The proposed resource portfolio is an economic and reliable mix of resources available to meet the capacity needs identified in this 2023 IRP Update.

Q. HOW DOES THE COMPANY'S REQUEST FOR RESOURCES COMPARE TO THE TOTAL PIPELINE OF POTENTIAL ECONOMIC DEVELOPMENT PROJECTS IDENTIFIED IN ITS FORECAST?

A. The Company's request for 3,300 MW corresponds to the increase and the accelerated timing in the load growth forecast, which represents only a fraction of

1 the now more than 21,000 MW of potential economic development projects seeking
2 to meet their electricity needs.

3 **Q. CAN THE COMPANY WAIT UNTIL THE 2025 IRP TO REQUEST THESE**
4 **RESOURCES?**

5 A. No. The magnitude and timing of the projected load that is being driven by
6 economic growth require the Company to act now to secure the resources needed
7 to continue to reliably serve our customers and meet our state's energy needs.
8 Waiting until the conclusion of the 2025 IRP would be too late and would risk not
9 being able to serve the new economic development load that is coming to Georgia.
10 Failing to serve these new large loads would stifle economic development and
11 prevent Georgia Power's customers from benefitting from the corresponding
12 downward pressure on rates anticipated as a part of this 2023 IRP Update filing.

13 **Q. WHY IS IT INAPPROPRIATE TO INCLUDE A COST-OF-SERVICE**
14 **STUDY IN THIS IRP UPDATE OR THE 2025 IRP?**

15 A. A cost-of-service study is a required aspect of base rate cases, which are the
16 appropriate proceeding in which to determine the cost of service and allocation of
17 those costs among rates and rate groups. The Company is not requesting to adjust
18 rates as part of this IRP Update and a cost-of-service study is neither required nor
19 possible. A cost-of-service study in its entirety takes multiple months and extensive
20 Company resources to prepare. In addition, a rate case budget is required as an input
21 to the cost-of-service study, and this information will not be finalized prior to the
22 2025 IRP filing.

1 **Q. IS THE COMPANY OPEN TO UPDATING RELEVANT PORTIONS OF**
2 **THE COST-OF-SERVICE STUDY THAT IT FILED IN THE 2022 BASE**
3 **RATE CASE TO SUPPORT ITS REQUEST IN THIS CASE?**

4 A. Yes. For purposes of high-level sensitivity analysis only, the Company performed
5 an adjustment to the cost-of-service study filed in the 2022 Base Rate Case to
6 isolate the revenues and revenue requirement associated with the resources
7 proposed in this case. Exhibit 1 reflects a sensitivity based on Exhibit LPE-1 from
8 the 2022 Base Rate Case and includes the additional loads, costs and revenues
9 associated with this filing, as requested by Staff Panel Newsome-Hayet-Wellborn
10 during Staff Direct Hearings. The results of this sensitivity measure the benefits to
11 customer rate groups as a result of the 2023 IRP Update by an increase to Net
12 Income or Return on Investment (“ROI”). The results of Exhibit 1 show an increase
13 in Net Income and improved or approximately equal ROI for each customer rate
14 group and clearly demonstrates that customer benefit is equal or improved across
15 the board. Since the billed revenue for non-marginal rate groups did not change as
16 a result of the 2023 IRP Update, the results from Exhibit 1 show lower costs borne
17 by other rate groups, which are now being allocated to the new large loads in the
18 Marginal rate group. This allocation produces benefits for other customer rate
19 groups, including Domestic and Small Business.

20 **Q. DID THE COMPANY FILE THE 2023 IRP UPDATE AT THE**
21 **APPROPRIATE TIME?**

22 A. Yes. The Company filed the IRP Update at the appropriate time and as soon as
23 reasonably possible based upon the information available to it and which was
24 needed for Commission consideration. Until June 2023, the capacity need driven
25 by increased growth could be met with either (1) existing Company capacity
26 resources, including the capacity PPAs approved in the 2022 IRP, or (2) an increase
27 in the megawatt targets for the All-Source Capacity RFP for 2029-2031. There
28 simply was no need to consider returning to the Commission prior to June 2023,

1 when the Company's forecasting sensitivities indicated its capacity need year
2 moved earlier by two years from winter 2028/2029 to winter 2026/2027. As further
3 described in Section III below, once the Company determined that the capacity need
4 advanced, it promptly took steps to alert the Commission and address that change,
5 resulting in the 2023 IRP Update. The continued growth in the load forecast from
6 September 2023 used in this IRP Update further accelerated the capacity need year
7 to winter 2025/2026.

8 **Q. WHY SHOULD THE COMMISSION APPROVE THE COMPANY'S**
9 **REQUESTS IN THE 2023 IRP?**

10 A. If approved, the Company's requests will allow it to timely meet the significant
11 energy needs being driven by Georgia's extraordinary economic growth while also
12 placing downward pressure on rates for the benefit of all customers. Thus, approval
13 of the Company's request is in the best interests of our customers and our state and
14 will help ensure Georgia Power can continue to provide safe, clean, reliable, and
15 affordable electric service to Georgia's thriving and growing economy.

16 **III. LOAD FORECAST AND PROJECTED GROWTH**

17 **Q. WHY SHOULD THE COMMISSION HAVE CONFIDENCE IN THE 2023**
18 **IRP UPDATE LOAD FORECAST?**

19 A. The 2023 IRP Update is informed by the latest economic trends and uses proven
20 methods to evaluate the probability, level, and timing in which the projected load
21 will materialize. PIA Staff and the Intervenors submitting testimony on this issue
22 accepted the validity of the Company's organic load forecast and the statistically
23 sound methodology used to account for the growth in new large load customers.
24 (See, e.g., Tr. 89, lines 10-11; Tr. 1190, lines 8-9.) All indications, including direct
25 input from customers, demonstrate that Georgia's tremendous economic growth
26 will continue and that we must invest in new resources now to meet the state's

growing energy needs and preserve and protect the reliability and quality of service our customers expect.

The Company's forecasting methodology for large loads accounts for numerous types of uncertainty, including the potential that load will not materialize, will be delayed, or will materialize at a lower level than expected. Moreover, our forecast for large loads is based on the most recent economic trends, includes projects that have already selected Georgia Power as their electric service provider, and incorporates direct input from customers about growth in our state. As of the 2023 IRP Update filing, the Company had already been chosen to serve over 3,600 MW of load from the approximately 17,000 MW pipeline of economic development — nearly 3,000 MW of which is already under construction. Since the 2023 IRP Update filing, the Company has been selected to serve an additional 2,602 MW out of the current economic development pipeline of approximately 21,000 MW. As such, the Company's forecast provides the most realistic depiction of large load growth in Georgia, and we have an extremely high degree of confidence in our forecast.

Q. WITH REGARD TO THE COMPANY'S FORECAST, HOW MANY MW ARE ASSOCIATED WITH ACTUAL ECONOMIC DEVELOPMENT PROJECTS ANNOUNCED IN GEORGIA?

A. Of the 51 large load customer projects included in the external adjustment to the Company's 2023 IRP Update Load Forecast, 32 projects, accounting for almost 10,500 MW, have already chosen to do business in Georgia. These customers have taken concrete actions evidencing their commitment to do business in Georgia, such as purchasing or leasing property.

Q. HOW MANY MW ARE ASSOCIATED WITH PROJECTS GEORGIA POWER HAS BEEN SELECTED TO SERVE?

A. At the time of the filing in October 2023, 14 customers, accounting for 3,612 MW, had selected Georgia Power as their electric service provider. As of March 18, 2024, the Company has been selected to serve an additional 2,602 MW for a total of 6,214 MW. These additional 2,602 MW include 968 MW expected to be online by winter 2027/2028.

Q. WHAT IS THE STATUS OF THE CUSTOMER CHOICE PROJECTS THE COMPANY HAS BEEN SELECTED TO SERVE WITHIN THE LOAD REALIZATION MODEL?

A. Fourteen of the 51 projects included in the Company's load realization model in the 2023 IRP Update filing have executed a Request for Electric Service ("RFS"). As shown in Table 1 below, of these fourteen projects, nine have broken ground, four are pending construction, and only one is delayed. The thirteen projects that have broken ground or are pending construction comprise 3,546 MW of the total 3,612 MW. This evidence suggests that the biggest customer choice projects are moving forward and making progress without material delays.

Table 1: Status of Committed Customers

DATA CENTER - 8 Total Customers			
5 broken ground		3 pending construction	
	MW		MW
REDACTED	324	REDACTED	120
REDACTED	280	REDACTED	180
REDACTED	1,271	REDACTED	130
REDACTED	200		
REDACTED	240		
Subtotal	2,315	Subtotal	430
INDUSTRIAL - 6 Total Customers			
4 broken ground		1 pending construction	
	MW		MW
REDACTED	126	REDACTED	170
REDACTED	243		
REDACTED	60	1 project delayed	
REDACTED	202	REDACTED	66
Subtotal	631	Subtotal	236
9 out of 14 customers have broken ground	2,946	5 out of 14 construction pending or delayed	666

1 **Q. HOW DOES THE COMPANY USE AN RFS TO INFORM THE**
2 **COMPANY’S DECISION THAT IT WILL BE REQUIRED TO SERVE A**
3 **CUSTOMER?**

4 A. The RFS is a signed commitment that memorializes a customer’s selection of
5 Georgia Power as their electric service provider. RFSs have consistently been
6 recognized to be a legally binding agreement and are routinely used in Georgia
7 Territorial Electric Service Act (“Territorial Act”) cases as evidence of customer
8 choice.² The Company incorporates all of the new large load customers with signed
9 RFS in the Company’s adjusted Load Forecast, which serves as strong evidence
10 supporting the Company’s decision that it will be required to serve these customers.

11 **Q. WHY DOES GEORGIA POWER NEED TO PROCURE CAPACITY TO**
12 **SERVE ADDITIONAL LOAD THAT HAS NOT YET COMMITTED TO BE**
13 **SERVED BY GEORGIA POWER?**

14 A. Customers expect Georgia Power to be prepared to serve their load. As evidenced
15 by our progress to date, which has led to securing 6,214 MW with committed
16 customers, we anticipate that projects will continue to advance through various
17 stages of economic development and ultimately continue to materialize. As
18 mentioned previously, the economic development pipeline continues to grow and
19 has increased to 21,000 MW since the Company filed this proceeding. Georgia
20 Power has consistently demonstrated effectiveness in acquiring and retaining
21 customers within a competitive market, achieving a historical win rate that exceeds
22 70% of projects (representing approximately 90% of the associated load). This

² See, e.g., Order for Transfer of Retail Electric Service, Docket No. 55460; Order for Transfer of Retail Electric Service, Docket No. 55473.

1 successful track record supports the inclusion of these projects in the Company's
2 forecast and the capacity need associated with these projections.

3 **Q. DOES THE IRP UPDATE ATTEMPT TO ADDRESS ALL OF GEORGIA'S**
4 **POTENTIAL ECONOMIC DEVELOPMENT LOAD GROWTH?**

5 A. No. The Company's forecast accounts for the fact that Georgia Power will
6 ultimately only need to serve a portion of the large load customer projects it has
7 identified. In August 2023, the Company identified approximately 17,000 MW of
8 committed and potential projects, representing the full load of customers in the
9 pipeline looking to locate or expand in Georgia through the mid-2030s. The 2023
10 IRP Update Forecast projects that, through the winter of 2030/2031, Georgia Power
11 will be asked to serve only 6,600 MW of new load, representing only a portion of
12 the 17,000 MW pipeline. The amount of customer projects in the pipeline has
13 continued to grow and now stands at more than 21,000 MW, demonstrating that
14 Georgia's economic development success continues to attract new customer
15 growth.

16 This IRP Update seeks authority to build or buy 3,300 MW of capacity resources
17 to meet the Company's capacity needs from 2026-2028 and ensure the continued
18 reliability of the electric System. Consistent with the 2022 IRP Order, the Company
19 will continue to implement all existing RFPs and will use the All-Source RFP to
20 source the balance of the capacity needed from 2029-2031.

21 **Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE**
22 **INFORMATION THAT THE COMPANY PROVIDED STAFF TO ASSIST**
23 **IN ITS EVALUATION OF THE LOAD FORECAST IN THIS CASE.**

24 A. As part of its initial filing, the Company provided short-term, long-term, peak, and
25 load realization models; workpapers including weather data, forecast inputs, short-
26 term model outputs, and Peak Demand aggregate and Territorial files that contain

1 final output information on peak and energy forecasts, and data supporting all charts
2 and tables included in the filing. The Company also held a technical session, at PIA
3 Staff's request, to help orient and familiarize PIA Staff's new consultant with
4 Georgia Power's practices, processes, and forecasting methodology. The Company
5 also provided guidance on how to acquire the software programs to aid in PIA
6 Staff's and PIA Staff's consultant's analysis of the Company's data. Once acquired,
7 the software programs are available for immediate use, and the models that were
8 provided to PIA Staff were self-contained and able to be run upon acquisition of
9 the software. The models shared with PIA Staff provided more information than
10 would normally be included in a static technical appendix; these models can also
11 be tested and used to develop PIA Staff's own comparable models. Ultimately, the
12 Company met with PIA Staff and PIA Staff consultants to review the models and
13 answer any questions, and to the extent PIA Staff had further questions or concerns,
14 the Company was open to additional meetings with PIA Staff.

15 **Q. DID ANY PARTY PRESENT TESTIMONY CHALLENGING THE**
16 **METHODOLOGY SUPPORTING THE COMPANY'S BASE FORECAST?**

17 A. No.

18 **Q. DID ANY PARTY PRESENT TESTIMONY CHALLENGING THE**
19 **COMPANY'S METHODOLOGY FOR ADJUSTING ITS BASE LOAD**
20 **FORECAST TO ACCOUNT FOR LARGE LOAD CUSTOMER GROWTH?**

21 A. No. In fact, PIA Staff agrees that the Company's methodology is appropriate and
22 GIPL agrees that a new methodology was needed to account for this growth. PIA
23 Staff and Intervenor objections regarding the load forecast are limited to the
24 underlying assumptions on load ramp, load value, and delay.

1 **Q. WHAT WERE PIA STAFF'S RECOMMENDATIONS REGARDING THE**
2 **ASSUMPTIONS USED IN THE LOAD REALIZATION MODEL?**

3 A. PIA Staff recommends three changes to the load realization model:

- 4 1. Use uniform load materialization probabilities for all customers, rather than
5 assume that data centers and cryptocurrency customers will materialize at a
6 different probability than other customer segments.
- 7 2. Use a REDACTED delay assumption for load ramp associated with data
8 centers, rather than the REDACTED delay proposed by the Company,
9 which is based on PIA Staff's assumption that supply chain delays and labor
10 shortages are likely to delay data center construction timelines.
- 11 3. Increase the range of alternative futures by varying the key assumptions to
12 produce a range of potential load additions along with a range of timing for
13 those load additions to assess risks to the Company and customers. (Tr. 9-
14 12.)

15 **Q. PLEASE RESPOND TO PIA STAFF'S ALLEGATION THAT THE**
16 **COMPANY HAS NOT PROVIDED EVIDENCE TO SUPPORT ITS**
17 **ASSUMPTION THAT DATA CENTERS AND CRYPTOCURRENCY**
18 **CUSTOMERS WILL MATERIALIZE AT A DIFFERENT RATE THAN**
19 **OTHER CUSTOMERS IN THE SAME INDUSTRY SEGMENT.**

20 A. The Company relied on prior experience with its 60 existing data center customers
21 to inform the assumption that data centers and cryptocurrency customers will
22 materialize at a different rate than other customer segments. The Company relied
23 on the expertise of its employees who are in direct contact with existing and
24 potential customers, including data centers, daily and who are intimately involved
25 in the progress of these customers from the initial request for service to the date
26 their facility is energized. The only distinction regarding the data center load
27 anticipated in this case and the data center customers already served by Georgia

1 Power is the speed and magnitude in which the load is projected to materialize. In
2 addition, one of Georgia Power's existing large load data center customers recently
3 informed the Company that the load realization for two of its hyperscale data
4 centers is approximately 80%, corroborating the Company's assumed load
5 realization.

6 **Q. DID STAFF PROVIDE EMPIRICAL EVIDENCE TO SUPPORT**
7 **CHANGING THE DATA CENTER AND CRYPTOCURRENCY**
8 **CUSTOMER LOAD REALIZATION ASSUMPTION?**

9 A. No. Staff simply rejected the Company's assumption, arguing that because the
10 Company relied only on its informed judgment, there was no reason to treat data
11 center and cryptocurrency customers differently than customers in other segments.

12 **Q. PLEASE DISCUSS YOUR CONCERNS WITH PIA STAFF'S CHANGES**
13 **TO THE COMPANY'S LOAD RAMP DELAY ASSUMPTION.**

14 A. PIA Staff's proposed change to the data center load ramp assumption lacks any
15 reasonable support. Indeed, PIA Staff relied on unrelated anecdotal references from
16 Google searches of dated construction trade press, blog posts, and a FOX 5 news
17 article to suggest that labor shortages and supply chain issues have delayed data
18 center construction elsewhere in the country. PIA Staff admitted during the hearing
19 that these articles may not be the best or most accurate sources but stated that their
20 intent in citing these articles was merely to demonstrate uncertainty. (Tr. 227-228.)
21 However, PIA Staff's references are not specific to Georgia and are unrelated to
22 the data centers seeking service from Georgia Power. Without justification, PIA
23 Staff assumes that potential delays have not already been addressed by the
24 construction timelines and load ramps of the large load customers coming to
25 Georgia. In contrast, the Company's assumptions are based on information
26 obtained directly from the customers developing the projects in question. These
27 customers are best positioned to address their project timelines based on their

1 substantial industry experience and intimate knowledge of the projects themselves.
2 Moreover, by altering the assumptions of the load realization model, PIA Staff's
3 efforts go beyond identifying areas of uncertainty or risk. If adopted, PIA Staff's
4 load forecast recommendations will materially impact the Company's ability to
5 serve new large load customer projects.

6 **Q. DID STAFF USE A RANGE OF ALTERNATIVE FUTURES LIKE IT**
7 **RECOMMENDS THE COMPANY USE?**

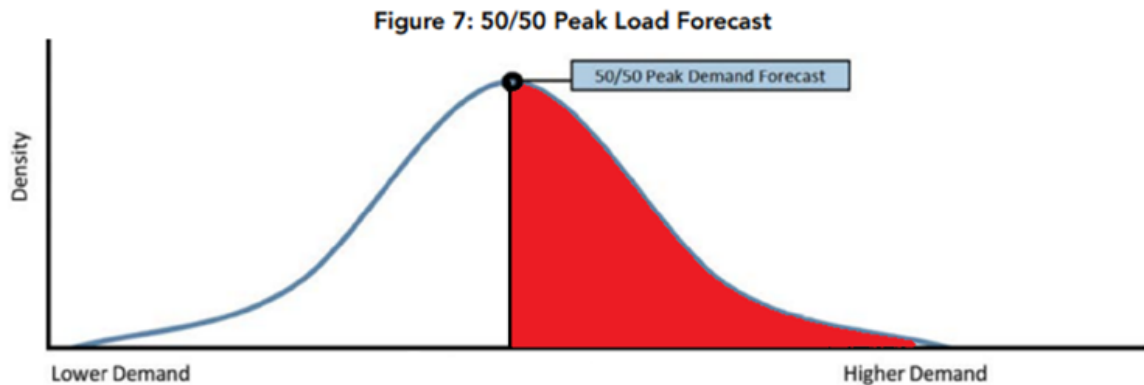
8 A. No. Staff only considered scenarios involving a delay in load and did not evaluate
9 what the load forecast would look like if loads materialized faster than projected.
10 Significantly, three large load customers included in the external adjustment to the
11 Company's forecast have now requested to accelerate their load ramp – seeking
12 2,331 MW to be served by 2031 rather than 2,173 MW by 2036 as they initially
13 requested. In certain years, such as 2028 and 2029, this acceleration would result
14 in approximately 800 MW of additional load than was assumed for the 2023 IRP
15 Update Load Forecast and demonstrates the potential for substantial load to
16 materialize at a faster pace than projected.

17 **Q. WHY WOULD IT BE INAPPROPRIATE TO USE A P50 LOAD VALUE AS**
18 **PROPOSED BY GIPL WITNESS HOTALING?**

19 A. Planning generation resources to the P50 load value presents unacceptable risk
20 when seeking to serve the significant large loads coming to the state. Planning to
21 P50 can help support a slower, steady growth in load. But the load growth being
22 experienced in Georgia is extraordinary, not slow and steady. Planning generation
23 resources to P50 necessarily means that the Company would not have sufficient
24 resources to meet customer needs in half of the potential scenarios for new large
25 load customers and would thus not be able to support as much new economic
26 development load coming to the state. Notably, GIPL used the Company's large
27 load forecast methodology and assumptions but proposed using a P50 level load

value instead of the P95 load value used by the Company. In doing so, GIPL asserted that the P50 value is, statistically speaking, the most likely outcome and should, therefore, be used in lieu of the P95 value. Using Figure 7 from GIPL Witness Hotaling's testimony, you can see that the P50 value occurs at the peak of the bell curve on the distribution of possible outcomes. However, as shown in the modified Figure 7 graphic below, electing to use the P50 value for the large load forecast means that there is a 50% chance that loads exceed the predicted value, as seen by the red shaded area under the curve. Simply put, if Georgia Power were to plan its System using the P50 value, that would mean there is a 50% chance that it would have too few resources to meet large load customer needs, and therefore would not be able to reliably support the demands of new economic load growth.

Figure 1: 50/50 Peak Load Forecast



Further, the load forecast is a static snapshot in time that does not capture the fact that additional load growth is taking place. (Tr. 1312, lines 12-15.) For each new large load customer that comes onto the System, the load level previously planned for becomes less representative of the higher needs the Company must serve. (Tr. 1312-1313.) Thus, as customer load continues to grow, it is even more risky to plan according to the P50 load level than the P95 load level. This further demonstrates why it would be inappropriate to plan for the P50 load level, as recommended by

1 Witness Hotaling, than the P95 load level, which better ensures the Company has
2 sufficient resources needed to reliably serve the growing customer demand.

3 **Q. IS THE COMPANY WILLING TO ADOPT A TRACKING SYSTEM TO**
4 **MONITOR MARKET ACTIVITIES AND TRACK THE STATUS AND**
5 **OUTCOMES OF POTENTIAL LARGE LOAD CUSTOMER PROJECTS?**

6 A. Yes. In fact, the Company began tracking this data in greater detail in 2023 in
7 response to the extraordinary growth in the state and the increase in large load
8 customers asking to be served by Georgia Power.

9 **Q. PLEASE RESPOND TO STAFF AND INTERVENOR SUGGESTIONS**
10 **THAT THE COMPANY SHOULD HAVE KNOWN EARLIER THAT**
11 **CUSTOMER LOAD GROWTH WAS SIGNIFICANT ENOUGH TO**
12 **REQUIRE RETURNING TO THE COMMISSION TO REQUEST**
13 **ADDITIONAL RESOURCES.**

14 A. The Company could not have foreseen the changes prompting the 2023 IRP Update
15 earlier than it did. As background, in August 2021, when the Load Forecast
16 supporting the 2022 IRP was completed, there was no indication that commercial
17 and industrial sectors would experience the exponential growth observed in 2022
18 and 2023. Before 2021, the Company averaged only about 100 MW of new large
19 load economic development customers per year. This total rose to 336 MW in 2021
20 (due to the win of a single customer), tripling the historical average, and 2,197 MW
21 in 2022, which was 22 times the historical average. The Company first identified a
22 new increase in projected load when it created its Budget 2023 load forecast in
23 August 2022 as part of its annual planning process. The Budget 2023 Forecast,
24 which was based on the latest data available at the time, identified an expected load
25 increase of only 1,100 MW through the winter of 2030/2031, as compared to the
26 2022 IRP filing.

1 In January 2023, following the continued increase in economic development
2 projects, the Company began more detailed tracking of customer choice activity on
3 a monthly basis. It also developed a model to produce load forecast sensitivities
4 with greater frequency than the typical annual load forecast to help further inform
5 its resource planning decisions. The load forecast sensitivities developed in June
6 2023 identified considerable increases in projected load and, for the first time,
7 identified an accelerated capacity need for the winter of 2026/2027.

8 To be clear, until June of 2023, all increases in projected load could be covered by
9 existing resources or addressed by increasing the size of the 2029-2031 All-Source
10 Capacity RFP that was approved in the 2022 IRP. Thus, it was not until June 2023
11 that the Company detected a change in the Company's capacity need year (i.e., the
12 year in which the Company will require additional resources moved from winter
13 2028/2029 to winter 2026/2027). It was this change that necessitated the
14 development of the 2023 IRP Update to procure resources to meet an even earlier
15 capacity need beginning in the winter of 2025/2026 based on the final load forecast
16 from September 2023.

17 **Q. HOW DO YOU RESPOND TO THE CONCERNS RAISED BY PIA STAFF**
18 **REGARDING THE COMMISSION'S RULES FOR IRP LOAD**
19 **FORECASTING AND THE COMPANY'S FILING IN THIS CASE?**

20 A. The Company complied with the Commission's Rules regarding the contents and
21 validity of a load forecast. As acknowledged by PIA Staff (*See* Tr. 244, lines 10-
22 13) and the procedural and scheduling order in this docket, the Company's IRP
23 Update is of a limited scope. Although the Company would typically provide a high
24 and low load growth sensitivity to the load forecast supporting the triennial IRP,
25 the Load Realization Model used to adjust the forecast in this case for the new large
26 load customer growth appropriately evaluated a range of outcomes and possible
27 futures within the context of the changed circumstances the IRP Update was
28 intended to address. The Company ran multiple load forecast sensitivities in the

1 months leading up to the IRP Update filing, each of which was provided to PIA
2 Staff in STF-DEA-1-4. The fact that the Company analyzed the different
3 sensitivities, chose the most reasonable load forecast to plan to, and proposed a
4 portfolio of resource solutions to meet the need is not a failure to meet Commission
5 rules directed at the triennial IRP filing and certainly did not prevent PIA Staff or
6 Intervenor from proposing an alternative forecast.

7 Second, the base forecast, which captures organic growth on the System, was
8 compiled using the same methodologies, models, and techniques as used in prior
9 IRPs and as accurately described in the Load Forecast Technical Appendix to the
10 2022 IRP. In addition, the Company provided alternate levels of expected growth
11 as part of its resource mix study. A description of all load forecast determinants was
12 provided in response to STF-JKA-2-10. The impact of self-generation and
13 cogeneration is included in the Load Forecast Technical Appendix of the 2022 IRP,
14 and the transparency of the Company's forecasting tools are as transparent and
15 appropriate as they have been in every IRP since 2001. In relying on the same
16 methodology previously used, it was not necessary to re-submit Sections 4 through
17 6 of the Technical Appendix of the 2022 IRP. The 2023 IRP Update was
18 appropriately focused on the Load Realization Model and forecast adjustments
19 supporting the substantial new large loads coming to the state.

20 **Q. WHAT IS THE RISK OF ADOPTING STAFF'S RESOURCE PLAN BASED**
21 **ON STAFF OR GIPL'S LOAD FORECAST IF MORE LOAD**
22 **MATERIALIZES THAN THEY PROJECTED?**

23 A. If the load materializes at a rate higher than projected and outpaces the generation
24 approved to serve that load, the Company would not be able to reliably serve its
25 growing customer load or support Georgia's economic growth. If there is
26 insufficient generation to support the addition of more customer load, the Company
27 will have to stop making offers to businesses looking to locate or expand in
28 Georgia. Customers who would otherwise locate or expand in Georgia are likely to

1 take their business elsewhere. In such case, Georgia would miss out on economic
2 growth, and the Company and its customers would lose the opportunity to place
3 downward pressure on rates by spreading the cost of electric service across a larger
4 customer base.

5 **Q. CAN THE COMPANY AND THE COMMISSION MITIGATE POTENTIAL**
6 **RISK IF THE COMMISSION ACCEPTS THE COMPANY'S PROPOSED**
7 **PLAN BUT LESS LOAD MATERIALIZES THAN PROJECTED?**

8 A. Yes. There are several actions the Company and the Commission can take to
9 mitigate risks associated with load materializing at a lower level than forecasted by
10 the Company. Primarily, the Company can sell capacity in the wholesale market or
11 slow down, reduce, or halt generation development in such a case. Other than
12 remarketing capacity, the Company can also manage the development timeline of
13 approved resources or the procurement amount from approved RFPs. For example,
14 the Company can (1) reduce the amount of BESS it develops based on the
15 unidentified balance of BESS MW in this case, and it can (2) reduce the target
16 capacity (MW) to be procured in one or more future RFPs, including the All-Source
17 RFP.

18 **IV. THE REQUEST FOR PROPOSAL PROCESS**

19 **Q. WHY DID THE COMPANY REQUEST AN EXCEPTION TO THE**
20 **COMMISSION'S RFP PROCESS IN THE IRP UPDATE?**

21 A. Due to the Company's capacity need in the winters of 2025/2026, 2026/2027, and
22 2027/2028, there simply isn't enough time to use an RFP, which typically takes two
23 to two-and-a-half years to implement, evaluate, contract, and certify resources to
24 meet the need. This is especially true in a constrained market with few existing
25 resources available for contracting as additional time is needed to construct new
26 resources and any necessary supporting transmission projects. Therefore, the

1 Company requested to procure resources pursuant to one or more of the RFP
2 exceptions to ensure it can serve the customer load identified in its forecast and
3 continue to maintain a reliable electric System.

4 **Q. DOES GEORGIA POWER SUPPORT THE COMMISSION'S RFP**
5 **PROCESS?**

6 A. Yes. Georgia Power supports the Commission's RFP process and has conducted
7 over 20 RFPs since 2006. The Company is currently developing and implementing
8 numerous RFPs, including the All-Source Capacity RFP, CARES US RFP, the
9 Biomass RFP, the DG RFP, and the 500 MW ESS RFP that were approved in the
10 2022 IRP. The Company fully intends to continue implementing its current RFPs
11 and utilizing the RFP process in procuring generation resources in the future.

12 **Q. WHY CAN'T THE COMPANY RELY ON EXISTING RFPs TO PROCURE**
13 **THE RESOURCES REQUIRED IN THE 2023 IRP UPDATE?**

14 A. The Company needs resources online to meet the capacity need in the winters of
15 2025/2026, 2026/2027 and 2027/2028, and the RFP process typically takes two to
16 two-and-a-half years to identify, evaluate (including associated transmission),
17 select, and certify capacity resources. Any new-build resources selected through
18 such an RFP would not only have to be identified on an expedited timeline but
19 constructed and brought online as early as November 2025 through November
20 2027, which is simply not feasible. Moreover, there is no guarantee that the market
21 would offer a sufficient quantity of firm, dispatchable resources in response to an
22 RFP to provide the required capacity in the timeframe needed. Also, the existing
23 RFPs are crucial to meeting the needs identified in the 2022 IRP for renewable
24 energy resources, ESS resources, and capacity resources for the needs in the 2029-
25 2031 timeframe and therefore must be conducted to best meet those specific needs.

1 **Q. STAFF WITNESS KADUK PROPOSED ADDING 500 MW OF CAPACITY**
2 **EQUIVALENCE TO THE RESOURCE LEDGER US SCALE RFP. WHY**
3 **WOULD THIS NOT BE APPROPRIATE?**

4 A. The Company only includes installed, planned, and committed resources in its
5 resource ledger beginning in the year the resource is known to be in-service and for
6 which the Company knows the resource's contribution to meeting capacity needs.
7 It is impossible to know how many bids submitted into the CARES 2023 US RFP
8 will be selected and will include renewable plus storage resources. There is also no
9 guarantee the Company can fill the suggested 500 MW of storage from the portfolio
10 of the 2023 CARES US RFP, which is the largest renewable RFP the Company has
11 ever conducted. In addition, no Georgia Power US RFP portfolio has ever had every
12 project achieve commercial operation at the same time, which PIA Staff Witness
13 Kaduk acknowledged on the stand. There are risks in assuming there will be 500
14 MW of renewable plus storage resources all online at the same time before 2028.

15 Ultimately, this decision does not have to be made in this case. The Company plans
16 to give the appropriate capacity credit to any storage resources that are selected in
17 the 2023 CARES US RFP. If Staff's prediction comes to fruition, the Company and
18 the Commission can act at the time of certification, when the resources procured
19 through the 2023 US RFP are known, to reduce the amount of capacity resources
20 the Company needs to procure in a future RFP such as the 2029-2031 All-Source
21 RFP.

22 **Q. PLEASE RESPOND TO THE TIMELINE OF DISCUSSIONS BETWEEN**
23 **THE COMPANY AND STAFF PRESENTED IN THE NEWSOME, HAYET,**
24 **WELLBORN PANEL.**

25 A. The Company always appreciates the opportunity to collaborate and work with
26 Staff to discuss issues and possible solutions as they arise, which affirmatively
27 evidences the constructive regulatory environment in Georgia. Although PIA

Staff's timeline accurately accounts for the chronology of the discussions, their presentation of what was discussed omits some important details that misconstrues the nature and timing of the Company's request.

PIA Staff's timeline suggests that the Company failed to notify the Commission early enough that its projected customer load had significantly increased. However, this ignores that in the 2022 IRP the Commission approved six capacity PPAs for over 2,200 MW and the All-Source RFP for needs in 2029-2031, which together would have been able to serve additional customer growth coming to the Company through 2031. As previously discussed, until June 2023 this additional load only increased the size of the Company's capacity needs in 2029 and beyond but did not advance the need year. The Company appropriately alerted the Commission of the need to act when the load forecast sensitivities first indicated an acceleration in the Company's capacity need year to winter 2026/2027.

PIA Staff's timeline also leaves out the Company's June 2023 proposal to divide the All-Source Capacity RFP into phases and issue an expedited "Phase 1" of the All-Source RFP in the fall of 2023. The Company proposed to shorten the RFP development timeline and to seek resources similar to those sought in the prior capacity RFP using the Commission-approved contracts from the 2022-2028 Capacity RFP. In response, PIA Staff questioned (i) whether the Company had the authority to issue more than one All-Source RFP under the terms of the 2022 IRP Final Order, and (ii) the appropriateness of procuring additional resources due to increased capacity needs without vetting the revised load forecast in a proceeding with hearings and public comment. Throughout the summer, the Company responded to follow-up questions, informal data requests, exchanged regular emails, and provided substantial data to PIA Staff that was not fully captured in PIA Staff's Testimony. Even though the nature of the Company and PIA Staff's discussions prior to the filing of the 2023 IRP Update does not change the Company's requests in this case, we wanted to clarify both the Company's and PIA

1 Staff's efforts to productively investigate and address the substantial energy need
2 facing the state.

3 **Q. DID THE COMPANY CONSIDER ISSUING AN RFI EARLIER, AS**
4 **PROPOSED BY SIERRA CLUB?**

5 A. Yes. In the absence of a targeted, expedited Phase 1 All-Source Capacity RFP, the
6 Company sought to issue an RFI as soon as possible to gain information regarding
7 the availability of existing and planned capacity resources for the capacity need
8 identified for years 2026 through 2028 (the timeframe being addressed in the
9 Company's 2023 IRP Update) as well as for years 2029 through 2031, the time
10 period to be addressed in the Company's 2029-2031 All-Source Capacity RFP. For
11 the years 2026 through 2028, the RFI would be very valuable in determining if
12 there were additional existing resources available beyond those already identified
13 by the Company. In August 2023, the Company proposed to issue the RFI through
14 the independent evaluator ("IE") website with the oversight of the IE that was
15 selected for the All-Source Capacity RFP. However, delay in finalizing the IE
16 contract led to the Company issuing the RFI on its own in September 2023 in an
17 effort to solicit timely feedback from the market.

18 **V. TARGET RESERVE MARGIN**

19 **Q. WHAT TARGET RESERVE MARGIN DID THE COMPANY USE IN THE**
20 **2023 IRP UPDATE?**

21 A. Consistent with the 2022 IRP Final Order, the Company used a 26% winter target
22 reserve margin for planning purposes. Planning for 26% in the long term and 25.5%
23 in the short term resulted in an 80% increase in reliability in the Company's 2021
24 Reserve Margin Study as compared to a 20% reserve margin, which was the 1:10
25 Loss of Load Expectation ("LOLE") threshold. The Company's winter target
26 reserve margin served the state well in recent extreme weather events, such as

1 Winter Storm Elliott on Christmas Eve in 2022 and Winter Storm Heather, which
2 occurred earlier this year on the second day of direct hearings in this case. Planning
3 to a 26% winter target reserve margin ensures that the Company is prepared to
4 handle reliability events such as these, even as customer behavior evolves over
5 time. Further, maintaining a 26% target reserve margin lowers expected customer
6 costs as compared to a 20% reserve margin per the 2021 Reserve Margin Study,
7 which considers not only capacity costs, but also production costs and reliability
8 costs.

9 **Q. IS THERE A GENERAL TREND IN THE INDUSTRY TOWARD WINTER**
10 **RESERVE MARGINS?**

11 A. Yes. Several utilities are now either establishing winter reserve margins or are
12 starting to plan for higher winter reserve margins. Duke Energy Carolinas, Duke
13 Energy Progress, Santee Cooper, MISO, SPP, and PJM have either increased their
14 winter target reserve margins or established winter target reserve margins in the last
15 few years. Decreasing the Company's reserve margin would be a step in the
16 opposite direction compared to the industry and would reduce Georgia Power's
17 System reliability.

18 **Q. WHY IS STAFF'S PROPOSED 24.5% TARGET RESERVE MARGIN**
19 **INAPPROPRIATE?**

20 A. Customers benefit from the enhanced reliability offered by planning to a winter
21 target reserve margin of 26% for very little additional cost. Planning to a lower
22 target reserve margin like the 24.5% recommended by PIA Staff reduces System
23 reliability and does not provide substantial cost savings. If the Company planned to
24 a 24.5% winter target reserve margin, the System's performance during extreme
25 winter weather events like Winter Storm Elliott would have been diminished. Also,
26 Staff's recommendation in the 2022 IRP for 24.5% sought to remove the risk of
27 under forecasting loads from the Reserve Margin Study, while only planning for

1 risks associated with over forecasting loads. Planning for only one direction of
2 movement on something like a load forecast is inappropriate because it fails to
3 sufficiently capture the reliability risk. The 2023 IRP Update is itself strong
4 evidence that loads can be higher than forecasted.

5 **Q. PLEASE RESPOND TO INTERVENOR RECOMMENDATIONS THAT**
6 **RE-RUNNING THE RESERVE MARGIN STUDY WOULD PLACE**
7 **DOWNWARD PRESSURE ON THE ECONOMICS OF RESOURCES**
8 **CONSIDERED BY THE COMPANY.**

9 A. Witness Hotaling suggested that higher current capacity prices might reduce the
10 Target Reserve Margin down to the 20% threshold for 1:10 LOLE. (Tr. 1286, lines
11 15–17.) While capacity prices do impact the economic evaluation in a Reserve
12 Margin Study, it would be inappropriate to update a single variable without
13 considering how other variables may have also changed. The assumption that a
14 higher capacity price could result in a lower Economic Optimum Reserve Margin
15 (“EORM”) also ignores the Value at Risk component to the Company’s Reserve
16 Margin Study, which considers the value to customers for a reserve margin higher
17 than the EORM. The Company will update all the relevant variables and perform a
18 full Reserve Margin Study that will be filed as part of its 2025 IRP. At that time,
19 the impact of capacity price changes can be properly evaluated in the context of all
20 other changes in the study, including any updates to the level of reserve margin
21 associated with a 1:10 LOLE.

1 **Q. SHOULD THE COMPANY SIMPLY REDUCE ITS WINTER TARGET**
2 **RESERVE MARGIN TO 20%, EQUIVALENT TO THE 1 IN 10 LOLE, AS**
3 **RECOMMENDED BY PIA STAFF AND SOME INTERVENORS?**

4 A. No. The Company does not recommend reducing the winter target reserve margin
5 below the 26% approved for planning purposes. Although some utilities plan to a
6 level of reliability associated with a 1:10 LOLE, the Company considers that to be
7 a minimum threshold, and also considers the costs and risks to customers when the
8 target reserve margin is set. Lowering the winter target reserve margin to 20%
9 would result in a reduced level of reliability, on par with or even below other
10 regions that had firm load shed during recent winter events. Lowering the reserve
11 margin to 20% would result in an 80% increase in the likelihood the Company
12 would need to shed firm load, and the loss of firm load would be expected to be
13 twice as severe, with a 110% higher amount of Expected Unserved Energy
14 (“EUE”). With a 20% target reserve margin, the Company would be twice as reliant
15 on interruptible loads and would expect higher generation production costs and
16 purchased power costs. This lower level of reliability without consideration of costs
17 and risks is not what the Company endeavors to provide its customers. System
18 wide, adoption of a 20% winter planning reserve margin reduces the System
19 capacity by approximately 1,800 MW. This 1,800 MW, embedded in the
20 Company’s 26% winter target reserve margin, was necessary to maintain reliability
21 during Winter Storm Elliott, and there is no evidence to the contrary.

VI. PROPOSED RESOURCE SOLUTIONS

Staff Economic Analysis

Q. PLEASE DESCRIBE STAFF'S ECONOMIC ANALYSIS AND RESOURCE MIX ANALYSIS.

A. PIA Staff conducted a review of the resources proposed by the Company. Their review encompassed two primary analyses – a Resource Mix Study and a Ranking Analysis – utilizing the Aurora optimization model, within the defined study period of 2024 to 2040, which was used to expedite simulation times. The Resource Mix Study was conducted to determine the optimal selection of resources. This study was also intended to address the perceived shortcomings in the Company’s economic analysis. In reevaluating the proposed resource investments, PIA Staff aimed to ascertain the necessity and economic viability of procurement of the Company’s proposed resources. The analysis purported to weigh the proposed new resources against generic candidate units. Additionally, an economic ranking analysis was carried out, positioning the Company’s identified resources on a spectrum from most to least favorable. This supplementary analysis was intended to provide the Commission with a structured reference should there be a requirement to pursue additional resources beyond the PIA Staff’s endorsement.

Q. DOES THE COMPANY HAVE CONCERNS WITH PIA STAFF'S ECONOMIC ANALYSIS AND RESOURCE MIX STUDY USED IN THE 2023 IRP UPDATE?

A. Yes. The Company has several reservations regarding PIA Staff's Economic Analysis and Resource Mix Study in the 2023 IRP Update. The extent of the issues signals to the Company that PIA Staff's findings are flawed and merit no consideration by the Commission. The identified discrepancies and oversights in PIA Staff's analysis are in the following key points:

- The abbreviated study duration ending in 2040 inadvertently skews results and biases the model against all new construction proposed by the Company, primarily because it fails to account for the complete operational lifespan of the proposed new construction Company-owned assets. This short study period also precipitated fundamental mistakes producing inaccurate results.
- PIA Staff's analysis relied on generic units that are not feasible for construction within the time frame of 2026-2028, yet they were assumed to be available regardless.
- The conditions set by PIA Staff only allowed for the selection of new Company-owned proposals at their explicit Commercial Operation Dates ("COD"), in stark contrast to the ongoing availability afforded to generic alternatives, which could be selected at any time. This discrepancy, combined with an error related to the incorrect entry of the CODs for Plant Yates Units 8-10, hindered the model's ability to consider the Company's proposed resources appropriately, effectively excluding Yates Units 8-10 from consideration.
- Finally, the approach taken did not consider variability of natural gas, ignoring the low and high gas price scenarios.

Q. PLEASE EXPLAIN THE IMPACT OF THE SHORTER STUDY PERIOD.

A. The truncated study period chosen by PIA Staff has considerable implications, not the least of which is the disregard for the long-term benefits that Company-owned assets with extended lifespans could offer customers. By arbitrarily setting 2040 as the study cutoff, PIA Staff's economic analysis fails to account for unit performance and cost savings that would accrue from assets like Plant Yates Units 8-10, the proposed BESS projects, and the proposed BESS plus Solar project—all of which are anticipated to operate beyond the end date assumed by PIA Staff.

PIA Staff’s methodological oversight in adjusting for the shortened study period also introduced significant errors, particularly in the assessment of Combined Cycle units with carbon capture and sequestration (“CC with CCS”). PIA Staff’s selection of a substantial volume of CC with CCS in the moderate gas, zero-dollar carbon scenario (“MG0”) raises questions about the legitimacy of their analysis. By limiting the final study year to 2040 in PIA Staff’s analysis, the availability of the 45Q tax credit — which is applicable only for the first 12 years of CC with CCS operation — was not correctly factored into the long-term economic model. Consequently, the stark cost increases that are expected to follow the 45Q tax credit’s expiration were disregarded in PIA Staff’s analysis. This oversight signifies broader analytical inaccuracies and undervalues the perceived benefits of the resources proposed by the Company, which in turn has contributed to PIA Staff’s recommendation to reject these resources.

Q. DID STAFF’S RESOURCE MIX ANALYSIS CONSIDER ADDING THE PROPOSED PLANT YATES UNITS 8-10?

A. No. PIA Staff’s analysis included a combination of errors that prevented the evaluation of Plant Yates Units 8-10 in the Resource Mix Analysis. Notably, the allowed selection dates for Plant Yates Units 8-9 and Unit 10 were incorrectly set to 1/1/2026 and 1/1/2027, respectively. In addition, there was no capacity modeled for Unit 9 in 2026, as the actual projected COD is in 2027, and only one month of capacity was modeled for Unit 8. PIA Staff artificially limited the opportunity for the model to pick Plant Yates Units 8-10 exclusively to the year of the entered selection dates and before any winter capacity contributions could be recognized by the model. Such limited parameters led to the Aurora model’s optimization algorithm dismissing the Yates Units outright without sufficient consideration.

In response to hearing requests, PIA Staff acknowledged that allowing the Yates CTs the flexibility to be chosen in years beyond 2026 and 2027 would have resulted

1 in the selection of Plant Yates Unit 8 in 2028, even without extending the study
2 period.

3 **Q. CAN GENERIC RESOURCES MEET CAPACITY NEEDS IN 2026-2028?**

4 A. No. Asserting that generic resources could meet the Company's capacity
5 requirements in 2026-2028 is fundamentally inappropriate. Generic resources lack
6 defined specifics such as location, transmission interconnection and deliverability,
7 land and fuel availability, finalized engineering plans, and the necessary
8 environmental permits.

9 The utilization of these hypothetical constructs in place of the Company's proposed
10 projects undermines reliability, as generic resources cannot be built swiftly enough
11 (if at all) to meet imminent capacity needs. A more reasonable approach would
12 bypass the use of generics from 2026-2028, focusing solely on actual, executable
13 resources.

14 **Q. DID THE COMPANY COMPLETE AN ANALYSIS CORRECTING FOR**
15 **STAFF'S ERRORS?**

16 A. Yes. The Company modified PIA Staff's modeling, which used the Company's
17 load forecast, to correct for the errors described above to conduct an updated
18 analysis. Specifically, the Company's analysis extends the study period to 2058 and
19 corrects the limitation on Plant Yates Unit 8-10 CODs. This recalibration not only
20 rectifies the CC with CCS error but also provides a more accurate representation of
21 new construction resource lifespans.

22 The results achieved by using PIA Staff's own model—with the Company's
23 corrections—led to the selection of previously excluded projects, including the
24 Robins and Moody BESS projects and Plant Yates Units 8-10. These outcomes
25 demonstrate that these projects included in the Company's proposed portfolio of
26 resources are economically favorable when evaluated without errors. The

1 Company's revised analysis correcting PIA Staff's modeling casts reasonable
2 doubt on PIA Staff's initial rejection of the proposed Yates CTs and Robins and
3 Moody BESS projects and underscores the importance of a more thorough and
4 long-term evaluation provided by the Company's adjustments to PIA Staff's
5 analysis.

6 ***The MPC and Santa Rosa PPAs***

7 **Q. WOULD FULLY INTEGRATED, JOINT RESOURCE PLANNING WITH**
8 **OTHER SOUTHERN COMPANY SUBSIDIARIES LIKE MPC HAVE**
9 **NEGATED THE NEED FOR THE MPC PPA AS ALLEGED BY GAM?**

10 A. No. To be clear, we do plan jointly with other Southern Company operating
11 companies. However, each retail operating company is subject to the oversight of
12 a different state regulator and is ultimately responsible for maintaining the
13 generation capacity needed to serve its customers consistent with the requirements
14 of the state in which it operates. Indeed, GAM witness Pollock acknowledged this
15 under cross-examination, stating that "over the long term, the notion is that each
16 utility, each operating company [of Southern Company], should stand on its own"
17 in terms of bringing resources online to meet their own load. (Tr. 1048, lines 810)
18 In addition, per the terms of the IIC, a utility may retire or seek off System
19 wholesale sales of excess capacity if in the best interest of its own customers. The
20 Mississippi Public Service Commission directed MPC to retire 950 MW of capacity
21 resources no longer needed to serve retail load in Mississippi. As previously
22 explained, the MPC PPA was necessary to secure the available capacity for Georgia
23 Power customers, and ensure that such capacity remained in the pool, dedicated to
24 Georgia Power customers, and was not sold off the Southern Company System or
25 otherwise retired. Had the Company not acted, Georgia Power would not have been
26 able to ensure that these resources were available to serve our customers.

1 **Q. CERTAIN INTERVENORS EXPRESSED CONCERN ABOUT THE LACK**
2 **OF FIRM TRANSMISSION SERVICE FOR THE SANTA ROSA PPA. DO**
3 **YOU HAVE AN UPDATE ON THAT ISSUE?**

4 A. Yes. Georgia Power was able to secure firm transmission on the Southern
5 Transmission System for transfer across the FPL/Southern Company interface
6 through the Winter of 2024/2025. The Company will continue to seek firm
7 transmission service for the remainder of term of the agreement.

8 **Q. HAS GEORGIA POWER BEEN ABLE TO REMARKET ANY MORE OF**
9 **THE CAPACITY FROM THE MPC PPA OR SANTA ROSA PPA FOR 2024**
10 **AND 2025?**

11 A. While no further contracts have been executed, the Company is actively engaged
12 with and in negotiations with other entities through its agent Southern Wholesale
13 Energy (“SWE”) for capacity sales in the years 2024 and 2025.

14 ***Proposed Yates CTs***

15 **Q. WHY SHOULD THE COMMISSION CERTIFY THE YATES CTS?**

16 A. Plant Yates Units 8-10 are critical components of the 2023 IRP Update that will
17 provide reliable and economical peaking resources needed to ensure Georgia Power
18 can continue to reliably meet the electricity needs of its customers and support
19 continued economic development in Georgia. Notably, the new units will be located
20 at the existing Plant Yates site, allowing the Company to avoid costs and other
21 issues related to the development of a greenfield site, while taking advantage of
22 existing site infrastructure. Moreover, the environmental conditions, fuel supply,
23 and life cycle operation and maintenance associated with the Plant Yates site are
24 all favorable. Plant Yates is also located in an area of the state that is continuing to
25 see significant electrical growth. Thus, locating these new CTs in this growing area

1 provides additional reliability to the area, which has seen limited growth in
2 generation development.

3
4 Finally, the Yates CTs will support the continued integration and penetration of
5 renewables and storage on the electric System. Notably, the Company's correction
6 of PIA Staff's expansion plans resulted in the selection of Yates 8 in winter 2027
7 and Yates 9-10 in winter 2028 as the Company proposed.

8 **Q. PLEASE RESPOND TO THE ASSERTIONS MADE BY INTERVENORS**
9 **THAT THE COMPANY DOES NOT NEED ALL THREE OF THE YATES**
10 **CTS IF TRANSMISSION RESTRICTS THE OUTPUT OF THE PLANT**
11 **DURING PEAK PERIODS WITH TRANSMISSION CONTINGENCIES?**

12 A. There is only one specific transmission case where the full output of the three units
13 was restricted. In all other scenarios, once online, all three units will be available to
14 be economically dispatched. It is more economical to build three units
15 consecutively to take advantage of economies of scale, especially when the
16 expansion plan indicates a need for CTs to meet future needs. Additionally, the
17 three CTs will be the most efficient CTs on the Southern Company System, which
18 enables all three units to be dispatched ahead of other CTs and the Yates 6-7 steam
19 units.

20 **Q. WHY SHOULD THE COMMISSION HAVE CONFIDENCE IN THE**
21 **ECONOMICS OF THE PROPOSED YATES UNITS?**

22 A. Even though the proposed Yates units are being procured outside the typical RFP
23 process, the Commission can have confidence in the economics of Plant Yates
24 Units 8-10. The Company routinely engages with established original equipment
25 manufacturers ("OEMs") and engineering, procurement, and construction ("EPC")
26 firms to evaluate the costs and risks associated with projects like those proposed at
27 Plant Yates. The expertise garnered from these engagements ensures a high level

1 of economic scrutiny and cost-effectiveness. Moreover, the Plant Yates project is
2 strategically positioned to meet the anticipated load growth in a timely manner. As
3 explained in the testimony of Aaron Abramovitz, the capacity additions from Plant
4 Yates Units 8-10, in conjunction with the other resources proposed in this IRP
5 Update and the expected energy sales' revenues, are projected to put downward
6 pressure on rates. The combination of timely delivery through credible partnerships
7 and the positive impact on rates underscores the economic viability of the Plant
8 Yates Units.

9 Additionally, when comparing to publicly available information for similar
10 technologies, the estimated costs for Plant Yates is comparable to other CTs. This
11 is demonstrated in "TS Attachment D – Cost Comparison of Similar Projects" filed
12 with the Yates Certification Application in this docket on January 31, 2024, as well
13 as Exhibit 2, which provides a supplemental update to this attachment to more
14 accurately capture the cost adjustment for one of the comparison units. In addition,
15 the cost of Yates Units 8-10 fall within the cost range for gas peaking technologies
16 included in Lazard's 2023 Levelized Cost of Energy Analysis attached as Exhibit
17 3. And while there are several site-specific aspects to the costs of the proposed CTs,
18 these references demonstrate that the Company's cost for Plant Yates Units 8-10
19 are in line with costs of comparable CTs.

20 **Q. IS GEORGIA POWER STILL COMMITTED TO RESPONSIBLY**
21 **TRANSITIONING ITS GENERATION FLEET TO INCLUDE MORE**
22 **ECONOMICAL, LOW- OR ZERO- CARBON RESOURCES?**

23 **A.** Yes, and we will continue to work constructively with the Commission to transition
24 the generation fleet in an economical and reliable way that is in the best interests of
25 our customers. This commitment includes a well-balanced and diversified approach
26 to strategically deploying clean, highly efficient, dispatchable BESS and natural
27 gas resources, such as those proposed at Plant Yates, needed to provide reliable
28 electric service. Significantly, we are already conducting some of the largest

1 renewable RFPs in the country and plan to continue to develop more renewable
2 resources in the future. Specifically, updated modeling for the 2023 IRP Update
3 indicates that adding up to approximately 10,000 MW of new renewable resources
4 by 2035 can provide economic benefits for customers. The certification of the
5 proposed resource plan in this IRP Update, including the Yates CTs, is a necessary
6 component of the Company's long-term fleet transition plan while maintaining a
7 reliable electric System to address customers' energy needs.

8 **Q. WOULD IT BE APPROPRIATE TO INCORPORATE INTO THIS IRP**
9 **UPDATE PROPOSED ENVIRONMENTAL REGULATIONS, LIKE THE**
10 **111 RULE, PRIOR TO FINAL APPROVAL, AS PROPOSED BY SIERRA**
11 **CLUB?**

12 A. No. It would be inappropriate to plan for the specific requirements of a proposed
13 environmental regulation such as the proposed 111 Rule, which would regulate
14 greenhouse gas emissions at fossil fuel-fired power plants.

15 The Company believes that the implications of a final 111 Rule are captured within
16 the range of carbon pressure scenarios included in the 2023 IRP Update. Since the
17 proposed 111 Rule has yet to be finalized and state plans have not yet been
18 developed or approved for existing unit requirements (which may take up to three
19 years under the proposal), the Company believes that detailed analysis of the
20 compliance options and development of the compliance strategy for the proposed
21 111 Rule would be premature and speculative. Specifically for the requests in this
22 2023 IRP Update, the contract periods for the PPAs with Mississippi Power and
23 Santa Rosa Energy Center LLC end prior to the compliance dates for existing units
24 in the proposed 111 Rule; therefore, these PPAs are not expected to be impacted by
25 this rule. Also, BESS are not subject to the 111 Rule.

1 Based on the proposed rule, the Company expects the proposed CTs at Plant Yates
2 to comply with the 111 Rule and does not anticipate any changes impacting the
3 decision to request these additional resources.

4 ***1,000 MW BESS – Robins, Moody, 200 MW BESS plus 200 MW Solar***

5 **Q. WHAT IS THE STATUS OF THE ROBINS, MOODY, AND 200 MW BESS**
6 **PLUS 200 MW SOLAR PROJECTS?**

7 A. All the BESS projects proposed in this proceeding continue to move forward in
8 order to meet a December 2026 in-service requirement. The Company issued
9 inquiry packages to several BESS OEMs and EPC contractors. The Company is
10 currently in the process of evaluating and finalizing contracts around these supplier
11 options. Additionally, the Company has continued negotiations with the developer
12 of the 200 MW BESS plus 200 MW Solar facility with the goal of having final
13 contracts signed as soon as possible.

14 **Q. HAS THE COMPANY IDENTIFIED ANY OTHER BESS PROJECTS TO**
15 **MEET PART OF THE 1,000 MW REQUEST IN THIS CASE?**

16 A. Yes. The Company has identified several BESS projects it is pursuing as part of the
17 need to deploy 1,000 MW of BESS by the end of 2027 to address the capacity needs
18 associated with serving the new load coming to Georgia.

19 ***DER***

20 **Q. DOES THE COMPANY AGREE WITH PIA STAFF WITNESS KADUK'S**
21 **PROPOSED SIZE CAP TO THE DER CUSTOMER PROGRAMS?**

22 A. No. The Company does not agree with the size cap PIA Staff Witness Kaduk
23 recommended for DERs in the DER Co-location program. The Co-location
24 program was designed to make more efficient use of resiliency resources that
25 customers are bringing to provide backup power for their operations, and to incent

1 cleaner resources certified and permitted for non-emergency use. Introducing a
2 10 MW cap would exclude a significant portion of the resiliency resources large
3 load customers will be procuring and prevent them from being used for the benefit
4 of all customers.

5 Further, PIA Staff recommends setting the limit on the installed DER to match the
6 customer's annual peak load at the premises, up to, but not exceeding the program
7 maximum DER size limit. This recommendation is inappropriate for two reasons.
8 First, resiliency assets designed to provide full back up are typically sized with
9 nameplate capacity exceeding peak load. This accounts for operational best practice
10 not to run resources for extended periods at maximum output and mitigates
11 concerns should an individual asset fail. Second, unlike resources utilized in the
12 DRC-1 tariff Witness Kaduk references, the resources deployed through these
13 programs will be supply side assets capable of pushing back to the grid. As a result,
14 there is no need or basis for putting a size cap based on load.

15 **Q. PLEASE RESPOND TO GAM WITNESS POLLOCK'S RECOMMENDED**
16 **MODIFICATIONS TO THE DER CUSTOMER PROGRAMS.**

17 A. One of GAM Witness Pollock's concerns is that the proposed tariffs do not specify
18 the amount of the required credits/payments. He believes that this gives the
19 Company "undue discretion" and that the "customer would have no opportunity to
20 either vet the proposed credits/payments or seek a remedy from the Commission."
21 (Tr. 962.) However, by not detailing the specific credit or payment within the terms
22 of the tariff, the programs have flexibility to accommodate different types of
23 resources, can expand to reflect additional use cases should they materialize, and
24 are able to adjust to changing conditions. That does not mean that customers and
25 the Commission will not have an opportunity to view or vet the values and
26 associated calculation methodologies. In fact, each of the proposed programs and
27 tariffs requires an additional customer agreement. The customer agreement and
28 supporting documents will provide further details, requirements, and specifications

1 for the individual customer and resources. The resources participating in DCL-1
2 and DCO-1 will be supply side resources subject to Commission certification and
3 approval.

4 Witness Pollock also expressed concern about the procurement of resources in the
5 proposed DER Co-location Program and wants to require a competitive solicitation
6 with engagement from the customer. The Company agrees that the participating
7 customer must be engaged in the selection of resources but does not support a
8 requirement that each resource must be competitively sourced. A participating
9 customer may have existing vendor relationships or specific preferences on what
10 technologies and or companies they would like to work with outside of a
11 competitive procurement process. In addition, the Company has already issued an
12 RFP and selected qualified vendors for the current DER Customer Pilot. These
13 same vendors can be utilized for the proposed DER programs.

14 **Q. DO THE DER CO-LOCATION AND CUSTOMER OWNED PROGRAMS**
15 **EXCLUDE CARBON FREE RESOURCES?**

16 A. No. The program is designed to be resource neutral; provided that such resources
17 are dispatchable, have a firm fuel supply, and are interconnected to transmit the
18 energy they produce to the electric grid. This could include microgrids, fuel cells,
19 or other carbon free resources. Ultimately, the participating customer will be
20 responsible for determining the set of resources that meet their needs and the
21 Company will evaluate and reflect the appropriate System value associated with
22 those resources.

1 **Q. SHOULD THE COMPANY CONSIDER ADDING A VIRTUAL POWER**
2 **PLANT OPTION TO ITS RESOURCE PORTFOLIO IN THIS CASE, AS**
3 **SUGGESTED BY THE COALITION OF LOCAL GOVERNMENTS AND**
4 **GEORGIA SOLAR ENERGY ASSOCIATION?**

5 A. No. The Company proposed expansions of existing and new distributed energy
6 resource programs that rely on end-use or customer-sited technology. Fully
7 leveraging additional load flexibility programs, like virtual power plants (“VPP”),
8 will require more planning time and further operational capabilities than exist in
9 this 2023 IRP Update. The Company is in the process of evaluating and planning
10 demand-side programs that will be filed in the 2025 IRP, including potential VPP
11 programs. Deriving System value from mass market load flexibility programs will
12 require continued investment in enterprise Distributed Energy Resource
13 Management Systems (DERMS) for visibility, predictability, and enhanced
14 operational capabilities of these resources.

15 ***Minimum Ownership***

16 **Q. SHOULD THE COMMISSION REVISE THE MINIMUM OWNERSHIP**
17 **REQUIREMENT IN ITS RULES?**

18 A. No. The Commission’s longstanding 70/30 policy ensures System reliability and
19 sufficient Commission oversight of the resources serving customers. Staff and
20 Intervenors dismiss the Commission’s 70/30 rule claiming that it is outdated and
21 does not ensure that the Company procures the least cost resources for customers.
22 However, this ignores the fact that apart from the resources requested in this case,
23 the vast majority of all other capacity resources since 2001 were successfully
24 procured through an RFP process. Further, allegations that the ratio is too high and
25 biased in favor of Company-owned resources are based on comparisons to utilities
26 in RTOs and deregulated markets, where service reliability has been a challenge in
27 extreme weather events. Notably, Georgia is not alone in providing a minimum

1 number of utility-owned and controlled resources to ensure a sufficient level of
2 reliability and oversight. For example, the 70/30 ratio is comparable to that set in
3 Virginia, where 65% of all new renewables are to be utility owned, and N.C.G.S.
4 § 62-110.9(2)(b) in North Carolina, which provides for all new resources to be
5 company owned except for 45% renewables and storage.

6 **VII. TRANSMISSION**

7 **Q. PLEASE CLARIFY THE COMPANY'S TRANSMISSION REQUEST IN**
8 **THIS CASE.**

9 A. The Company requests approval of the transmission improvements necessary to
10 accommodate the resources proposed in the 2023 IRP Update. These improvements
11 were identified in the preliminary transmission screening analyses filed in the
12 Technical Appendix to the 2023 IRP Update, confirmed in the Transmission
13 Supplemental Filing, and are consistent with the types of transmission
14 improvements typically required to accommodate new generation added to the
15 System.

16 **Q. IS THE COMPANY REQUESTING COMMISSION APPROVAL OF EACH**
17 **OF THE EIGHT PROJECTS LISTED IN THE TRANSMISSION**
18 **SUPPLEMENTAL FILING?**

19 A. No. Consistent with Georgia Power's annual transmission planning processes, the
20 Company will continue to study and reevaluate the actual transmission projects
21 needed to bring the Yates CTs online. The eight projects identified are the slate of
22 projects currently identified as necessary to support the Yates CTs. As the
23 transmission system changes and additional studies are completed through
24 established processes, it is possible that the projects necessary to bring the Yates
25 CTs online may change or be replaced with better alternatives. This is consistent

1 with how the Company conducts its standard transmission planning process in the
2 triennial IRP.

3 **Q. ARE THE TRANSMISSION SCREENING ANALYSES AND**
4 **TRANSMISSION SUPPLEMENTAL FILING COMPREHENSIVE**
5 **ENOUGH TO SUPPORT THE COMPANY'S REQUEST IN THIS CASE?**

6 A. Yes. The Company conducted initial screening analyses for the 2023 IRP Update
7 filing at a base load level that includes all committed large loads. The Company
8 then continued to refine the analyses for the supplemental filing with an updated
9 load forecast that includes committed and potential large loads. Both versions of
10 the analyses yielded the same results for transmission needs validating the
11 comprehensive process conducted by the Company. Additionally, the Company
12 conducted a Unit Designation Study for the Yates CTs that further validated the
13 transmission needs.

14 **Q. DO THE TRANSMISSION LIMITATIONS ON THE PROPOSED YATES**
15 **UNITS LIMIT DELIVERY FROM THE UNITS ALL THE TIME?**

16 A. No. The transmission upgrades required to unlock the full designated capacity of
17 the three proposed Yates CTs only impact power delivery in peak demand periods
18 under certain transmission contingencies. For most hours throughout the year, the
19 new Yates CTs will be available to serve load up to the full designated capacity as
20 soon as they come online.

21 **Q. DID THE COMPANY PROVIDE SUPPORT FOR THE 600 MW**
22 **TEMPORARY DELIVERY LIMITATION FOR THE YATES CTS IN**
23 **PEAK PERIODS UNTIL 2028 WHEN TRANSMISSION CONSTRAINTS**
24 **ARE ALLEVIATED?**

25 A. Yes. As shown in the supporting studies and workpapers accompanying the
26 Transmission Supplemental Filing on January 19, 2024, the Company provided

1 documentation of its analysis and results regarding the transmission limitations on
2 the proposed Plant Yates CTs until required transmission improvements as listed in
3 the Supplemental Filings are complete.

4 **Q. ARE THE PROPOSED YATES CTS SUBJECT TO TRANSMISSION**
5 **CURTAILMENT RISK AS A RESULT OF THE COMPANY HAVING**
6 **REQUESTED ENERGY RESOURCE INTERCONNECTION SERVICE**
7 **RATHER THAN NETWORK RESOURCE INTERCONNECTION**
8 **SERVICE?**

9 A. No. Since the Company's transmission planning process includes firm and future
10 firm commitments only, there is no curtailment risk for the delivery of power from
11 the proposed Yates CTs because of the Company's interconnection service request.
12 This concern from Staff Witness Goggin and SREA Witness Olson represents a
13 fundamental misunderstanding between the requests and studies for
14 interconnection service and delivery service on the Southern Company System. As
15 explained in the Company's response to STF-GS-2-1, neither Energy Resource
16 Interconnection Service ("ERIS") nor Network Resource Interconnection Service
17 ("NRIS") conveys delivery rights to a generator. Delivery service in the Southern
18 Company System is separately requested through a transmission service request for
19 point-to-point transmission or through the designation of the resource as a network
20 resource for networked transmission service. The Company has already requested
21 that Plant Yates Units 8-10 be designated as network resources and that designation
22 study is complete.

23 The fact that transmission operators in other parts of the country and in different
24 market structures combine interconnection and delivery service as part of a NRIS
25 request does not signal a fundamental flaw or risk in how the Company has planned
26 for the delivery of power from the proposed Yates CTs.

1 **Q. DOES THE COMPANY CONSIDER NON-WIRES ALTERNATIVES IN**
2 **ITS TRANSMISSION PLANNING AND, IF SO, WHAT ALTERNATIVES**
3 **WERE CONSIDERED IN THIS CASE?**

4 A. Yes, the Company considers non-wires alternatives in its transmission planning and
5 has demonstrated the integration of these solutions in past projects where they
6 added operational flexibility and were more cost effective. However, given the time
7 constraints in this case, the Company was unable to explore all the options typically
8 available for a given transmission constraint or deficiency as part of the
9 transmission analyses supporting the resource requests in this case. Nevertheless,
10 the transmission projects identified to support the Yates CTs are consistent with the
11 typical types of projects needed to accommodate the addition of large generation
12 resources to the System.

13 **Q. PLEASE RESPOND TO STAFF AND INTERVENOR**
14 **RECOMMENDATIONS THAT THE COMPANY EMPLOY EMERGING,**
15 **GRID ENHANCING TECHNOLOGIES AND NON-WIRES**
16 **ALTERNATIVES LIKE DYNAMIC LINE RATING, GEOLOGICAL**
17 **TPOLOGY OPTIMIZATION, FLEXIBLE AC TRANSMISSION**
18 **SYSTEMS (“FACTS”), ETC.**

19 A. The Company already employs many of the alternative and advancing solutions
20 that Staff and Intervenor propose where they provide value to customers. Grid
21 Enhancing Technologies refers to a broad range of technologies, and these are
22 considered as part of the Company’s 10-year Transmission Planning Process. For
23 example, the Company already uses FACTS on the System through its deployment
24 of static VAR compensators and static synchronous compensators to improve
25 power quality and efficiency of the transmission grid. The Company has also
26 specified the use of series reactors and series compensation as power flow control
27 devices in addition to advanced conductors. As a standard practice and through
28 collaboration with the Southern Company Research and Development team, the

1 Company continues to consider new types of technologies in its evaluation criteria.
2 However, there are limitations to using some of the suggested technologies as they
3 are not mature enough for deployment on the System, require long lead times, or
4 are inappropriate for long term planning. To this point, dynamic line ratings
5 (“DLR”) have the potential to enhance operational flexibility by incorporating
6 various factors such as wind speed, temperature, load profiles, and solar irradiance.
7 These benefits occur in real-time or near real-time conditions, however, which
8 make it inappropriate to use DLR capabilities as a long-term planning solution
9 because it is impossible to know today what speeds the wind will blow at or what
10 the solar irradiance will be many years in the future. Although not a long-term
11 planning solution, the Company is evaluating opportunities for DLR
12 implementation under unique circumstances to provide real-time operational
13 benefits as a temporary solution until a long-term solution can be executed.

14 **Q. DOES THE COMPANY USE AMBIENT-ADJUSTED RATINGS (“AAR”)**
15 **IN THEIR OPERATIONS AND PLANNING PROCESSES?**

16 A. Yes. The Company uses AAR in its dynamic ampacity ratings program for
17 transmission planning and operations planning processes that includes local
18 parameters such as weather and wind. By use of this program, the Company equips
19 its operators with current System conditions and minimizes risks associated with
20 short-term, excess conductor loading. Within the Company’s transmission planning
21 processes, the Company leverages AAR as a bridge to permanent solutions, where
22 appropriate. These applications tend to occur in the early years of the planning
23 horizon when there is not sufficient time to construct a project.

24 **Q. WHY DIDN’T THE COMPANY CONSIDER BATTERIES SITED CLOSE**
25 **TO LOAD AS A TRANSMISSION SOLUTION IN THIS CASE?**

26 A. Batteries sited near load are not a practical solution or replacement for the identified
27 transmission upgrades for several reasons. First, the battery would need to charge

1 from the grid, which causes it to act like additional load, thereby exacerbating the
2 problem the additional resources and transmission solutions are trying to resolve.
3 Second, a battery serving as a solution to a *transmission* contingency cannot be
4 counted as both generation capacity and a transmission solution by planners on the
5 Southern Company System. To serve as a transmission solution, a battery would
6 need to be fully charged around the clock, available when and if called upon to
7 address a contingency since contingencies can occur at any time and potentially for
8 extended durations. Third, a 4-hour battery is not a practical solution to address
9 transmission contingency scenarios. For example, a tornado could create an
10 unexpected outage during hot weather conditions that lasts for a week. For batteries
11 to resolve the transmission constraints identified in the transmission supplemental
12 filing analysis, the transmission grid would need to have enough available capacity
13 to charge the battery system(s), they would need to be of significant size and
14 discharge time, and there would need to be multiple battery systems to cover the
15 multiple contingencies across different locations identified in the analysis. The
16 overall cost and land requirements to support battery projects that can cover
17 extended duration outages would be cost prohibitive, especially when
18 contemplating the relatively small magnitude of the total amount of transmission
19 projects identified in the supplemental transmission filing. In addition, a total net
20 present value of the battery systems versus wire solutions would need to be run to
21 contemplate the total life-cycle costs of the two alternatives.

22 **Q. SHOULD THE COMPANY PROACTIVELY INVEST IN MORE 500 KV**
23 **TRANSMISSION LINES ACROSS THE STATE AS RECOMMENDED BY**
24 **STAFF WITNESS GOGGIN, SACE WITNESS PATEL, AND SREA**
25 **WITNESS OLSON?**

26 **A.** No, not as part of its request in this case. Intervenor-proposed 500kV solutions
27 cannot be implemented in the required timeframe and would not completely address
28 the local area 230kV constraints identified to bring the Yates CTs online. That said,

1 the solutions proposed in the 2023 IRP Update and supplemental filings could
2 complement future 500kV development.

3 Further, simply proposing to build more 500kV lines in the state misunderstands
4 how transmission planning is coordinated with generation resource planning in
5 Georgia and would result in very expensive infrastructure investment with no
6 guarantee to alleviate known or anticipated transmission constraints. In deregulated
7 markets, transmission owners build large transmission lines across states hoping
8 that they have sited the infrastructure where independent power producers will seek
9 to interconnect. In contrast, Georgia Power builds transmission as needed to deliver
10 power from facilities that have been sited, financed, and have initiated the process
11 of interconnecting to the System. Georgia Power's integrated approach ensures
12 interconnections actually occur and minimizes transmission investments based
13 upon speculation. Further, Witness Goggin's testimony seems to ignore the
14 integrated nature of the transmission system in Georgia whereby Georgia Power
15 jointly plans and operates the networked transmission system with the other
16 Georgia ITS participants in the state: Georgia Transmission Corporation ("GTC")
17 and the Municipal Electric Authority of Georgia ("MEAG").

18 In addition, adding or upgrading existing line voltage to 500 kV is not as simple as
19 swapping out the line on existing structures. The Company requires additional
20 rights of way access for larger voltage lines, the acquisition of which adds
21 substantial time and cost to the process of rebuilding or retrofitting a line. Finally,
22 Witness Goggin seems to gloss over the significant costs and time requirements
23 associated with changing the voltage level of existing facilities, which would be
24 additional costs borne by Georgia Power customers.

1 **Q. PLEASE RESPOND TO THE RECOMMENDATION OF SEVERAL**
2 **PARTIES THAT THE COMPANY IMPLEMENT A MORE HOLISTIC,**
3 **INTEGRATED PLANNING BETWEEN TRANSMISSION AND**
4 **GENERATION THAT IS PROACTIVE RATHER THAN REACTIVE.**

5 A. The Company already does most of the planning improvements parties recommend.
6 Unlike deregulated markets, which lack the insight and structural mechanisms to
7 jointly plan transmission and generation, the Company's IRP process already
8 holistically and intentionally considers the balance between transmission
9 investment and generation deployment. While transmission is a significant aspect
10 of IRP processes, long-term firm commitments by third parties under a FERC-
11 jurisdictional Open Access Transmission Tariff ("OATT") is also a key driver in
12 the development of transmission expansion planning. Additionally, Southern
13 Company and Southeastern Regional Transmission Planning ("SERTP") Sponsors'
14 transmission planning processes utilizes multi-disciplined analyses that identify
15 System needs using least-cost and reliable solutions from all reasonably available
16 alternatives. As an added step, the Commission reviews, regulates, and approves
17 the Company's planning process and ensures that the assets built are reliable,
18 economic, and in the public interest.

19 **Q. DOES GEORGIA POWER ALREADY PARTICIPATE IN REGIONAL**
20 **PLANNING WITH NEIGHBORING SYSTEMS?**

21 A. Yes. That is the purpose of the SERTP organization. Georgia Power is also a
22 Participant in the Georgia ITS with GTC, MEAG, and Dalton Utilities.

VIII. CONCLUSION

Q. IN CONCLUSION, PLEASE SUMMARIZE WHY THE COMMISSION SHOULD APPROVE THE COMPANY'S REQUEST WITHOUT MODIFICATION.

A. The 2023IRP Update presents a plan that will ensure Georgia Power can continue to reliably serve the state's growing capacity needs while supporting economic growth and lowering rates for all retail customers. The Company's plan provides substantial benefits for our customers and our state, and we request that the Commission approve the Company's request without modification.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

1 MR. MARZO: With your permission,
2 Mr. Chairman, I would ask the rebuttal panel to
3 summarize the testimony.

4 CHAIRMAN SHAW: Yes, sir. Go ahead.

5 MR. GRUBB: Good afternoon, Commissioners.
6 We appreciate the opportunity to be here with you
7 today. As previously discussed by Mr. Abramovitz,
8 the Company reached a constructive Stipulation with
9 PIA staff yesterday, and the Georgia Association of
10 Manufacturers, which was filed with the
11 Commissioners this morning. We will take this
12 opportunity to reiterate the Company's support of
13 the stipulation as a fair resolution of issues in
14 this case, and to present our rebuttal testimony,
15 which was previously filed in support of Georgia
16 Power's 2023 IRP Update.

17 The 2023 IRP Update, as amended by the
18 stipulation, will ensure the Company can preserve
19 and protect the reliability and quality of service
20 our customers expect, and address the capacity
21 needs driven by the robust economic growth taking
22 place in Georgia.

23 Our plan provides substantial economic and
24 reliability benefits to the state and our
25 customers, who can expect to see downward pressure

1 on rates in connection with the growth supported by
2 the resources requested in this filing.

3 The benefits to customers are reflected in
4 the high-level sensitivity analysis, included as
5 Exhibit 1 in our rebuttal testimony, which adjusts
6 the company's cost-of-service study from the 2022
7 base rate case and shows the impact of the
8 company's request in this case on each customer
9 rate group.

10 Georgia Power is requesting approval for
11 approximately 3300-megawatts of economic and
12 reliable capacity resources, to meet customers'
13 growing energy needs for the period from December
14 of 2025 through November of 2028. The company's
15 request is informed by the 2023 IRP Update load
16 forecast, which is based on current economic trends
17 and a statistically sound methodology, providing
18 the most realistic projection of growth.

19 Notably, the resources requested in this case
20 represent only a fraction of the resources that
21 would be needed to serve the more than
22 21,000-megawatts of potential projects in Georgia's
23 economic development pipeline, underscoring the
24 reasonableness of the company's measured request.

25 As stipulated, 2780-megawatts of the

1 company's requested resources would be approved in
2 this case, with 500-megawatts of the 1000-megawatts
3 requested being procured through a narrowly
4 tailored and expedited RFP for resources to meet
5 needs in the winter of 2027 and 2028.

6 Our testimony presents a comprehensive
7 overview and defense of the company's 2023 IRP
8 update load forecast, which is directly informed by
9 recent economic developments and input from
10 customers. The forecast is based on current
11 economic trends and a statistically sound
12 methodology. This risk-adjusted forecast
13 meticulously accounts for potential uncertainties
14 in the size, timing, and materialization of the
15 large load customer projects seeking to be served
16 by Georgia Power.

17 We are confident in our Load Forecast, and
18 the Commission should also be confident in it.
19 Significantly, the customer load committed to be
20 served by Georgia Power has increased, rising from
21 approximately 3600-megawatts in October to now over
22 6200-megawatts. This increase is due to the 11
23 additional customers, with over 22,600-megawatts of
24 load, who have signed contracts with Georgia Power
25 since our initial filing.

1 Our customers' investments in the State have
2 also continued to materialize. 13 of the 14 new
3 large load customers committed to take service from
4 Georgia Power in October, have facilities that are
5 either under construction or in the late stages of
6 development prior to starting construction. In
7 addition, several of the company's customers have
8 now accelerated their load ramp, bringing their
9 full operations online by 2031, which is roughly
10 five years earlier than they had previously
11 indicated.

12 The company continues to support planning to
13 a P95 load value, to ensure that it has sufficient
14 resources to reliably support the demands of this
15 new economic development in the state. Planning
16 generation resources to a P50 load value means the
17 company would not have sufficient resources to meet
18 customer needs in half of the potential scenarios
19 for new large load customers.

20 Doing so would present unacceptable risk when
21 seeking to serve significant large loads coming to
22 Georgia and is inappropriate in this case.
23 Notably, the pace of economic development in the
24 state has continued to surpass the forecasted
25 growth over the past several months, further

1 demonstrating the need for planning to the higher
2 load.

3 Any risk associated with loads materializing
4 at levels lower than the company forecasted can be
5 mitigated through the numerous measures which are
6 available to the Company and this Commission, such
7 as selling capacity on the wholesale market, or
8 slowing down, reducing, or halting generation
9 development.

10 On the other hand, the company would not be
11 able to reliably serve growing customers, growing
12 customer load, or support economic growth, if the
13 load were to materialize at a rate that outpaces
14 the generation available to serve the load. In
15 such cases, businesses looking to locate or expand
16 in Georgia may look to locate outside of state,
17 removing the opportunity to place downward pressure
18 on rates for all customers and to continue to help
19 Georgia to grow and prosper.

20 The company's request to utilize the
21 Commission's process to certify resources outside
22 of an RFP is driven by the need to move quickly, to
23 obtain resources to meet capacity needs starting in
24 the winter of '25/'26. The typical RFP takes two
25 to two-and-a-half years to implement, and would

1 simply take too long to address the accelerated
2 capacity needs we are facing, especially when
3 considering the limited availability of existing
4 resources in the market, and the need to construct
5 new resources and transmission projects needed to
6 support them.

7 We support the Commission's RFP process and
8 have successfully conducted over 20 RFPs since
9 2006. We are currently implementing several RFPs
10 that were approved in the '22 IRP, and these RFPs
11 are critical for meeting capacity needs from 2029
12 through 2031. Notwithstanding the timeline for a
13 typical RFP, as part of the stipulation, the
14 company has agreed to issue a narrowly tailored,
15 expedited RFP for battery energy storage systems
16 resources for the winter of '27/'28.

17 The company continues to plan to a 26 percent
18 target reserve margin, consistent with the
19 Commission's 2022 IRP Final Order. A 26 percent
20 target reserve margin is vital to ensuring system
21 reliability during extreme weather events and
22 episodes, as evidenced by the company's ability to
23 serve customers' loads during recent winter storm
24 events, Winter Storm Elliott and Winter Storm
25 Heather.

1 A reduction in the reserve margin would not
2 be in the best interest of customers and would
3 reduce the reliability of the electric system. The
4 company must maintain an appropriate level of
5 preparedness to mitigate unforeseen weather
6 challenges and maintain system reliability.

7 Lowering the winter target reserve margin to
8 20 percent, which is equivalent to a
9 one-in-ten-year loss of load event, has been
10 advocated by some parties, but would lead to a
11 substantial decline in reliability, escalate costs
12 and risks for customers. Importantly, the Company
13 is currently updating the Reserve Margin Study and
14 will file it, along with recommendations in the
15 2025 IRP, as always.

16 The proposed Yates CTs will be reliable and
17 cost-effective peaking resources that are essential
18 to addressing the capacity need identified in the
19 '23 IRP Update and maintaining the reliability that
20 our customers expect. Despite concerns regarding
21 transmission restrictions in limited cases, the
22 Plant Yates CTs will be the most efficient CTs on
23 the Southern Company system, and are strategically
24 located to support anticipated load growth.

25 Due to the economies of scale in building

1 three new generation units, it is most economical
2 to build all three units together, which also best
3 prepares the Company to meet future capacity needs
4 and the need for dispatchable generation resources.

5 Regarding the Mississippi Power Company and
6 Santa Rosa PPAs, these agreements provide
7 substantial capacity benefits for Georgia Power's
8 customers in their near-term window being addressed
9 in this case.

10 Georgia Power remains dedicated to
11 transitioning our generation fleet towards more
12 economical, low- or zero-carbon resources, as
13 evidenced by our plans to develop BESS and natural
14 gas projects in this case, as well as the continued
15 development -- or, deployment of renewable
16 resources.

17 The stipulation, if approved, would support
18 the company's development of 500-megawatts of BESS
19 resources, including the Robins and Moody's BESS
20 projects, and would approve each of the company's
21 DER customer programs, the curtailable load tariff,
22 and the expansion of the residential thermostat
23 demand response program.

24 This company has undertaken a comprehensive
25 transmission screening analysis and supplemental

1 filing to identify, quantify, and support the
2 transmission requests necessary to reliably deliver
3 the portfolio of resources requested in this case.
4 The only transmission projects necessary to support
5 this request, in this case, are those needed to
6 accommodate the new resources at Plant Yates.

7 Notably, the transmission upgrades required
8 to unlock the full-designated capacity of the three
9 proposed Yates CTs only impact power delivery in
10 peak demand periods under certain transmission
11 contingencies. For most hours throughout the year,
12 the new Yates CTs will be available to serve load
13 up to the full-designated capacity as soon as they
14 come online.

15 Finally, our approach to transmission and
16 generation planning is integrated, contrasting with
17 the speculative nature of transmission planning in
18 deregulated markets. The company's proactive and
19 holistic approach to integrating transmission and
20 generation planning is evidenced by the
21 comprehensive coordination present in the company's
22 IRP processes, as well as through participation in
23 regional planning efforts through the SERTP
24 organization and the Georgia Integrated
25 Transmission System.

1 In conclusion, Georgia Power's 2023 IRP
2 Update, as amended by the stipulation, establishes
3 a plan that ensures the company can preserve and
4 protect the reliability and quality of service that
5 our customers expect. The update will ensure the
6 company can continue to reliably serve Georgia's
7 growing capacity needs, and presents a significant
8 opportunity to put downward pressure on the rates
9 for all retail customers by spreading the cost of
10 electric service across a larger customer base.

11 The company's plan provides substantial
12 economic and reliability benefits to the state and
13 our customers. As such, we respectfully request
14 the Commission approve the company's 2023 IRP
15 Update, as modified by the stipulation. Thank you.

16 MR. MARZO: Thank you, Mr. Grubb.

17 Mr. Chairman, the witnesses are available for
18 questions from the Commissioners, obviously, and
19 cross-examination for parties.

20 CHAIRMAN SHAW: All right. Commissioners --
21 Commissioner Echols?

22 VICE CHAIRMAN ECHOLS: Yes. You mentioned
23 the 500 MW narrowly tailored IRP twice, that's for
24 '27, '28, right?

25 MR. GRUBB: Yes, sir. For the third year of

1 needs that we're looking at in this case. That's
2 correct.

3 VICE CHAIRMAN ECHOLS: And help me again, is
4 it just batteries, or is it solar plus batteries or
5 can it be any other source or is it limited?

6 MR. GRUBB: So it's storage. So it's
7 batteries. It can be placed and Attachment C
8 discussed that. It can be placed, at existing
9 solar or it could be standalone. The main driver
10 is what transmission is needed, but, yes, it is
11 solely batteries from the standpoint of -- that's
12 needed to be able to expedite that RFP, the shorter
13 construction.

14 VICE CHAIRMAN ECHOLS: How will the bidders
15 know which solar array -- Taylor County, Mitchell
16 County, Twiggs County, how do they know which one
17 is available to place it so they can do their bid?

18 MR. GRUBB: So some of it could be the
19 developers themselves, who have those purchase
20 power agreements with the company, could do it. So
21 very similar -- we're targeting some products that
22 are very similar to what we did at Robins and for
23 what we're doing at Robins and Moody.

24 And so to reduce that amount of transmission
25 you have to build, they can go to existing solar

1 sites. So any existing solar site that has a
2 contract with the company is eligible. And then,
3 otherwise, if they're already in the
4 interconnection studies and they're already in the
5 interconnection queue and they've got projects
6 there, those are eligible, as well.

7 VICE CHAIRMAN ECHOLS: Now, this is a little
8 bit hypothetical here. I may have to clarify it
9 for you. But, in your opinion, is there more
10 ratepayer protection for this 500 megawatt narrowly
11 tailored RFP, by doing it as an RFP, in case the
12 project's late, and they maybe miss a tax credit or
13 the IRA gets changed, if an administration changes
14 that, is there -- would you say that there's more
15 protection having someone else build it on the hook
16 for what they bid or having the company do it?

17 MR. GRUBB: So, Commissioner, I would say
18 both have their values. All right. So I think
19 that when you go to the market, it allows
20 comparison between what the company has bid and
21 what the market can do. But the company is always
22 putting our -- either bringing it forth to the
23 Commission or submitting an RFP, at our cost.

24 But as far as -- I wasn't sure if the IRA
25 question was specifically around that -- we also

1 will look to take advantage of those tax incentives
2 on anything we do. But what the RFP does is it --
3 per staff and other folks, is it gives you a chance
4 to compare them to other markets. And we have a
5 lot of megawatts that we need.

6 And so we do think that we need the market's
7 help, especially if we start looking through the
8 All-Source RFP, there's a lot of megawatts to be
9 built. So I think ownership from the company and
10 from the market all have their benefits.
11 Obviously, if you go through an RFP, it allows the
12 Commission to more directly compare those.

13 VICE CHAIRMAN ECHOLS: Okay. Thank you.

14 CHAIRMAN SHAW: Any other questions?

15 (No response.)

16 CHAIRMAN SHAW: All right. We'll move on.
17 Georgia Public Service Commission.

18 MR. THOMAS: No questions.

19 CHAIRMAN SHAW: Advanced Power Alliance.

20 MR. CARVER: No questions, Mr. Chairman.

21 CHAIRMAN SHAW: Clean Energy Buyers
22 Association. Dunbar?

23 MR. DUNBAR: Thank you, Mr. Chairman. Good
24 afternoon, Panel.

25 THE PANEL: Good afternoon.

1 CROSS-EXAMINATION

2 BY MR. DUNBAR:

3 Q. As you know, my name is Scott Dunbar, counsel
4 for CEBA, Clean Energy Buyers Association. I'd like to
5 look at your rebuttal testimony, page 23, please.

6 A. (Witness Grubb) Okay.

7 Q. So on line 25 it states, quote: If there is
8 insufficient generation to support the addition of more
9 customer load, the company will have to stop making offers
10 to businesses looking to locate or expand in Georgia.
11 Customers who would otherwise locate or expand in Georgia,
12 are likely to take their business elsewhere, end quote.

13 Do you see that?

14 A. (Witness Grubb) Yes, I do.

15 Q. Did you review the direct testimony of CEBA's
16 witness, Ms. Priya Barua, in this proceeding?

17 A. (Witness Grubb) I did. It's been a few weeks
18 but, yes.

19 Q. Certainly. Anything that you don't remember,
20 just let me know.

21 Do you recall that one of Ms. Barua's main
22 recommendations was that Georgia implement
23 two-bring-your-own-clean-energy-supply programs?

24 A. (Witness Grubb) I do recall that generally,
25 yes.

1 Q. And one of the two bring your own supply
2 programs was a sleeved-PPA structure. Do you recall that?

3 A. (Witness Grubb) I do. I do believe it also,
4 subject to check, or you're confirming for me, that it was
5 mostly focused around solar, if I recall correctly. I'm
6 not trying to put words in your mouth, I'm just trying to
7 recall.

8 Q. It was focused around clean resources. And
9 we may have used solar as an example. But it was not
10 limited to solar.

11 A. (Witness Grubb) Okay.

12 Q. Are you comfortable talking about that?

13 A. (Witness Grubb) Okay. Sure, sure.

14 Q. So in what we've called a sleeved-PPA
15 structure, is it your understanding, Georgia Power would
16 sign a PPA for a resource that is dedicated to a
17 particular customer, and that customer would pay the full
18 cost of the resource, plus a reasonable administration
19 fee?

20 A. I understand that's the general structure of
21 it; correct.

22 Q. Great. And do you recall from her testimony
23 that one of the advantages of this structure is that any
24 resource that is dedicated to a particular customer does
25 not need to be acquired through competitive bidding, and

1 so it can be acquired much faster than going through an
2 RFP process?

3 A. (Witness Grubb) I believe I recall that
4 generally. And, again, we're talking about a PPA between
5 the company and that other -- and the resource, right?
6 Not directly serving the customer, but a resource to
7 Georgia Power, that then would be kind of subscribed to
8 that customer? I'm not trying to put words in your mouth
9 again, either. I'm just trying to think through, make
10 sure we're talking about the same thing.

11 Q. Thank you. No, that's all correct. And we
12 appreciate the clarity, that our proposal is focused on a
13 resource being dedicated to a particular customer, nothing
14 that -- there's nothing physical about --

15 A. (Witness Grubb) Not electrically dedicated,
16 or physically dedicated, but -- okay.

17 Q. That's right. And just before I ask you a
18 question about your testimony just to make sure we're all
19 on the same page, the structure and why we're calling it a
20 sleeved PPA is that Georgia Power would be the entity
21 actually -- that actually has a PPA --

22 A. That contracts.

23 Q. -- with that resource. And then the customer
24 would have a contract with Georgia Power that gives them
25 the benefits and requires the customer to pay for the cost

1 of the resource. Does that all --

2 A. (Witness Grubb) If that's the premise we're
3 discussing, then I'm good to talk through it.

4 VICE CHAIRMAN ECHOLS: Can I ask a follow-up
5 question on that? I understand that Alabama Power
6 may have a product like this for a customer or two.
7 Are you aware?

8 MR. GRUBB: On the solar side?

9 VICE CHAIRMAN ECHOLS: I'm not sure exactly.
10 It's a bring your own power -- a sleeved PPA -- I'm
11 sure it's -- probably is a clean product. Are you
12 aware of that?

13 MR. GRUBB: I'm generally familiar that they
14 have some, but I don't know the specifics,
15 Commissioner.

16 VICE CHAIRMAN ECHOLS: Is there any reason we
17 would be hesitant to copy something Alabama
18 Power -- they certainly have copied everything else
19 we've done, so...

20 MR. GRUBB: Yeah. I mean, I think the main
21 thing here is from a timing standpoint. So the
22 competitive solicitation is part of it. But then
23 it also becomes the time to physically build it,
24 and then the transmission side is obviously
25 important.

1 So whatever resource we're looking at, you've
2 got to make sure that you've got time to build it,
3 but you've also got to make sure that you've got
4 time to understand that transmission aspect of.
5 But Commissioner, to the Alabama program, I'm not
6 familiar enough with it, but we can check --

7 VICE CHAIRMAN ECHOLS: Maybe you can check on
8 it and get back with me later on that. Thank you.

9 MR. GRUBB: Yes, sir.

10 MR. DUNBAR: Thank you, Commissioner. I can
11 cross one of my questions off my list.

12 BY MR. DUNBAR:

13 Q. Thank you for your patience, going through
14 all that background and laying that foundation.

15 So going back to the testimony we read a
16 moment ago, your argument is that if there's not enough
17 available capacity on the Georgia Power system, Georgia
18 Power might need to turn prospective new customers away;
19 correct?

20 A. Yeah. So, to be clear, this testimony was
21 looking at a more restricted resource plan than what
22 the -- than what the company has proposed and what the
23 stipulation adopts. So it was fewer resources, is what
24 this testimony is based around, except this was around if
25 you only had the Mississippi Power and Santa Rosa PPA.

1 So, with that, the load forecast that was
2 being discussed didn't have a capacity need until '29.
3 And so the testimony is around the higher-load levels that
4 the company is forecasting to, if you weren't able to
5 deploy resources by that time frame, then you've got
6 two years where you have reliability risk. So that's what
7 we were talking to. So, again, Company's planning with
8 resources allows more of that load to come to the state.
9 If you had fewer resources, whether it's staff's
10 suggestion or not, just in general, then until you can go
11 through that RFP process and physically deploy that
12 resource, then you push out that time frame that you can
13 accommodate new load.

14 Q. Thank you for that.

15 Would you agree, if Georgia Power had the
16 sleeved-PPA program that we were just discussing, Georgia
17 Power would be able to serve any customer who was able to
18 bring enough clean energy capacity to meet their own load;
19 right?

20 A. Well, it's going to depend on the capacity
21 equivalents and what those resources do. And so I
22 don't -- it would depend on what those resources are, if
23 they were able to fully serve that customer's load --
24 which there aren't many carbon-free resources that, around
25 the clock, will serve them, other than nuclear. So it

1 would depend on what those resources are. So there are
2 some risks in that, but again, I think it comes down to
3 mainly the time to physically build the generation
4 resource, but then also, from a transmission standpoint,
5 making sure you have the delivery.

6 So when we're looking three years out, that's
7 pretty challenging, which is why we focused the RFP that
8 we've agreed to in the stipulation we'll work with staff
9 on, and why we've had to move to developing the other
10 resources that we have, from that timing standpoint.

11 Q. Okay. So I think -- I think I heard "yes"
12 for the right type of resource, to answer my question.

13 A. (Witness Grubb) I think the timing becomes
14 the most important thing here, in terms of what resources,
15 how long it takes to physically build them, what
16 transmission is required for that. So I think it's mostly
17 a timing issue, if we were to have that type of a program.

18 Q. And I don't mean to -- well, let me just try
19 to answer the question a slightly different way. If
20 Georgia Power -- if a large new customer approached
21 Georgia Power and you did not have the capacity, in the
22 time frame needed, to serve that customer, but that
23 customer said, well, we're willing to pay for our own
24 dedicated resource that could serve our load, perhaps
25 serve it 24/7, and we'll pay for the full cost of that

1 resource, it won't be located on our property, but it will
2 be located somewhere on the Georgia Power system, that
3 would -- that would help you be able to serve that
4 customer, right, if the customer was bringing their own
5 solution?

6 A. (Witness Grubb) So, in general, if we had
7 that type of program in place and, of course, we would
8 want to make sure -- and I think you're saying the same
9 thing, we'd have to make sure that, from a cost standpoint
10 that that's properly accounted for, which I know you're
11 saying is the case -- yes, that would help bring
12 generation to the system.

13 We just would have to talk about the timing
14 and those kind of things. But, in general, yeah, adding
15 resources to the system, with the timing to add them, does
16 help everybody, from a service standpoint.

17 COMMISSIONER MCDONALD: Where did the
18 forecasted capacity needed for Rivian fall back
19 into meeting these expectations of today?

20 A. (Witness Grubb) Yes. So Rivian is not our
21 customer, and so they're not part of our forecast. But I
22 think, Commissioner -- and Mr. Valle can help me here,
23 we've got a -- there's a really large economic development
24 pipeline that we've forecasted, and we're forecasting a
25 small part of it. So Rivian isn't our customer so it

1 didn't impact our forecast.

2 A. (Witness Robinson) I think another important
3 thing to consider in the PPA that is being discussed is
4 the reliability aspect of that. And if that resource
5 that's being sleeved is not available 24/7, it needs to
6 have -- there'd either have to be some curtailment
7 provisions for that customer, or there would have to be --
8 sorry, is that loud enough, Commissioner? Okay.

9 There'd have to be curtailment provisions for
10 that customer, there'd have to be some protection in that
11 agreement to be able to use company generation in those
12 times when that resource is not available.

13 A. (Witness Grubb) So we would have to design
14 it, right, obviously. And, again, not saying you're
15 saying we wouldn't, but there are a lot of caveats around
16 it that we would have to think through and work through.
17 But, you know, in general, yeah, the more resources you
18 get, the better. We've just got to make sure we
19 understand the impacts to all the other aspects of the
20 business.

21 BY MR. DUNBAR:

22 Q. Sure. Great. Thank you.

23 Would you please turn to page 25 of your
24 testimony, the rebuttal?

25 A. (Witness Grubb) Yes.

1 Q. So on line 14 it says, quote: The company
2 needs resources online to meet the capacity need in the
3 winters of 2025/2026, '26/'27, '27/'28, and the RFP
4 process typically takes two to two-and-a-half years to
5 identify, evaluate, including associated transmission,
6 select and certified capacity resources, end quote.

7 Do you see that?

8 A. (Witness Grubb) Yes, I do.

9 Q. Can you please provide an update on the
10 All-Source RFP that was approved in the 2022 IRP? Is
11 Georgia Power ready to issue that RFP imminently?

12 A. (Witness Grubb) Yeah. So, generally, I can.
13 There are standards of comment in place that --
14 communications around that RFP need to go through the
15 independent value website. But I do believe the schedule
16 is public. And so the service date has begun. I believe,
17 without flipping all the way to my notes, the contracts,
18 the pro forma PPAs and RFP documents, are out there for
19 developer comments, questions, and answers.

20 So I believe that is where we are to this
21 date. So it has been -- it hasn't been issued yet,
22 because we're going through that initial phase of we
23 present the -- we present the proposals -- and,
24 Commissioners, that's part of the RFP process that we
25 have, is so that the market can comment on, and make --

1 and ask questions around those documents. And so we're
2 currently in that phase, as I understand it. And so
3 we're -- yes. The comment phase, it looks like, is
4 through this week.

5 Q. And is there a firm date by which it will
6 actually open?

7 A. (Witness Grubb) So there's a tentative
8 schedule that's out there on the IE website that the
9 company has proposed. Again, I think there's staff and
10 others will be involved in that, as well. But, right now,
11 the schedule is showing it'll be issued in -- after it
12 gets Commission approval, so it -- May is the time frame
13 right now.

14 Q. Okay. Thank you.

15 So, on that same page, page 25, line 22, it
16 says, quote, also, the existing RFPs are crucial to
17 meeting the needs identified in the 2022 IRP for renewable
18 energy resources, ESS resources, and capacity resources
19 for the needs in the 2029, 2031 time frame, and therefore
20 must be conducted to meet those specific needs, end quote.

21 Do you see that?

22 A. (Witness Grubb) That -- yes, I do.

23 Q. If the Commission were to direct Georgia
24 Power to accelerate the All-Source RFP, and some resources
25 were able to come online by 2026 or 2027, those resources

1 would still be online and able to contribute to meeting a
2 portion of your resource needs in the later years, 2029
3 and 2031; right?

4 A. (Witness Grubb) Right. They're not required
5 to. So the All-Source, I think, is targeting '29, '30,
6 '31. I believe the current draft of the RFP does allow
7 for earlier development if it's valuable and if it's
8 economic for customers, but you just don't know that
9 you'll get that response.

10 And so I think that's something that down the
11 road as the All-Source plays itself out, that's something
12 that could be in there. But what you can't do is assume
13 that you're going to get those resources. And so what
14 we've focused on is a plan to meet those needs in that
15 first year of need, '25/'26, '26/'27, and then the RFP
16 that's narrowly focused from the stipulation would meet
17 that third year of need.

18 So it depends on if people bid those into the
19 All-Source. So it's -- I think it's -- we've allowed them
20 to if they want to, but we will value that, but it's not a
21 requirement, and we're not sure you're going to get That
22 frame. So that's something we'll know as that RFP itself
23 plays out.

24 Q. Okay. But you would agree that the
25 Commission, through its order in this case, has the

1 authority to increase the amount of capacity Georgia Power
2 procures through that All-Source RFP, and other RFPs, to
3 ensure that capacity needs are met, both in the early
4 years of '26, '27, and '28, and the later years that you
5 originally intended to cover by the All-Source; right?

6 A. (Witness Grubb) So the stipulation in this
7 case takes care of our needs through -- and our customers'
8 needs, through the winter of '27 and '28. And so, again,
9 if the All-Source has some bids that contribute there,
10 that's something to be taken into account there. And then
11 as far as the megawatts of the all source RFP, we've
12 got -- we're getting some guidance on that.

13 But the ultimate amount that will be procured
14 will be based on the needs when we bring that forward to
15 certification. So the Commission doesn't have to order an
16 amount of megawatts in the RFP, there's a range that's
17 provided and then we'll make that ultimate decision on
18 megawatts when it's completed and certified.

19 Q. Right.

20 A. (Witness Grubb) So there's no action the
21 Commission needs to take on the megawatts in that
22 All-Source RFP.

23 Q. If it approves the stipulation without
24 modification?

25 A. (Witness Grubb) If it approves the

1 stipulation.

2 Q. Okay.

3 A. (Witness Grubb) But, again, that All-Source
4 is focused on '29, '30, and '31.

5 Q. If you would please turn to page 27 of your
6 rebuttal.

7 A. (Witness Grubb) Okay. Which lines?

8 Q. Line 14.

9 A. (Witness Grubb) Okay.

10 Q. It describes, quote, the company's June 2023
11 proposal to divide the All-Source capacity RFP into
12 phases, and issue an expedited phase one of the All-Source
13 RFP in the fall of 2023. Then it continues, the company
14 proposed to shorten the RFP development timeline, and to
15 seek resources similar to those sought in the prior
16 capacity RFP, using the Commission-approved contracts from
17 2022 to 2028 capacity RFP, end quote.

18 I'm hoping you can elaborate on this proposal
19 that you made to staff in June of 2023. In what ways
20 would you have expedited this proposed phase one of the
21 All-Source RFP?

22 A. (Witness Grubb) So the main point here is
23 that the time for this type of RFP has passed, in terms of
24 what we're talking about. This was nine to ten months
25 ago. And we were putting this in testimony just to add a

1 little more to the discussion of the timeline with staff
2 had in there.

3 But we did try to work with staff, but it
4 would have been focused on some existing resources. And
5 so I can't remember all the details, what we were looking
6 to expedite, but the thought would have been, if there
7 were some existing resources out there, you could have
8 expedited some steps. But, again, not material to this
9 case, because we weren't able to get that done. And so it
10 was a different nature.

11 What we've got in the stipulation is a
12 different focus. But, again, this was focused on trying
13 to get and see if there were any existing resources in the
14 market. So this would have to have been done last fall.
15 But I can't remember all the specifics of what we were
16 looking to expedite. It's been quite a few months.

17 Q. Why did Georgia Power not propose, in this
18 docket, to undertake that same expedited process that you
19 were considering last summer?

20 A. (Witness Grubb) Yeah. So partly, the needs
21 year moved up even sooner. And so there was no time to do
22 even an expedited one. And then, again, it was really
23 around the timing of getting that RFP out.

24 Q. Okay.

25 A. (Witness Grubb) So there was -- the

1 opportunity would have been there last fall had the needs
2 year not moved up, but with the needs year moving up an
3 additional year and not getting that in the fall, it's
4 just not an option in this case. So we focused in,
5 through the stipulation and working with staff, on that
6 narrowly-focused one to handle '27 and '28.

7 Q. Okay. Would you please turn to page 37 of
8 the rebuttal. Here, you're discussing the lack of firm
9 transmission service for the Santa Rosa PPA.

10 A. (Witness Grubb) Which lines? I see the
11 lines, but the questions --

12 Q. Oh, I'm sorry.

13 A. (Witness Grubb) It's fine.

14 Q. Lines 4 through 7.

15 A. (Witness Grubb) Okay. Yes.

16 Q. It says, quote, Georgia Power was able to
17 secure firm transmission on the Southern transmission
18 system for transfer across the FPL Southern Company
19 interface through the winter of 2024 and 2025. The
20 Company will continue to seek firm transmission service
21 for the remainder of the term of the agreement.

22 So just to confirm, this means that Georgia
23 Power does not have firm transmission for the Santa Rosa
24 PPA beyond early 2025?

25 A. (Witness Grubb) So I'll let Mr. Robinson help

1 me here. This does not mean -- when we did the
2 transmission screening, the projects that it needed --
3 there were no projects needed to accommodate Santa Rosa
4 from a -- in a similar way it was for Yates, but we --
5 there are some transmission projects that are going to be
6 completed that would remove that limitation, but, again,
7 we've got them through the winter of '24/'25. And what we
8 can do is we can request it 13 months out. So it's a
9 short-term transmission service, but the long term has to
10 have some projects completed.

11 Anything to add there, Mike?

12 A. (Witness Robinson) The projects are timed for
13 summer of '26. And they were actually projects that were
14 included in our '22 IRP associated with Bowen.

15 A. (Witness Grubb) But we are able to dispatch
16 those resources through the winter of 2025. And as we've
17 noted in the filing, we are looking to sell those in the
18 wholesale -- that resource, through the wholesale market,
19 which we can do depending on the counter-party. So we are
20 continuing to look to sell it, we do have service through
21 '25. And that's just, again, under certain cases, a lot
22 of times you will have access to those resources.

23 Q. Okay. So it sounds like it's possible that
24 Georgia Power would not be able to get that firm
25 transmission service for the Santa Rosa PPA for 2026 and

1 2027, in which case that resource would not be able to
2 contribute toward meeting your peak demand needs between
3 '26 and '28.

4 A. (Witness Grubb) No --

5 A. (Witness Robinson) Again, those restrictions
6 on firm transmission service are relieved in summer of '26
7 with the addition of the projects that I mentioned
8 earlier. So for the period of time that you're talking
9 about -- I don't know how much closer I can get this to my
10 mouth. I'm sorry.

11 But for the projects that you're talking --
12 for the time frame that you're talking about, those
13 projects would be in service to relieve those
14 restrictions.

15 Q. Okay. Thank you. I think maybe the
16 microphone is off perhaps.

17 A. (Witness Robinson) It's on now. Thank you.

18 Q. Okay. I'd like to talk next about the Yates
19 CTs, would you please turn to page 38 of the rebuttal?

20 A. (Witness Grubb) Okay.

21 Q. So you're discussing transmission constraints
22 facing the Yates CTs on that page. And on lines 12 to 13,
23 you state there's only one specific -- sorry, forgot to
24 say "quote." Quote, there is only one specific
25 transmission case where the full output of the three units

1 was restricted, end quote.

2 And then I want to look at one other piece of
3 testimony before I ask you some questions on page 46.

4 A. (Witness Grubb) So real quick, that was --
5 just to make sure, that was line 12 and 13 you just read,
6 just for the record.

7 Q. Thank you.

8 A. (Witness Grubb) You're fine. I'm just making
9 sure we got it.

10 And then you said page 46?

11 Q. Page 46, please. Line 14.

12 A. (Witness Grubb) okay. Yes. I see that, that
13 question on 14?

14 Q. That's right, yeah.

15 So the question says, quote, do the
16 transmission limitations on the proposed Yates units limit
17 delivery from the units all the time, end quote.

18 And the response says, quote, no. The
19 transmission upgrades required to unlock the
20 full-designated capacity of the three proposed Yates CTs
21 only impact power delivery in peak demand periods under
22 certain transmission contingencies, end quote.

23 Do you see that?

24 A. Yes.

25 Q. Can you please describe the conditions of

1 that specific transmission case in which the full output
2 of the three units is restricted?

3 A. (Witness Robinson) So I believe those are
4 peak cases, so a summer peak and a winter peak. As far as
5 the contingencies, those are trade secret and I cannot
6 discuss those.

7 Q. Okay.

8 A. (Witness Robinson) But they would be
9 transmission contingencies that occur under the studies
10 that we did for what we call N minus one and N minus G, so
11 you have generator out and a line out. And it restricts
12 the output of those CTs during that period of time.

13 Q. Okay. So during those peak conditions as you
14 described, the total firm output of the proposed CT units
15 is only 600 megawatts; is that correct?

16 A. (Witness Robinson) No. It could be up to the
17 full amount if those transmission contingencies are not in
18 place. If the transmission contingency occurs, then those
19 units will be restricted.

20 Q. Okay, okay. Thank you for that
21 clarification.

22 And in those transmission contingency cases,
23 the total firm output is only 600-megawatts; correct?

24 A. (Witness Robinson) Due to the contingencies
25 during that period of time, yes, they -- until those

1 projects that we refer to that are timed that relieve
2 those, it is restricted to 600-megawatts under those
3 contingencies, yes.

4 Q. Okay. And the combined nameplate capacity of
5 the three CTs is about 1400-megawatts when they're running
6 on natural gas; correct?

7 A. (Witness Bush) That's right. It's about
8 1325.

9 Q. Oh, okay. Closer to 13.

10 A. (Witness Bush) Yes.

11 Q. What do you estimate the capacity factor of
12 the Yates CTs will be?

13 A. (Witness Bush) In our model runs of those
14 CTs, Commissioners, they are very efficient. And we do
15 see them in the near term, running. I think it's -- it is
16 a trade secret number, but running a little bit more than
17 we do as we go through time, but very low -- life capacity
18 factors for those units are -- will be in single digit
19 capacity factors, our expectation.

20 Q. Single digits?

21 A. (Witness Bush) Uh-huh.

22 Q. Thank you. So less than 10 percent.

23 Continuing on page 46, that same page at
24 line 18, you state, quote, for most hours throughout the
25 year, the new Yates CTs will be available to serve load up

1 to the full-designated capacity as soon as they come
2 online, end quote.

3 Do you see that?

4 A. (Witness Robinson) Yes.

5 Q. But as we just discussed, the Yates CTs will
6 have single-digit capacity factors, meaning you don't need
7 them to serve load for most hours of the year; right? You
8 only need them for a handful of hours in the year.

9 A. (Witness Grubb) But when you need them, you
10 need them. And so that's what we're saying, is if that
11 contingency is in place, you've got several hundred more
12 megawatts that are available, by having that third unit
13 there.

14 A. (Witness Robinson) And it's very likely they
15 could run 8,760, all hours of the year, because of that
16 contingency not being in place.

17 VICE CHAIRMAN ECHOLS: Available.

18 MR. GRUBB: They're available to.

19 MR. ROBINSON: Available to -- that's right.

20 Right.

21 VICE CHAIRMAN ECHOLS: Available to --

22 BY MR. DUNBAR:

23 Q. So I just heard you, Mr. Grubb, say when
24 those transmission contingencies are in place, you have a
25 few hundred megawatts available to you, but you've asked

1 for authorization to build 1320-megawatts; right?

2 A. (Witness Grubb) Yeah. And the point was,
3 when those contingencies are not in place, this is talking
4 about all three units will be available. And they're
5 going to be the most efficient CTs on the system, so
6 they'll run first.

7 And, Commissioners, those capacity factors
8 may be low, but they're those cold winter mornings and
9 those hot summer afternoons when you really need those
10 peakers to come on. Mostly, it's been the cold winter
11 mornings. And so the point here is, if that transmission
12 contingency is not in place, we would expect all three of
13 those units to be able to contribute to meeting load in
14 those cases.

15 Q. But it sounds like there's -- to use a
16 technical term, pretty good chance that you could be
17 facing a peak load period, either in the winter or the
18 summer, and you're not going to be able to access most of
19 the capacity of the CTs?

20 A. (Witness Grubb) For that one year.

21 A. (Witness Robinson) That's actually incorrect.
22 During those period of times of the winter peak and summer
23 speak, during those years of restriction, if that
24 contingency is not in place, it can run up to full
25 nameplate rating.

1 Q. How often is the contingency expected to be
2 in place?

3 A. (Witness Robinson) Well, it depends on the
4 contingency, there's multiple identified in the study.
5 Many of them are the loss of a 230KV line. That doesn't
6 happen often, but it can. So it can be a one-in-five-year
7 event, but it could happen multiple times in a year. But
8 we can't plan for probability. We have to plan for
9 absolute, from a NERC-reliability standard prospective.

10 Q. And is the contingency, like the example you
11 mentioned of a 230KV line going down -- that sort of thing
12 is likely to happen during winter storms; right?

13 A. (Witness Robinson) More during summer or
14 spring storms, like we've had here recently, versus
15 winter. In winter, it could if you had a tree fall off
16 the right-of-way that had snow on it, or something like
17 that.

18 But, typically, it's during periods of time
19 like this, where we have tornadoes come through like we
20 did, like we heard the public witness this morning talk
21 about the tornado that came through Valdosta last night.
22 Those are the things that we have to plan on. And when
23 that comes through, if it takes a 230 line out, it could
24 be out for a week as we repair and try to put that line
25 back in service.

1 Q. Okay. And that could be going on during a
2 peak summer day?

3 A. (Witness Robinson) Absolutely. It sure
4 could.

5 Q. Okay, okay. I'll move on.

6 If you would turn to page 43, please. I'd
7 like to talk about the DER co-location and customer-owned
8 programs.

9 A. (Witness Grubb) Page 43, yes.

10 Q. At line 13, the question asks, quote, do the
11 DER co-location and customer-owned programs exclude
12 carbon-free resources, end quote.

13 And the answer says, no. Quote, no. The
14 program is designed to be resource neutral, provided that
15 such resources are dispatchable, have a firm fuel supply,
16 and are interconnected to transmit the energy they produce
17 to the electric grid, end quote.

18 Do you see that?

19 A. (Witness Smith) Yes.

20 Q. Would solar-plus-storage projects qualify for
21 the DER programs?

22 A. (Witness Smith) Yes, they could.

23 Q. And you said, yes, they could. Is there a
24 reason why they couldn't?

25 A. (Witness Evans) Well, if they don't meet the

1 requirements of the program. Obviously, we've laid them
2 out in the tariff, and we mention them here, firm fuel
3 supply, being interconnected to push full back -- their
4 full capabilities back onto the grid, they must be able to
5 be charged via the grid; right?

6 That's part of that firm fuel supply. And
7 that's the case, that the battery is not fully charged
8 when we need it; right? We need to be able to charge that
9 battery to dispatch during those reliability events. But
10 solar plus storage can absolutely participate. In fact,
11 we're in active conversations with customers that are
12 interested in that aspect.

13 Q. Okay. Could you elaborate just a little bit
14 about the firm fuel supply? So you do consider a battery
15 connected to a solar facility on a customer's site to be
16 firm fueled?

17 A. (Witness Evans) Well, it would have to be --
18 also be enabled to charge from the grid, as well. It
19 couldn't only charge from the solar facility. And so the
20 interconnection would have to enable that.

21 You know, these are the types of details,
22 Commissioners -- each one of these assets that go through
23 this program will have go back through certification.
24 These are the types of details that we'll work with that
25 customer on, exactly what is required there, and present

1 them to the Commission before the assets are certified.

2 Q. Okay. That's helpful.

3 And just to be absolutely sure, you're not
4 planning to require a customer who wants to participate,
5 with the solar system and a battery system, to also have a
6 diesel generator connected to that, as long as it can be
7 charged from the grid under the interconnection
8 arrangement, it should qualify?

9 A. (Witness Evans) That's right. The battery
10 portion, especially, would qualify for the capacity
11 equivalence value of that battery.

12 Q. Okay.

13 A. (Witness Evans) And also, you know, the
14 customers that we're talking to are looking at a variety
15 of resources and not just one. So a customer could opt to
16 also have other types of resources on site for different
17 levels of resiliency in addition to the battery. They
18 could have just the battery and solar program. Again, as
19 long as it meets the qualifications of the program, those
20 are absolutely -- can be part of it.

21 A. (Witness Evans) And if the customer is going
22 to rely on that system to also run during periods of
23 reliability, where it's separated from the grid, they
24 probably want to have a recent generator in that system,
25 just from a reliability perspective, to be able to provide

1 their full load during that period of time. Just in case
2 the sun wasn't shining the day before to charge the
3 batteries.

4 Q. That would be up to the customer to decide?

5 A. (Witness Evans) Absolutely.

6 Q. Great. That's great news. Thank you.

7 Just one more line of questioning. On
8 page 45, if you would turn to that. I would like to
9 discuss what is affectionately known as the 70/30 rule,
10 that requires -- the policy under which Georgia Power owns
11 70 percent of its supply-side resources.

12 So on page 45, line 2, you state that the
13 Commission's current policy, of allowing Georgia Power to
14 own at least 70 percent of its supply-side capacity, is
15 comparable to policies set by statute in Virginia and
16 North Carolina.

17 Do you see that?

18 A. (Witness Grubb) Yes.

19 Q. With respect to Virginia, is it your
20 understanding that the 65 percent utility ownership
21 threshold you reference, is with respect to new renewable
22 resources that are acquired to meet Virginia's renewable
23 portfolio standard?

24 A. (Witness Grubb) I believe that's it. And we
25 didn't do a nationwide search. What we were looking for

1 here is, there was just some questions on, had any other
2 utilities had anything around ownership, and so we pulled
3 those. And, of course, I think it's important to look at
4 North Carolina. It looks like all of theirs are owned.
5 So the point here was that there are other jurisdictions
6 that have some ownership percentages on resources.

7 Q. Right. So sticking with Virginia for just a
8 second, the Virginia policy you referenced does not set a
9 minimum utility ownership threshold for all supply-side
10 resources; correct?

11 A. (Witness Grubb) I don't think we've testified
12 to that. But I'm not a hundred percent sure what that is.
13 But, yeah, what we were showing here again was just --
14 there were questions around, are any other utilities -- do
15 they have some sort of ownership percentage, and that's
16 what we pulled.

17 So not that it's a direct comparison. And,
18 again, there could be other states. We didn't do an
19 exhaustive nationwide search, but just pointing to the
20 fact that there are other jurisdictions that have some
21 ownership and purchase percentages.

22 Q. Okay. So with respect to North Carolina, you
23 would agree then that that policy of -- that requires new
24 resources to be owned by the utility, that's with respect
25 to new resources that are procured to comply with the

1 carbon reduction goals in that state; correct?

2 A. (Witness Grubb) Yes, that's my understanding.

3 Q. So there, again, it doesn't set a minimum
4 utility ownership threshold for all supply-side resources?

5 A. (Witness Grubb) I don't know. I'm sure they
6 have ownership, and so there is a percentage they have.
7 But, yes, it's just anything new would be company-owned.
8 Again, we were just finding examples. The testimony was
9 around, Georgia is not the only jurisdiction that has some
10 sort of reflection of ownership percentages.

11 Q. Okay. That's all I have.

12 MR. DUNBAR: Thank you, Panel. Thank you,
13 Commissioners, Mr. Chairman.

14 CHAIRMAN SHAW: Thank you.

15 Heelstone.

16 MR. GALLOWAY: No questions, Mr. Chairman.

17 CHAIRMAN SHAW: Georgia Association of
18 Manufacturers.

19 MR. JONES: Thank you, Mr. Chairman. I have
20 just a couple of questions for the panel.

21 CROSS-EXAMINATION

22 BY MR. JONES:

23 Q. I think most of my questions, Panel, will to
24 to Mr. Evans, but, certainly, whoever is the appropriate
25 person to respond.

1 But, Mr. Evans, were you here earlier when
2 Ms. Whitfield asked Mr. Abramovitz questions about RTP
3 customers and allocation of costs?

4 A. (Witness Evans) I was.

5 Q. Are there fixed-cost components to the
6 marginal portion of RTP rates?

7 A. (Witness Evans) Yes. As we discuss in rate
8 cases, and I think just about every rate case before the
9 Commission, RTP has five components to it. Three of those
10 are related to lambda, as Mr. Abramovitz mentioned, but
11 then also, there is the reliability component, which is
12 meant to cover generation, the marginal cost of generation
13 investment; and the transmission component, which is meant
14 to recover the marginal cost of transmission. And all of
15 those are directly assigned -- removed from existing
16 customers, and reassigned to RTP customers in the cost of
17 service study, in every one we file.

18 Q. Regarding the marginal component of RTP, can
19 you please describe why it is designed as a marginal
20 tariff, and what costs it recovers?

21 A. (Witness Evans) Certainly.

22 So, in our cost of service study, but also in
23 the design of the rate in general, it is meant to recover
24 the marginal cost to serve the next kilowatt hour. So
25 those loads being identified as marginal, we are looking

1 forward at what the next cost that we incur as a system to
2 serve that load, so that -- so from a lambda perspective,
3 we're always charging, when representing the next unit to
4 come online, right, so that next marginal cost of energy.

5 Additionally, throughout the year, we look at
6 the marginal cost of capacity that the company will incur,
7 and assign that, and allocate that, and trigger those
8 components throughout the year, to recover that from those
9 customers. That's a great benefit that RTP has provided,
10 of not just providing the right real-time price signal to
11 those RTP customers, but to benefit all customers by
12 recovering that cost, and serving economic development of
13 being a competitive rate, but one that also puts downward
14 pressure on rates and benefits all of our existing
15 customers.

16 Q. Do RTP rates fluctuate?

17 A. (Witness Evans) Very much so.

18 Q. Do RTP customers assume the risks that are
19 associated with those fluctuations?

20 A. (Witness Evans) That's correct.

21 Q. What are some of the consequences that can
22 occur for the assumption of that risk?

23 A. (Witness Evans) Well, as we've experienced
24 over the years, sometimes we have very high price signals
25 that RTP customers experience. Based on that, they can

1 choose to either respond, take load off of the system
2 during those critical times and avoid those costs, or to
3 pay those very high price signals. And when they do, they
4 pay for the marginal cost to serve that load.

5 MR. JONES: That's all I have, Mr. Chairman.
6 Thank you.

7 CHAIRMAN SHAW: Thank you, Mr. Jones.
8 Georgia Center for Energy Solutions?

9 (No response.)

10 Georgia Coalition of Local Governments.

11 MS. BROWN: No questions.

12 CHAIRMAN SHAW: Georgia Interfaith Power and
13 Light.

14 CROSS-EXAMINATION

15 BY MS. WHITFIELD:

16 Q. Good afternoon, gentlemen.

17 THE PANEL: Good afternoon.

18 Q. I want to start by talking about the rate
19 impact questions. Trying to understand better how we
20 landed at the 289 number, and using Mr. Abramovitz's
21 testimony, but then also, I assume the cost of service
22 study allocation played into that, though I might be
23 wrong.

24 But I guess one place to start is, the
25 testimony indicates that there is going to be a -- that

1 the benefit, identified by Mr. Abramovitz in this
2 levelized chart, this will be allocated according to an
3 equal percentage.

4 I don't know. Is it, Mr. Evans, the right
5 person for this?

6 A. (Witness Evans) Sure. And can you point me
7 to a --

8 Q. Can you just describe how that happened?

9 A. (Witness Evans) Can you point me to the page
10 or line number in testimony?

11 Q. I can. Let's see. Well, the equal
12 percentages is in Abramovitz's line at -- page 10. I
13 don't know that I have it numbered for you. Let's see.

14 A. (Witness Evans) Line number on page 10, I'm
15 trying to find it.

16 Q. Oh, for Abramovitz's?

17 A. (Witness Evans) Yes.

18 Q. And, also, your cost of service study looks
19 like it's on page 10 of your testimony, as well.

20 Sorry, everything got moved around when --
21 page 10, lines 5 to 11, is where Abramovitz is testifying
22 about allocating the net benefit on an equal percentage
23 basis.

24 A. (Witness Evans) That's right. So what that
25 is simply doing -- and that's not coming from the cost of

1 service study, or an allocation from the cost of service
2 study. That is simply looking at, whenever you take the
3 net benefits from the chart that you're showing there, and
4 look at an equal percentage across all of the rate groups,
5 what that impact would be on 1000-kilowatt-hour bill.

6 Q. Okay. Equal percentage of what? Like the
7 number of customers? What's the denominator there?

8 A. (Witness Evans) Oh, yes. It's essentially on
9 a kilowatt-hour basis, similarly to the way that the
10 increases were allocated in recent proceedings that had an
11 even increase to all. We looked at those as reference
12 points to then say, okay, if we had this amount of a net
13 benefit, that we were now going to represent on an equal
14 percentage basis, what was that impact -- what would that
15 impact be today, on a 1000-kilowatt-hour bill?

16 But it is not looking at the cost of service
17 allocations. So that's -- you referenced Mr. Abramovitz's
18 testimony, in mine -- or the panel's testimony. Page 10
19 on mine, discusses the allocation methods that we used,
20 that are highlighted in Exhibit 1 of the main panel
21 testimony.

22 Q. Okay. In terms of that allocation based on
23 kilowatt hour, I believe you said, there was some
24 testimony in the 2022 rate case by Georgia Power, that the
25 rates in that case were being allocated by an equal

1 percentage across rate groups?

2 A. (Witness Evans) Yes. That's common for
3 Georgia Power, when we propose new tariffs in the rate
4 case. Those tariffs adjust each rate by an equal
5 percentage, for the original filing.

6 Q. Okay.

7 A. (Witness Evans) Then the ultimate decision,
8 by the Commission, makes movements towards parity as the
9 Commission sees fit. But the original tariffs that we
10 file are on an equal basis across all.

11 Q. I'd like --

12 MS. WHITFIELD: If Mr. Sherrier can approach
13 with an exhibit, Chairman Shaw?

14 CHAIRMAN SHAW: Go ahead.

15 (The documents referred to were marked for
16 identification as GIPL Exhibit 1.)

17 BY MS. WHITFIELD:

18 Q. I'd like to hand you what we'll mark as GIPL
19 Exhibit 1. And unfortunately, with my apologies, it is
20 not marked yet, but I'd like to designate it as GIPL
21 Exhibit 1. And this is a page from the rate case
22 testimony, I hope, that shows the rate groups.

23 A. (Witness Evans) Right.

24 Q. And the ultimate outcome of Georgia Power's
25 proposed equal percentage allocation across the rate

1 classes.

2 Does that -- give you a second to take a
3 look.

4 A. (Witness Evans) That's right.

5 Q. So I'm trying to understand this better
6 because, looking at this, I'm reading that there's an
7 equal percentage allocation, but here, the impact is that
8 the domestic group bill goes up by 11.4 percent, the
9 marginally priced bill goes up 6.3 percent.

10 A. (Witness Evans) Yes. So subject to check, I
11 believe that the equal percentage applies to what we call
12 traditional base tariffs. So whenever you look at the R
13 rate, the prices and then the revenue recovery from that
14 rate itself. Whereas this looks at the total bill impact;
15 right?

16 As we discussed earlier, and discuss at
17 length in rate cases, where the composition of rates is
18 part of that proceeding, real time pricing has two
19 components to it. There's the traditional customer base
20 line, which is priced at one of our traditional tariffs.
21 And then there's the marginal energy, which is priced at
22 real time pricing. So the marginal price to here is
23 not -- the increase is applied to the traditional base
24 tariffs for the marginal group.

25 Q. And I'm a little out over my skis here, but

1 when you say "base tariffs," that is basically base rates,
2 is that?

3 A. (Witness Evans) Great question. We have a
4 lot of "base" words being tossed around. Traditional base
5 tariffs, for the CBL component of RTP customers, they'll
6 take service under one of our traditional tariffs, like a
7 power and light large tariff, for instance.

8 So their load, on their CBL portion, will be
9 billed to them based on that traditional base tariff.
10 Their marginal load will then be priced at the real time
11 price, whatever that might be, hour by hour, throughout
12 year.

13 Q. Okay. So this explains that the -- I think,
14 you tell me. But I think this explains why, on page 8 --
15 and it should be double-sided, I believe, if you flip it
16 over, at lines 1 through 3, you indicate that this equal
17 percentage allocation says that, consistent with existing
18 practice, the base rate increase does not apply to
19 incremental RTP usage.

20 A. (Witness Evans) That's right. And also, as
21 it also says, the large differences that you see is also
22 driven by fuel. So customer -- so different rate groups,
23 you have different load factor and therefore have
24 different energy costs. So based on how much the fuel
25 component of the total bill for a certain type of customer

1 is, will also impact that total percent bill impact that
2 we have listed there.

3 Q. Right, sure. But this domestic increase
4 here, residential class increase of 11.4 percent, didn't
5 include the \$16 a month that was incorporated into rates
6 from the next fuel case, right? I mean, that was handled
7 separately. So that still doesn't even include that;
8 right?

9 A. (Witness Evans) Yes. Commissioners, I'm
10 sorry. This -- this isn't my testimony --

11 Q. No, I know. I know.

12 A. -- from the '22 case. So I can't speak to
13 the details of what was included or not. Since it wasn't
14 part of that proceeding, I would assume not, but I can't
15 speak definitively.

16 Q. When we last spoke, Mr. Grubb, you indicated
17 that Georgia Power hasn't had a chance yet to do an
18 analysis on a billed basis as opposed to a rate basis.

19 Have you been able to do that, including
20 riders and fuel and --

21 A. (Witness Grubb) Could you say that again?
22 Sorry.

23 Q. That's fine.

24 Last time we spoke, you indicated that
25 Georgia Power hadn't had a chance to analyze what the

1 impact would be on the whole bill, not just the rate, but
2 the whole bill, including the riders like ECCR and fuel,
3 and what the customer ultimately pays.

4 I'm wondering if you've had a chance to do
5 that since?

6 A. (Witness Evans) Right. So I --

7 A. (Witness Grubb) Yeah. I think that -- I
8 believe the 289 is representative of what that impact
9 would be. That is the downward pressure that we, today,
10 from this proceeding, expect to see.

11 Q. Would you expect that that downward pressure,
12 that 289, would include fuel? So if fuel prices go up, if
13 there's something wild that happens between now and the
14 rate case and fuel prices spike, would that 289 include
15 that spike, that residential customers bear the risk of?

16 A. (Witness Evans) Well, Commissioners, all
17 customers bear the risk of fuel. And just as part of this
18 proceeding, we would expect at least the 289 to be
19 realized, and put downward pressure on whatever cost
20 increases or decreases occur between now and the rate
21 case, such that if a decrease occurs, it will add to that
22 decrease. If an increase occurs, it will mitigate that
23 increase by at least the 289 that we've committed to.

24 Q. So it doesn't include fuel, the 289?

25 A. (Witness Grubb) That figure does not, but,

1 again, on a fuel case standpoint, each customer is going
2 to -- help me here, every customer is going to pay for
3 their fuel costs, because it's a per-kilowatt-hour charge.
4 And so as these loads increase, they are going to pay
5 their share of fuel, right, fair to say?

6 A. (Witness Evans) Yes.

7 Q. And you were talking before with Mr. Jones
8 about how the marginal price has a lot of fluctuation,
9 goes up and down a lot, what's the primary driver of all
10 that fluctuation for them?

11 A. (Witness Evans) Well, the greatest
12 fluctuation that we see is when those triggers, for
13 generational reliability and transmission reliability
14 occur. That's what increases prices the most.

15 Q. Mr. Evans, so you indicated that this 168 was
16 allocated -- I don't want to misrepresent you -- but
17 allocated in an equal percentage manner similar to how it
18 was done here in 2002.

19 A. (Witness Evans) Again --

20 Q. In 2022, I'm sorry.

21 A. (Witness Evans) Again, I believe so. Again,
22 I don't know exactly that exact table, how that was
23 calculated, but I would suspect it was similar.

24 Q. Okay. Is this how the money that's allocated
25 across classes, when you do that equal percentage

1 allocation, is this how you typically come up with that
2 amount? Like, do you -- before you make an allocation of
3 RTP revenues across the classes, which is what I'm hearing
4 from the Company, is that RTPs coming in, these big mega
5 companies are coming in, they're going to pay pretty high
6 bills, because they have really high needs. That's going
7 to lead to a really big revenue number. And even if you
8 take out all of these asset costs for a levelized year,
9 you still have that benefit to allocate.

10 So my question is: Is that how you come up
11 with the benefit to allocate when you do an equal
12 allocation, like you were just describing?

13 A. (Witness Evans) Yes. And whenever we file
14 the original tariffs in a rate case proceeding -- and most
15 recently that was -- I don't know the exact percentage,
16 but that was a rate increase -- that rate increase that
17 was sought, from traditional base tariffs, was then
18 equally applied to be recovered from each individual rate.
19 So, yes, an equal percentage based on the total increase
20 sought, that same increase was realized from the rates.

21 Q. My question is a little different. It's
22 about how you get to that equal percentage. And my
23 question is: Do you get to that benefit, that you're
24 going to allocate, by charging that large load class with
25 these costs? That's what I'm asking (indicating).

1 Are you suggesting -- I'm trying to
2 understand. You're suggesting that you're going to charge
3 these costs against the revenue, and then anything left
4 over is going to get allocated to all the customer
5 classes. Is that --

6 A. (Witness Evans) I think I can help. I think
7 I understand. I'll try to help.

8 Q. Okay.

9 A. (Witness Evans) So that chart is just simply
10 representing, from a total company level, cost and
11 benefits. There is no class or customer segment
12 determination in it.

13 Q. Okay.

14 A. (Witness Evans) So just like in a rate case,
15 whenever we determine what the overall increase or
16 decrease is, we're looking at the total retail
17 jurisdiction, and seeing what is the overall increase
18 requested, or the decrease requested, and adjusting
19 traditional base tariffs by that same percentage, just as
20 we've done.

21 Q. Okay. So it's not how it would be done from
22 an individual classes' perspective, from a residential
23 ratepayer's perspective?

24 A. (Witness Evans) No. It is how we adjust the
25 tariffs whenever -- in rate cases, whenever we file them.

1 Q. You adjust the tariffs this way?

2 A. (Witness Evans) From a total company impact
3 perspective, that same percentage is applied to the
4 individual rates.

5 Q. This percentage here?

6 A. (Witness Evans) Is that -- is that how you do
7 it?

8 Q. I'm not trying to be cute. I really like --
9 or "gotcha." I really don't -- I really don't know.

10 A. (Witness Evans) Sure. I'll try to explain
11 again. That chart represents total company's costs and
12 benefits, from this proceeding.

13 Q. Right.

14 A. (Witness Evans) And it, in this case, shows a
15 decrease. That percentage decrease would then be applied
16 equally to all of the existing rates.

17 Q. Okay.

18 A. (Witness Evans) In the last rate class, that
19 chart showed an increase. That increase was applied
20 equally to all traditional rates.

21 Q. Okay.

22 A. (Witness Adams) So it is done in the same
23 manner.

24 Q. Okay, got it.

25 So basically what I'm hearing is that you

1 take the revenue, you pull out -- on a company-wide basis,
2 it wouldn't just be this proceeding. On a company-wide
3 basis, it would be all the revenue, all the costs,
4 whatever is left, you allocate; right?

5 A. (Witness Evans) That's right.

6 Q. You are cabining it to this proceeding, or
7 attempting to with this chart, but where is the cost to
8 serve these customers?

9 A. (Witness Evans) So the incremental costs
10 incurred are represented by the gray bars. Now that
11 doesn't count the existing infrastructure that will also
12 serve them.

13 Q. Yeah.

14 A. (Witness Evans) Right? That is done through
15 the cost of service exhibit that we filed as part of our
16 main -- as part of the Panel's rebuttal testimony.

17 Q. Okay. So the cost of serving this marginal
18 class is reflected by these resources that you're
19 requesting in this proceeding, because this is the class
20 causing those resources to be brought on board?

21 A. (Witness Evans) No. Again, that chart isn't
22 representing any class costs at all. Those are total
23 company resources that we're requesting to serve new load,
24 and additional revenues that will be enabled by bringing
25 those resources online.

1 Q. Okay. Let's look at your cost of service
2 study. Does the cost of service study -- this is your
3 Exhibit 1. So it's at the end of the testimony.

4 Is this cost of service study -- well, I
5 guess, what is this showing, in as close to English as you
6 can get with the technical stuff?

7 A. (Witness Grubb) We try.

8 Q. I mean --

9 A. (Witness Evans) As the Commission knows, I
10 tried to simplify this. In rate cases, we file, I think,
11 about 820 pages of cost of service data. We provided that
12 in Excel format to support it, but did try to simply it as
13 far as the outcome. It's a simple comparison -- and I'll
14 say simple, but you check me on that.

15 Q. I mean, not to me, but --

16 A. (Witness Evans) The top section represents
17 exactly what we filed in the last rate case; right? It
18 comes from my Exhibit LPE 1, Schedule 1.

19 Q. Yes.

20 A. (Witness Evans) The middle section is taking
21 that exact cost of service study, as filed, and simply
22 making three adjustments to it: One, we're adding the
23 revenues, that were shown on the blue bar that you were
24 referencing. We're adding the revenue requirements in the
25 appropriate places, from the gray bars that were

1 represented.

2 Q. Uh-huh.

3 A. (Witness Evans) And we're adding the loads
4 that create the revenues shown in the blue bar.

5 Q. Uh-huh.

6 A. (Witness Evans) And from that, it shows new
7 allocations of cost, both those costs shown there and our
8 existing costs. As we said, in direct testimony and
9 during the hearings, a benefit of this is that new
10 kilowatt hours allow for a greater base to allocate and
11 spread existing cost recovery to.

12 So all of our cost allocations were impacted
13 by new load allocators. Load is the primary allocation
14 factors that our costs are allocated to. So by new load
15 coming online in a certain rate group, in this case the
16 marginal rate group, they are being allocated more costs
17 as a result of that. So that's what this middle section
18 shows.

19 And the bottom section is simply the delta
20 between that, showing the net benefit of increased net
21 income. And net income in this standpoint, from a
22 cost-of-service perspective, only represents how much
23 certain rates are covering, or not recovering, their
24 costs.

25 Q. Right.

1 A. (Witness Evans) Right? So, obviously, the
2 overall net income allowed by the company is determined in
3 rate cases, this is simply showing what the impacts or
4 movements among that is, primarily due to the cost
5 allocation changes. And then, of course, the return on
6 investment, which is a simple calculation of the net
7 income over the rate base for that particular rate group.

8 One key item that we point out in testimony
9 is, the billed revenue for the non-marginal rate groups
10 didn't change, because we took -- we started with the 2022
11 cost of service study, and simply added the revenue and
12 loads and costs from this proceeding. So for the domestic
13 rate group, for instance, their billed revenue didn't
14 change as a result of that, but their net income went up.
15 That shows that costs were removed from that rate group.

16 Q. Right. So billed revenue staying the same in
17 these assumptions, does that mean that the assumption
18 baked into this chart is also that bills and rates stay
19 the same from 2022, that that's kind of already baked in?

20 A. (Witness Evans) I would say that we isolated
21 the change just to what's happening in this proceeding, to
22 see what the impact of this proceeding is, both the
23 revenues and the costs. We're not making any future
24 adjustments to, or assumptions on what the future might
25 hold. It's simply what this case is at, is requesting the

1 impacts of it, and showing it from a cost of service
2 standpoint. I believe it was also -- as the staff panel
3 had laid out exactly this, as far as what sensitivity they
4 were looking for, from a cost of service perspective.

5 Q. Okay, great.

6 And in order to get that return on investment
7 number, you also have to have that denominator of the net
8 income, right, which is a total investment, or a rate
9 base. What assumptions did you make, in making -- in
10 changing those figures?

11 A. (Witness Evans) So, again, we allocate -- we
12 allocated all costs, both rate base and expenses, as the
13 cost of service study filed in 2022 did. We made no
14 changes to that, other than increasing the loads, as filed
15 in this proceeding. So the marginal loads went up, which
16 meant that they got allocated a greater percentage of the
17 rate base that was being allocated but no allocation
18 changes were made. So, you know, our main allocators, as
19 part of the cost of the service study, for a long time,
20 are that generation investment, for example, is allocated
21 on each one of the monthly peaks. On a -- what's called
22 12 coincident peaks. That occurred here. What did change
23 is the loads that was -- that those 12 peaks were
24 calculated based on.

25 Q. Uh-huh.

1 A. (Witness Evans) So only as a result of the
2 new large loads being included.

3 Q. Okay. So I think what I heard you say is
4 that the total investment number, or rate base number,
5 that's used as the denominator to calculate that return on
6 investment number is basically 2022, plus the revenue
7 requirements from this chart, from the Abramovitz
8 Figure 1?

9 A. (Witness Evans) That's correct. It also --
10 the revenues and the costs also tie back to the
11 discovery -- the DR -- DEA3-6, that we referenced a number
12 of times in our direct hearings and direct testimony.

13 Q. Yes.

14 A. (Witness Evans) So both the revenue and the
15 cost of the revenue requirements --

16 A. (Witness Grubb) And that was the chart that I
17 was speaking to in direct, that was not -- it was just
18 that high level. What we've done here is what I said we
19 hadn't done it in the first one.

20 A. (Witness Evans) And I wouldn't say that they
21 tie back to that chart specifically, because that chart is
22 levelized over a three-year period, '26, '27, '28, whereas
23 this exhibit is only looking at the 2028 revenues and
24 costs.

25 Q. Okay. Did you include any costs related to

1 transmission, or any of those other things that weren't
2 included, as part of these costs?

3 A. (Witness Evans) No, again, we tied it
4 directly back to the DEA3-6 revenue requirements, and
5 revenue's included.

6 Q. Okay. So this chart, if we look at it,
7 return on investment is also called parity; correct?

8 A. (Witness Grubb) We're still on Exhibit 1;
9 right? Just making sure.

10 Q. Yes.

11 Yeah. I'm just flipping around.

12 A. (Witness Grubb) That's fine. Just making
13 sure we're with you.

14 Q. Still on Exhibit 1.

15 A. (Witness Grubb) Just making sure we're with
16 you.

17 Q. And I'm looking at that middle row, and see
18 that the return on investment that you listed here for
19 residential is 5.5, and for marginal, it's 9.8. And
20 there's quite a big difference in how those parity numbers
21 are impacted in this chart.

22 And my question is: Recognizing that in the
23 past, the Commission has urged rates to approach the
24 average of all of those, which is the parity number -- by
25 offering this to the Commission as reflective of what

1 Georgia Power will put forward, is Georgia Power
2 representing that it is prepared to recommend an outcome
3 that has this much disparity between ROIs to protect
4 residential ratepayers?

5 A. (Witness Evans) The cost of service study is
6 not meant to represent or urge for a policy decision by
7 the Commission, it is meant to be a benchmark that those
8 decisions can be made from, while considering other
9 factors. The cost of service study is not an answer to
10 which your rates are calculated based upon, but it
11 directly informs that ultimate determination of the
12 adjustment of rates. So, no, is your answer.

13 Q. Okay, thank you.

14 All right. So we were talking about the rate
15 impacts, and all of the numbers are basically 2026 through
16 2028; correct?

17 A. (Witness Evans) Are you referring to
18 Mr. Abramovitz's chart now?

19 Q. I'm talking about generally, the Company's
20 representations about what will happen to the rates in
21 this proceeding. I haven't seen any representations about
22 what -- well, I'd like to ask you, what are the Company's
23 representations about what happens after 2028, with
24 respect to rate impacts?

25 A. (Witness Evans) Well, we can both talk about

1 these; right? So there's additional revenues that will
2 continue to increase, based on our projections. Also,
3 there are variables that we don't know at this time. As
4 Mr. Abramovitz said, that we can't make an ultimate
5 determination of what will happen to rates.

6 A. (Witness Grubb) Yeah. So you've got the --
7 from the generation standpoint, we've got the All-Source
8 RFP, so it's going to depend on what we procure, and what
9 we're adding to the resources to serve this load. But as
10 Mr. Evans said, the revenue requirements for these
11 resources decline over time.

12 And so from these resources, you would expect
13 it to be even more positive. But there's just a lot of
14 things in '28, '29, and '30 that are still yet to play
15 out.

16 A. (Witness Evans) That's right. And while the
17 revenue requirements from these resources decline over
18 time, just as our load projections have shown increases
19 over time, the revenues associated with those loads also
20 increase over time. So you've seen revenue requirements
21 for these resources decrease, and revenues resulting from
22 these resources being certainly -- enabling them to
23 increase.

24 A. (Witness Grubb) And I think again, too -- and
25 we've talked about this, too, Commissioners, when we price

1 any of these new large loads, through the rate impact
2 measure, we're looking at making sure that, over the life
3 of those projects, there's downward pressure on rates for
4 everyone else, so that's behind that, as well.

5 Q. So the rate impact measure, that is what's
6 been used repeatedly to justify that these large loads
7 are, in the long run, expected to yield a systemwide
8 benefit -- or a company-wide benefit; correct?

9 A. (Witness Evans) Yes.

10 A. (Witness Grubb) And the rate impact measure
11 test is used in other places, as well, it's not just on
12 these, right, it's DSM and several other factors, as well.

13 Q. Right.

14 In the rate impact measure tests, are you
15 familiar with the generation capital that's assigned to
16 these customers?

17 A. (Witness Evans) Yes.

18 (The documents referred to were marked for
19 identification as GIPL Exhibit 2.)

20 Q. And are you aware -- well, I think maybe it's
21 better to do it this way, I'm getting into dangerous trade
22 secret territory, and I don't want to violate any of the
23 Company's protections. So what I would like to do is
24 provide the Panel and the Commission with a hand-out that
25 is trade secret, so that I can refer to that to ask my

1 questions, and get this information into the record,
2 without violating those trade secret obligations. And
3 here's a copy, if you want.

4 This is going to -- this information is a --
5 is our summary of rate impact measure information for
6 these large load customers, that is what is the company is
7 relying upon to say that, in the long run, there will be a
8 benefit to the system -- which, by the way, we don't agree
9 with in the -- in 30 years. That's what they show. So
10 we're not disputing that. Our concern is about ratepayer
11 impact in 2029, when there's no protections baked in.

12 MR. MARZO: I appreciate counsel trying to
13 keep the protective of trade secret information. I
14 am just trying to understand what are the source
15 documents for this?

16 MS. WHITFIELD: These are -- I don't have
17 the -- it's one of the Company's document
18 responses. I suspect Mr. Evans will recognize it.
19 It's -- Attachments A through P are all copies of
20 RIM results for different customers.

21 MR. MARZO: Okay. Well, Mr. Evans can look
22 at it and see if he knows. But I'm just -- it
23 would help to kind of know where the data was
24 coming from. These calculations are not -- these
25 are exclusively excerpts from company responses,

1 not calculations done by GIPL, or am I --

2 MS. WHITFIELD: No. This is all straight
3 from Company responses. This chart here.

4 MR. MARZO: Comes out of the Company
5 responses?

6 MS. WHITFIELD: Yes. These are averages, so
7 this is just like totaling that up and averaging
8 it. The weighted average one is the only one that
9 has any like --

10 MR. MARZO: So that was a calculation?

11 MS. WHITFIELD: That's a calculation, yeah.
12 Which I would ask him if he agrees, if he doesn't,
13 so be it.

14 MR. MARZO: The witnesses can look at it -- I
15 mean, not knowing what the DR it comes from, I
16 would just ask them if they recognize the
17 information. If they don't, then it would be
18 difficult for them to convey that they agree with
19 it.

20 CHAIRMAN SHAW: You can allow --

21 MS. WHITFIELD: Can I approach? Thank you.

22 BY MS. WHITFIELD:

23 Q. So I'll give you guys a second to look at
24 this. And these are from Staff-LA-15, Attachments A
25 through P.

1 A. (Witness Grubb) You said LA-15 -- I don't
2 have it with me, so it doesn't matter. It's an LA --

3 MR. MARZO: And do y'all have the actual data
4 request response? I'm not trying to be difficult,
5 I'm just --

6 MS. WHITFIELD: The Excel spreadsheets?

7 MR. MARZO: Yeah. Well, yeah, like the
8 actual --

9 MS. WHITFIELD: On my computer.

10 MR. MARZO: -- DR itself, or any indication
11 of the connection to this exhibit?

12 MS. WHITFIELD: No.

13 MR. SHERRIER: Not printed up.

14 MS. WHITFIELD: Uh-uh.

15 MR. MARZO: Like I said, Mr. Chairman, to the
16 extent that they're actually familiar with how
17 these numbers have been broken out from this
18 exhibit, I'll let the witnesses answer the question
19 and tell you if they're familiar. But to the
20 extent they're not, I mean, there's several
21 hundreds, if not thousands, of sub parts of data
22 requests in this case.

23 So I just want to hear what counsel is going
24 to ask, if somebody's going to verify calculations
25 and numbers and, you know, you can just produce the

1 DR to do that, I would ask that the DR be produced,
2 and not a separate calculation. Her witness could
3 put forward an exhibit like this if they wanted
4 somebody to validate calculations.

5 CHAIRMAN SHAW: That's fair enough.

6 MS. WHITFIELD: I will say, Chair, that we
7 didn't appreciate that there would be a stipulation
8 that stopped residential protections in 2028. And
9 we do now, and what happens between 2028 and 2029
10 matters a lot. And that's what this is designed to
11 ask about.

12 MR. MARZO: Mr. Chairman, I disagree with the
13 statement that the stipulation somehow doesn't
14 protect customers beyond 2028. It, in fact, does.
15 I think, Mr. Evans, in fact said, based on our
16 calculations -- which all the parties in this case,
17 who have actually done some work on forecasting,
18 have agreed, the load growth is coming, load is
19 coming.

20 We've talked about the decline of revenue
21 requirements. We've talked about the fact that we
22 expect increased revenues being produced from these
23 loads. Everything that we've talked about is
24 protections well beyond 2028, going out into
25 decades. So that is a total mischaracterization of

1 the stipulation as put forth by the Company in this
2 case and the staff, and GAM.

3 CHAIRMAN SHAW: Who on the panel would be the
4 one to answer the questions?

5 MR. EVANS: I would.

6 CHAIRMAN SHAW: That's what I thought. I'm
7 going to allow Ms. Whitfield to ask the question
8 and then we will go from there, and just see if
9 we're comfortable with --

10 MS. WHITFIELD: I'm going to tread very
11 lightly. I just -- it's really important. And I
12 want to make sure that it's in the record and
13 available to the Commissioners.

14 BY MS. WHITFIELD:

15 Q. Mr. Evans, if you could, just big picture,
16 describe what goes in that generation capital bucket of a
17 RIM study?

18 A. (Witness Evans) Certainly. And I think it's
19 important to realize that the RIM calculation is a life
20 cycle calculation. It's not intended nor --

21 CHAIRMAN SHAW: Speak up a little.

22 A. (Witness Evans) The RIM calculation is not
23 something that's meant to be used for an annual
24 determination of costs or benefits. That's meant to
25 represent the downwards pressure on rates, or the impact

1 on rates that an offer or a program has, over the
2 evaluation period.

3 Now, all of our projects pass RIM, meaning
4 they will put downward pressure on rates. To look at the
5 RIM statement and grab an individual year is inappropriate
6 to determine what ultimately happens on rates. However,
7 the DEA3-6, Mr. Abramovitz's charts, and the cost of
8 service study, all show the downward impact on rates that
9 we have based on actual revenue requirements and actual
10 revenues in those years. That's the appropriate venue and
11 calculation to look at for that.

12 Q. Mr. Evans, could you please, in a high level
13 way, describe what falls into the generation capital
14 bucket of a RIM study?

15 A. (Witness Evans) Yes. It's the generation
16 capacity costs required to serve that load.

17 Q. Okay. And just as a general trend, I'm going
18 to ask you as a general trend, to keep us safe here,
19 generation capital has a big shift of how its considered
20 to be part of the charges that are on the system around
21 2009, would you agree with that?

22 A. (Witness Evans) I would not.

23 Q. Okay. How would you characterize the timing
24 of when generation capital is allocated to a particular
25 RIM customer?

1 A. (Witness Evans) Well, none of the RIM
2 statements we ran went to 2009.

3 A. (Witness Grubb) Did you say "2009," 2029?

4 Q. 2029.

5 A. (Witness Grubb) Okay.

6 Q. Do you want me to re-ask the question?

7 A. (Witness Grubb) So ask the question again
8 with "2029," and we'll -- let's see what we can do with
9 it.

10 Q. Touche, good listening.

11 Would you agree that in 2029, there's a
12 significant change in the impact of generation capital on
13 the system?

14 A. (Witness Evans) I see that listed here. I
15 don't know that that's the case. Again, it would depend
16 on the evaluations, and when they occurred.

17 Q. Okay.

18 A. (Witness Evans) That's triggered usually by
19 our need year at the time of the evaluation. That does
20 not mean that generation capacity costs are not incurred
21 prior to that. They're simply modeled as a PPA, or a
22 purchase, for that capacity cost prior to that. So in
23 every year of the evaluation, whether it's before or after
24 the need year, generation capacity costs are being
25 allocated to these loads.

1 Q. So how does the Company decide when
2 generation capital then becomes part of a customer -- when
3 is that sort of charged, put that in quotes, but when is
4 it charged to a customer, under a RIM study?

5 How do you make that determination?

6 A. (Witness Evans) It's generally tied to the
7 need year.

8 A. (Witness Grubb) Right. So, Commissioners, if
9 you think about 2022 IRP, we talk about it in this case.
10 There was -- we were above the target reserve margin,
11 coming out of that with the six PPAs that we got approved.
12 And so if you're adding load, and it's putting load on the
13 system before you have the need year, the marginal
14 costs -- or the costs of that generation, is less than
15 what you have to build.

16 And so what that means is when, you're
17 looking at a -- pricing a customer choice job, it depends
18 on when you're making the offer, what the loads on the
19 system are. So until this need year moves, it's pretty
20 representative. I think that's part of it. When you see
21 that shift in '29, as to Mr. Evans's point, there still is
22 generation costs before then, because that load is being
23 added to the system. But if you don't have to add
24 generation, it's a lower cost, then when you hit that year
25 of need, now you've got to represent in that analysis that

1 you're adding generation cost.

2 A. (Witness Evans) And that year changes --
3 subject to check, I don't know because I don't have any
4 visibility into what is behind these numbers, but I
5 believe some of these were calculated years ago.

6 A. (Witness Grubb) With the earlier offers,
7 that's right.

8 A. (Witness Evans) So back then, our need year
9 was 2029. As our need year has moved, the offers have
10 reflected that.

11 Q. So would it be fair to say then, this column,
12 the generation capital column, is a proxy for need year at
13 the time the RIM study is completed, as determined in
14 that -- at that time?

15 A. (Witness Evans) I don't -- I can't speak to
16 that. I didn't make the column or the chart, so --

17 Q. Generally. All right. Not with respect to
18 this column then, generally, would you agree that
19 generation capital in a RIM study is a proxy for the year
20 of need when that RIM study is run?

21 A. (Witness Evans) Yes.

22 A. (Witness Grubb) Yes.

23 Q. Let's move on to Yates.

24 CHAIRMAN SHAW: Mr. Sherrier, you pick these
25 up, okay?

1 MR. SHERRIER: Yes, sir.

2 BY MS. WHITFIELD:

3 Q. So I'd like to turn your attention to
4 page 38, lines 20 through 21.

5 A. (Witness Grubb) I'm sorry. I was putting my
6 copies up again. I'm sorry.

7 Q. That's fine. Page 38, lines 20 to 21.

8 And this is where you're answering the
9 question: Why should the Commission have confidence in
10 the economics of the proposed Yate units?

11 Now, before, Mr. Grubb, I believe -- you let
12 me know when you're ready.

13 A. (Witness Grubb) I'm sorry. 38, which lines?
14 I was still shuffling.

15 Q. You're fine. 20 to 21.

16 A. (Witness Grubb) Okay. Yes.

17 Q. So, Mr. Grubb, I believe it was you, before
18 mentioned that I think -- I have it in quotes in my notes.
19 I think it's a quote. When you go to the market, it
20 allows comparisons of the price.

21 Did Georgia Power test the Yates prices
22 against the market?

23 A. (Witness Grubb) Yes. So my quote was talking
24 about an RFP. And it may not be technology specific, it
25 does allow the different solicitations. But to this we

1 did not, because we don't have time to run an RFP. But
2 that doesn't mean we're not confident in the costs.

3 Q. Okay. So let's look at that cost. You
4 provide basically two pieces of evidence to support your
5 conclusion that it's cost effective, or that the company
6 should have confidence in it being cost effective. One of
7 those is Attachment D to the Yates certification
8 application; correct?

9 A. (Witness Bush) That's correct.

10 Q. And in that attachment, and I understand
11 you've updated with more recent numbers, but in that
12 attachment, Georgia Power chose three projects to compare;
13 correct?

14 A. (Witness Bush) Well, actually, Commissioners,
15 there's no publicly available data, that is a general
16 location, where you can go find this type of information.
17 So this is actually what we found at the time, when we
18 certified, actually.

19 Since then, we've found one other publicly
20 available set of information around CTs of this nature.
21 And, again, we're talking about advance-class CTs, that
22 have state-of-the-art emission controls. And so when you
23 make comparisons of this type, you have to make sure
24 you're making them with the right technology, and then you
25 have to equalize, or normalize, for the period of going in

1 service.

2 Q. Do you know offhand what the fourth CT was
3 that you identified?

4 A. (Witness Bush) Yes. Associated Electric
5 Co-op has recently announced building a combustion turbine
6 there in Oklahoma. And they publicly announced that --
7 both, I think, the price and the megawatts.

8 Q. And among the three that you chose as part of
9 this attachment, Plant Yates has the highest cost per
10 kilowatt hour; correct?

11 A. (Witness Bush) When you look at the numbers,
12 that's correct, Commissioners. But, remember, what we're
13 trying to do here is find public information about similar
14 types of resources.

15 And while the number may be in absolute
16 terms, higher, it's within, in my view, a range similar to
17 Yates. We don't know about the particular sites. We
18 don't know about -- I do know, if you read Canal's
19 publicly available information, you know, they indicate,
20 oh, we have exceptional access to fuel. We already had
21 fuel storage, we used existing facilities, we had
22 transmission with no needs for upgrades.

23 So, again, those are all qualitative
24 components that do go into the costs, but we don't have
25 any real insight into what that was. So while, yes, the

1 number is higher, generally speaking, I would say they're
2 all within a similar range of costs.

3 Q. The second piece of evidence that you refer
4 to is Lazard's 2023 levelized cost of energy analysis,
5 which I believe is an exhibit to your testimony,
6 Exhibit 3.

7 A. (Witness Grubb) That's right.

8 A. (Witness Bush) That's correct.

9 Q. And am I correct that, in this exhibit, the
10 place to look is the gas peaking row, because these are
11 CTs?

12 A. (Witness Bush) That's correct. The Lazard
13 report is generally a levelized cost of energy. And when
14 you compare technologies, we would say that's not how you
15 want to do that. But in the report itself, it does have
16 a -- an exhibit itself that talks about the capital
17 cost -- what they call overnight capital costs for
18 different technologies. And what we've done in this
19 exhibit is, we've pulled out the capital costs for a
20 similar technology.

21 Again, if you look at the numbers themselves
22 and the information behind that technology, there's no
23 indication -- first of all, what year dollars these
24 overnight costs are in, and that's important when making
25 the comparison, nor is there the specifics behind the

1 technology. And I could find nowhere in their
2 documentation where they were talking about advanced class
3 machines.

4 Again, these are modern machines -- or
5 whether they had controls, state-of-the-art controls, like
6 we have at Yates. So you have to take all of that into
7 consideration when you look at the numbers.

8 Q. Would you agree that Yates is in the top
9 quarter of the most expensive gas peaking costs, reflected
10 on that grid?

11 A. (Witness Bush) Yes. I would say it's in the
12 upper half of that, for sure. But, again, we're talking
13 about publicly available, generic numbers, and you have to
14 take into account many other factors. I do not believe
15 that this CT technology is of the advance class nature,
16 but it was one of the few things we could find that
17 publicly stated some range of cost for a combustion
18 turbine.

19 Q. So let's move to ownership. You understand,
20 Panelists -- I'm not sure who the right person is -- but
21 Plant Yates requires the Commission to find -- to approve
22 Plant Yates, it requires the Commission to find that
23 Georgia Power needs to own 70 percent of its resources?

24 A. (Witness Grubb) I would disagree that that's
25 what the Commissioners have to make their decision on.

1 What we've said in this case is, Yates is beneficial
2 because it can be deployed and serve customers' needs, by
3 coming online at the end of '26 and the end of '27. The
4 70/30 is a consideration of it, but it's not the main
5 driver.

6 So the Commissioners -- the decision for
7 Yates in this case is that it is resources -- that they
8 are resources that we can deploy to meet these earlier
9 need years. They are the types of dispatchable generation
10 that we need. So it does contribute to the 70 percent.
11 And so that is a part of it. But that is -- that is an
12 exception that we're asking for the RFP rule, but that's
13 not the only reason why we identified Yates.

14 Q. So we can -- we'll debate that as lawyers, I
15 suppose, but in the meantime, recognizing that the
16 ownership requirement is relevant and is part of your
17 request, let's talk about your defense of it on page 44.
18 So on page 44, lines 22 through 24, you are addressing
19 concerns here about this process being bad for bills, this
20 ownership requirement, being bad for price pressure. And
21 you say that --

22 A. (Witness Grubb) I'm sorry. Can you tell me
23 which lines again?

24 Q. Yeah, sure. 22 through 24. So if it helps,
25 you can start up at 19 where it says, Staff and

1 intervenors dismiss the Commission's 70/30 rule, claiming
2 it's outdated, and does not ensure the company procures
3 the least cost resources for customers.

4 A. (Witness Grubb) Right.

5 Q. And then in response say, However, this
6 ignores the fact that, apart from the resources requested
7 in this case, the vast majority of all other capacity
8 resources since 2001, were successfully procured through
9 an RFP process?

10 A. (Witness Grubb) Right.

11 Q. But you can own resources that go through an
12 RFP process; correct?

13 A. (Witness Grubb) Yes. And we often have.
14 What our point here in the case, again, is -- and I wasn't
15 saying that 70/30 isn't applicable, and that we're asking
16 for that as one of the reasons to have an exemption to the
17 RFP, but you -- not to put words in your mouth, but I
18 heard it as, we were using a 70/30 -- we were adding Yates
19 for the 70/30 rule, and we aren't. We're adding Yates
20 because it's a resource that can come online in time to
21 meet needs.

22 Does it impact 70/30, it does. Is that an
23 exemption we need, yes. But the main thing is, we went to
24 the market first, in the system, and then we needed to
25 deploy resources. So it is absolutely applicable in the

1 case, I just didn't want it to seem that we were adding it
2 just to maintain the 70 percent.

3 Q. I got it.

4 Mr. Grubb, you said across the street to the
5 legislators, that Georgia Power's compliant -- and this is
6 in a different context. You were talking about community
7 solar, to be fair. So I'm not suggesting you were saying
8 this about this proceeding, or about Yates.

9 A. (Witness Grubb) Right.

10 Q. You said to the legislature, Georgia Power
11 is -- quote, compliant with the Commission rule RFP
12 process. It's through that process that we get the best
13 prices.

14 Do you agree with that statement here?

15 A. (Witness Grubb) I don't recall saying that
16 exactly. I'm not saying I didn't. I think what I'm
17 talking about there is, we have very much been through the
18 RFP process for almost everything we've done. We very
19 rarely have ever asked for the exemptions on the RFP
20 process. And so we are doing it here. But, again, it is
21 because of the timing.

22 And so we have been very supportive of the
23 RFP process. We have done -- I mean, McDonough, Vogtle,
24 they all were done through the RFP process. So, yes, we
25 can't own resources through there. But, again, the

1 Commission's rule allow for exemptions. And that's what
2 we're using here in this case, because there are cases
3 where there may not be time to do RFPs. And so the RFP
4 process is absolutely supported by us.

5 We've said it a time again -- we've done over
6 20, since 2006, we're doing seven more. We will continue
7 to do them when time allows.

8 COMMISSIONER MCDONALD: Mr. Grubb.

9 MR. GRUBB: Yes, sir.

10 COMMISSIONER MCDONALD: You used the word
11 "timing." Break out the timing that you're talking
12 about.

13 MR. GRUBB: Yes. Great --

14 COMMISSIONER MCDONALD: All the factors that
15 are involved in the timing aspect.

16 MR. GRUBB: So give me just a second, and I
17 will. It'll take me a little bit of time. But
18 I'll do it from a planning standpoint. So when
19 this load forecast moved our generation need up by
20 three years, we needed to have resources online by
21 the end of '25, the end of '26, and then the end of
22 '27.

23 The only ones that were available to be
24 online by the end of '25, would have to be
25 something that was existing. And we were able to

1 do that through the Mississippi Power PPA, and the
2 Santa Rosa PPA, because you didn't have to build
3 resources, and you didn't have to build
4 transmission.

5 Once we exhausted that, we looked at, what
6 can you build the quickest, and those would be CTs
7 and batteries. But, thinking about transmission,
8 we needed to find sites that we didn't have to --
9 that we had time to deploy that.

10 So from a timing standpoint and the RFP
11 process, you can't start developing until you've
12 certified the resources. And so by that need year
13 moving up three years, it used up that RFP time.
14 So you have to be able to move, in those first
15 two years, quickly.

16 So what we've stipulated to is for that,
17 having resources online by the end of '27. It's a
18 very narrow-focused RFP that will not require
19 transmission evaluation, it won't require
20 transmission build. That's the three years in this
21 case, Commissioner. The winter of '29, '30, and
22 '31 is going through the All-Source RFP right now.

23 So when we saw that need year move up by
24 three years, you lose the ability to do our normal
25 three to -- you know, two-to-three-year RFP

1 process -- two-year process, so that's why we had
2 to move and get those resources that we could get.

3 COMMISSIONER MCDONALD: What moves the
4 quickest, the battery or the CT?

5 A. (Witness Grubb) So the CT -- from a
6 construction standpoint, I'll let Mr. Bush weigh in. The
7 batteries are a little quicker. I think transmission is
8 an important part of it, we were building them where we
9 don't have to build transmission delivery projects. But I
10 think CTs are a little slower than batteries.

11 A. (Witness Bush) That's right, Commissioner.
12 When you think about just the construction component --
13 and a lot of things have to happen to get you to a
14 position where I can make this statement -- so you have to
15 have the site development work, you have to have the
16 contracts in place, all of that. But when all of that is
17 done and you have transmission service, for a
18 traditional -- a battery, you can come online in, say,
19 12 months or so, from a physical construction time frame,
20 and it will be longer than that for simple-cycle
21 combustion turbines.

22 MS. WHITFIELD: If Mr. Sherrier may approach
23 with an exhibit, Commissioner?

24 CHAIRMAN SHAW: Go ahead.

25 (The documents referred to were marked for

1 identification as GIPL Exhibit 3.)

2 BY MS. WHITFIELD:

3 Q. Gentlemen, I'm going to show you -- what is
4 in black and white is Georgia Power's response to GIPL's
5 hearing request at the first hearing, what is in red is an
6 update to that hearing request Georgia Power subsequently
7 provided to GIPL, and I know intends to add to the record
8 but hasn't gotten a chance to yet. I'll give you a minute
9 to take a look.

10 A. (Witness Grubb) So I'm familiar with the
11 hearing request, but the red that's been added is what I'm
12 needing to look at. You said that's been added?

13 Q. Yes. So what this is -- and if you want to
14 look at Georgia Power's direct response, it's in the red
15 footnote at the bottom, so that's the direct quote from
16 the email response.

17 And just to lay the foundation while he's
18 taking a look, GIPL asked for information about when PPAs
19 have been unable to perform for Georgia Power, as they're
20 contractually required to, in a way that's endangered
21 customer load. And Georgia Power wasn't able to provide
22 an answer to that specific request, I assume it's because
23 they don't maintain it in that format.

24 But they did provide an initial response,
25 which is the black-and-white piece, and a follow-up, so

1 that they would indicate the contractually required piece,
2 to show when -- how performance did, that led to a payment
3 reduction to the PPA, when they weren't able to perform.
4 And that was used as a proxy for the PPA not being able to
5 perform.

6 A. (Witness Grubb) Right. So we showed a
7 percentage that were unavailable, and then there's a
8 reduced percentage that actually had a payment reduction
9 because of that, which is exactly our point.

10 Q. Yes.

11 A. (Witness Grubb) So when you look at ownership
12 and PPAs. And, Commissioners, we talked in the '22 IRP
13 around reliability, and one of the aspects of that is
14 winterization. So the Company has taken steps to
15 winterize our plants over the last several years, through
16 the polar vortex and then after Winter Storm Elliott, and
17 have continued to improve our winterization.

18 We can do that on our plants, because of our
19 focus on reliability and obligation to serve. For a PPA,
20 it is hard to put that direct incentive in it. They are
21 incented by what it may do to their payment reduction. So
22 there are plenty of -- there are a lot of percentage
23 availability requirements in PPAs, where they could be
24 unavailable in a winter event and not have a reduction in
25 payment.

1 Now, we are supportive of PPAs. I don't want
2 this to sound like we aren't supportive of PPAs. We are
3 supportive of RFPs, we're supportive of PPAs. But, at the
4 end of the day, their incentives are based on contractual
5 obligations. And so what this shows is there were a
6 higher percentage of PPA resources not available, than
7 there were actually ones that were not available and had a
8 payment reduction.

9 Q. So another way to explain that could be, that
10 the PPAs are assumed to have some limitations to their
11 capacity, but only when they violate that contract would
12 you reduce their payments?

13 A. (Witness Grubb) So it's an incentive in the
14 PPA, for them to be available as much as they can. And I
15 don't want this to come across as, PPAs don't do what they
16 can, but at the end of the day, it is a different
17 obligation. And so there are percentage availability
18 requirements, that a winter event may only be a few hours,
19 and it may not be enough in a monthly situation to impact
20 their payment. So that PPA's incentive to go winterize,
21 and avoid an outage in a winter storm, is not as high as
22 the Company's is, from an ownership standpoint.

23 Q. And just for the record, Mr. Grubb, that's
24 your interpretation, based on Georgia Power having an
25 unavailability event of 15 percent of its capacity for

1 Winter Storm Elliott, and PPAs that were held to account
2 for their unavailability only being at 6 percent?

3 A. (Witness Grubb) Yes. But our accountability
4 as a power company is to go winterize and make those
5 investments, and -- so that we don't shed firm load in
6 those events, which we did not. And so there's always
7 challenges to machines.

8 But we have seen our performance -- since the
9 polar vortex back in 2013, to Winter Storm Heather, has
10 drastically improved across the company's fleet. As you
11 can see here, we had a 20 percent lower unavailability on
12 our machines in -- in the Winter Storm Heather earlier
13 this year, versus Winter Storm Elliott.

14 So, again, the point here is that there's a
15 balance between ownership and PPAs that we support. We do
16 see value in PPAs. But, at the end of the day, they are
17 different. We work with and get comments from the market
18 on those PPAs. There's incentives on them. But if you
19 try to put all of that risk on them, it's tough and they
20 price it high. So it's just a difference between
21 ownership and PPAs.

22 But, again, I would say what we did here was
23 show that, from a percentage standpoint, PPAs didn't
24 perform quite as well as the Company did, from a
25 percentage standpoint.

1 Q. And then when you take into account to the
2 extent they're complying with the contract, that actually
3 flips; correct? They're complying with their obligation
4 to provide load. They're actually --

5 A. (Witness Grubb) Yeah. Well, they still
6 weren't available; right?

7 Q. Correct.

8 A. (Witness Grubb) Per the contract, that's our
9 point. There are 6 percent of them that had a reduced
10 payment for being unavailable.

11 Q. Okay.

12 A. (Witness Grubb) There's 19 percent of them
13 that were unavailable and had no payment impact.

14 Q. Is Georgia Power looking into how to shore up
15 those contracts?

16 A. (Witness Grubb) We are. We look at monthly
17 value factors. And, again, it's a balance, because we
18 want to encourage PPAs. We want the market to bid in. If
19 we were to try to put damages in a contract, that if we
20 have a winter event and your PPAs not available, you have
21 to pay for the fact that we shed firm load, that's too
22 much risk, so it's a balance. But we are currently
23 looking at that, as well.

24 Q. Okay. Let's shift to reserve margin, which
25 is important because, ultimately, the implication of not

1 having enough, and what that means. If the company
2 doesn't have enough to serve its load, what are the risks
3 that we're looking at? One in ten is the industry
4 standard for risk threshold for loss of load; correct?

5 A. (Witness Grubb) Well, so it's an industry
6 practice. I know a lot of utilities look at it. I don't
7 know that there's a published standard. But it is a level
8 that a lot of people look at. We, Commissioners, use that
9 as an absolute minimum when we do our reserve margin
10 study.

11 Q. Yes. And 20 percent reserve margin is what
12 Southern Company has identified to meet that industry
13 practice?

14 A. (Witness Grubb) I wouldn't say we identified
15 it meets that practice. We use it as a minimum, and our
16 last reserve margin study, at 20 percent reserve margin,
17 was a one in ten loss of load event, but that is not what
18 we plan to. That's a minimum. That's in part of this
19 study.

20 Q. But you agree that 20 percent is the
21 identified target reserve margin, to meet that industry
22 practice for reliability?

23 A. (Witness Grubb) Yes. In our reserve margin
24 study, a 20 percent results in a one in ten loss of load
25 expectation.

1 Q. And have you analyzed what the impact would
2 be if the company planned to P50, and P95 actually
3 appeared?

4 A. (Witness Grubb) If we -- well, no, not from
5 the standpoint of a reserve margin, because we apply the
6 same reserve margin to whatever load forecast we do.

7 Q. I mean, in terms of the capacity shortfall
8 that you would anticipate, if you actually built resources
9 out to P50?

10 A. (Witness Grubb) I can't remember the exact --

11 A. (Witness Valle) So from a load forecasting
12 perspective, the difference between a P50 level and a P95
13 level, which is what we're using in our planning, is
14 roughly 2500-megawatts.

15 A. (Witness Robinson) Just a reminder, on
16 December 24 of 2022, we wouldn't had that shortfall, we
17 would have shed load.

18 Q. Have you provided documents to this
19 Commission that identify which resources would have caused
20 load to shed, in the circumstance that you're talking
21 about? Like gas, for example, which these PPAs rely upon.

22 A. (Witness Robinson) No. I'm speaking in
23 general, given where we were on December 24 of 2022, and
24 the margins that we had. If we had that load, the 95 load
25 that came and we planned for P50, and we had a

1 2500-megawatts difference, then, on that day, we would
2 have been in a load shed event. We would have been in an
3 DEA-3, and we would have been shedding load.

4 Q. So right. What I'm asking is, that specific
5 moment in time that you're talking about, when the system
6 has gotten to what sounds like it's closest it has gotten
7 in some time to needing to shed load, though it didn't --

8 A. (Witness Grubb) In Winter Storm Elliott.

9 Q. In Winter Storm Elliott?

10 A. (Witness Grubb) Yeah.

11 Q. Have you provided the Commission with which
12 kinds of resources didn't -- weren't available?

13 A. (Witness Grubb) So, we did have -- I was here
14 and spoke to the Commission on Groundhog's Day, last year,
15 about Winter Storm Elliott, and we did have discussions
16 with staff. I can't recall what all we turned over,
17 coming out of the Winter Storm Elliott. But, again,
18 Commissioners, as Mr. Robinson has mentioned and as you
19 know, in those discussions, 26 percent -- or, the short
20 term is 25.5. But we were right at 25.5 in Winter Storm
21 Elliott, and it was one of the main reasons why we did not
22 sheet firm load.

23 Asking about the one-in-ten and the
24 20 percent, as you all know, in the reserve margin study
25 and the IRP, we look at all of that. We look at

1 economics, we look at reliability. And so the 26 percent
2 is about a 1 in 18 loss of load expectation. So it's
3 80 percent more reliable than the 20 percent, and so it
4 served us well.

5 But to that, I can't recall what we turned
6 over with staff. But there were different units that were
7 out on that day. But, again, it takes the entire fleet.
8 We had the entire fleet committed, and we were able to
9 make it through Winter Storm Elliott without shedding firm
10 load.

11 Q. Mr. Grubb, I appreciate that. And I watched
12 the hearing that you're referring to. If my memory is
13 correct, you did not have information about the specific
14 kinds of assets that weren't available. It's important
15 here -- the reason I'm asking here is because the PPAs
16 that have been requested are largely fossils, gas?

17 COMMISSIONER PRIDEMORE: Please speak into
18 the microphone so we can hear you.

19 MS. WHITFIELD: Yes, ma'am.

20 Is that better?

21 COMMISSIONER PRIDEMORE: Yes. Please.

22 We remind you over and over again. But this
23 doesn't -- she has a hard time. She can't do her
24 job, if she can't hear the things that you want us
25 to hear.

1 MS. WHITFIELD: Thank you for the reminder.

2 A. (Witness Grubb) So publicly, at that hearing,
3 I probably didn't disclose those. But there were PPAs
4 out, there were fossil units out, there were renewable
5 units out, nuclear, I don't think was, and some coal
6 units. But it was also a three-or-four-day event, and so
7 it depends on which hours you're looking at.

8 BY MS. WHITFIELD:

9 Q. Right. I'm just asking about this one event,
10 that the panel has referenced repeatedly over the course
11 of these hearings, as justification for why it needs such
12 a large reserve margin, why reliability is so important.

13 And what I'm asking is, is investing further
14 in gas resources moving us in the right direction, to
15 address the concern that the Company's raising? And as
16 far as I'm aware, there are no resources available even
17 under trade secret protection, to non-staff.

18 A. (Witness Grubb) So I'd have to come back to
19 your last one. I'm not sure what you're asking for there.
20 But let's circle back to that.

21 But, no. I mean, so we factor all of that
22 into the reserve margin study, the different performances
23 from the gas units. That's also why we have capacity
24 equivalents on solar and batteries, is to capture what the
25 likelihood in those resources and events are. So, again,

1 the reserve margin drives the size of the fleet that you
2 have going into that day.

3 And because we had 26 percent reserve
4 margins, we had enough resources, based on the full fleet,
5 PPAs, company owned, we did have purchases from other
6 regions. We sold to other regions throughout that event.
7 So gas units are absolutely reliable. We capture that in
8 the study.

9 And, again, back to the winterization, we
10 have increased the temperatures and the miles per hours
11 that we winterize our gas units to.

12 A. (Witness Robinson) And I can speak to how
13 much solar we had online at 7:45 on December 24, 2022,
14 which is near peak, and that was 15-megawatts. So the sun
15 was just coming up, and we had 15-megawatts of -- about
16 over 3,000-megawatts of solar that we had connected to the
17 system at that time. So we didn't have a lot of solar
18 online that we could count on at 7:45.

19 MS. WHITFIELD: Chairman, may I make a
20 hearing request for the other kinds of assets that
21 weren't available at that time. And what I'm
22 talking about specifically is the peak time, when
23 the Company got the closest, most precarious, I
24 think -- the closest to having a shed load during
25 Winter Storm Elliott, during those hours, which

1 resources were not available.

2 CHAIRMAN SHAW: Very well.

3 BY MS. WHITFIELD:

4 A. (Witness Grubb) I do know we had a lot of oil
5 CTs running. I do know that. Just in case anybody is
6 curious.

7 Q. That's great.

8 I'm trying to cut is what I'm doing. I know
9 it's taking me a minute to pause, but I'm trying to
10 streamline. I thought a lot of this would be cut watching
11 staff.

12 CHAIRMAN SHAW: I will just add that I'm glad
13 the lights stayed on that morning.

14 MS. WHITFIELD: You and me both.

15 COMMISSIONER PRIDEMORE: Was that Christmas?
16 I believe it was Christmas.

17 MS. WHITFIELD: It was Christmas Eve, I
18 believe.

19 MR. GRUBB: Well, and the second day, we were
20 in hearings in here, was Winter Storm Heather. I'm
21 glad we were all able to have that discussion.

22 BY MS. WHITFIELD:

23 Q. Let's see. All right. Let's look at another
24 exhibit.

25 A. (Witness Grubb) In the exhibit in testimony

1 or you have one?

2 Q. Oh, no, no. I'm going to hand you one if the
3 Chair --

4 A. (Witness Grubb) Okay. I was just -- wasn't
5 remembering a reserve margin exhibit in our testimony. I
6 just wanted to make sure.

7 COMMISSIONER MCDONALD: What are you saying,
8 or who are you talking to?

9 MS. WHITFIELD: I'm sorry, Commissioner. I
10 was just talking to Mr. Sherrier about -- asking
11 him if he could hand one of these to Mr. Grubb or
12 maybe Mr. Valle or Mr. Grubb. I'm not sure.

13 BY MS. WHITFIELD:

14 Q. What I'm handing you is a -- excerpt from the
15 reserve margin study that was completed by Southern
16 Company in advance of the 2022 IRP. And it is page 13.
17 And this particular chart is where load forecast error is
18 taken into account, and considered as part of the reserve
19 margin calculations.

20 A. (Witness Grubb) Right. Right.

21 Q. And you're aware that when conducting a
22 reserve margin study, Southern Company takes into account
23 the likelihood that its load projections will be wrong;
24 correct?

25 A. (Witness Valle) That is correct.

1 Q. And, in this particular study and the
2 18 years that were looked at, Southern Company found that,
3 as a system, it had forecasted too much load every year.

4 A. (Witness Grubb) That's correct. And so it
5 was -- yes, for 18 years, that was correct.

6 Q. So rather than planning a reserve margin that
7 takes into account the history of over-forecasting, you
8 made an adjustment to that reserve margin; correct?

9 A. (Witness Grubb) That's correct. And,
10 Commissioners, and that is because planning for a load
11 forecast -- and a lot of this is in real time, so as you
12 enter into those events, what would your load forecast be,
13 even though we had had years of being over-forecast, I
14 think the last two years shows that there's a risk of
15 being under-forecasted, as well.

16 And so from a planning standpoint, and
17 looking at load forecast error, the Company's position is,
18 you should be able to plan for being over a forecast and
19 under forecasting. Planning for just being over
20 forecasting takes out the risk that needs to be accounted
21 for, that if you are under-forecast.

22 So what we did was, we took that
23 distribution, and we spread it across being over and
24 under-forecasted. And that was the -- we think that's
25 prudent -- or, that is prudent, because there are cases

1 where you could be under-forecasted, and you want to be
2 able to serve that load.

3 Q. So, in other words, Mr. Grubb, 50 percent of
4 the time, you assume that the load forecast would be too
5 high, and 50 percent of the time, you assume the load
6 forecast would be too low?

7 A. (Witness Grubb) So I can't remember -- I
8 wasn't the main witness on the reserve margin study. I
9 can't remember exactly, but, no, what we didn't want to do
10 is have all of the load forecast error distribution be to
11 only over-forecasting, because from a long-term planning
12 standpoint and looking ahead, you need to take into
13 account -- you need to account for the risk that, going
14 into one these events, or going into the next year, you
15 could be seeing load higher than you forecasted. To plan
16 for that not ever occurring, to us, is not reasonable.

17 Q. So Georgia Power doesn't believe then that
18 its load forecasting process leads to a 50 percent chance
19 that it would have too few resources to meet its
20 customers' energy demand.

21 A. (Witness Grubb) Say that again.

22 Q. Georgia Power doesn't believe, then, that its
23 load forecasting process leads to a 50 percent chance that
24 it would have too few resources to meet its customers'
25 demand.

1 A. (Witness Grubb) So what we're saying is that,
2 as part of the reserve margin study, you need to capture
3 both aspects of the load forecasting regardless of what
4 your historical load forecast was, because that risk,
5 going forward, exists, regardless of what the historical
6 is. I don't know if you have anything -- this was a
7 little bit before you jumped in -- well, you were there.

8 A. (Witness Valle) I think you covered. But I
9 want to mention, Commissioners, that, you know, when you
10 look at the load forecasting error, the sources for the
11 load forecasting error are twofold: One is the model
12 itself, right, no matter how sophisticated your models
13 are, they're going to have some errors. They're going to
14 have some deviations expected into the future.

15 And the other source is related to the inputs
16 that you get into the model. A lot of these inputs are or
17 econometric, or economic assumptions. And so to the
18 extent that these economic assumptions are in a certain
19 direction, they may lead into a certain result. But our
20 models are inherently unbiased. We plan and we calibrate
21 it to an historical period, where we don't have a natural
22 bias or underlying error.

23 Q. All right. Let's move your chart. It's
24 actually Ms. Hoatling's chart, but it's on page 20,
25 lines 9 through 11.

1 A. (Witness Grubb) This is in the main
2 testimony?
3 Q. Yes.
4 A. (Witness Grubb) Which page again? I'm sorry.
5 Q. Page 20, lines 9 through 11.
6 A. (Witness Grubb) Okay. Figure 1.
7 Q. Figure 1.
8 A. (Witness Grubb) It's the page with Figure 1
9 on it; correct?
10 Q. Yes, correct.
11 A. (Witness Grubb) Not the lines you cited, just
12 making sure I'm on the right one.
13 Q. The bell curve.
14 A. (Witness Grubb) Right.
15 Q. Yep. So on those lines, though, you say
16 that, simply put, if Georgia Power were to plan its system
17 using the P50 value, that would mean there's a 50 percent
18 chance that it would have too few resources to meet large
19 load customer needs, and, therefore, wouldn't be able to
20 reliably support the demands of the growth?
21 A. (Witness Grubb) Correct.
22 A. (Witness Valle) That is correct.
23 A. (Witness Grubb) Talking about, again, the
24 load forecast and the resources. If you had -- if the
25 higher load forecasted occurred, then you either have

1 reliability issues, or you have to not add that load to
2 the system.

3 Q. When you say "reliability issues," Mr. Grubb,
4 do you mean that the reserve -- like, if the reserve
5 margin goes from 35 to 34, is that a reliability issue
6 that you would account for?

7 A. (Witness Grubb) No. What we were saying here
8 was looking at our load forecast, with our 26 percent
9 reserve margin, if you only had the resources to serve a
10 P50 with a 26 percent reserve margin, but your loads
11 actually went above your P50 and you were not able to add
12 resources, now you're not at a 26 percent.

13 And so now you have a lower level of
14 reliability on the system. We would not want to move to
15 that lower level of reliability on the system. So we
16 would have to not allow new load growth. We would stay at
17 26 percent reserves. So that's what we're comparing is
18 that, when you can't add resources until a few years
19 later, you have a real reserve margin, what is your
20 reserves.

21 And so what we're saying, if you were at 26
22 and you couldn't add resources for a few years, you've
23 either got to stay flat, or you add load and you have a
24 lower reserve margin.

25 Q. So if you plan a P50 and P95 appears, in

1 2026, do you have an issue?

2 A. (Witness Grubb) I think it was -- well, we
3 didn't plan to P50 on our resources. So I don't know that
4 I have the chart there. I think looking at, if you had
5 had just the PPAs, you do have a -- in '26 and '27, you
6 have something below the 26 percent reserve margin.

7 A. (Witness Valle) Commissioners, real quick, I
8 wanted to -- if you look at the figure that is referred
9 here, it's a bell curve, right, that is fat in the middle
10 and skinny at the ends. So that flat point in the middle
11 is what is called sometimes the median, or the P50. And
12 it's an asymmetrical distribution, it's what separates the
13 data in half. So half of the values are going to be on
14 one side, half of the values are going to be on the other
15 side. But if you think about it, P50 is comparable or
16 akin to flipping a coin.

17 So when it comes to reliability for planning
18 for our customers, that level of certainty, you know, a
19 50/50 chance, is not enough to plan the resources, to
20 preserve and maintain reliability.

21 And I was just going to wrap up that the
22 level that we have selected provides a higher level of
23 confidence, right, that the load is going to be at a level
24 or below, and it gives a proper signal for the reliability
25 that we have been planning. And that's why, within the

1 interactions that we have with Commission staff and their
2 consultants, they were supportive of using the level that
3 we are using.

4 Q. For the purposes of the stipulation?

5 A. (Witness Valle) I would say even before the
6 stipulation. If you read staff testimony, they were
7 supportive of the use of P95.

8 Q. Mr. Valle, you're aware that staff's load
9 projections came in to be lower than GIPL's load
10 projections at P50; correct?

11 A. (Witness Valle) So the projections that staff
12 created were lower for two different reasons. So
13 Commission staff had a criticism of the delay assumptions,
14 and also the load materialization. But that has been
15 overcome within the stipulation, but it was a different
16 reason than the use of P95 or P50.

17 Q. I'll let staff respond to that if they want
18 to.

19 MS. WHITFIELD: May Mr. Sherrier approach
20 with the emails?

21 (The documents referred to were marked for
22 identification as GIPL Exhibit 4.)

23 BY MS. WHITFIELD:

24 Q. So there's been a lot of talk about how much
25 time we have before -- like, that we don't have time to do

1 the RFPs. And so as my last -- not question, but as my
2 last topic, I want to ask about the timeline. I know.

3 And what Mr. Sherrier just handed you are
4 emails, between staff and Georgia Power, that GIPL
5 requested as part of an Open Records Act request. And I'm
6 going to ask you about some of them, but we may not need
7 to refer to them.

8 Okay. On page 13 of your testimony, lines 1
9 through 5, you mentioned that last October, when you filed
10 this IRP amendment, Georgia Power had been selected to
11 serve, meaning it signed customer choice agreements with,
12 I think, 3,612 megawatts.

13 A. (Witness Grubb) Yes, line 1, page 13.

14 Q. Yes.

15 A. (Witness Grubb) Yeah. As of the filing,
16 that's correct.

17 A. (Witness Valle) Yes.

18 Q. Approximately how many of those were known to
19 the Company in 2021 and 2022? Approximately how many of
20 those megawatts had been -- were under contract with the
21 Company in 2012 and 2022?

22 A. (Witness Valle) So '21, '22, close to --
23 subject to check, I think it's close to -- so like 3,000,
24 I would say. I'm sorry.

25 A. (Witness Grubb) Your question was when they

1 were known, in which years?

2 Q. 2021 and 2022, sorry.

3 A. (Witness Valle) Yeah. So I think 2021, we
4 have 2100-megawatts, one and -- sorry 2022.

5 A. (Witness Grubb) Yes. It's in the main.

6 Q. I don't want to trick you. I can just ask
7 you if my number is right.

8 A. (Witness Grubb) No, we know. The years as
9 you've -- as we've seen, the years can get -- so '21 is
10 the year we went around 300-megawatts. And then '22 is
11 when we went around 2100.

12 Q. Okay.

13 A. (Witness Grubb) It was a bar chart that was
14 in the initial --

15 A. (Witness Valle) So 2100 in 2022, and then
16 1700 in 2023.

17 A. (Witness Grubb) Right.

18 Q. Okay. And then January 2023 is when you ran
19 the first large load model?

20 A. (Witness Valle) That is correct.

21 Q. And you ran it again in March 2023.

22 A. (Witness Valle) Yes, that's correct.

23 Q. As of March 2023, Georgia Power had over
24 3,300 megawatts under contract?

25 A. (Witness Grubb) That's true. And, again,

1 Commissioners, we've talked about it, that's what we've
2 won. What the load-forecasting side does is it takes
3 those customers -- obviously 3,000 megawatts doesn't show
4 up in that year, we ramp it in, in the load forecast. And
5 so those were being captured in the new load forecast
6 model, with those ramps.

7 Q. So none --

8 A. (Witness Valle) I'm sorry. Real quick. One
9 thing that we have got to be careful here is that, in some
10 figures, when we reported the total customer wins, that
11 doesn't mean that it's -- it constituted the total amount
12 that we consider for load adjustments, because there are
13 certain projects that are below a threshold that we assume
14 that are captured in the organic or baseline portion of
15 the -- so we don't consider every win as part of the
16 adjustment.

17 Q. But as of March of 2023, 91 percent of the
18 megawatts that is selected to serve Georgia Power, at the
19 time of this IRP filing, was already known to the company?

20 A. (Witness Grubb) But it had not -- in that
21 load forecast, it had not impacted our capacity need year.
22 So that's why we talked about, in testimony, and
23 everything else, June of 2023, is when we saw the needs
24 year move up. Up until that point, Commissioners, you
25 know, coming out of the IRP, you had space above that

1 target reserve margin.

2 We were able to -- we were -- you had some
3 capacity that could be added, without having to go build a
4 generation. So it was until June of '23, when we saw that
5 capacity need year move up. So, at that point, the RFPs
6 that we were going to do out of the IRP, the All-Source
7 RFP was just going to be for more megawatts at that point.

8 A. (Witness Bush) And several of the customers
9 that comprise that 3,000-megawatt came to us after that
10 date and asked for accelerated load ramps, so bring their
11 load up, the requirement up.

12 Q. So in June, you reran the model?

13 A. (Witness Valle) Correct.

14 Q. You reran it again in July?

15 A. (Witness Valle) Yes.

16 Q. And again in August, which is the final model
17 that was presented in this IRP; correct?

18 A. (Witness Grubb) That's right.

19 A. (Witness Valle) That's correct.

20 Q. Okay. So I want to look at -- in June, when
21 the year of need moved, as you've described, June and July
22 and August, Georgia Power got busy, as you described in
23 your last hearing. Developed -- in July of 2023 alone,
24 you were developing Plant Yates. You were negotiating
25 Santa Rosa, and you were negotiating Mississippi Power,

1 and you began due diligence on BESS Plus Solar, I think is
2 the unidentified one.

3 A. (Witness Grubb) Yeah, that's right. Because,
4 Commissioners, even though you're looking at, could you do
5 RFPs, we knew that, especially in those earlier need
6 years, you were not going to be able to do one. So to
7 accommodate the load growth that we saw, and the economic
8 development in the state, we knew we were going to need to
9 go find resources and develop those resources. So we did
10 start that, when we saw that need year moved.

11 Q. And in August, you were equally busy. I
12 won't read through the list, but there's a long list in
13 your prior testimony and in hearing requests, the things
14 you were up to.

15 What I would like to do is look at the email
16 from August 25th, and this is an email from Ms. Pryor to
17 Commission staff. I think I gave my copy. Do you have
18 another copy?

19 A. (Witness Grubb) Yeah. Around the All-Source
20 which is, again, targeted for '29, '30 and '31.

21 Q. So this is an email back and forth about the
22 RFP?

23 A. (Witness Grubb) About the All-Source RFP.

24 Q. About the All-Source RFP, correct.

25 A. That's right.

1 Q. And one of the things said by Ms. Pryor, on
2 behalf of Georgia Power, is that one of the concerns of
3 the company is trying to finish the RFP in time to have
4 resources certified as part of the 2025 IRP. She goes on
5 to say, we don't think it's necessary or advantageous to
6 do so.

7 A. (Witness Grubb) So, yes. So this was, again,
8 around trying to get an All-Source evaluated and certified
9 by the '25 IRP, which would have been -- the schedule was
10 not possible, when you start talking about the amount of
11 megawatts that the All-Source is going to have, and the
12 evaluation needed on the generation side, and then also
13 the transmission side. So staff did propose a schedule.
14 I didn't read the whole thing, but --

15 Q. Right.

16 A. (Witness Grubb) -- it's around their
17 solicitation schedule. We worked with staff, we always
18 looked to collaborate with staff on these. They had some
19 questions around making sure we had due diligence on the
20 load forecast and the exact need, which is what we're
21 doing in this proceeding. But our feedback here is,
22 trying to get an All-Source done between June of '23, when
23 the need year moved, and basically the end of this year is
24 not possible when you look at the time that we need to
25 evaluate, from a transmission and a generation standpoint.

1 Q. And you would agree that staff disagreed;
2 correct? With your timing.

3 A. (Witness Grubb) I don't want to speak for
4 staff.

5 Q. You would agree that staff was representing
6 to the Company that they believed the Company could move
7 faster?

8 A. (Witness Grubb) They did, and they have. I
9 think the main point here was, the time of the evaluation
10 is where we mostly disagreed.

11 Q. All right. So you reran the load realization
12 model five times in eight months in 2023?

13 A. (Witness Valle) Correct.

14 Q. Did you rerun it to justify the pipeline
15 growing, that you've been talking about?

16 A. (Witness Valle) No. The load forecast was --
17 the sensitivities were done to inform how the load was
18 realizing. So the pipeline was growing in an exponential
19 manner, right, so we started at the end of 2022, when we
20 did the budget for 2023. We had something like almost
21 1800-megawatt and we reflected an external adjustment of
22 1200-megawatt.

23 Then by January, the pipeline, grown to over
24 4000-megawatts, then by March, the pipeline grew to over
25 6,000-megawatts, and then by June, it was

1 12,000-megawatts. So every time that we were looking at
2 the portfolio and the economic development pipeline, it
3 was growing.

4 And so it was our obligation to develop the
5 sensitivity. So I want to remind everybody that normally,
6 our process is to run the forecast once a year. But
7 because we saw all of these advances and going fast,
8 because speed happened, right, it didn't just happen in
9 Georgia, it happened at a national scale. We were
10 appropriately and proactively informing the impacts into
11 the forecast.

12 Q. So, just to be clear, the company has not
13 rerun a load realization model since this docket was
14 filed?

15 A. (Witness Valle) No. We have some initial
16 sensitivities. We haven't done that, because the minute
17 that you have a new sensitivity or a new forecast, it
18 changes the request. So we are in the middle of this
19 process. But we have done some exploration, right,
20 despite the fact that the pipeline grew up from the time
21 of the filing, from 17,000-megawatts, until recently,
22 21,000-megawatts, so that's 4,000 more megawatts into the
23 pipeline. We have done some initial explorations.

24 A. (Witness Grubb) But most of that -- because
25 the pipeline's growing -- and if you think about it,

1 they're new into the pipeline. It's more -- it's later.

2 Q. Right.

3 A. (Witness Grubb) So if you rerun it now, it
4 doesn't necessarily hit '25 and '26. Because if someone
5 hasn't come to the state and started working on it,
6 they're not likely going to hit '25 or '26.

7 So we do expect if we run it, that those
8 years of the All-Source RFP will get bigger. Of course,
9 we'll be able to base that on the budget 2025 IRP, but the
10 shorter-term years, we don't expect that any of these new
11 pipeline projects would impact those shorter-term needs.

12 Q. Has the short-term need gone down?

13 A. (Witness Valle) Can you repeat that, please?

14 Q. In the sensitivities run by the Company, has
15 the short-term need -- which I mean by 2028, has it gone
16 down?

17 A. (Witness Grubb) Not to change the resource
18 plan, no.

19 Q. Has -- have the number of megawatts the
20 company expects, based on its load sensitivities in the
21 modeling, has that gone down?

22 A. (Witness Valle) It's not.

23 MS. WHITFIELD: Could I make a hearing
24 request for the sensitivities that have been run by
25 the Company on the load growth since this docket

1 was filed?

2 CHAIRMAN SHAW: Okay. That's fine.

3 MR. GRUBB: And so I guess one -- I'm not
4 saying we won't give them to you, but I think one
5 of the things you can help me here is -- obviously
6 is, those may be sensitivities -- they weren't put
7 full -- through the full load forecast, so we'll
8 just have to make sure --make sure y'all know what
9 you're seeking.

10 A. (Witness Valle) Those were initial
11 explorations, so they haven't gone through the whole
12 process. But we can provide what we have. No problem.

13 Q. Okay, great.

14 MS. WHITFIELD: Nothing further. Though, I
15 would ask to move GIPL's Exhibits 1 through 3 (sic)
16 be into evidence.

17 CHAIRMAN SHAW: So marked.

18 (GIPL Exhibits 1 through 4 were admitted into
19 evidence.)

20 MS. WHITFIELD: Thank you.

21 CHAIRMAN SHAW: Okay. Let's take a
22 ten-minute break. See everybody back here at 3:45.

23 (Whereupon, a break was taken.)

24 CHAIRMAN SHAW: Okay. Our next cross will be
25 from Georgia Solar Energy Association,

1 Mr. Moreland.

2 MR. MORELAND: Thanks, Chairman.

3 CROSS-EXAMINATION

4 BY MR. MORELAND:

5 Q. My name is Don Moreland. I'm with the
6 Georgia Solar Energy Association. I just have a couple of
7 questions around the demand response programs that you
8 guys have in this IRP. A lot has already been talked
9 about in terms of the expected load growth, short term and
10 long term, but -- and so I won't really direct you
11 directly to a line in the rebuttal testimony, unless you
12 want me to. But is it safe to say that you're seeking the
13 authority to build or buy 3300-megawatts of capacity
14 resources to meet your capacity needs from 2026 to 2028?

15 A. (Witness Grubb) The stipulation reduced that,
16 with the 500 going through an RFP, but, yes.

17 Q. Thank you for that.

18 And then also mentioned in -- on page 13 in
19 the rebuttal testimony, the amount of load growth has
20 actually increased since you first filed this IRP update;
21 correct?

22 A. (Witness Valle) That is correct.

23 Q. So is it safe to say that there's a lot going
24 on, and it's a bit unpredictable, and you're doing your
25 best to kind of keep up with the economic development

1 growth?

2 A. (Witness Grubb) It's fair to say there's a
3 lot going on. But yeah, we've identified a plan here,
4 but, yes, there's a lot of opportunities for resources as
5 we look forward.

6 Q. And does your load growth in this IRP take
7 into consideration, I guess, organic growth that might
8 come about with increased population, small businesses,
9 increased electric vehicle demand, things of that nature?

10 A. (Witness Valle) Yes, that is correct. The
11 total forecast of the company is made up of a baseline
12 forecast of organic growth and then the adjustment for
13 large loads.

14 Q. Is it possible -- not saying it's probable,
15 but is it possible that circumstances beyond the company's
16 reasonable control to build or buy 3300, or the amount of
17 capacity you're seeking authorization for, is it possible
18 that circumstances outside the company's control could
19 impact your ability to meet that capacity?

20 A. (Witness Grubb) I mean, I would say we feel
21 very confident in what we're deploying. I mean, obviously,
22 the PPAs are there. But I mean, there's not -- always a
23 possibility of something, but in terms of the PPAs, we're
24 confident in those. We're confident in being able to
25 develop. But I'm not sure I hundred percent followed your

1 question, but, yeah, we feel very confident for what we
2 have got identified. There's always something that
3 could --

4 Q. A force majeure event?

5 A. (Witness Grubb) Yeah.

6 Q. Yeah, something along those --

7 A. (Witness Grubb) Minus that, we feel very
8 confident.

9 Q. All right. Given the magnitude and the
10 timing of the historic economic growth and the increased
11 load in your forecast just since October, would it be
12 prudent for the company to have additional capacity
13 available to step in should such an unforeseen event take
14 place?

15 A. (Witness Grubb) So I don't know that our
16 forecast has changed since October. We've -- the page I
17 think you reference is more the customers that we've
18 signed, so we have gotten more certainty in that forecast.
19 I don't know that our projections have changed since
20 October.

21 So I'll let you confirm that.

22 A. (Witness Valle) Yeah, that is correct. So
23 these customers that have committed to Georgia Power were
24 already part of the forecast that we included in the
25 filing. At any point in time, there's a natural

1 progression in the economic development pipeline, so these
2 customers, these 11 customers accounting to 2600 megawatts
3 that committed to Georgia Power, moved from early stages
4 into the selection for our company.

5 A. (Witness Grubb) But, Mr. Moreland, if you
6 could repeat your question. I think you were asking
7 around having additional resources. Is that what your
8 question was? I don't think I answered your question. I
9 think I gave you information, but I didn't answer.

10 Q. Yeah. Just because of the amount of load
11 growth and the short period of time that that growth is
12 needed, I'm asking is it prudent for the company to have
13 some kind of backup source in case, you know, one of these
14 unforeseen events should happen, in order to meet the
15 demand in that 2026-to-2028 time frame?

16 A. (Witness Robinson) Well, we do have the
17 interruptible program that Mr. Evans can speak more to.
18 And there's an additional request in this -- and there's
19 an additional request to expand that here, but I'll let
20 Mr. Evans address.

21 A. (Witness Evans) Yes. There's a number of
22 programs that we proposed here in addition to our current
23 demand response programs and our Real Time Pricing program
24 that have demand response elements to them, or allow for
25 customer-sided supply-side resources to add further

1 capacity benefits to the grid.

2 Q. And is one of those programs the residential
3 thermostat program?

4 A. (Witness Evans) It is.

5 Q. Can you tell us a little bit about the
6 thermostat program, say, you know, how it works, and the
7 benefits to customers and the company, please?

8 A. (Witness Evans) Sure. The residential
9 thermostat program is one of our -- we're seeking for it
10 to be certified as an expanded program. It currently is
11 serving around 25,000 residential customers with a demand
12 response element, such that during -- when the
13 customers -- when the company can send signals to the
14 customer, that thermostat automatically precools and then
15 sheds load controlled by the thermostat during
16 dispatchable events. Expanding it to 50,000 is something
17 that we think we can accomplish during the time that we've
18 requested, through the end of 2025. That's doubling the
19 program in what I believe is 21 months, which we believe
20 is aggressive. But we think we can capture that benefit
21 for all customers while we continue to evaluate other
22 demand side options.

23 A. (Witness Robinson) Which we detailed in
24 paragraph 21 of the stipulated agreement. I would say
25 that going back to the last IRP and rate case, the company

1 had asked for approval of a distributed energy resource
2 management system, which we are in the process of an RFP
3 for right now. And so very close to selecting that
4 product for us for deployment. That's going to allow many
5 more options for us as far as looking at those types of
6 programs in the future, giving us the ability for
7 visibility and, hopefully, control in the future.

8 Q. Would you say that the thermostat program is
9 providing net benefits to the grid and to the company?

10 A. (Witness Evans) We currently project -- I
11 believe the number is about 17 megawatts of capacity
12 benefits from the current program and project to double
13 that. So, yes, that is directly represented on the
14 resource ledger in deferring other types of generation.

15 Q. Is this the type of program that puts
16 downward pressure on rates?

17 A. (Witness Evans) I would have to check. I
18 don't believe that one does. I believe that one fails the
19 RIM test and puts upward pressure on rates, but it does
20 provide capacity benefits.

21 Q. Does the company manage that program itself,
22 or is there a third party?

23 A. (Witness Evans) We have a third-party
24 facilitator.

25 Q. And who is that?

1 A. (Witness Evans) I believe -- I'm not sure if
2 it's public.

3 Is it public?

4 Q. Does Uplight sound right?

5 A. (Witness Evans) That's correct.

6 Q. Could you explain what company internal
7 planning and operational resources were required to
8 implement and support the thermostat program with Uplight?

9 A. (Witness Evans) I cannot say all of them. I
10 know that we have an implementation arm that is dedicated
11 to implementing all of our DSM programs, and there's a
12 program manager that's responsible for that. I was not
13 part of that whenever the program originally got stood up,
14 so I can't speak to everything that was involved to enable
15 it.

16 Q. Will Uplight continue to be the DERMS
17 provider for the expanded program should it be approved by
18 this Commission?

19 A. (Witness Evans) Well, you know, DERMS has a
20 lot of different meanings. And whenever you use it, it's
21 very different from the grid-centric DERMS that
22 Mr. Robinson would speak to and mentioned as part of the
23 outstanding RFP. Uplight would continue through this
24 cycle, as was approved in the current DSM cycle. We're
25 just looking to expand it for the current cycle only, and

1 then in the '25 programs that will all be reevaluated as
2 part of our overall DSM proposals then.

3 Q. Okay. Thank you. That helps quite a bit.

4 So, kind of, going to a residential and small
5 commercial virtual power plant program, could a
6 third-party DERMS provider, maybe, for lack of a better
7 term, manage that program, as well?

8 A. (Witness Evans) What program are you
9 speaking -- help me.

10 Q. A proposed virtual power plant program. In
11 Georgia Solar's testimony, that was proposed.

12 A. (Witness Evans) Oh, I can't speak to how your
13 proposed program would be implemented. We -- there is
14 some value in certain types of programs, to being able to
15 tap into those third parties. There's also very much
16 value in having our own grid-centric DERMS. That unlocks
17 different value streams and creates additional savings
18 opportunities and benefits for all customers through these
19 types of load-flexibility programs.

20 Q. Could Uplight implement a virtual power plant
21 program?

22 A. (Witness Evans) I'm not positive.
23 Potentially.

24 Q. All right. Are you aware of last year, that
25 Uplight acquired AutoGrid, which is one of the largest

1 DERMS providers in the country?

2 A. (Witness Evans) I know they have some
3 relationship now. I'm not sure who acquired who. But,
4 yes, they're -- they have some type of corporate
5 relationship.

6 Q. In the stipulated agreement on page 17 --
7 paragraph 17, I should say, you state that the company is
8 evaluating and planning a residential solar and battery
9 storage program for 2025, a demand side program for 2025?

10 A. (Witness Evans) We're evaluating and
11 developing it, that pilot for '25, yes.

12 Q. Is it safe to say that by the time the 2025
13 IRP runs its course, that it will still take a while to
14 implement any new demand side program, such as the one in
15 paragraph 17?

16 A. (Witness Evans) The goal would be to have
17 that program running by '26, just like our other Demand
18 Side Management programs. Now, I'm not saying that this
19 would be part of the Demand Side Management docket, but
20 those programs are designed to produce savings over the
21 '26, '27, and '28 period.

22 Q. That answers my next question, so very good.

23 And, lastly, is there -- would you agree the
24 Commission has the authority to move forward with a
25 residential solar and small commercial solar and battery

1 storage pilot program for this IRP, so we have more data
2 and could possibly expand that program for the 2025 IRP?

3 A. (Witness Evans) What program are you -- I got
4 lost a little bit.

5 A. (Witness Grubb) Are you asking: Could you do
6 paragraph 17 earlier? Is that --

7 Q. Yes. I'm asking can the -- does the
8 Commission have the authority to approve paragraph 17 in
9 this IRP so we have data and we can hit the ground running
10 for the 2025 IRP?

11 A. (Witness Evans) The Commission could
12 certainly approve it. Whether we would actually be able
13 to deploy it and have meaningful data to inform the '25
14 IRP, I don't believe so. I don't think that timing would
15 work out, but the Commission can certainly approve it.

16 A. (Witness Grubb) Yeah. To echo that, I mean,
17 we're putting the 2025 IRP together now, in terms of the
18 first steps of it, so I don't think you would gain
19 anything to Mr. Evans's point.

20 Q. Would starting the pilot program now help
21 meet the demand need in the 2026-2028 time frame?

22 A. (Witness Evans) As I think the '25 --
23 proposing it in '25 would, as well. You know, we, in this
24 IRP proposal, made adjustments to known programs that we
25 had now and other programs that we could deploy, but that

1 did not mean that we would not continue to work and
2 develop new proposals as part of the regular '25 cycle,
3 which we're actively doing right now. It was not saying
4 that those will not be on the table of things we're
5 proposing. It was just isolating the things that could
6 provide known capacity value in the shortened time period.

7 A. (Witness Grubb) And, Commissioners, I think
8 there was some discussion earlier today on a lot of these
9 paragraphs, and we do these things. But we do see more
10 opportunity on some of these types of programs and some of
11 these paragraphs near the end of the stipulation, because
12 of the megawatt needs that we have out in the '20s, and
13 the value of any project that helps us meet capacity need.
14 So these last few paragraphs, I think we're as excited and
15 have as many opportunities on these types of programs that
16 we've had in quite some time.

17 A. (Witness Robinson) And I think another thing
18 that's going to very important for implementation of this
19 program is the deployment of our DERMS system, that I've
20 mentioned before, that we're currently in RFP for, to
21 fully integrate that into our system. And currently,
22 right now the timing for that is the beginning of '26.

23 Q. So in time -- would that be in time for what
24 could be proposed in the 2025 IRP?

25 A. (Witness Evans) The programs that we propose

1 in the '25 IRP could -- would be designed to take full --
2 to realize the full capabilities of the DERMS system
3 because those programs would be authorized, proposedly, to
4 run in '26, '27, and '28. So we would design those
5 programs based on DERMS being online.

6 A. (Witness Robinson) Yeah. And the DERMS
7 system is not absolutely needed to bring these systems
8 online, but it is needed for full integration into our
9 dispatch.

10 A. (Witness Evans) That's right.

11 Q. And that's kind of getting to my point. This
12 is really -- my final question is: Full implementation is
13 different than a pilot program. What's in paragraph 17 is
14 proposed as a pilot program. Whereas, I'm asking is it
15 prudent for the company to start a pilot program now so
16 that program can be fully implemented in 2025, and ready
17 for the 2026-to-2028 time frame?

18 A. (Witness Evans) Yes. Again, I don't know
19 that the timing would inform or change what we filed in
20 '25 just because of, again, having to do that design work,
21 that implementation work, that solicitation to get
22 customers on it and then have learnings from that, in time
23 for the '25 filing. I think that's somewhat aggressive,
24 so I don't know that it would substantially change what we
25 did in '25. But, again, as per the stipulation, that is

1 something we commit to developing for that cycle.

2 Q. Okay. Thank you. No further questions.

3 A. (Witness Evans) Thank you.

4 A. (Witness Grubb) Thank you.

5 CHAIRMAN SHAW: Georgia WAND?

6 (No response.)

7 CHAIRMAN SHAW: Georgia Watch?

8 (No response.)

9 CHAIRMAN SHAW: MARTA?

10 MS. STURM: No questions.

11 CHAIRMAN SHAW: Microsoft?

12 MR. DOWDY: No questions, Mr. Chairman.

13 CHAIRMAN SHAW: Resource Supply Management?

14 MR. BAKER: Good afternoon, gentlemen.

15 THE PANEL: Good afternoon, Mr. Baker.

16 CROSS-EXAMINATION

17 BY MR. BAKER:

18 Q. Thank you for coming again. Always
19 informative.

20 A. (Witness Grubb) You, as well.

21 Q. I don't agree with you all the time, but
22 you're informative and it's interesting.

23 A few clarification questions first. Isn't
24 it true that the company has no obligation to serve
25 customers -- or only has an obligation to serve customers

1 in your service territory?

2 A. (Witness Grubb) That's true. But we have the
3 opportunity to serve them outside the service territory.
4 And as we've talked about in this filing, being able to
5 support the growth of Georgia and being able to present
6 downward pressure on rates, any project that we can go in
7 and serve, helps all customers. And then I think from the
8 Territorial Act standpoint, too, it's been great for the
9 growth of this state. So we want to be in a position
10 where we can serve our inside service territory but also
11 be able to make offers on those outside our service
12 territory.

13 Q. Understood. You want to be acquiring
14 valuable new customers if you can, but -- if there's a new
15 customer -- I believe in your prior testimony you said a
16 third of the new large load customers are located within
17 your service territory. You have an obligation to serve
18 those folks?

19 A. (Witness Grubb) Yeah, that's true. I think
20 the mix is a little different for what we see now. But,
21 again, yes, you technically are correct. It's an
22 obligation to serve those inside.

23 Q. Has that mix changed since the new addition
24 of the large load customers from the previous testimony?

25 A. (Witness Valle) I can comment that of the

1 6200-megawatts that we have in committed load right now,
2 around 4300-megawatts are inside the territory, so the big
3 majority now is inside territory.

4 Q. And also a clarification, at this time, the
5 company has sufficient capacity resources to serve your
6 current customers and provide for normal organic growth;
7 is that correct?

8 A. (Witness Grubb) Without the external
9 adjustments, that's correct, but the load forecast is what
10 we're aiming to serve.

11 Q. And I get that. I understand that. But if,
12 hypothetically, we went back to the old days of
13 100-megawatts, you know, large load customers per year,
14 right now you have adequate capacity resource to serve
15 everybody here plus organic -- regular organic growth?

16 A. (Witness Grubb) So through 2029, out of the
17 last IRP we did, hypothetically, but yes.

18 Q. All right. At page 13, you refer to the 14
19 of 51 projects included in the company's load realization
20 model in the 2023 IRP update filing having signed a
21 request for electric service. Is there any penalty if a
22 company that has signed a request for electric service,
23 for whatever reason, never goes online? And I'd just
24 point to say, I know Rivian isn't your customer, but in a
25 Rivian situation where you have this big expectation, a

1 billion-and-a-half of economic development incentives, and
2 all you have a sudden, poof, they're on pause. And, you
3 know, depending if you look at their financials, odds are
4 that they may not be coming back.

5 A. (Witness Evans) Well, like you said, they're
6 on pause, and that's very different from the customers
7 that are backing the load request in this case. Those are
8 some of the most financially stable companies in the
9 world, so I think that's a very different case than the
10 Rivian example, from the customer that we don't serve,
11 that you mentioned.

12 Q. All right. Let me just take Rivian off then.

13 My question is: If a customer signs a
14 request for electric service, is there any penalty if that
15 company doesn't fulfill its obligation to come online and
16 get service from the company?

17 A. (Witness Robinson) So one of the things we do
18 in our offers is, for directly assign costs, which is
19 typically costs that can only be used by that customer, we
20 directly assign that cost, and that's paid for upfront by
21 that customer. So if that customer never comes, that's
22 infrastructure that's been put in the ground and paid for
23 by that customer that they don't get back.

24 Q. So for transmission, let's say that the
25 company spends, you know, funds for building out

1 transmission to serve this prospective large load
2 customer. And then, for whatever reason, the large load
3 customer does not complete the project and does not go
4 online, so they would -- that company would be responsible
5 for the full cost of that transmission expenditure plus
6 any other like -- any other equipment expenditures the
7 company had to make to provide service for that site?

8 A. (Witness Robinson) Typically, it's on
9 premise, and serves only that customer. That customer
10 pays for that upfront. It's a directly assigned cost.

11 A. (Witness Evans) In many cases, yes -- oh,
12 sorry, yes.

13 A. (Witness Robinson) For upstream costs, there
14 are benefits to the state in further economic development
15 for using those facilities. We have the integrated
16 transmission system here in Georgia where we put those
17 facilities in what we call parity, and we all can use
18 those facilities to serve future load. And so, those
19 upstream improvements have benefits to the state for
20 future development.

21 A. (Witness Valle) And, Commissioners, I would
22 like to also add that that scenario that Mr. Baker is
23 describing about a customer failing after signing an
24 RFP -- I'm sorry, a request -- RFS, is very unlikely, and
25 it's something that we have incorporated into our load

1 forecasting model. So we don't assume that everything
2 that signs an RFS will materialize. There's a small
3 percentage, based on some historical information that we
4 have, that we have included into the model.

5 Q. Understood. But, I mean, I think everyone,
6 if you asked them a year ago, they were pretty sure Rivian
7 was going to be building a car manufacturing facility in
8 the state of Georgia, and that is questionable at this
9 time, so things change in the economy.

10 A. (Witness Grubb) I think Mr. Valle just hit on
11 that, Commissioners. That's part of the statistical
12 models that we do, is we don't assume a hundred percent of
13 everything's coming to the state, that it signs and then
14 it shows up, at its announced load. That's all factored
15 into the work that Mr. Valle and the team have done.

16 A. (Witness Valle) Yeah. To make sure, Rivian
17 has not eliminated Georgia as a -- they have put -- they
18 have suspended their plan, but they have not say they're
19 going away.

20 CHAIRMAN SHAW: But didn't you say earlier,
21 also, just in terms since we're talking about
22 Rivian, they were not going to be a Georgia Power
23 Company customer anyway?

24 A. (Witness Valle) Yeah, they're not. But I'm
25 just clarifying that.

1 A. (Witness Grubb) But if you look at the one
2 that we do serve, like Hyundai, they're actually moving
3 their production of cars up sooner than they thought. So
4 all the signs for them are very positive, so that is one
5 of the customers that we do serve.

6 Q. Okay. Thank you. At page 29, you state that
7 several utilities have established winter reserve margins,
8 and you specifically reference several of those utilities.
9 Do you know what their winter reserve margins are?

10 A. (Witness Grubb) Yes. So I've got a list, if
11 will you give me just a second, Mr. Baker. I think TVA is
12 at 25. I think some of the Dukes are at 20. Give me just
13 a second. But our point there is that we moved to
14 seasonal planning. We increased the reserve margin, I
15 believe in the 2016 IRP, to capture winter. We moved to
16 seasonal planning in the winter reserve margin in '19 and
17 '22, but you've seen a continued trend of that. Yes, so
18 Duke Energy, I believe, is at 22. TVA is near 20. MISO
19 is around 25 in the winter, and Duke and FPL have moved to
20 a 20, and Dominion and South Carolina have moved to a 20.
21 So they were in the lower teens, I believe.

22 Q. Okay. So all of them had established winter
23 reserve margins lower than Georgia Power's?

24 A. (Witness Grubb) And several of those shed
25 firm load in Winter Storm Elliott, as well.

1 Q. All right. And in the stipulation, there's
2 provision for RFPs for the construction of 500 new battery
3 energy storage systems. What is the status of the
4 500-megawatts of BESS that was authorized in the 2022 rate
5 case?

6 A. (Witness Grubb) So that RFP will be issued
7 some point this year. We've been focused on the
8 All-Source and working on that one. So, again, that was
9 for a different use case, but I think it will be sent out
10 sometime this year. So this -- it was not -- the
11 stipulation is for resources to be online by the end of
12 2027, and so because of that, it's narrowly focused. The
13 500-megawatts is going to need to be grid-charged, or we
14 want to allow grid-charge, which means you open it up to
15 lot more value. You've got to do transmission
16 evaluations. And so it can't meet this need, but we will
17 issue it some point this, year for COD somewhere in the
18 mid- or the late-20s.

19 Q. All right. And going back to the discussion
20 about the 70/30 PPA -- or PPA mix, isn't it true to say
21 that back in 2001, that the use of PPAs by utilities was
22 in its infancy and there wasn't much of a track record as
23 far as utilities having experience dealing with and using
24 PPAs for providing service to their customers?

25 A. (Witness Grubb) Yes. That was in the earlier

1 stages of that. I think there were some other aspects
2 that -- I can't speak for the Commission, especially not
3 the Commission back then, but it was around reliability.
4 But I would say that, while we have a lot more experience
5 with PPAs, one of the things that's important from an
6 ownership standpoint is reliability, but also flexibility.
7 And so I don't think the grid has gotten any more -- any
8 less complicated from a reliability standpoint. And so
9 there are aspects of ownership that give you more
10 flexibility, and Mr. Robinson could speak to that from a
11 transmission standpoint.

12 So yeah, while the PPAs are more developed
13 now, the benefits of ownership are being able to handle
14 reliability issues, like we talked about, but also
15 flexibility. It's a lot harder to contractually cover
16 something that might happen in the next 20 years, as
17 opposed to ownership. An example being, several -- a few
18 years ago, all of the capacity value for PPAs was in the
19 summer, and we still have contracts where that is the case
20 because we can't adjust them. And so, while the PPA
21 industry is a lot stronger, the reliability and
22 flexibility needs of ownership are still valuable.

23 Mike, I don't know if there's anything you
24 want to add from a transmission standpoint.

25 A. (Witness Robinson) I think, Commissioners, as

1 Mr. Grubb said, the system is not getting any less
2 complex; it's getting more complex. And so ownership
3 definitely gives a benefit from a transmission reliability
4 perspective, particularly on control and visibility.

5 Q. Well, Mr. Robinson, following up on that, is
6 it -- batteries.

7 A. (Witness Robinson) Batteries died.

8 A. (Witness Grubb) We brought some with us,
9 though, because we're planners. Do we have them? We've
10 got them. It's the reserve margin, resiliency, whatever
11 you want to do, we've got extra batteries.

12 Q. Mike, how many batteries do you have?

13 A. (Witness Grubb) We have five or about
14 26 percent above what we thought we needed.

15 A. (Witness Evans) Looks like we have about two
16 dozen there.

17 A. (Witness Grubb) This is shoulder season so
18 you're somewhere between 26 and 16, but he's got them.

19 Q. So these are your shoulder batteries?

20 A. (Witness Grubb) Can't let a day go by without
21 reliability humor; right? Probably can.

22 Q. What you are guys going to do once this is
23 all over?

24 A. (Witness Grubb) Well, we have a '25 IRP
25 coming up, if you haven't heard. So we got plenty.

1 Q. Oh, I heard that.

2 A. (Witness Grubb) We've got plenty.

3 A. (Witness Robinson) And I'm back. And that's
4 one of the issues with using batteries for transmission
5 solutions.

6 Q. I hope you have the four-hour batteries in
7 your microphone.

8 All right. Getting back --

9 COMMISSIONER PRIDEMORE: These are jokes that
10 only the people in this room would laugh at.

11 MR. GRUBB: I think this is one is going
12 viral.

13 CHAIRMAN SHAW: You can tell it's been a long
14 day.

15 BY MR. BAKER:

16 Q. All right. I was going to ask Mr. Robinson,
17 Mr. Grubb was talking about the complexity and reliability
18 of transmission issues. Is there a difference in
19 reliability and complexity when you're talking about, say,
20 a PPA that is out of -- let's say, the Mississippi PPA, as
21 opposed to a PPA where the facility is located in the
22 state of Georgia? Is there a difference as far as
23 reliability, complexity, transmission issues? I would
24 assume it would be easier in Georgia?

25 A. (Witness Robinson) Well, there are a couple

1 of factors there. The benefit to the Mississippi PPAs,
2 and Santa Rosa, too, is that they are in our collective
3 balancing area. Santa Rosa used to be, it's grandfathered
4 as far as access to it. But because those units are in
5 our balancing area, we have more control from that
6 perspective. There are more transmission lines between
7 here and there, so there could be issues there, but that's
8 why we plan for those things.

9 Q. And not specifically, just generically, not
10 referring to the Mississippi specifically or Santa Rosa,
11 but generically. When you're dealing with a PPA, is it
12 better, or would the company prefer to deal with a PPA
13 that is located in the state of Georgia, as opposed to
14 having it located outside and sending power into the state
15 of Georgia?

16 A. (Witness Robinson) From a transmission
17 perspective, I think the Mississippi PPA versus a PPA here
18 in Georgia is pretty much the same.

19 COMMISSIONER MCDONALD: Can't hear a thing
20 you're saying.

21 MR. ROBINSON: I'm sorry?

22 COMMISSIONER MCDONALD: Can't hear a thing.

23 CHAIRMAN SHAW: It's a two-hour battery, not
24 even a two-minute battery.

25 MR. ROBINSON: Is that better? It has to

1 touch my lips.

2 MR. GRUBB: We're going to clean that one.

3 COMMISSIONER PRIDEMORE: The State might
4 donate this to you when this is over with,
5 Mr. Robinson. Just keep it.

6 MR. GRUBB: You can use mine.

7 A. (Witness Robinson) But hopefully that
8 answered your question, Mr. Baker.

9 A. (Witness Grubb) So, Commissioners, I want to
10 again -- we are in favor of PPAs right, we just think it's
11 an important balance.

12 And, Mr. Baker, what I was talking through
13 more there was not physical reliability but if -- for
14 instance, if you have a contract with a PPA, you have
15 certain flexibility and certain requirements in that PPA.
16 If the operating conditions around that change, you may
17 not have the contractual ability to change the way that
18 resource operates, whereas, you can on the ownership side.

19 So it wasn't as much physically that a CC
20 under a PPA is different than a CC if we owned it. But if
21 we say, hey, we need to operate these CCs differently for
22 A, B, or C, we have to go check the contract on the PPA.
23 Whereas, if we own it, we just do it. So that was the
24 point I was making in terms of trying to contract
25 flexibility.

1 BY MR. BAKER:

2 Q. But would you agree that, based on 23 years
3 of experience utilizing PPAs, that the company is able to
4 use them more effectively and anticipate issues ahead of
5 time, based on the 23 years of experience?

6 A. (Witness Grubb) Depending on the asset. We
7 are always looking at our contracts through RFPs, and
8 making sure that we're capturing the latest and greatest
9 on the system, and working through those. So, yeah.
10 Again, it wasn't a "no PPAs comment" at all. It was there
11 is a difference between the two, which is why there's a
12 balance.

13 A. (Witness Robinson) And we adjust as we learn,
14 too. I think that's to your point, to your question.
15 Like for the solar PPAs that we have, we're now requiring
16 those to go on AGC. So that is a reliability tool that we
17 have, as far as being able to control those units from our
18 centralized dispatch. And so that's something that we've
19 done recently to ensure the reliability of those units and
20 the system.

21 Q. I guess my point was, I was trying to get to
22 the point that the 70 percent, 70/30 percent rule,
23 shouldn't be considered a hard -- it should be subject to
24 the changing circumstances and the availability of
25 resources that provide potential benefit to the company

1 and to its customers, as far as just saying, oh,
2 70 percent, that's it.

3 A. (Witness Grubb) So it's worked well. As
4 we've talked about, the Commissioners -- the order is what
5 set the percentage. But I think you could consider the
6 fact that you're saying that the PPA industry is more
7 developed, but there are other factors, too, that have
8 changed in the industry. So if we revisit that, I think
9 all of that would be something we would all have to
10 consider.

11 CHAIRMAN SHAW: Thank you, gentlemen. Hope
12 to see you in 2025.

13 THE PANEL: Thank you.

14 CHAIRMAN SHAW: Sierra Club.

15 MR. FABISH: Good afternoon, Commission.

16 Good afternoon, panel.

17 THE PANEL: Good afternoon.

18 CROSS-EXAMINATION

19 BY MR. FABISH:

20 Q. I'm Zack Fabish for the Sierra Club. Just a
21 few questions. One of the benefits of going towards the
22 back of the pack alphabetically is everyone else asks
23 everything good already.

24 So look on page 18 of your testimony, around
25 lines 1 through 4. You talk about one of the company's

1 customers talking about load realization at a couple of
2 its hyperscale data centers. My question is -- and I
3 apologize for my ignorance -- what is a hyperscale data
4 center?

5 A. (Witness Valle) So I can give it a try.

6 So a hyperscale data center is a large, large
7 center that processes data. It goes into the aspects of
8 cloud computing, and pretty much everything but artificial
9 intelligence. That's --

10 CHAIRMAN SHAW: What was the last thing.

11 Pretty much everything but what?

12 MR. VALLE: Artificial intelligence.

13 CHAIRMAN SHAW: Oh, okay.

14 MR. FABISH: So about how many of them are
15 there nationally?

16 A. (Witness Valle) At the time of the filing, we
17 had 33 data centers, 21 were hyperscalers.

18 A. (Witness Robinson) Did you ask nationally?

19 Q. I did ask nationally, but --

20 A. (Witness Valle) Oh, I'm sorry.

21 Q. Let me step back a second. I'll ask the
22 questions around here. No.

23 A. (Witness Grubb) I won't ask any. Believe me,
24 I don't want to ask any. We're getting enough.

25 Q. So to clarify, your response was about the

1 number in Georgia Power's system?

2 A. (Witness Valle) In our portfolio of loads,
3 yes.

4 Q. And so even more in Georgia?

5 A. (Witness Valle) Presumably, yes.

6 Q. And do you have a sense of how many
7 nationally?

8 A. (Witness Valle) No.

9 Q. Okay. So this one customer's anecdote about
10 two centers really only refers to a tiny fraction of the
11 relevant industry; right?

12 A. (Witness Grubb) Say that again. I missed
13 that last part.

14 Q. I'm sorry. So this customer's anecdote about
15 two hyperscale data centers really only refers to --
16 directly to a tiny fraction of the relevant industry; is
17 that right?

18 A. (Witness Valle) Are you talking about the --

19 A. (Witness Grubb) So you're on page 18, line 3,
20 Mr. Fabish. Okay.

21 Q. Yeah.

22 A. (Witness Grub) The two -- talking about where
23 we reached out to the two in terms of the materialization
24 of their load?

25 Q. Yeah.

1 A. (Witness Grubb) Okay. Just wanted to be sure
2 we were following the right question.

3 Q. Absolutely.

4 A. (Witness Valle) Absolutely. So noting the
5 quantity, it's evidence that we didn't have at the time of
6 the filing. So, you know, our models were informed with
7 data and expertise. We've been using the word "informed
8 judgment."

9 Informed judgment, Commissioners, is not just
10 a wild guess or an educated guess. It's an analysis of
11 information that we get from the customers. It's that
12 information gets studied by our engineering department;
13 right. We look at the side. We look at the availability
14 of power in that side. We look if we have transformers
15 and equipment to serve that load, and depending on how
16 that conversations goes, the load, the ramp gets adjusted
17 into our model. So within our simulations, within our
18 considerations of uncertainty, there was a load
19 realization that we developed with customer information
20 and expertise.

21 Our point here is that recently, one of our
22 existing customers was able to provide us with operational
23 information about how this hyperscaler -- how it is
24 operating in a different state. So these are -- this came
25 into the market before the ones that are in the pipeline

1 for us, and their materialization is close to 80 percent,
2 which is very much in line with our assumptions. So the
3 range of assumptions that we use in our models and the
4 information that we're getting from these two data centers
5 is very much in line.

6 A. (Witness Evans) That's right, Commissioners.
7 And that's reinforced with the actual customers that we
8 are signing contracts for electric service for. Over
9 2,000-megawatts, as we sit here today, have executed a
10 contract for electric service. That reinforces those
11 various assumptions that Mr. Valle described.

12 A. (Witness Robinson) And we're out there
13 building facilities for these, as well. And so as we're
14 building substations and lines, we're seeing the
15 development that's happening on the other side of those
16 facilities, and there's steel going up in the air. And so
17 these things are coming and coming quick.

18 Q. Thanks. But this customer you refer to in
19 your testimony is not itself offering testimony in this
20 docket; is it?

21 A. (Witness Grubb) I don't know that there's a
22 data center customer specifically that is offering. So I
23 don't...

24 A. (Witness Evans) That's right. It's just
25 reinforced with the contracts the customers have signed,

1 contracts for electric service with financial commitments
2 based on that load realization that reinforces the same
3 assumptions.

4 Q. Okay. Turning a little bit, I know there's
5 been a lot of discussion today about the P95 approach. I
6 have a couple of questions about that. First, I believe
7 earlier you testified that 50 percent is at the middle
8 point of the bell curve; right?

9 A. (Witness Valle) That is --

10 Q. P50, sorry.

11 A. (Witness Valle) Yeah. P50 is called the
12 median, and that separates the data in half.

13 Q. Is this one of situations where, like, P100
14 goes to infinity or does it cap at some level?

15 A. (Witness Valle) In a normal distribution,
16 yes, it will go to minus infinity, to plus infinity. But
17 we don't have a normal distribution. We have a
18 distribution that goes from zero to the size of the
19 pipeline, and I would say within that, the values are
20 concentrated between 25 and 50 percent of the size of the
21 full pipeline.

22 Q. Okay. Thank you. So the approach you took
23 means that there's a 95-ish percent confidence that the
24 company will have more than adequate capacity to meet the
25 forecasted load; is that right?

1 A. (Witness Valle) No. So our point is that
2 when we're planning for the system; right. So we're
3 planning for generating resources, using a higher level of
4 confidence allow us to preserve the reliability that our
5 customers see. If we were to plan on a 50/50, you know,
6 that would not be acceptable to maintain the levels of
7 reliabilities in our system. That was my point.

8 A. (Witness Evans) And it's also important to
9 realize that that forecast was at a moment in time; right.
10 The total pipeline, as Mr. Valle has described, has grown
11 from 17,000 at that time to over 21,000 today. The
12 commitments we had at that time were 3600 to over
13 6200-megawatts of commitments today. So it is also
14 realizing that the growth continues and that that forecast
15 was at a moment in time. It does not represent the future
16 growth as it continues to occur.

17 Q. Okay. I appreciate that. That wasn't really
18 my question. I apologize for not being clear.

19 A. (Witness Evans) Oh, I'm sorry. Can you
20 repeat it?

21 Q. No. I think you more than adequately
22 answered the question I was posing.

23 Where I'm going with this is that if you end
24 up with more capacity than is actually needed when we get
25 to the possible futures, when the possible future devolve

1 into actual futures and we're actually there, will the
2 company be retiring resources if they aren't needed?

3 A. (Witness Grubb) So I would say in this time
4 frame through '28, we would not. I think the retirement
5 question is more for the next phase, beyond '28. But what
6 we would do is if the load does not show up, we can sell
7 more of the capacity, in the short term, to the wholesale
8 market. That RFP that we've now stipulated to, for '27
9 and '28, is going to be able to capture any changes
10 between now and when we certify those resources, so we'd
11 have some leverage to reduce the resources.

12 But I think your point, too, was
13 95 percent -- there's the chance that it's lower. I would
14 flip it just a little bit and say that what we're -- we're
15 planning the P95 so that we're able to handle a high level
16 of new projects coming to the state. If you go to P50,
17 there's some opportunities that you miss. And so as
18 Mr. Valle and Mr. Evans said, over the last several months
19 we've continued to see that forecasted growth be less than
20 that economic development pipeline.

21 So when we think P95, we think more like what
22 you can enable us to serve. So it's the same thing you
23 said statistically, it's just a little bit different way
24 of looking at that, if that makes sense.

25 Q. Yes. Appreciate that.

1 Let's see. On page 40, the testimony -- and
2 I don't have line number for you, I apologize. You just
3 discussed the company's take on incorporating proposed
4 environmental regulations, like the 111 rule, into these
5 proceedings.

6 A. (Witness Grubb) Yes. I found it. I'm with
7 you. I'm with you.

8 Q. Good. Good. Fantastic. Is it the company's
9 position that it is never appropriate to analyze proposed
10 environmental rules and their kind of compliance costs in
11 an IRP?

12 A. (Witness Grubb) No. I mean, we study it.
13 And one of the things we would say,
14 Commissioners, we've been looking at scenario planning, so
15 we feel like a lot of our scenario planning captures the
16 carbon pressure that would be around this. So I know we
17 evaluate it in terms of comments and those types of
18 things, but what we're saying here is just, until we know
19 the final impact of it, is not to make decisions in this
20 case until we know when it's final and how it's really
21 going to apply. We'll capture that in the '25 IRP and
22 whichever ones the state plans are finalized before.

23 Q. That anticipates question I was going to ask
24 you. And you're aware the EPA expects to finalize the 111
25 rule in about a month?

1 A. (Witness Grubb) Yes. My understanding --
2 you'll know a lot more about it than I do, but I think it
3 will be finalized on the new generation and also existing,
4 but I think existing has to go through a state process,
5 which I think takes a little longer than the new
6 resources.

7 So we'll know part of it, I think -- minus
8 any kind of legal challenges, I think we will know the
9 requirements on new resources sooner than we will
10 existing, is my understanding.

11 Q. Okay. And is it your understanding that the
12 proposed 111 rule covers -- maybe not all of them, but
13 certain categories of carbon-emitting resources?

14 A. (Witness Grubb) Correct.

15 Q. Okay. So non-emitting infrastructure like
16 batteries would not be covered?

17 A. (Witness Grubb) Right. And so when you look
18 at this particular filing, the PPAs are only through 2028.
19 So it doesn't impact them. And then the batteries that
20 we're -- we've proposed and then also the stipulated RFP
21 batteries, would be affected. And then from the Yates
22 CTs, our understanding is that it would be able to meet
23 that with expected capacity factors.

24 Q. But if the capacity factors change in the
25 final rule, that's something you'd have to look at?

1 A. (Witness Grubb) That's correct. Yes.

2 Q. Does the company expect to model 111 rule
3 compliance in the 2025 IRP if the rule is finalized
4 between now and...

5 A. (Witness Grubb) Yes. I think we would have
6 to, from looking at unit retirement studies, any
7 requirements that are put on there. And it would be
8 incorporated in the environment compliance strategy that
9 we file, as well, if it's final and we can evaluate it.

10 Q. Okay. Thanks.

11 Last set of questions. You include as an
12 exhibit and you talk about it in your testimony, the
13 levelized cost of energy analysis; right?

14 A. (Witness Grubb) Yes. The Exhibit 3 from the
15 levelized cost of energy? Yes.

16 Q. Yes, that's the one.

17 A. (Witness Grubb) Okay.

18 Q. Under that analysis, solar PV ranges from
19 about \$700 a kilowatt to about \$1,400 a kilowatt; right?

20 A. (Witness Bush) That's correct. With that in
21 there, I think I would just also add that normally those
22 are the -- dollar per KW is in DC. So you have to be very
23 careful. Most of the time you would need to multiply
24 those between 1.2 and 1.3 times to get something
25 equivalent on the AC side, but that's correct.

1 Q. So with that caveat, the range in that
2 exhibit there is pretty similar for gas peakers; right?

3 A. (Witness Grubb) It is, for the capital costs.
4 I mean, obviously, there are two different characteristics
5 to those resources, but yes. Comparably, from a straight
6 capital standpoint, they're a similar range.

7 A. (Witness Bush) One is I would call a energy
8 resource. One is a capacity resource -- combustions,
9 turbines, on demand when you need them, not energy
10 limited, can meet it any time of the day or night. So
11 very different resources.

12 Q. Provided you have firm gas supply for that
13 particular resource; right?

14 A. (Witness Grubb) Or backup fuel.

15 A. (Witness Bush) Backup fuel. Right. That's
16 right.

17 A. (Witness Grubb) They do need fuel to your
18 point, yes.

19 Q. And last question, just on that exhibit, coal
20 is much, much more expensive than solar or gas or like --

21 A. (Witness Grubb) To build, yes.

22 MR. FABISH: Okay. I think that is all the
23 questions that I have. Thank you so much, panel.

24 THE PANEL: Thank you.

25 MR. FABISH: Thank you, Commissioners.

1 CHAIRMAN SHAW: Southern Alliance for Clean
2 Energy.

3 CROSS-EXAMINATION

4 BY MR. JACOB:

5 Q. Good afternoon. Bryan Jacob for Southern
6 Alliance for Clean Energy.

7 THE PANEL: Good afternoon, Mr. Jacob.

8 Q. It's possible that you heard a conversation I
9 was having with Mr. Abramovitz this morning, so I'm going
10 to actually start there. Your testimony included --
11 referenced some actions that the company and Commission
12 could take if the new load ends up being lower than your
13 forecasting. And you said that you might reduce the
14 target capacity that would be procured in one of the
15 future RFPs, and you specifically illustrated the current
16 All-Source RFP.

17 A. (Witness Grubb) That's right.

18 Q. What other RFPs that have already been
19 approved might be impacted in that scenario?

20 A. (Witness Grubb) So that's mainly it, and I
21 say that from the standpoint of the CARES or renewable
22 RFPs. While we've had some discussion, there are some
23 capacity equivalences that could come out of there, the
24 CARES megawatts are approved by the Commission. We would
25 not adjust those megawatts. So if we're doing

1 2100-megawatts of utility scale solar through CARES, we've
2 got the rollover from CRSP.

3 We won't procure those megawatts regardless
4 of what happens with loads because those are about
5 megawatts for energy resources. We may get some capacity
6 value out of those, as Mr. Kaduk put in his testimony, we
7 will see when we get there. We would reflect that going
8 down the road. Capacity RFPs are the ones that allow you
9 to do that flexibility. So the All-Source could change
10 based on what comes out of CARES, what comes out of the --
11 this filing, what comes out of load changes. So it would
12 really be more of the capacity ones that we would look
13 adjusting, not the solar ones.

14 Q. Okay. So I think you're answering the other
15 question that I asked him which was, can you assure us
16 that the total renewable procurements will be the same or
17 higher if this resource portfolio gets approved?

18 A. (Witness Grubb) We were ordered by the
19 Commission in the '22 IRP to procure 2100-megawatts of
20 utility scale, 200-megawatts of EG. We rolled over the
21 CARES, and so that RFP has approved those megawatts. We
22 will move forward with procuring those renewable
23 megawatts.

24 Q. Okay. I'll actually come back sequentially.
25 But I want to jump ahead to page 40, lines 2 through 4

1 now. I'll let you get there.

2 A. (Witness Grubb) Okay. 40, 2 through --

3 Q. 2 through 4, where you say that: Updated
4 modeling for the 2023 IRP indicates that adding up to
5 approximately 10,000-megawatts of new renewable resources
6 by 2035 can provide economic benefits for customers.

7 A. (Witness Grubb) That's right.

8 Q. And you're not asking for approval of
9 10,000-megawatts in this filing?

10 A. (Witness Grubb) No, we aren't. And what you
11 probably recall from the 2022 IRP is we -- by that time,
12 we estimated around 6,000-megawatts by 2035. The 2100 or
13 so of that we got approval specifically to do. We would
14 come back in following IRPs for the rest. So in the next
15 IRP, we will reflect what those are that will drive the
16 solar procurement.

17 So this was -- we ran expansion plans for
18 this case. It showed more solar in those expansion plans
19 than it did in the '22 IRP. So we're just saying that
20 there's an indication that there's even more economic
21 benefit for solar to continue to be a part of it. So no
22 request in this case, since it's about capacity resources,
23 just indicating in the '25 IRP, we'll likely see a
24 stronger signal for continued solar than we saw out of the
25 '22.

1 Q. But in those mitigation scenarios that we
2 were just discussing, could approval of the fossil
3 resources in this IRP update in any way deduct from that
4 10,000-megawatts of renewables by 2035, if the load
5 doesn't materialize?

6 A. (Witness Grubb) I don't think so, Mr. Jacob,
7 from the standpoint of when we run those expansion plans,
8 we will incorporate the capacity resources. But we put
9 solar in there, not from a capacity standpoint, but from
10 an energy standpoint. So the IRA and those assumptions
11 will still drive those renewable numbers. And so when you
12 think about that production cost model, it looks at solar
13 as energy. It looks at the capacity resources as serving
14 it, so it will evaluate it.

15 Nothing out of this case should drastically
16 change the renewable signal in those models, and with more
17 load you may even see it somewhat higher. I can't promise
18 that, but we'll capture all of that, but I don't think --
19 there's some weird, really detailed modeling thing where
20 they may impact each other, but overall I would not expect
21 the capacity decisions out of this IRP update to change
22 the renewable signal very strongly, if at all.

23 Q. Okay. Back to page 28 of the prefiled
24 rebuttal testimony, I'll give you time to get there.

25 Okay. So let's see. It would be line 12 to

1 16 or so. You mentioned something about a delay in
2 finalizing the contract with the independent evaluator,
3 and that that led to the company issuing the RFI on its
4 own back in September of last year. Can you elaborate on
5 what caused that contract to be delayed?

6 A. (Witness Grubb) Yes. So it was just some of
7 the discussions we had with staff last year, working
8 through the RFPs and the expedited RFP. There was just --
9 there were some nuances in the contract. We use that IE
10 for a lot of our RFPs, and there was some concern that you
11 may not be able to have that IE on RFPs if we used it on
12 the RFI. So we were just trying to work through that with
13 staff.

14 It was just easier to just go and do it on
15 our own. But it doesn't really change the nature of the
16 RFI at all, in terms of what we would have done had we
17 worked with staff on it. It would have been looking for
18 the same, similar information. But it was just a nuance
19 that we were trying to work through, and we were losing
20 some time. We wanted to see if there's any marketing
21 resources out there, and so we just went ahead on our own.
22 But doesn't change the nature of the RFI or the purpose
23 that it served.

24 Q. Did the delay in any way also delay when you
25 filed this IRP update?

1 A. (Witness Grubb) It did not. When we looked
2 at -- I mean, we had initial discussions with the staff
3 and the Commission in August on what we were looking at
4 for this IRP update, in general. Because as I've said,
5 when we saw the need year move, we immediately went to
6 system length and what we could get there, existing
7 marketing resources.

8 The RFI helped us see if there was anything
9 out there that we didn't know otherwise. We had market
10 intelligence through our wholesale entities, our
11 operations guys. We knew the market activity just through
12 publications and those types of things, so it wouldn't
13 have changed our timing. The timing was driven by the
14 need to get here as soon as we could to help identify the
15 resources, but we had to have resources.

16 So whether the RFI would have been a few
17 weeks earlier or a few weeks later, I don't think it would
18 have changed our timing at all. And that RFI provides us
19 a lot of good information outside of this update, gives us
20 a lot of good information for the next All-Source RFP, as
21 well.

22 Q. So I'm now on page 31 of the prefiled
23 testimony around line 10.

24 A. (Witness Grubb) Okay.

25 Q. You've got some very precise and quantified

1 assertions regarding the impact of the reserve margin.
2 For example, on page 31 you claim that, quote, Lowering
3 the reserve margin to 20 percent would result in an
4 80 percent increase in the likelihood the company would
5 need to shed firm load.

6 A. (Witness Grubb) Yes, that is correct.

7 Q. So is that from a reserve margin study from
8 back in 2021, or has that been updated?

9 A. (Witness Grubb) Yeah, it's the '21 reserve
10 margin study that was filed in the '22 IRP, and that's a
11 reflection of 20 percent being a 1-in-10 loss of load, and
12 26 percent being 1-in-18 year loss of load. So you have
13 an 80 percent increase in reliability, in terms of a less
14 frequently predicted event, so that's all out of the '21
15 reserve margin study filed in the '22 IRP.

16 A. (Witness Robinson) And a reminder, if you
17 apply that 20 percent to December of '22, that 80 percent
18 becomes a hundred percent.

19 Q. So that was the Winter Storm Elliott?

20 A. (Witness Robinson) Correct.

21 Q. Okay. Got it. Is that 2021 reserve margin
22 study also the source of the testimony that you have from
23 page 31 where you say: With a 20 percent target reserve
24 margin, the company would have twice -- would be twice as
25 reliant on interruptible loads and would expect higher

1 generation production costs and purchase power costs?

2 A. (Witness Grubb) That's correct.

3 Q. Same? Okay.

4 A. (Witness Grubb) That's right.

5 Q. Now, this takes me back a few pages to 29.

6 You've got a comment that planning to a lower target
7 reserve margin, like the 24.5 percent recommended by PIA
8 staff, reduces system reliability and does not provide
9 substantial cost savings. Can you be more precise about
10 those, like how much reliability reduction and how much
11 cost savings?

12 A. (Witness Grubb) So it would be -- it would be
13 in that same study, so when we look at those reserve
14 margins, if you think about the old bathtub curve in the
15 IRP, right, it's capturing reliability costs, production
16 costs, purchase costs, and then the cost to build it. So
17 it's that combination of those costs is what we're
18 referring to there.

19 Q. So the 24.5 percent reserve margin level is
20 identifiable in that prior study?

21 A. (Witness Grubb) Subject to check, but yes.
22 It should be in all those different -- either in our
23 reserve margin study or staff's testimony. It should be
24 somewhere in there. Probably in the study. I just can't
25 remember exactly how many increments we give all that data

1 in, but it should be in there.

2 A. (Witness Robinson) And if you apply the
3 24.5 percent to December of '22, you're shedding load.

4 Q. All right. Different subject altogether.
5 I'm now on page 44 of the prefiled.

6 A. (Witness Grubb) And we're totally good to
7 keep changing pages. If you just let us know where you're
8 going, we're good. No need to apologize about flipping.
9 We're good.

10 Q. Okay.

11 A. (Witness Grubb) Yeah, we're good.

12 Q. So what can you tell about the VPP programs
13 that you're evaluating for the 2025 IRP?

14 A. (Witness Evans) We're under -- in the early
15 stages of investigating what value those might bring, with
16 the different use cases, the different pros and cons of
17 design and what value streams they unlock, and how to
18 appropriately set up the program to maximize that benefit
19 that they could potentially bring to the system for all
20 customers.

21 Q. What would the programs be? Like, for
22 example, in the stipulation today, we see -- I think it's
23 point number 17 has the behind-the-meter solar and
24 storage. Is that one of the programs that you're talking
25 about?

1 A. (Witness Evans) That is absolutely one of the
2 programs we're talking about.

3 Q. And would it also include the DER customer
4 programs that had previously been filed?

5 A. (Witness Evans) Those are already filed, so
6 we weren't talking about those as being things that we're
7 actively developing; right? I mean the term "virtual
8 power plant" I think has different meanings to different
9 people; right? I sometimes joke that if you ask 10
10 people, you're going to get 12 different definitions of
11 it.

12 So in this context we did mean dispatchable
13 behind-the-meter customer-sided programs that were not
14 currently offered; right? I think in some definitions our
15 current thermostat could be viewed, and I do, as a type of
16 a virtual power plant program. So we're expanding that,
17 but we are looking at new types of programs to put under
18 that umbrella to offer customers.

19 Q. All right. Let's see. Mr. Dunbar asked you
20 some questions earlier today about the 70 percent
21 ownership requirement, and actually, I wanted to give you
22 an opportunity to maybe even revisit an answer that you
23 gave about North Carolina.

24 Mr. Grubb, I believe you said that Duke is
25 required to own a hundred percent of its new renewable

1 energy?

2 A. (Witness Grubb) That's what we put here, and,
3 again, we didn't do a national search. I mean, it says:
4 Provides for all new resources to be company owned. But I
5 think that --

6 Q. Were you perhaps talked about wind resources,
7 onshore and offshore wind?

8 A. (Witness Grubb) I don't think it was just
9 wind.

10 Q. If you had been asked a question about solar,
11 would your response have been that Duke would be required
12 to own 55 percent and independent power producers would
13 have to own 45 percent?

14 A. (Witness Grubb) Yes, so line 5 says: Except
15 for 45 percent renewables and storage. So I think that's
16 55 percent. The other side would own the rest. So again,
17 I don't know all of the details on the North Carolina one
18 with Duke, but, yeah, I think what we say here is:
19 Provides for all new resources to be company owned except
20 for 45 percent renewables and storage.

21 Q. Okay. I just thought the record from earlier
22 might have been a little bit confusing.

23 A. (Witness Grubb) Well, yeah. I don't know it
24 in full detail, so that could have been the case.

25 Q. Well, so you offered the examples of Virginia

1 and North Carolina, and I think, as was already
2 established, those pertain to renewables only. So is that
3 your understanding of how the 70 percent rule in Georgia
4 should be applied, as well?

5 A. (Witness Grubb) No. What we were saying
6 here -- and again, on North Carolina, I thought they had
7 some ownership on non-renewable resources, too, but
8 subject to check. I don't know that. But what we were
9 doing here was just pointing to -- there were other
10 jurisdictions that have some sort of a ownership
11 percentage on resources. Not saying it's directly tied to
12 ours. We actually -- our 70/30, the way we do the math is
13 based on capacity equivalence of the fleet and so
14 renewables are not -- they're a small contributor to that
15 because of our ELCC. So we do the 70/30 based on capacity
16 equivalence. So if we were to show nameplate, then our
17 30 percent would be a lot larger because of the solar --
18 instead of 5000-megawatts of solar, in the math, we're
19 lower than that because we're showing the capacity
20 equivalence of it because it's a reliability number in our
21 interpretation.

22 Q. I think maybe you ventured an answer to this
23 earlier, but can you provide examples of other
24 jurisdictions that apply an ownership percentage like that
25 to traditional combustion resources?

1 A. (Witness Grubb) We did not do a national
2 search, so we would have to investigate that more.

3 Q. All right. Let's see, I'm on page 45,
4 rolling into 46, as well. You indicate that the company
5 is not requesting Commission approval of the eight
6 listed -- the eight transmission projects listed in the
7 transmission supplemental filing. So if you're not asking
8 for permission for those transmission projects now, when
9 do you plan to request that approval?

10 A. (Witness Robinson) So this is typical of how
11 we handle transmission projects associated with resources
12 and our IRP filings. We ask for portfolio projects -- as
13 far as rate recovery, for those to be brought back in the
14 rate case. But as we iterate our planning process, those
15 projects may change. Project may move out, or we may find
16 a better solution, and so as we go through the yearly
17 planning process, we will update that. And it will be
18 updated in the '25 IRP, as well, as far as the
19 transmission projects that are necessary for the Yates
20 CTs.

21 Q. What is the current cost estimate for those
22 transmission upgrades?

23 A. (Witness Robinson) Right at \$59 million.

24 Q. And just to get clarity on this, which also
25 came up earlier, in the stipulation, point number 12,

1 where you're saying that you would not seek cost recovery
2 of any project -- of any project construction costs that
3 exceed the proposed project construction costs in the
4 company's January 31, 2024 application for certification,
5 other than acts of God. Are those transmission costs
6 included or excluded from that?

7 A. (Witness Robinson) The 59 million is not in
8 that certification, but the interconnection costs
9 associated with -- transmission costs, which is associated
10 with interconnection, is in that certification.

11 Q. All right. So you will -- will the actual
12 requests for those projects be part of the 2025 IRP
13 filing?

14 A. (Witness Robinson) What we're asking for is
15 approval of the portfolio of projects in this IRP filing,
16 which is what we typically do, as I mentioned before, in
17 our IRPs, as it relates to resources. Cost recovery of
18 such will come through the rate case, which will be filed
19 next year. Also a reminder, not all these projects are
20 Georgia Power projects. There's one or two, subject to
21 check, that's actually Georgia Transmission Corporation
22 and responsibility of their budgets to go and make that
23 happen.

24 Q. I guess I'm confused by the Q&A on page 45
25 and 46, then. Is the company requesting Commission

1 approval of each of the eight projects listed in the
2 transmission supplemental filing? The answer is no, but
3 you're saying that you're asking for approval of a
4 portfolio of things?

5 A. (Witness Grubb) That currently is those eight
6 projects. That's right.

7 A. (Witness Robinson) That's correct. We are
8 not asking for specific approval line item by line item
9 with eight projects. We're specifically asking for
10 approval of the portfolio of projects, which could change
11 over time, and is likely to change. That happens often,
12 where a project moves in, moves out, or we find a better
13 solution that's more economical or is more reliable, as it
14 relates to the constraints identified in the Yates CT
15 studies.

16 A. (Witness Grubb) So, again, approval for those
17 projects as we build and develop Yates. And if they
18 change, whatever projects those end up becoming would go
19 through ASR, or the rate case, for cost recovery of those
20 projects. The specific projects that are known at that
21 time.

22 Q. Okay. Let's see on page 48 starting on
23 line 6 you say that: Given the time constraints in this
24 case, the company is unable to explore all the options
25 typically available for a given transmission constraint or

1 a deficiency as part of the transmission analyses. Were
2 you required by the Commission to file this IRP by a
3 certain date?

4 A. (Witness Grubb) No. We've been clear. We
5 filed this IRP update to be able to accommodate the
6 additional new load from economic development, and to
7 support growth in the state, deploy the resources to serve
8 it, and put downward pressure on rates. So we were not,
9 but it was -- we do need to know the transmission aspects
10 of those resources to know that we truly can deploy them
11 to serve that load and so that's why we did the
12 transmission screening.

13 A. (Witness Robinson) But I will remind you, we
14 do have an interim process, so we continue to study the
15 transmission system. If we identify a better solution,
16 then we will bring that forward. We will choose that
17 solution. We do that through our annual process with the
18 integrated transmission system partners. We jointly plan
19 the system, and then we approve the plan. The ten-year
20 plan that's filed every year with the Commission is our
21 plan, it's an ITS plan. So it's not that those projects
22 are set in stone. That's why we're asking for a portfolio
23 of projects associated with, because they could change and
24 likely to change. That does happen as the load flow
25 models change moving forward.

1 Q. How much extra time would it have taken for
2 you to explore non-wires alternatives?

3 A. (Witness Evans) Well, we did look at some
4 non-wire alternatives as it relates to redispatch,
5 operating guides, other types of non-wire alternatives or
6 what we call -- new technology, I believe, is the way it's
7 referred to in the ten-year plan. So those were
8 identified. But to do -- and please, for my edification,
9 so I can answer the question, what do you define as a
10 non-wire alternative that we did not look at?

11 Q. Well, there were -- am I allowed to answer?

12 A. (Witness Grubb) Just seeking clarification
13 on.

14 A. (Witness Robinson) Just to seek
15 clarification.

16 Q. There were recommendations by some of the
17 transmission witnesses in the last round for a variety of
18 things, grid enhancing technologies, dynamic line ratings,
19 various things of that sort.

20 A. (Witness Robinson) Right, I think we did
21 address in our testimony the application of the dynamic
22 line ratings to long-term planning. I think we were very
23 specific about that. As far as batteries for solutions --
24 or solutions to transmission, we gave three very good
25 reasons why that's not a workable solution. But the

1 overall reason is cost. You're talking about eight
2 projects where you're having to inject, for contingency,
3 hundreds of megawatts onto the system to solve for those.

4 Now, you look at the hour -- the hours that
5 you need that battery available for that contingency, and
6 having to build that, that is extremely expensive. So you
7 look at the life -- we talked about life cycle
8 replacement. A reconductor will get you 40 years
9 additional life. A rebuild of a line will get you 80
10 years, because you're replacing all the structures and the
11 conductor.

12 If you've got a battery system that you're
13 deploying, or a transmission constraint, it's going to sit
14 there and float most of the time. It's very unlikely that
15 it's going to discharge for that contingency, because that
16 contingency doesn't happen a lot. Now, we would discharge
17 it for maintenance purposes, but you have to be careful
18 there because if you discharge it and you have a
19 contingency, then you don't have your battery for your
20 contingency.

21 So if you look at the life cycle cost of the
22 battery, 10, 15, 20 years, say, 20 years, and you've got a
23 project that's a wire project that's 40 years, so you've
24 got to replace that battery system twice or a rebuild of a
25 line that's 80 years, so now you have got to replace that

1 battery system four times. And looking at the net present
2 value, we don't have to do an exhaustive analysis on
3 the -- what you would choose, on a battery system versus a
4 reconductor.

5 And just a reminder to the Commission, we
6 brought forward in this case 3300-megawatts of a portfolio
7 of projects as far as resources, but only \$60 million
8 worth of transmission. That is miniscule. That is \$18
9 per KW. And I think Mr. Bush would testify, as a
10 developer, that's not a lot of transmission at all. So I
11 think a lot of the intervenors treating it like it's a big
12 number. It's really not a big number. So we are bringing
13 forward very traditional solutions that we can make happen
14 in that period of time.

15 Now, if we study -- next year, we determine
16 that a Series Compensation device may be a better
17 solution, we will choose that. But in the meantime, as we
18 were doing studies for this, it made more sense to choose
19 the projects that we did. They were more economical, we
20 could get them done in the time frame, to get them done
21 for the units that we were proposing.

22 Q. So I'm still having a hard time now
23 reconciling the way you answered the question in the
24 prefiled versus the way you're answering it now, because
25 it's in the context of considering non-wires alternatives.

1 And it says: However, given the time constraints in this
2 case, the company was unable to explore all the options
3 typically available for a given transmission constraint or
4 deficiency as a part of the transmission analysis
5 supporting the resource request.

6 A. (Witness Robinson) Well, so, we were, like,
7 like Series Compensation. But for batteries, I did that
8 analysis here in front of everybody. And so there's not
9 an exhaustive study that needs to go along with that. You
10 can do it in your head. It's just not economical. It's
11 ridiculous, the cost of batteries to these solutions that
12 were proposed from a transmission perspective. So it's
13 not that you have to have a full-blown study. You can do
14 qualitative analysis on some of these things and say, this
15 is just not a good solution right now and come back at a
16 later time, there may be a better technology to deploy,
17 and we will do that in the annual process we have. But as
18 it relates to these studies, we did have a quick
19 turnaround, and so we did use more traditional type
20 solutions. But we also looked at redispatch and other
21 solutions that are non-wire alternatives.

22 Q. Could the portfolio that you're requesting
23 have been different if you had the extra time?

24 A. (Witness Robinson) I --

25 A. (Witness Grubb) The portfolio of transmission

1 projects or the -- transport generation.

2 Q. And even capacity generation resources?

3 A. (Witness Robinson) So I will remind the
4 Commission that this is 3300 megawatts of resources that
5 we've identified with only \$60 million worth of
6 transmission. That is amazing. And that is a testament
7 to the proactive nature of our planning process. So we're
8 working with resource planning looking at these
9 opportunities, knowing that we can sign these PPAs,
10 knowing where these units are, knowing what the
11 constraints are, and being able to bring forward a
12 portfolio of projects with a minimum amount of
13 transmission associated with them to make them happen.

14 Q. Earlier today, Advanced Power Alliance put a
15 SERPT document into the record, and it somewhat validates
16 what you're talking about. I'm assuming you're familiar
17 with it. There's about a hundred million dollars' worth
18 of north -- South Georgia to North Georgia corridor. Do
19 you recall how much capacity that could transmit?

20 A. (Witness Robinson) So that's -- so you have
21 to understand the context of that study, and by the way,
22 the filing was not the full report. The full report is
23 141 pages long. It was just an excerpt on one study that
24 Sierra asked for in the stakeholder process. So it was
25 1600 megawatts from South Georgia to Atlanta, or North

1 Georgia, for 2028 only. And so we did identify
2 \$96 million worth of upgrades that were needed, or
3 projects that were needed, in 2028.

4 But also provided in that document was a list
5 of overloads, or close to being overloads, like 95 to a
6 hundred percent, in time, as load grows on the system, are
7 going to become problems. So you can't look at it just
8 one year. You really need to look at it on the planning
9 horizon. If you're looking at the planning horizon, that
10 cost is going to be significantly more.

11 The other thing that's not in that study is
12 the load that we're talking about here, the additional
13 6600-megawatts of loads that we've got to serve in the
14 Atlanta area by 2030. And so as you add that, that number
15 is going to go through the roof, as it relates to that
16 \$96 million that was identified.

17 So going back to the 2022 IRP, the North
18 Georgia Reliability and Resiliences Plan that we proposed
19 was envisioning this point in time, proactively, in 2035,
20 where we've retired our coal units, and we've got now
21 14,000 megawatts of solar in South Georgia. How do we
22 make that happen? And so the North Georgia Reliability
23 Plan has in there a proactive study looking at solar
24 sensitivities and what corridors we would need to go
25 address and build to make those megawatts flow from South

1 Georgia to North Georgia. And we've got a meeting with
2 Commission staff tomorrow to update them on that. We are
3 making very good process on that study.

4 But one of the things we're looking at --
5 we're not looking at 1600-megawatts in one year. We're
6 looking at 6,000, 8,000, 10,000-megawatts of transfers
7 from South Georgia to North Georgia in all years of the
8 planning horizon. So when you look at all years of the
9 planning horizon, and you're talking about the solar that
10 we need to do and make happen by 2035, you're talking
11 about billions of dollars' worth of transmission, not just
12 96 million in one year.

13 Q. All right. I'm still with a few
14 transmission-related questions. I'm looking at page 49,
15 and found it interesting that in your rebuttal about
16 dynamic line ratings you indicated it would be:
17 Impossible, as a quote, to predict solar irradiance many
18 years into the future. Has it been your experience that
19 solar irradiance in Georgia has changed significantly over
20 long periods?

21 A. (Witness Robinson) On a cloudy day, yes.

22 Q. Over long periods?

23 A. (Witness Robinson) No. But on a cloudy day
24 it changes from day to day. If you've got a sunny day and
25 a cloudy day, solar irradiance is different. And so if

1 you've got a transmission line that has a certain rating
2 on a sunny day versus a cloudy day, the loading on the
3 line may be the same.

4 Q. The quote is: These benefits occur in real
5 time or near real-time conditions, however, which make it
6 inappropriate to use DLR capabilities as a long-term
7 planning solution because it's impossible to know when the
8 wind will blow.

9 A. (Witness Robinson) Right. Correct. And we
10 are looking at dynamic line ratings and the software and
11 the technology to unlock operational benefits, looking at
12 bridging caps to long-term solutions. The DLR is not a
13 long-term planning tool. It is not. It relies on how
14 fast the wind is blowing, how much sun is shining, and
15 it's not just where your load is. It could be anywhere in
16 the state. And so you look at this time in 2030, 2035,
17 where we've got 14,000-megawatts of solar in South Georgia
18 and continuing to grow in Atlanta, you could have a
19 thunderstorm in South -- well, let's not a good example,
20 because all your solar's out. But you could have a
21 thunderstorm in middle Georgia, where your lines are, and
22 your characteristics of your line are different because of
23 weather.

24 You can't predict that ten years from now.
25 You cannot rely on dynamic line ratings for a long-term

1 transmission planning project, because we plan to NERC
2 Reliability Standards. That project that you build has to
3 be there, it has to perform, and you can't do that on
4 probabilities. DLR, that's exactly what it does. You
5 would be using dynamic line ratings five, ten, seven years
6 from now and making predictions on how much sun is
7 shining, how fast the wind is blowing, and other things to
8 factor in.

9 Now, we are interested in DLR, and we use
10 Ambient Adjusted Ratings in our models, as we mentioned in
11 testimony, too, but DLR is not ready for prime-time,
12 long-term planning.

13 Q. So let's go there, because you go talk about
14 Ambient Adjusted Ratings on page 49. Can you explain the
15 difference between those and dynamic line rating?

16 A. (Witness Robinson) Sure, Ambient Adjusted
17 Ratings, we have a program that we use, that we reference
18 here, which is called Dynam, that we use in the operations
19 world where we adjust the ratings of our lines based on
20 certain factors, including real-time temperature. So we
21 know what the temperature is in Macon. We know what the
22 temperature is in Savannah, and so we apply an aggregate
23 temperature to those line ratings.

24 And then we also plan to a two-mile-an-hour
25 wind, so we assume a two-mile-an-hour wind in those

1 ratings. And so that allows an operator -- so say the
2 line is rated to a hundred amps. But when using Ambient
3 Adjusted Ratings, an operator can use that tool and
4 calculate that maybe we can get an additional 25-megawatts
5 out of that line in real time. And so we will be able to
6 do that and adjust the rating of that line in real time.

7 Now, we do it for off-peak and long-term
8 planning, and that's just really looking at the different
9 temperature ratings. So instead of being on peak where
10 you're planning to 95 degree, you've got an off-peak and
11 assuming a temperature of, say, of 70 degrees. And so you
12 would adjust the rating of your line for off-peak planning
13 purposes.

14 Q. And you're saying that, within the company's
15 transmission planning processes, the company leverages AAR
16 as a bridge to permanent solutions where appropriate. Is
17 this filing proposing AAR as a solution for the identified
18 load growth at all?

19 A. (Witness Robinson) No. Because we already
20 use AAR.

21 Q. Why did the rebuttal not address the
22 recommendations for reconductoring existing transmission
23 corridors with advanced-high-performance conductors?

24 A. (Witness Robinson) That's already a tool that
25 we look at. It is expensive. It's more expensive than

1 traditional conductors. In fact, I've got a piece of it
2 here that we've used in the past. This is called ACCR, so
3 this is aluminum conductor, ceramic reinforced. So the
4 core of it is ceramic. You can get this conductor over
5 200 degrees ambient temperature or -- not ambient
6 temperature, but the operation temperature, and you can
7 get more current through it, but it's expensive to do.
8 And so you need a real expensive project to choose, to
9 defer, to use this technology, and we've used it before.
10 There's plenty of examples where we've chosen advanced
11 conductors and ACCR to rig it up to our line.

12 COMMISSIONER PRIDEMORE: Can I look at that?

13 MR. ROBINSON: Sure. May I approach?

14 COMMISSIONER PRIDEMORE: How many of these do
15 you need on a single line?

16 MR. ROBINSON: So this is just to replace the
17 existing conductor. So where we've used this -- so
18 where the normal conductor would have steel in the
19 center, this has ceramic core, and so it doesn't
20 stretch it as much when it heats up. And so you
21 can get less sag out of it.

22 The other thing that this has is trapezoidal
23 wire. I think I mentioned that in previous
24 testimony. Where a normal wire is round, this wire
25 is trapezoidal, so it fits together better. And so

1 what's called "skin effect," you get the
2 efficiencies out of skin effect, and you get more
3 ampacity out of your line.

4 But this wire is a lot more expensive than
5 normal wire. Where we've used this before, like in
6 Savannah, where we had the old box towers and a
7 very tight right-of-way, so we were able to
8 reconductor that line with this conductor using
9 existing box towers and the same right-of-way. If
10 we would have used normal, we would have had to put
11 larger towers in to keep the belly of the conductor
12 off the ground. And so this saved us a tremendous
13 amount of dollars in Savannah on a project that we
14 had.

15 We would definitely choose this if it was
16 economical. But for what we're talking about now,
17 \$60 million worth of reconductors, we wouldn't have
18 chosen this.

19 CHAIRMAN SHAW: That's what I would have
20 done.

21 BY MR. JACOB:

22 Q. A lot of your rebuttal testimony focused on
23 the interveners that were proposing long-term 500 KV
24 transmission solutions. But local area constraints,
25 including those around Yates CT, could be addressed by

1 reconductoring existing voltages with advanced conductors;
2 correct?

3 A. (Witness Robinson) Correct. That's what I
4 just spoke of in the project that we did in the Savannah
5 area.

6 Q. But the company's filing and supportive
7 documentations in this case don't provide any analysis
8 around reconductoring at that 230KV voltage for Yates CTs;
9 do they?

10 A. (Witness Robinson) The projects that we've
11 identified are reconductors of 230 and 115.

12 Q. Within those eight that we were talking about
13 earlier?

14 A. (Witness Robinson) Hold on a second.

15 Q. 230KV rebuild, that's a reconductor and a
16 rebuild of structures. Switch replacement, that's just --
17 I'm trying not to be -- to say too much.

18 A. (Witness Grubb) It's trade secret. Yeah.

19 A. (Witness Robinson) The projects are trade
20 secrets --

21 A. (Witness Grubb) Generally, you're fine. The
22 types, you're absolutely --

23 A. (Witness Robinson) Switch replacement is
24 increasing the ampacity of a switch. 115KV line rebuild
25 is upgrading the conductor or reconductoring as well as

1 replacing structures. 115KV rebuild, same thing. 230KV
2 rebuild and jumper replacement. 115KV rebuild. 230KV
3 reconductor, and a 230KV rebuild. And the rebuild, what
4 that is, is a lot of these lines were constructed in the
5 '70s and '80s, and so they were built to a certain
6 National Electric Safety Code standard.

7 And that changed about 20 years ago, where
8 they changed the ice and wind loading requirements for the
9 Southeast. And so when you touch a project like that,
10 where you rebuild a reconductor, you now have to take into
11 account heavier ice loading and more wind, and so that
12 requires, typically, structure change out. So when you
13 see a rebuild, that's usually what is -- we're putting
14 more -- a bigger conductor in, and we're having to go and
15 replace pretty much every single structure.

16 Q. So the reconductoring there, maybe we
17 misinterpreted it to be reconductoring in conventional
18 conductors. Are any of those using the advanced
19 conductors like you just passed around?

20 A. (Witness Robinson) No. Because we did not
21 choose them. They're part of our portfolio, but we did
22 not choose them because of the expense.

23 Q. Okay. Page 51, you're stating that: Georgia
24 Power builds transmission as needed to deliver power from
25 facilities that have been sited, financed, and have

1 initiated process of interconnecting to the system. So am
2 I correct in interpreting that to mean that you plan your
3 transmission after determining where generation resources
4 are already being sited?

5 A. (Witness Robinson) Absolutely not. We do
6 that in a very proactive manner, working with our resource
7 planning team, looking at siting and resources in the
8 future. We're informed by our interconnection queue, so
9 looking at our OASIS queue, GTCs, OASIS queue. We work
10 with GTC and MEAG on their resource assumptions, and so
11 all of that goes into our planning model, and so we are
12 building for the future using all of those assumptions.

13 Now we've gone beyond that with the North
14 Georgia Reliability and Resiliences Plan, saying we
15 envision this future. Where you retire coal in '35, and
16 you're adding 14 -- well, 14,000-megawatts of solar in
17 South Georgia, if we're not able to get some of it to
18 North Georgia.

19 We know that because that's where the
20 requests are, so we're informed by our OASIS queue on the
21 request of where all the solar is going. And so we've
22 identified proactively these studies, to go look at these
23 corridors, and where we build transmission in the future
24 to bring those megawatts from South Georgia up to North
25 Georgia to serve the load.

1 Q. I get how the process works that direction.
2 I guess what I'm looking for is, are there scenarios where
3 the transmission plan then informs where generation should
4 be sited?

5 A. (Witness Robinson) In any vertically
6 integrated process, that happens. And so there's
7 conversations that happen all the time with generation
8 development resource team on a siting of -- that also
9 happens -- could happen throughout the SERTP process, this
10 IRP process, as we study and make assumptions. But, you
11 know, that is the benefit of having a vertically
12 integrated planning process and working with an IRP in
13 front of the Commission in a constructive manner like we
14 do, bringing all that together and planning it proactively
15 for the future.

16 Many companies in deregulated markets don't
17 do that anymore, and that's a lot of the frustration that
18 you hear in these conversations about transmission not
19 being built, is because they don't have the signals. So
20 Mr. Bush has the signal of when and where to build
21 transmission. We have the signals of -- sorry, when and
22 where to build resources. We have the signals on when and
23 where to build transmission.

24 Those utilities in those areas -- and I have
25 conversations with many of my peers about this very

1 thing -- they would love to be Georgia Power Company.
2 They would love to have our vertically integrated process,
3 planning generation, transmission, distribution altogether
4 in front of this Commission through an IRP process in a
5 constructive manner. And I've got plenty of examples
6 where I've had peers that tell me whether they're in ISO
7 or New England ISO: I would kill to be you and to be able
8 to do what you do. And that's build transmission.

9 Q. Mr. Robinson, I think only one more question
10 for you, and then we can zoom out and let some other
11 people get more involved. So I heard one of your
12 responses, when you were talking with Mr. Dunbar earlier
13 today, that -- about the customers bringing their own
14 resources, and that they would have to be curtailable
15 unless they were completely dispatchable. Did I
16 understand it correctly?

17 A. (Witness Robinson) What I was referring to is
18 you would have to have reliability considerations in any
19 kind of construct. What Mr. Dunbar was talking about, I
20 believe he was talking about sleeving PPAs, and if your
21 only resource is that PPA, if you're not relying on the
22 company resources to fill in the gaps, then you would
23 either be -- if you're relying on that PPA a hundred
24 percent, if that PPA's not there, you're curtailed.

25 Or you would have to have some type of

1 construct to rely on the pool of generation, and that's
2 the issue. That's the difficulty that comes into that
3 whole situation is, we dispatch the system together. We
4 don't sleeve megawatts through our system from point A to
5 point B. And so reliability is key in that situation, and
6 that's what I was referring to, is those things we would
7 need to be considered.

8 Q. You weren't here for the first round of
9 hearings so...

10 A. (Witness Robinson) I watched some.

11 Q. Okay. Well -- and I had asked the other
12 panelists a question. I would love to get your take on
13 it, which was about the new CNI Curtailable Load Program
14 that's proposed, and how much capacity contribution you're
15 currently modeling that to deliver into this IRP update.

16 A. (Witness Evans) I think we answered that, but
17 I'd be happy to address it now. So the new CL program,
18 because we don't have any customers signed up for it, we
19 have not started to reflect any resources on the resource
20 ledger front. As customers are engaged, we will reflect
21 those, and they will defer future resources at that time,
22 just like we do with our current programs.

23 Q. So back to the conversation Mr. Dunbar was
24 having, you've got some customers who are interested to
25 bring in a sleeved PPA, and you're saying that, well,

1 unless it's completely dispatchable, they're going to have
2 to accept a curtailment. Well, you've got a lot of
3 customers that are coming in bringing no resources, no
4 sleeve PPA, entirely relying on the company's resources.
5 Can you also oblige them to take on a curtailable load?

6 A. (Witness Grubb) So to be clear, on the
7 discussion with Mr. Dunbar this morning what we were --
8 this afternoon, sorry. I'm usually in the morning so I
9 had to adjust there. When we're talking about a sleeved
10 PPA, Mr. Robinson was talking about a construct where it's
11 directly serving that customer. That's not how we do
12 things. So every resource on the system serves everybody.
13 And so when we talk about that sleeve PPA, we need to talk
14 about it from that standpoint.

15 So I think there's a little bit
16 misunderstanding this morning on which we were talking
17 about. I was trying to figure out which one we were
18 speaking of. The ones that can be done here in Georgia
19 would not be for a resource designated to customer, from a
20 megawatt hour provision standpoint. Can subscribe it, get
21 RECs, but any resource that's added to the system serves
22 everybody. So from that standpoint, we wouldn't curtail a
23 resource, because it's not serving a customer.
24 Mr. Robinson was speaking to, if you had that construct
25 where it was physically serving that customer, dedicated

1 to that customer, which we don't do.

2 So to your question, all the other customers
3 are coming and bringing resources. If they bring them, it
4 might be like the DER program or those types of things,
5 but it's still used for the system. So we would not
6 curtail their load based on a single generator. We would
7 only do it if we had to shed firm load, which we don't
8 plan on doing. So I hope I'm -- there's a distinction on
9 that sleeved PPA structure. We would be talking about the
10 one that serves everybody, not specifically dedicated to a
11 customer.

12 BY MR. JACOB:

13 Q Okay. Different line of questioning. I saw
14 a bunch of references to a pipeline, but I want to ask
15 about a different pipeline that you didn't mention.

16 What percentage of the Transco Southeast
17 Supply Enhancement Project will serve Plant Yates?

18 A (Witness Grubb) So we are not getting firm
19 transportation for Plant Yates. If we were to have some
20 of that firm transportation before we needed it elsewhere,
21 we could use it. But right now, none of it's specifically
22 allocated to Plant Yates.

23 Q Am I correct that Southern Company Services,
24 rather than Georgia Power, is responsible for 400,000
25 dekatherms per day in the pre-application that they put

1 forward to FERC?

2 A (Witness Grubb) That's right. And most of
3 that would be for future gas usage. If we had that gas
4 before we had other resources, we could use it at Yates.
5 But we are not getting that specifically for the Yates
6 CTs.

7 Q This is --

8 A (Witness Grubb) It depends -- it depends on
9 when we get them and other gas assets on the system.

10 MR. JACOB: Okay. A few questions on the
11 stipulation. And the first one, Mr. Chairman,
12 might actually be more of an administrative or
13 housekeeping matter. I will ask it as a question
14 first here.

15 BY MR. JACOB:

16 Q Support No. 12, you asked the Commission to
17 proceed with a hearing on the application for
18 certification of the Yates Units 8 through 10. That is
19 part of this same docket.

20 So the question is: At the end of the
21 proceeding today, is ex parte going to kick in since
22 there's another hearing envisioned in the same docket?

23 A (Witness Grubb) No.

24 CHAIRMAN SHAW: Yeah. Ex parte will kick in
25 as it relates to this IRP Update. That would be a

1 whole separate deal with the certification of
2 Yates.

3 MR. JACOB: So we can continue having
4 conversations about certification of Yates 8
5 through 10 without violating ex parte?

6 CHAIRMAN SHAW: There's plenty of lawyers
7 around here we can ask that to.

8 MR. GRUBB: Yeah. Not me.

9 MR. JACOB: One of them may be wanting to
10 contribute now.

11 CHAIRMAN SHAW: Go ahead.

12 MR. MARZO: Mr. Chairman, if I could -- and
13 I'm sure Mr. Bond can tell me if he disagrees with
14 what I'm about to say. I mean, so there is a
15 certification proceeding that is required by law to
16 take place with Plant Yates.

17 And as we filed this particular IRP Update,
18 we filed for both approval of Yates, and then later
19 certification is how we identified in our
20 additional filing.

21 So the way we understand the process will
22 work now is tomorrow there is a -- there is a fee
23 that would be put on in normal course for a
24 certification proceeding and that will cover Yates.
25 But if Yates is approved here, the certification

1 process was just necessary to follow with the
2 specific procedural things that we have to do in
3 that case.

4 So as it pertains to the ex parte, I think
5 maybe you're correct in terms of this is a separate
6 case about approval. Once approved, we have to go
7 through the process and procedure of the
8 certification application.

9 CHAIRMAN SHAW: And I agree with you.

10 MR. MARZO: Yeah.

11 CHAIRMAN SHAW: I mean, that's -- ex parte
12 will take place until this case is concluded.
13 Until we vote on it and then you have the order.

14 MR. JACOB: Shortly after the 16th?

15 CHAIRMAN SHAW: Right.

16 MR. JACOB: Okay.

17 BY MR. JACOB:

18 Q All right. The company originally stated
19 that it needed 200 megawatts of new solar with battery
20 storage; correct, in the original filing?

21 A (Witness Grubb) So we identified that
22 200 megawatts of storage, plus 200 megawatts of solar as
23 part of the initial 1000 megawatts of battery energy
24 storage. So it was -- it was a project that had to have
25 solar constructed to charge the battery versus the Robins

1 and Moody, which was existing solar.

2 Q But if the stipulation is approved, point
3 number 11 strikes that; correct?

4 A (Witness Grubb) As part of that -- what is
5 now the 500 for the first year of need. And it could be
6 bid into the RFP. But, yes, it is not approved without
7 going through an RFP, if that is the course we go down.

8 Q Which party negotiating the stipulation
9 pushed to have that provision removed?

10 A (Witness Grubb) I -- we don't speak to which
11 parties did what in the stipulation. We have an agreement
12 between the parties --

13 Q I could try.

14 Okay. So that -- well, yeah, jump -- jumping
15 to a slightly different take on that. Down to point
16 number 17, that deals with the residential and small
17 commercial behind-the-meter solar and storage.

18 Will that pilot be sufficiently sized to
19 backfill the 200 megawatts approximately of solar that is
20 no longer part of this package?

21 A (Witness Grubb) No. If you look at the
22 stipulation back to paragraph 7 and 8 and 9 cover the fact
23 that the 1000 megawatts that we asked for approval was not
24 approved. It's split, basically, for 500 in that '26/'27
25 time frame, which would be Robins and Moody and other

1 battery projects we identify. That had been that 200 as
2 part of that, but that's no longer part of it.

3 And then in -- you'll have an RFP to do the
4 remainder of BESS for '27 and '28. And so --

5 Q Sorry.

6 A (Witness Grubb) No, that's fine. I'm just
7 trying to speak through it.

8 So the RFP -- if we want to put that
9 200 megawatts through there, we can, but it's not being
10 directly replaced. The RFP will drive what does that.

11 Q How much solar and storage do you anticipate
12 in this behind-the-meter solar pilot with point number 17?

13 A (Witness Grubb) So that will depend on the
14 design of the program and what we see in the '25 IRP as
15 those capacity needs. And so, again, something we're
16 looking forward to working on.

17 We've been -- we've been thinking about these
18 types of projects. We've got -- we see a lot of potential
19 for them. But it's not going to change the request in
20 this case. This case would still be what we've got to
21 meet those first two years of need.

22 And then that third year of need would be met
23 by the 500 megawatt, or whatever it ends up being, in the
24 RFP. The RFP will be at the size that it needs to be.

25 So that could be driven more by some later

1 capacities. It's just going to depend on the design of
2 it.

3 Q Which will be -- go ahead.

4 A (Witness Grubb) No. You go ahead.

5 I'll come back. You go ahead.

6 Q Well, I was going to say: That design would
7 be informed, in part, by the two meetings that that
8 stipulation talks about with interested parties and staff.

9 But how will the interested parties be
10 identified and do they have to be signatories to the stip
11 to participate?

12 A (Witness Grubb) I don't know that they have
13 to be a signatory to the stip. I don't think they would
14 be. We hadn't figured out how to define it.

15 But, I mean, there's a lot of interested
16 parties. So we'll have to think through that.

17 But the point being that we see a lot of
18 potential for it. We know there's a lot of interest in
19 it. And so we'll work with staff and others -- the
20 parties to put together a program.

21 Q I'll end with a question that I also asked
22 Mr. Abramovitz earlier today about stipulation No. 21, the
23 evaluation of energy infrastructure reinvestment, clean
24 energy financing, and other types of opportunities for
25 federal funding.

1 What is the time frame for that? Will it be
2 in time for the 2025 IRP?

3 A (Witness Grubb) When -- when you say in time
4 for it, do you mean to -- to be asked for approval there?

5 Q Yeah. Is there any chance that that
6 stipulation is going to lead to something that we see in
7 the 2025 IRP?

8 A (Witness Grubb) So No. 21. It could. We --
9 we're already looking at program design for 2025 IRP. So
10 I think this will bolster those efforts.

11 MR. GRUBB: So I don't know if you've got
12 anything to add there?

13 A (Witness Evans) No. I agree.

14 I mean, obviously, any programs that we would
15 file in '25 that we could take advantage of this, we're
16 actively investigating that and we'll incorporate that
17 into the proposals that we put forward in the '25 IRP.

18 A (Witness Grubb) And I would say that I think
19 that would be our intent, at least the company's, because
20 there's a lot of interest in that.

21 A (Witness Evans) Yeah.

22 A (Witness Robinson) And that applies to the
23 IIJA, too. I think you asked some questions on that this
24 morning. And so we do have -- we're in phase -- or, yeah,
25 phase two of GRIP applications currently right now.

1 And so we did receive encouragement on five
2 of six of our filings that we made with DoE. So we're
3 determining which of those we're going to file coming up
4 here in the next month. I think there's two deadlines;
5 mid-April and mid-May.

6 So determining when we hear back on those
7 programs, they could inform the '25 IRP. We'll see on
8 timing. But we're -- we're really hoping that we get some
9 interest this time.

10 I think last time we made a couple of
11 applications -- us and the Southern Company, sister
12 companies as a whole, and we were not successful. But I
13 think the -- the -- on the IIJA, I think I saw less than
14 20 percent of the applications were approved on the first
15 phase.

16 And so we've -- we've learned from that
17 filing and we're -- we're applying that to the phase two.
18 And so hopefully we're going to be successful in getting a
19 couple of those awarded to us towards the end of this
20 year.

21 Q Whereas some of these provisions specifically
22 state that interested parties will be involved, invited to
23 engage somehow, is there an opportunity in stipulation No.
24 21 for interested parties to also be involved?

25 A (Witness Grubb) I mean, I think we're always

1 open and shown ourselves to be open to interested parties.
2 So I think we'd be open to discussions with customers
3 or -- or groups at any time.

4 A (Witness Robinson) Yeah, and we're -- we're
5 actually signed on to several phase two GRIP applications
6 where we're an interested party. And so we're working
7 with others, whether it's advanced conductor manufacturers
8 or neighboring utilities, on projects that are beyond
9 the -- the five to six that I mentioned before, so...

10 MR. JACOB: All right. Thank you very much.

11 MR. GRUBB: Thank you, Mr. Jacob.

12 MR. JACOB: No further questions. Thank you.

13 CHAIRMAN SHAW: All right. Next, Southern
14 Renewable Energy Association.

15 CROSS-EXAMINATION

16 BY MR. MAHAN:

17 Q Good afternoon, panel.

18 A (Witness Grubb) Good afternoon.

19 Q We're going into evening. I'm Simon Mahan
20 with the Southern Renewable Energy Association.

21 I want to start off by talking about -- on
22 your testimony on page 5, line 3, the company's been
23 selected to add an additional 2.6 gigawatts of new load
24 and existing customers are seeking to expedite another
25 2.1 gigawatts of new load.

1 And so that's -- that's another -- you know,
2 rough math here -- 4.7 gigawatts of -- of new load that
3 wasn't accounted for when the IRP was filed in October; is
4 that -- is that right?

5 A (Witness Grubb) No, that -- that's not
6 correct.

7 And Mr. Valle can correct me here. It was
8 part of the forecast, but what we've done is that has
9 moved from projected loads to committed loads. So it
10 doesn't increase the load forecast, it's just putting more
11 certainty around these customers, and that's --

12 A (Witness Valle) Yeah. Absolutely. And
13 it's -- it's to illustrate the -- the movement that has
14 been happening in the pipeline.

15 Q And the company has already identified, as
16 well, that there's 21,000 megawatts of -- of pipeline
17 customers between now and 2031, I think. Is that --

18 A (Witness Valle) So, yeah. So it's going to
19 evolve over time. But, yeah, the total amount of nominal
20 capacity. So these are -- these are load announcements.
21 It's -- it's accounting for 64 customers. It's totaling
22 now 21,000 megawatts.

23 Q What's your current peak?

24 A (Witness Valle) It's about 16 and a half.

25 Q So you're talking about more than doubling

1 the size of your system in the next decade?

2 A (Witness Valle) So --

3 A (Witness Grubb) Only if we won all 21,000.

4 That's not what we're asking for.

5 A (Witness Valle) And it -- it's also not
6 realization; right? So we're not asking for the full
7 pipeline. So it's not 21,000, it's only a fraction of
8 that.

9 Q Sure. But thing -- things are changing very
10 rapidly and -- and things are growing more quickly than
11 what the company has expected. And in the stipulated
12 agreement -- I can't remember the number just off the top
13 of my head here -- but the 200-megawatt solar plus battery
14 resource was stripped out as an approval item. It's --
15 it's removed; correct?

16 A (Witness Grubb) As -- as we just discussed
17 with Mr. Jacob, that's correct.

18 Q And so it's possible that even with the
19 stipulated agreement today, if it's approved as is today,
20 that the company might be capacity short sometime in the
21 next decade?

22 A (Witness Grubb) No. So what we've -- what
23 we've got identified here is we've got the resources for
24 '25/'26, '26/'27. We'll do an RFP for '27 and '28 that
25 will be certified for the amounts that need to meet that

1 need.

2 And then the All-Source RFP will address '29,
3 '30, and '31. So we don't know yet what those resources
4 will be, but we have plans in place to get us at least
5 through 2031.

6 Q So we're -- we're betting on those RFPs
7 working out and getting the resources out of those?

8 A (Witness Grubb) Like we -- we always do when
9 time allows, that's correct.

10 Q And just going back to the whole genesis of
11 this Integrated Resource Plan is the capacity shortfall
12 that y'all started seeing in 2023. Particularly it was
13 around that June time that you saw this capacity
14 shortfall; is that right?

15 A (Witness Grubb) The load forecast reflected
16 enough growth to move that capacity needs year up, that's
17 correct.

18 Q Are you familiar with Docket 4822, the
19 avoided cost docket?

20 A (Witness Grubb) I am.

21 Q Are you aware that the company submitted two
22 weeks prior to this IRP a avoided cost forecast showing
23 that PURPA facilities -- the forecast for PURPA facilities
24 would be \$0 for paid capacity resources between now and
25 2029?

1 A (Witness Grubb) That's correct. And that
2 filing is based on our budget 2023 data, which was prior
3 to the needs year shifting. So that will be updated
4 sometime this summer with the budget 2024.

5 Q And so I actually have a quick question on
6 that. So in the stipulated agreement -- it's Attachment C
7 and I'm going to go back to this at some point, but this
8 is the -- the battery RFP.

9 You mentioned --

10 A (Witness Grubb) Right.

11 Q -- that -- it mentions in there that the
12 battery -- the new battery RFP will be based off of the
13 load projections of the final B-2025. So that's the --
14 the business case, or what --

15 A (Witness Grubb) That means budget 2025. So
16 that will be the load forecast that Mr. Valle and team
17 will finish this fall that will support the '25 IRP.

18 Q Okay. And do you have a more firm date as
19 opposed to just fall for that?

20 A (Witness Grubb) Well, so, we -- so our
21 planning process is usually by the end of August, but then
22 it's got to go through all our planning process.

23 But the budget refers to the regulatory year
24 in which that load forecast will be used. So we finish it
25 up as our annual planning process the end of this year.

1 We'll run our expansion plan cases, we'll file the IRP in
2 January. That will be the load forecast.

3 Q Got it. All right. Thank you.

4 A (Witness Grubb) Uh-huh.

5 Q Page 6, line 6 of your testimony, you
6 mentioned the CARES RFP. We've been talking about it.
7 This RFP was approved with the 2021 or 2022 Integrated
8 Resource Plan.

9 And that RFP is ongoing right now; correct?

10 A (Witness Grubb) That is correct.

11 Q And that RFP allows for solar plus battery
12 resources to be submitted as proposals; correct?

13 A (Witness Grubb) That is correct.

14 Q And the company generally views solar plus
15 battery resources as capacity resources; correct?

16 A (Witness Grubb) So the prior CARES utility
17 scales had use cases that were more kind of a smoothing
18 and a firming, so it didn't have as much capacity value.
19 This one will.

20 The use case is a little different. So it's
21 going to just depend on, you know, what the final bids are
22 and what the successful bids are.

23 Q And the current CARES RFP that's ongoing live
24 right now can allow projects to go operational as early as
25 2026; correct?

1 A (Witness Grubb) They can, if those are the
2 successful bids.

3 Q And it also includes an option for a
4 carbon-free energy-around-the-clock resource; right?

5 A (Witness Grubb) Yeah. I'm a little less
6 familiar with that. But, yes, that was part of the
7 solicitation.

8 Q And, also, in the 2021 Integrated Resource
9 Plan, there was a provision for the CARES RFP that the
10 CARES RFP could be larger for economic development
11 purposes; is that correct?

12 A (Witness Grubb) Correct. I don't -- I don't
13 know what the status of that is, but there was -- we could
14 come back and request that for CARES economic development.

15 Q Is economic development similar to load
16 growth?

17 A (Witness Grubb) So, yeah, that would be -- it
18 doesn't necessarily have to be load growth.

19 Well, I can't remember the details around the
20 CARES. But, yes, it would be a customer that's come to
21 the state that wants some solar for renewable energy
22 credit purposes.

23 Q And if -- if we're updating the 2022
24 Integrated Resource Plan with this docket right now, and
25 the CARES RFP is from that older docket, wouldn't it make

1 sense to also update the CARES RFP program to expand it?

2 A (Witness Grubb) So the CARES RFP was approved
3 in the '22 IRP. It is ongoing right now. So it is -- it
4 is active.

5 So expanding it -- it was a 2100 megawatts
6 across the two CARES, plus the rollover from CRSP. So
7 that -- those megawatts have been approved in that RFP and
8 that's what we'll -- we'll procure.

9 Q Yeah. But I'm just saying, because we're
10 updating that IRP and the things that came out of that
11 IRP, wouldn't it make sense to look at -- in addition to
12 the stipulation. I'm not saying instead of the
13 stipulation.

14 In addition to the stipulation, perhaps
15 expanding that CARES RFP maybe as a -- a fallback option
16 perhaps for additional resources?

17 A (Witness Grubb) So a few points there. We're
18 not updating the 2022 IRP. The 2022 IRP had a lot of
19 great things come out of it that we're still moving
20 forward with. So this '23 IRP Update is to handle that
21 interim year.

22 But, again, those are -- were -- from our --
23 primarily for utility-scale renewable resources. We don't
24 know what kind of storage bids will be in there.

25 So you could expand it and get no capacity

1 outputs out of it. The better plan would be to complete
2 those two renewables and we'll be right back in the '25
3 IRP next year on what that next renewable solicitation
4 needs to be.

5 Q But with 21,000 megawatts potentially coming
6 up in the next decade, we need capacity, but we probably
7 also need energy, as well; right?

8 A (Witness Grubb) Which we spoke about before.
9 Those projections in the 2022 IRP are higher now when we
10 run these expansion plans.

11 And in the '25 IRP, we will lay out the plans
12 for renewables beyond the '29 time frame that -- that
13 CARES is addressing. So CARES is addressing that '26,
14 '27, '28. There will be another one.

15 We will project and bring forth
16 recommendations and settle in the '25 IRP what that next
17 renewable solicitation pattern is.

18 Q All right. Let's also talk then about --
19 also, on your testimony, page 6, line 6, the 500-megawatt
20 energy storage RFP from the 2022 Integrated Resource Plan.

21 And -- and, as I understand it, that's a
22 different RFP for batteries than the -- what is proposed
23 in the stipulation for an additional 500 megawatts; is
24 that -- that correct?

25 A (Witness Grubb) Yes. That was approved in

1 '22, that's correct. Mainly focused on operating reserves
2 for the -- continuing to add renewables on the system.

3 Q Wouldn't it be quicker and easier to merge
4 those two RFPs together to follow the shorter RFP timeline
5 that -- that's been outlined in the stipulation so we
6 don't have two battery RFPs back-to-back in the same year?

7 A (Witness Grubb) No. I would say mainly
8 because, like we've talked about, the -- the 500 megawatts
9 of batteries is designed to be standalone grid charge,
10 which takes a lot more time to evaluate from a
11 transmission standpoint, and also will likely require
12 transmission projects.

13 So the time frame on the resources coming out
14 of the 500-megawatt energy storage RFP will be different
15 than the stipulated RFP. The stipulated RFP is narrowly
16 focused to find batteries that don't require transmission
17 evaluation, which could take ten months, and also doesn't
18 require transmission delivery projects.

19 We do not want to -- we don't want to limit
20 the 500-megawatt batteries from that standpoint. We want
21 it to be more open. And so that's why I would say you
22 need to keep them both separate.

23 Q I saw Mr. Robinson grab the microphone. He
24 was getting ready.

25 A (Witness Grubb) (Indiscernible.)

1 A (Witness Robinson) Ready to sing.

2 Q But isn't it true that battery storage
3 projects can already -- can also bid in to the capacity
4 RFP that's also currently underway and under development?

5 And those battery resources in the capacity
6 RFP could also be delivered as soon as 2026?

7 A (Witness Grubb) Possibly. I don't -- with
8 the transmission aspects in that RFP, we're not sure. I
9 think it's available to it.

10 But there are different use cases. The
11 500 megawatts is for two-hour batteries and the All-Source
12 has a minimum of four. Because, again, that 500 megawatts
13 was looking more for operating reserve-type batteries,
14 where the shorter duration serves that role. Whereas, the
15 All-Source is looking for capacity where that four-hour
16 minimum is preferred.

17 Q Okay. All right. Let's -- let's turn to
18 Attachment C. So this is the -- the proposed RFP kind of
19 framework for the proposed 500-megawatt battery RFP in
20 this docket; right?

21 A (Witness Grubb) That -- that's true. Again,
22 part of that first bullet that we talked about before is
23 it's 300 to 500 now. It will be adjusted based on
24 whatever the capacity needs in that year may be.

25 Q And so it could be more than 500?

1 A (Witness Grubb) More or less. But, to your
2 point, it may be more if the -- depending on what the
3 loads look like. So it just depends on what comes out of
4 this case, what comes out of CARES. Everything impacts
5 each other.

6 Q Okay. And I'm looking at -- I don't -- this
7 is kind of like the first little circle bullet that
8 doesn't -- that's not a solid dot. It says that only
9 submissions requiring minimal transmission improvements
10 will be considered.

11 A (Witness Robinson) Correct. So looking at
12 that date of December 1st, 2027, what we mean by minimal
13 transmission is that for the interconnection or for
14 delivery, that those facilities can be constructed and be
15 in service by that date.

16 Q So interconnection, but then separately
17 deliverability; correct?

18 A (Witness Robinson) Correct. So the paragraph
19 above that defines what can be considered in the RFP. So
20 that's one that -- that's facilities that have an existing
21 interconnecting agreement, ones that are currently in the
22 transitional serial cluster process for Order 2023, and
23 then any that have surplus interconnection ability.

24 Q You mentioned in here one of the -- the ways
25 to expedite this RFP -- and I think this is a really

1 positive thing to expedite these RFPs. One of the
2 recommendations here, or what's -- what the plan is, is to
3 use the existing independent evaluator for this battery
4 RFP.

5 If I recall in some previous testimony, there
6 was some difficulty in -- in using the independent
7 evaluator to even put out the RFI for this Integrated
8 Resource Plan.

9 Have you-all talked to the independent
10 evaluator, Axion, about whether or not they can
11 effectively do this RFP?

12 A (Witness Grubb) Not -- not directly. And I
13 think the important thing is it's going to be based a lot
14 on the All-Source in terms of like the PPAs. And they
15 have the websites and the structures to stand up.

16 One of the reasons we needed this in here was
17 because if you do -- and it's staff's -- staff is the ones
18 that can reach out to the IE. If you did an IE RFP, that
19 takes time. And so in a normal RFP process, if that's
20 something staff and the company want to move forward with,
21 they can.

22 In this case, that's one of those expedited
23 pieces is we don't have time to go get a new IE, to build
24 websites. So you've got to take advantage of it.

25 The other point that you mentioned on the RFI

1 was more a rules and a contractual issue, not a -- not a
2 capability issue.

3 Q Okay, okay.

4 A (Witness Grubb) Yeah.

5 Q Yeah, because it -- it seems like we've got
6 the CARES RFP, we've got the capacity RFP, we've got the
7 2022 battery RFP.

8 A (Witness Grubb) A lot of RFPs.

9 Q We've got this new battery RFP.

10 A (Witness Grubb) Right.

11 Q It seems like they're going to be rather
12 busy.

13 A (Witness Grubb) We're all going to be rather
14 busy.

15 Q Yeah. Yeah, that's right.

16 A (Witness Grubb) All of us.

17 Q Okay. I'd like to turn -- we're still on
18 Attachment C, but we're on the proposed schedule.

19 A (Witness Grubb) Yes.

20 Q It's the third item where you file for a
21 Commission approval of the RFP documents.

22 Does that get filed in this docket or does
23 that get filed in a separate docket?

24 A (Witness Grubb) Usually RFPs are -- are their
25 own docket number.

1 Q Okay. So --

2 A (Witness Grubb) And that would be a different
3 proceeding.

4 Q Is there still an opportunity for parties to
5 be involved in that docket?

6 A (Witness Grubb) Like any RFP docket, I think
7 there is a -- there is an opportunity there. Mostly from
8 a developer and bidder standpoint, though.

9 Again, for this one, as you'll see, the
10 contracts, the PPAs that will be approved in the
11 All-Source happened before this. And so to save time, to
12 expedite this RFP, we would use the same -- pretty much
13 the same contract.

14 So we are shortening a lot of that. So from
15 an RFP standpoint, the developers will have a little bit
16 of time. But mostly it will roll out looking similar to
17 the All-Source, in terms of a contract, but then it's
18 specifically on these aspects of who's in play
19 (indiscernible) --

20 Q Well, I'm -- I'm asking if -- if we can
21 participate in that docket because your third bullet on
22 that same page says: For the elimination of a comment
23 period from bidders and interested parties, which that
24 normally happens at the very beginning.

25 A (Witness Grubb) Right.

1 Q I understand that can be a lengthy process.
2 And so I'm trying to figure out: Do we still have a venue
3 through that docketed proceeding to offer some -- some
4 comments?

5 And it sounds like the answer is yes.

6 A (Witness Grubb) It will be tight. I mean, so
7 we're --

8 Q Sure.

9 A (Witness Grubb) -- we're saying we're
10 eliminating it because we just don't have the time. And
11 what we'll lean on is comments that we got from anyone in
12 the All-Source about that PPA structure.

13 Q Got it. Thank you.

14 I noticed the bid due date is August 14th of
15 this year?

16 A (Witness Grubb) That's right.

17 Q And in order to submit a proposal, you need
18 to either have an existing interconnection agreement, so
19 you've already had to have gone through generator
20 interconnection?

21 A (Witness Robinson) That's correct.

22 Q You have to be in the serial study.

23 A (Witness Robinson) The cluster study. The
24 transitional from serial to cluster.

25 Q The serial or -- or the cluster transitional?

1 A (Witness Robinson) No. It's the transitional
2 that's -- that's currently closed right now. So you would
3 have to be in that process right now for Order -- the
4 compliance transitional period that we have for
5 Order 2023.

6 Q Because I -- I was reviewing those materials
7 about Order 2023 and it looks like the date to enter into
8 the serial trans- -- the serial -- the new serial version
9 between now and the cluster studies in 2026, you have to
10 file or request by June? June 4th?

11 A (Witness Robinson) Yeah. I'm not -- I'm not
12 overly familiar with that date, but I believe the window
13 has closed for participation. So you would have to have
14 an interconnection request in currently in the cluster
15 study transitional queue.

16 Q And with the serial cluster study that's
17 underway right now, we're anticipating large generator
18 interconnection agreements to be delivered in December of
19 this year?

20 A (Witness Grubb) I can't remember --

21 A (Witness Robinson) December or January time
22 frame, I believe.

23 Q Okay. And --

24 A (Witness Robinson) Subject to check.

25 Q And so companies are going to be bidding in

1 battery -- if they're in that serial transitional cluster
2 right now, they're going to have to bid in a project in
3 August, but they're not going to have clarity on their
4 interconnection until December?

5 A (Witness Robinson) That's correct.

6 Q Okay. The certification line -- this is
7 second to the bottom -- you're anticipating certification
8 of -- of the resources in this RFP in July 23rd, 2025.

9 So that -- the certification of these
10 batteries -- of the 500 megawatts is going to occur before
11 the certification of the 2029 to 2031 capacity RFP; is
12 that correct?

13 A (Witness Grubb) Yeah. Mainly because you
14 need to have -- you've got a construction timeline that's
15 shorter, and so trying to get that certification out
16 there. Trying to back up from physically constructing a
17 battery from that December 1st, '27, trying to back up and
18 give you enough time to do that. So, yeah, it would be
19 before the All-Source.

20 Q Like I said, I -- you know, I think this is a
21 positive development of moving these RFPs quicker. Is
22 there some way that the company and maybe PIA staff and
23 interested parties can work on maybe developing a similar
24 expedited schedule for the -- for future RFPs?

25 A (Witness Grubb) So this is expedited by not

1 allowing projects that have to have transmission delivery
2 studies on them, which is not optimal from a standpoint
3 of -- it's like the All-Source, you've got to get
4 8,000 megawatts. You're going to want to have the
5 broadest product category that you can have and no
6 transmission evaluation aspects to it. So there are
7 certain pieces that we might could expedite, but not the
8 evaluation.

9 So what we've structured this around is
10 your -- is those two -- those two requirements that take a
11 lot of time. So possibly having to build transmission
12 projects --

13 A (Witness Robinson) Yeah, to add to
14 Mr. Grubb's point --

15 A (Witness Grubb) -- and evaluation.

16 A (Witness Robinson) -- I think it's very
17 important that we do a full evaluation on transmission,
18 looking at all factors and not just a limited evaluation.
19 So from a reliability and diversity perspective, it's very
20 important for future RFPs that we have that full -- full
21 evaluation done.

22 A (Witness Grubb) And, also, Mr. Mahan, in the
23 first part of this where you're -- you know, we're talking
24 about comments and everything, we do -- it is beneficial
25 for the market to have time to comment, do Q and As and

1 know what's coming.

2 And so everything is pretty tight in this,
3 but that's what we're having to do to -- to meet that
4 earlier need year. So there may be some things that we
5 can take out of it, but I don't think that the majority of
6 the normal two-year process will be able to be normally
7 taken out. And, again, if you've got enough time, that's
8 the best way to do it.

9 Q So we're talking still, though, about this
10 expedited battery RFP. And it's -- it's the proposed
11 schedule down here at the bottom.

12 You've got a line item for 180 days of
13 transmission studies. And these resources are meant to be
14 capacity resources, so --

15 A (Witness Grubb) Right.

16 Q -- presumably they have the highest level of
17 transmission analysis proposed on them.

18 A (Witness Grubb) Well, so -- but -- but we're
19 limiting -- this is interconnection studies and a little
20 bit of delivery studies, not full-on delivery studies.

21 Usually what you also have to do --

22 Q What's a little bit of a delivery?

23 A (Witness Grubb) So -- so the -- the delivery
24 study, if you -- if you determine pretty quickly -- and
25 Mike, you can help me here -- that it's not going to be

1 available to be done by December 27th, we wouldn't
2 continue to study it.

3 A (Witness Robinson) Right. That's -- that's
4 what we mean by minimal transmission. That the location
5 of the battery and the -- you know, we're going to have to
6 run some -- some fairly quick screens to determine what
7 that means.

8 This is a very concise schedule for us from a
9 transmission planning perspective to run these studies.
10 It's going to be very tight.

11 And so we're going to have to do some -- some
12 analysis on the front end to determine whether or not
13 transmission facilities identified for delivery can meet
14 that minimal transmission requirement by December 1st of
15 2027.

16 A (Witness Grubb) So there's also studies --
17 Mike, help me here again. Or Mr. Robinson. Sorry.

18 If -- if they're putting it behind existing
19 solar, there's still studies that have to done --

20 A (Witness Robinson) Correct.

21 A (Witness Grubb) -- at the point of
22 interconnection, too. So --

23 A (Witness Robinson) That's right. You may
24 have an existing interconnection, but this surplus
25 interconnection that's mentioned here can consider

1 batteries with existing solar. But there still are some
2 analyses that need to be done just to make sure that there
3 aren't any issues.

4 Q Okay. Let's talk about Plant Yates for a
5 bit. And as we all know, it's -- it's unable to fully
6 dispatch until the transmission upgrades are provided by
7 the year 2028.

8 A (Witness Robinson) That's correct.

9 Q But it can -- it still provides value between
10 now and 2028, even though it's not 100 percent nameplate
11 capacity; right?

12 A (Witness Robinson) That is correct. And it
13 may have the ability to run every hour of the year to
14 100 percent. We may not run it because of economics,
15 but -- Mr. Bush can talk to that -- but it's constrained
16 under certain contingencies and scenarios.

17 So peak season with transmission lines out
18 that have been identified and the unit out scenarios that
19 are in the studies. So only during those periods of times
20 would they -- would those units be restricted. So
21 others -- other period of times, so many hours of the
22 year, those units will be available full capacity.

23 Q Yeah. So -- so we're considering it a
24 capacity resource, even though there are some situations
25 where it may not be fully dispatchable?

1 A (Witness Robinson) Over 600 megawatts until
2 the transmission projects are done in '28, as you -- as
3 you refer to. But --

4 A (Witness Grubb) For that one year.

5 A (Witness Robinson) Right.

6 Q So we -- we've got to talk about page 47,
7 line 4 through 26 -- it's -- it's -- I think it's
8 basically the whole page -- regarding the Energy Resource
9 Interconnection Service versus the -- I suspect this is
10 why Mr. Robinson is here.

11 A (Witness Grubb) I didn't answer it quite
12 right your first time, did I?

13 Q It's all right. It's all right.

14 A (Witness Evans) Phone a friend.

15 A (Witness Grubb) I did.

16 Q So Energy Resource Interconnection Service is
17 what the company requested for generation interconnection
18 for the Yates units, and then also the Robins and the
19 Moody Air Force Base battery units; is that correct?

20 A (Witness Robinson) That's correct.

21 Q Can you explain that neither Energy Resource
22 Service, which is what you requested, nor Network Resource
23 Interconnection Service convey delivery rights.

24 But that -- that terminology that you're
25 using, "rights," that sort of indicates some sort of

1 contractual agreement of deliver -- deliverability;
2 correct?

3 A (Witness Robinson) Not under NRIS or the
4 Network Resource Integration Service.

5 So here in Southern Company's territory,
6 Commissioners, the NRIS does not give you designated
7 network service. So to have firm service and be
8 designated, there's only a couple of ways that can be done
9 under our Open Access Transmission Tariff. And that first
10 is through a point-to-point transmission service request.

11 Q Which is a contractual request?

12 A (Witness Robinson) That's correct.
13 Through -- through the OATT tariff, to become a designated
14 resource by a load-serving entity in the footprint, or to
15 have what's called Network Integrated Transmission Service
16 under the tariff, as well.

17 Q And so those are all contractually provided
18 ways of getting transmission service?

19 A (Witness Robinson) There are agreements
20 associated with all three of those.

21 Q But, inherently, the generator
22 interconnection process, the Energy Resource
23 Interconnection Service, the Network Resource
24 Interconnection Service, those are engineering studies?

25 A (Witness Robinson) That's correct.

1 Q They're not contractual studies?

2 A (Witness Robinson) Correct.

3 Q So they're determining the physical
4 limitations of the transmission system, not the
5 contractual limitations; correct?

6 A (Witness Robinson) Correct.

7 Q So what is the big difference between an ERIS
8 engineering study and an NRIS engineering study?

9 A (Witness Robinson) An Energy Resource
10 Interconnection Study will look at just interconnecting
11 the unit to the system and the immediate area around it
12 and improvements that are needed to ensure stability,
13 voltage, the ability for that unit to run in that -- in
14 that scenario.

15 A Network Resource Integration Service looks
16 at those things, as well as deliverability of megawatts
17 out of that unit. But it does not give you deliverability
18 rights. It only -- it only informs you of what you
19 might -- you might anticipate if you file a TSR,
20 Transmission Service Request, or a designation request, or
21 a network integrated transmission service request.

22 So here at Southern Company, NRIS really does
23 not get you anything from a contractual perspective. It
24 only informs on what network upgrades may be needed for
25 deliverability.

1 We do that through the studies that we did
2 that we submitted in September with this filing, the
3 supplemental studies that we did for Yates in January, and
4 then we did a designation study that is complete that was
5 finished in -- subject to check, I believe it was in
6 February.

7 Q So an Energy Resource Interconnection Service
8 study only looks at being able to put a new generator on
9 using the transmission system on an as-available basis?

10 A (Witness Robinson) Did you say ERIS?

11 Q Correct.

12 A (Witness Robinson) That's correct.

13 But it also looks at the feasibility of
14 connecting that unit to the system and how the system
15 reacts to that unit from a stability voltage perspective.
16 All those things need be -- need to be looked at as it's
17 related to interconnection service.

18 What it doesn't -- what it -- what ERIS does
19 not get you is knowledge of what potential network
20 upgrades may be needed for deliverability. We do that
21 here through those other methodologies that we mentioned.
22 Through that designation as a native load resource,
23 through TSR, Transmission Service Request, or through a
24 network integration transmission service.

25 Q So --

1 A (Witness Robinson) Just because other
2 entities in deregulated markets use NRIS as a designation
3 vehicle, that doesn't mean we do it here.

4 The -- the OATT tariff, the Open Access
5 Transmission Tariff, Commissioners, is a pro forma tariff.
6 So ours looks like somebody's in the northeast, it looks
7 like California's, or it looks like PG&E's. They all look
8 the same.

9 So you can go pull up their tariff and they
10 have an NRIS study. Ours informs, it does not give you
11 rights. Theirs might give you rights, depending on what
12 area you're in. But we do not offer that here in the
13 southeast and in Southern Company area -- territory.

14 Q And so in the Southern Company system, the
15 Energy Resource Service, which is what Yates and the
16 batteries evaluated, is it possible the studies come back
17 quicker and show fewer transmission upgrades necessary
18 than an NR- -- than a Network Resource Interconnection
19 Study?

20 A (Witness Robinson) It is -- it is potential
21 that they come back with different answers. Not
22 necessarily a hundred percent confident on the timing if
23 every study would come back quicker if you did an ERIS
24 over an NRIS. It probably would be -- it probably has
25 some factors to do with the study and the -- and the

1 complexity of that study.

2 Q But an NRIS study would have potentially
3 highlighted more transmission upgrades at a potentially
4 higher cost compared to an ERIS study?

5 A (Witness Robinson) Yes.

6 Commissioners, because it looks at
7 deliverability. So not just interconnecting the unit to
8 the system, but it looks at delivering those megawatts out
9 to the system.

10 Q Okay. Let's -- let's move on to page 37,
11 line 1, where you talk about securing firm transmission
12 from FPL to Southern for the Santa Rosa power purchase
13 agreements.

14 Did you have to do some sort of service
15 assessment for the Mississippi power purchase agreements,
16 as well?

17 A (Witness Grubb) Yeah. So we did that when we
18 screened them before the original filing. And no
19 transmission projects were needed for Mississippi to be
20 part of the system, but, of course, they already were.
21 And so the system -- they are already in the system
22 serving the Southern pool.

23 Q Well -- so we're talking about two different
24 things here again. One is engineering, construction,
25 building new transmission versus the contractual side.

1 So my understanding of what this reads as is
2 you-all purchased a contract to flow over FPL's lines to
3 move the megawatts from Florida to Georgia; right?

4 A (Witness Grubb) You said Mississippi. So I
5 was just --

6 Q Yeah. So did you --

7 A (Witness Grubb) I was going back to Santa
8 Rosa.

9 Q Did you do a similar contract to move the
10 megawatts from Mississippi somewhere else?

11 A (Witness Grubb) No. Because, again, they're
12 in the Southern pool. So nothing physically is changing
13 in that relationship.

14 We're -- that we're paying Mississippi for
15 those megawatts, but the Southern Company system and the
16 Southern Company pool is running exactly the same way it
17 would today.

18 A (Witness Robinson) So when you stay in the
19 system -- so say you have units that are in Mississippi,
20 they are not modeled to provide only Mississippi load.
21 It's -- it dispatches to the whole Southern Company,
22 Southern balancing area. The pool that we operate, that's
23 how we plan the system.

24 And so we are taking over the units that are
25 already running and already have that capability inside

1 the Southern balancing area.

2 Q But, if I recall, you-all are wielding that
3 power from Mississippi to TVA, at least in the short term?

4 A (Witness Grubb) For the wholesale sale, yes.

5 Q All right. Have you conducted --

6 A (Witness Grubb) Or a -- a portion of that.

7 Q Have you conducted a system impact study
8 regarding Plant Daniel in Mississippi moving that power to
9 TVA?

10 A (Witness Grubb) So the transmission
11 service -- I'd have to look at the -- first off, it was
12 trade secret of who it was sold to.

13 Q I definitely found it through other --

14 A (Witness Grubb) Did you, okay?

15 Q It's actually on the OASIS site.

16 A (Witness Grubb) Okay. So they would -- I
17 think their responsibility is for us to get it to them and
18 then they -- they take it from there on. I can't remember
19 the exact details, but we'll deliver it to them and they
20 will take transmission service to serve their needs.

21 Q Okay, okay. And, Mr. Robinson, I'm glad you
22 mentioned the North Georgia Reliability and Resilience
23 Action Plan. That wasn't -- there wasn't a major update
24 provided in this Integrated Resource Plan regarding that
25 transmission planning effort, was there?

1 A (Witness Robinson) That's correct. I believe
2 we answered that in a data request.

3 Q Okay. And you're familiar with FERC Order
4 2023, which deals with reforming the generator
5 interconnection transmission -- and earned transmission
6 process?

7 A (Witness Robinson) Yes, I am.

8 Q And are you aware that FERC is currently --
9 or is potentially going to finalize a new transmission
10 planning rule sometime soon?

11 A (Witness Robinson) We are aware, yes.

12 Q So it seems like there's a lot of outstanding
13 -- and going back to Mr. Jacob, his questions regarding --
14 there's a lot of discussion in your testimony how you're
15 not requesting transmission to be approved, but Stipulated
16 Agreement No. 17 approves any and all transmission
17 associated with anything dealing with this docket; is that
18 correct?

19 A (Witness Grubb) No.

20 A (Witness Robinson) I have to -- may we read
21 the stip?

22 Which paragraph is that?

23 Q Seventeen.

24 A (Witness Robinson) No. Seventeen is --

25 A (Witness Evans) No. 17 refers to residential

1 and commercial battery pilot.

2 Q Maybe it's not 17. Sorry.

3 A (Witness Robinson) Nineteen?

4 Q Nineteen.

5 A (Witness Robinson) We're asking for
6 transmission projects necessary to accommodate the loads
7 and resource portfolio approved in the updated IRP.

8 Q But that's not finalized because it could
9 change if you find something better?

10 A (Witness Robinson) Correct. Which is what
11 happens in every filing that we have. Every IRP filing we
12 ask for the portfolio of projects to be approved, but with
13 the understanding that we iterate our planning process.

14 It's a yearly process and those things can
15 change. They can move out. Some projects can move in.
16 Or if we find a better alternative, we may choose that
17 alternative.

18 Q So it's -- it seems kind of unusual to
19 include transmission -- specific transmission information
20 in this docket if, one, you weren't seeking to get it
21 approved, and, second, if it's potential to significantly
22 change.

23 So why -- why bother include it at all?

24 A (Witness Robinson) Well, I think it's very
25 important to inform the Commission what is required to

1 support these 3300 megawatts. That's the best information
2 we have today is the studies that we've run. We've run
3 them three times; in September with the filing, in January
4 with the supplemental filing, and then the designation
5 study that was completed.

6 And I looked. It was in March when it was
7 completed. And all three of those informed that's those
8 eight projects are the right projects to take forward.

9 A (Witness Grubb) And --

10 A (Witness Robinson) Sorry.

11 A (Witness Grubb) No. And so we are asking for
12 approval. The distinction is that cost recovery will come
13 at a different point once those projects are known.

14 So we have asked for approval so that we can
15 move forward with identifying those transmission projects
16 and constructing them. To Mr. Robinson's point, if they
17 change a little bit, we'll do that.

18 But it's approval. We do need approval from
19 the Commission to build the projects to allow the delivery
20 from Yates.

21 A (Witness Robinson) And another point that we
22 made earlier is not all of those projects are owned by
23 Georgia Power Company. There's at least one that is owned
24 by Georgia Transmission Corporation.

25 Q So, again, why file that -- the Georgia

1 Transmission Corporation transmission plan in this docket
2 if, one, the Commission doesn't oversee them, and, two, it
3 could potentially change?

4 A (Witness Robinson) I think it's very
5 important to inform the Commission of all the things that
6 need to be done to make this happen. If there was an
7 upgrade needed in TVA's territory, I would expect that we
8 would highlight that, as far as what that requirement
9 would be. That's not the case here.

10 The other thing, just reminding everybody
11 that the ten-year plan that we use to study these
12 resources is a product of the ITS. So it is a product of
13 Georgia Power, Georgia Transmission Corporation, MEAG and
14 Dalton Utilities.

15 Q And you mentioned SERTP earlier how the
16 1.6 gigawatts of power from Georgia -- southern Georgia up
17 to northern Georgia, the \$100 million figure or
18 whatever -- you said that's not a good enough study
19 because it only looked at one year, 2028; is that right?

20 A (Witness Robinson) That was the year that was
21 requested. That was the year that was looked at. As I
22 mentioned before, there were also multiple lines that were
23 identified that were close to being overloaded. That if
24 you looked in further years, likely those would need
25 projects to relieve those overloads.

1 Q In the SERTP transmission planning process,
2 can stakeholders request multiple years of evaluation for
3 the exact same study?

4 Personally, can I request multiple years'
5 worth of study for a specific study in the SERTP process,
6 or am I required to submit a single year?

7 A (Witness Robinson) I can't recall. I know
8 you submitted five last year to be looked at and four were
9 chosen. All of those that were requested seemed to be for
10 one year or certain season.

11 Q Would it surprise you if we were required to
12 submit a single year?

13 A (Witness Robinson) It would not.

14 Q And that's a limitation of the SERTP process,
15 not some other limitation?

16 A (Witness Robinson) Like I said, I'm not
17 specifically familiar with that limitation.

18 MR. MAHAN: All right. I appreciate it.

19 Thank you very much.

20 MR. GRUBB: Thank you.

21 CHAIRMAN SHAW: All right. Department of
22 Defense.

23 MR. McNUTT: No questions, Mr. Chairman.

24 CHAIRMAN SHAW: Walmart.

25 I'm not trying to rush you, but the air

1 conditioning turns off at 6:30.

2 MR. GRUBB: It's on right now?

3 CHAIRMAN SHAW: Yeah, exactly. It's not
4 working well.

5 MR. GRUBB: It's a little hot up here.

6 CHAIRMAN SHAW: It is working. So we did get
7 them to extend it until 6:30.

8 MS. EATON: Sir, no -- no worries. I have
9 three pages and it's very brief.

10 CROSS-EXAMINATION

11 BY MS. EATON:

12 Q I asked Mr. Abramovitz this morning about the
13 stipulation the parties received today. And I'm assuming
14 you have a copy of that in front of you?

15 A (Witness Grubb) Yes, ma'am.

16 A (Witness Evans) Yes.

17 Q Paragraphs 13, 14 and 15 reference the DCL-1,
18 DCO-1 and CL tariffs. And we understand that the company
19 is working with GAM and staff on the tariff language.

20 Would Georgia Power agree to send that
21 language to Walmart -- the draft tariff language before it
22 goes to the PSC for approval in this docket so that to the
23 extent there is any clarifications or issues, we might be
24 able to clear up that they're seeing something that we've
25 already seen?

1 A (Witness Evans) Yes. As interested
2 customers, we're always happy to share that information.

3 Q Sure. I want to talk to you briefly about a
4 couple of topics that were raised during the staff and
5 intervenor hearing. First, just want to talk about solar
6 construction.

7 In your rebuttal testimony you had a pretty
8 long section, six, talking generally about intervenor
9 recommendations and critiques of the resources Georgia
10 Power requested in this IRP Update.

11 A (Witness Grubb) Yes.

12 Q And on page 41 you have described the
13 200 megawatts of BESS and 200 megawatts of solar. And
14 it's our understanding that pursuant to Paragraph 11 of
15 the stipulation that that is now out of Georgia Power's
16 request; is that right?

17 A (Witness Grubb) Yeah. So that specific
18 project is not approved. The stipulation says if it were
19 to be -- if we wanted to offer it in an RFP, we could.
20 But it's not approved per the stipulation.

21 Q Sure. And I want to clarify that that is
22 also not part of the pilot that you're discussing in
23 Paragraph 17; is that right?

24 A (Witness Grubb) That's right. This would be
25 more of a utility-scale storage and solar as opposed to

1 that program, that's correct.

2 Q Sure. It's my understanding that Georgia
3 Power currently has a small community solar program. I
4 think it's 8 megawatts of new solar farms that would
5 supply the program. Subject to check, I think it's 2
6 megawatts -- an area in service near Athens, 2.4 megawatts
7 in service near Augusta, and a 3.6 megawatt farm near
8 Savannah.

9 Does that sound right?

10 A (Witness Grubb) Subject to check, that sounds
11 about right, yes.

12 Q Okay. And according to the company's
13 website, any residential customer on the standard
14 residential service rate and small business customers on
15 the GS rate located in your territory could apply to
16 participate in that program; is that right?

17 A (Witness Grubb) Sounds -- sounds right. I
18 don't deal with it every day, but that sounds right, yes.

19 Q Sure. And are those the only community -- is
20 that the only community solar that Georgia Power currently
21 offers?

22 A (Witness Grubb) I believe currently that's
23 the case.

24 Q Did you have an opportunity to either review
25 the prefiled direct testimony of Walmart's witness Lisa

1 Perry or review the hearing transcript from March 1st?

2 A (Witness Grubb) Yes. But it's been a few
3 weeks, so I couldn't tell you that I recall all of it.

4 Q Sure.

5 A (Witness Grubb) I don't want to speak for the
6 rest of the panel, but...

7 Q Sure. For context, Ms. Perry testified that
8 in Georgia where third-parties are generally prohibited
9 from reselling electricity from a solar installation,
10 there are other opportunities for customers to support
11 solar-generation resources. For example, Walmart could
12 invest its own capital in solar projects where the utility
13 owns and operates the solar installation, with or without
14 co-located energy storage as a system resource. And that
15 that type of arrangement not only provides the utility
16 with access to a greater number of generation resource,
17 but could also provide cleaner power for all of its
18 customers. And that's just a summary of her testimony in
19 that regard.

20 Would Georgia Power commit to working with
21 customers, like Walmart and others, that might be willing
22 to invest their own capital in solar projects to develop
23 system resources?

24 A (Witness Grubb) So I want to be sure I -- the
25 first part. So is it -- so it's a customer developed

1 providing it behind the meter or is it -- I'm sorry. I
2 missed that first part.

3 Q It could be either way. Behind the meter or
4 not.

5 A (Witness Grubb) Yes. I want to be --

6 Q It would be a customer-funded program.

7 A (Witness Grubb) Yeah. I mean, we're always
8 open to working with customers. I don't deal on the
9 renewable side very often. So I don't know what all
10 programs we offer.

11 But I think if it's something that
12 customers -- we're always interested in talking with them.
13 I can't commit to it right now because I don't know -- I
14 don't deal in that world.

15 But I don't know if you've got anything, Lee.

16 COMMISSIONER McDONALD: Does that conflict
17 with the community solar program that we have?

18 MR. GRUBB: I think it would depend on the
19 structure, Commissioner. I mean, right now the
20 community solar program is company-owned solar
21 resources that people can, you know, subscribe to
22 and get the credits and the RECs. It would depend
23 on what the nature of this is.

24 I would -- I would think this would be a
25 little more customer specific where the credits and

1 the renewable energy credits would go to the -- for
2 example, to Walmart if they were setting up that
3 resource.

4 So it -- it sounds like these would be for a
5 different class of customers, Commissioner. I
6 think it would depend on how we would structure it.

7 MS. EATON: In my hypothetical and her
8 testimony is dealing with Walmart investing its own
9 capital in solar projects where the utility owns
10 and operates the solar installation. So it would
11 be somewhat more like the community solar program
12 in that regard.

13 MR. GRUBB: Okay.

14 COMMISSIONER McDONALD: Would that -- are you
15 talking about if Walmart builds a solar program and
16 then customers can buy into that solar program?

17 Are you reselling electricity; is that --

18 MS. EATON: I don't believe that's what
19 they're contemplating. I think it's contemplating
20 helping to actually create the solar facility
21 itself and then that program -- that facility would
22 end up being owned and operated by the utility.

23 They would, of course, be a potential
24 customer of that facility. But they're talking
25 about the facility as being either co-located on

1 property that they own or not. I don't think it's
2 specific.

3 But they're talking about just really --
4 their goal is to increase community solar programs
5 everywhere. And they're willing to put some of
6 their own money in to make this happen.

7 MR. GRUBB: So, yeah, I think it would just
8 depend on the structure of it. I mean, if it's
9 something that a customer is interested in that
10 helps community solar for other customers, as long
11 as we handle it and the program design is correct,
12 I think we would be open to discussions.

13 MR. EVANS: That's right.

14 BY MS. EATON:

15 Q I also wanted to talk to you about the pilot
16 program that's in Paragraph 17 of this stipulation. I
17 think you talked a little bit about that earlier, but do
18 you have anymore details about the size of the pilot or
19 what location or locations would be involved and the types
20 of customers involved?

21 Because the stipulation is fairly vague
22 there.

23 A (Witness Evans) Yes. Not at this time.
24 That's all that we're looking to develop as we develop the
25 program for filing next year's IRP.

1 As we mentioned, this is something that we
2 were already looking at and investigating. So that's part
3 of the development process that will be filed next year.

4 Q Do you already have sites selected for that
5 particular pilot or no?

6 A (Witness Evans) Oh, no.

7 Q Okay.

8 A (Witness Evans) No. And it will also, of
9 course, as it outlines in the stipulation, be informed
10 with the meeting with staff and interested parties here
11 soon.

12 Q Okay. Last, I'm going to talk a little bit
13 about the virtual power plants. You talk about it in your
14 rebuttal testimony starting at page 44, lines 1 to 14.

15 I will give you a second to get to that page.

16 A (Witness Evans) I'm there.

17 Q Okay. I believe your -- the sentiment is
18 that the company believes that development of virtual
19 power plants would require more planning and time and
20 further operational capabilities than exist in this
21 docket, but you're not opposed to that concept; is that
22 right?

23 A (Witness Evans) Certainly not. And I think
24 we go on to say that we're actively looking at that
25 potential as part of new programs filed in the '25 IRP.

1 Q Sure. And I believe on -- you talked a
2 little bit with Mr. Jacob about whether -- that you would
3 consider dispatchable behind-the-meter customer-sided BESS
4 as a virtual power plant; is that right?

5 A (Witness Evans) It could, depending on what
6 capabilities it could provide to the utility, to other
7 customers, and all the things that go into the program
8 design about it. But that potential absolutely exists
9 there.

10 Q Do you have any pilot virtual power plant
11 projects being planned or any more information you could
12 provide on that particular part of the stipulation?

13 A (Witness Evans) No. Again, it's -- it's in
14 the same stage of development, right. Very early. That's
15 part of that process to outline exactly how those use
16 cases are going to be, what those values are. All the
17 parameters, the customer interaction, the marketing,
18 things like that, to make sure that whenever we launch it,
19 it will be successful.

20 Q And would Georgia Power be willing to commit
21 to collaborate with its customers, such as Walmart, who
22 may want to use their only capital to also facilitate the
23 construction of virtual power plants that could help reach
24 the customer and the utility's sustainability goals?

25 A (Witness Evans) Absolutely. We're always

1 open to hearing from our customers and collaborating with
2 them.

3 MS. EATON: Thank you. That's all.

4 MR. GRUBB: Thank you.

5 CHAIRMAN SHAW: Redirect.

6 MR. MARZO: Good evening, Mr. Chairman.

7 REDIRECT EXAMINATION

8 BY MR. MARZO:

9 Q Good evening, gentlemen.

10 A (Witness Grubb) Good evening.

11 A (Witness Evans) Good evening.

12 Q I just want to ask you a few questions from
13 some questions that were asked earlier, beginning with
14 CEBA, and then I think followed up by Mr. Jacob's, SACE
15 counsel.

16 They were asking you several questions. One
17 was around sleeved PPAs and other bring-your-own-option
18 sort of programs that have been suggested in this case.

19 Do you recall those?

20 A (Witness Grubb) I do.

21 A (Witness Evans) Yes.

22 Q Okay. First, I want to ask you: Doesn't
23 Georgia Power already offer a number of subscription
24 programs for commercial/industrial customers?

25 A (Witness Grubb) We do.

1 Q Okay. And were you here or did you hear the
2 testimony of Ms. Barua that CEBA's counsel referenced
3 earlier in his cross-examination?

4 A (Witness Grubb) Yes.

5 Q And I believe she acknowledged that Georgia
6 Power's program is one of the several green tariffs that
7 are offered to commercial/industrial customers around the
8 country. And it's one of the beneficial programs to those
9 customers?

10 A (Witness Grubb) I do recall.

11 Q Now, CEBA and Mr. Jacob, on behalf of SACE,
12 asked about the sleeved PPA proposal in particular. Can
13 you explain for me why that -- can you explain to me your
14 concerns about why that lacks the benefits of the
15 company's current programs and what you believe are your
16 concerns with that type of program?

17 A (Witness Grubb) Yeah. So I do believe the
18 company offers a lot of good programs. The concerns there
19 would be like we just talked a little bit about this
20 afternoon is the nature of that PPA. If it's -- all of
21 the resources on the Georgia Power system serve all
22 customers. Obviously they're dispatched different.

23 But we don't have any generation resource
24 that is earmarked, for lack of a better term, from a
25 megawatt hour standpoint to customers. We have

1 subscriptions, we have credits, and those types of things.
2 And so the first concern would be that.

3 The biggest concern would be making sure that
4 anything we do doesn't change the structure and how we
5 generate the system. So it would have to be a PPA to the
6 company that provides service to all customers.

7 Q And is that to say, Mr. Grubb, to stay in
8 line with the constructive regulatory environment here in
9 Georgia and the structure that this Commission follows, in
10 terms of how this regulatory market is organized?

11 A (Witness Grubb) That -- that's the reason for
12 that -- that discussion that I just had, yes.

13 Q And I believe Commissioner Echols had asked
14 some questions about the Alabama Power Program. And I
15 know you didn't know specifics.

16 But is it your understanding that that is not
17 a sleeved program the way that Mr. Dunbar was defining it
18 in his cross-examination?

19 A (Witness Grubb) Yeah. My understanding is
20 that in that situation, again, that resource serves all
21 Alabama Power customers and goes into their system to
22 serve customers, just like all other resources.

23 Q And just one last question here. In regards
24 to trying to meet customers and work with customers to
25 develop innovative options, is it your opinion that

1 Georgia Power has consistently done that for the last
2 several IRPs?

3 A (Witness Grubb) Yes.

4 Q Is it the company's intent to continue to do
5 that in the next IRP?

6 A (Witness Grubb) Absolutely.

7 Q Okay. And is it your understanding from
8 those who offered those suggestions of various programs in
9 the last round of hearings, that largely those
10 witnesses -- Ms. Barua, for example, admitted
11 implementation of those programs really doesn't fit the
12 timelines we're trying to address in this case?

13 A (Witness Grubb) That's correct.

14 Q Okay. So to the extent that there are
15 programs that the Commission may want to consider that fit
16 our regulatory construct, the 2025 IRP is the proper place
17 to consider those?

18 A (Witness Grubb) Yes, sir.

19 MR. MARZO: Okay. Thank you.

20 Thank you, Mr. Chairman. That's all I have.

21 CHAIRMAN SHAW: Thank you.

22 Commissioners, any other follow-up questions?

23 (No response.)

24 CHAIRMAN SHAW: Yes, sir.

25 MR. MARZO: Commissioner, I do want to move

1 my exhibits.

2 CHAIRMAN SHAW: All right. So marked.

3 (GPC Exhibits 15 through 19 were admitted
4 into evidence.)

5 CHAIRMAN SHAW: Any follow-up questions?

6 COMMISSIONER PRIDEMORE: No.

7 CHAIRMAN SHAW: All right. Thank y'all for
8 sticking with us today. We made it before the air
9 condition is shut off. So that's a really good
10 thing.

11 Go ahead, Ms. Whitfield.

12 MS. WHITFIELD: I just have a quick
13 housekeeping matter. I said there were three GIPL
14 exhibits. There are four.

15 CHAIRMAN SHAW: Okay.

16 MS. WHITFIELD: The first is two pages from
17 Leggs' 2022 rate case testimony. The second is
18 trade secret. The third is the hearing request.
19 And the fourth is open records emails.

20 And I've provided a labeled copy of all of
21 that to both counsel for Georgia Power Company, as
22 well as the court reporter.

23 CHAIRMAN SHAW: Okay. Thank you, ma'am.

24 MS. WHITFIELD: Thank you.

25 CHAIRMAN SHAW: Are there any other

1 housekeeping matters to take up?

2 MR. MARZO: I do need to excuse my witnesses.

3 I don't want them here overnight, so...

4 MR. GRUBB: Nor do we want to be.

5 CHAIRMAN SHAW: Gentlemen, thank y'all. And
6 you are excused.

7 MR. GRUBB: Thank you.

8 CHAIRMAN SHAW: I'll ask the court reporter
9 at this time to make all exhibits a part of the
10 record.

11 Any other housekeeping matters?

12 (No response.)

13 CHAIRMAN SHAW: Hearing none, we're
14 adjourned. Thank y'all.

15 (Whereupon, the proceedings ended at 6:25 p.m.)

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C E R T I F I C A T E

I Brenda P. Elwell, Certified Court Reporter,
do hereby certify that the foregoing transcript is an
accurate record of the proceedings had in the
above-entitled matter at the time and place therein set
forth.



Kelley Marie Nadotti, RPR, CCR
CCR 6256-8388-8026-4192



Brenda P. Elwell, RPR, CCR, B-2023

EXHIBIT 1 – Cost Impact by Rate Group Sensitivity

	<u>Domestic</u>	<u>Small Business</u>	<u>Medium Business</u>	<u>Large Business</u>	<u>Agricultural</u>	<u>Government</u>	<u>Lighting</u>	<u>Marginal</u>	<u>Total Retail</u>
2022 Rate Case Test Year									
Net Income	668,694	169,009	331,733	69,040	3,556	21,616	33,058	219,114	1,515,820
Return On Investment	5.21%	7.28%	9.35%	8.66%	6.31%	3.71%	7.96%	6.33%	6.31%
<i>from Exhibit LPE-1, Schedule 1.00</i>									
Adjusted with 2023 IRP Update - 2028 Costs and Revenues									
Net Income	755,793	181,601	358,497	76,106	3,894	26,158	33,630	530,865	1,966,544
Return On Investment	5.51%	7.40%	9.35%	8.74%	6.47%	4.15%	8.05%	9.83%	7.18%
Difference									
Net Income	87,099	12,592	26,764	7,066	338	4,542	571	311,751	450,724
Return On Investment	0.3%	0.1%	0.0%	0.1%	0.2%	0.4%	0.1%	3.5%	0.9%

Rebuttal Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, Michael B. Robinson, and Michael A. Bush

On behalf of Georgia Power Company

Docket No. 55378

Exhibit 1 - Page 1

EXHIBIT 2 – Revised TS Attachment D to the Yates Certification Application

Comparison of Advanced Frame Simple-Cycle Combustion Turbine Projects - Amended Canal 3 and Grand River 2024 \$ Cost (in red)

Project	Plant Yates CT Units 8, 9, & 10*	Canal 3 (ref 1,2,3)***	Grand River Dam Authority (ref 4,5)****
Plant Capacity (MW)	1,325	350	420
Reported Completion Cost (k\$)	REDACTED	\$280,000	\$410,000
Actual Project Cost (\$/kW)	REDACTED	\$800	\$976
Reported Completion Cost (2024 k\$)**	REDACTED	\$336,375	REDACTED
Current Project Cost (2024\$/kW)**	REDACTED	\$961	REDACTED
Location	Newnan, GA	Sandwich, MA	Chouteau, OK
Site	Existing	Existing	Existing
Owner	Georgia Power Company	Stonepeak Infrastructure Partners	Grand River Dam Authority
EPC Contractor	Black and Veatch/Mitsubishi	Burns & McDonnell/Skanska USA Civil	Unknown
Commercial Operation	12/1/2026, 5/1/2027, 8/1/2027	June-2019	April-2026
Configuration	Simple Cycle CT	Simple Cycle CT	Simple Cycle CT
Turbine Technology	Mitsubishi M501 JAC	GE 7HA.02	Mitsubishi M501 JAC
Fuel Type	NG/ULSD	NG/ULSD	NG/Unknown
Emissions Control	Hot SCR	Hot SCR	Unknown

*Yates CT cost of gas lateral and financing excluded for comparison

**Values adjusted using escalation of REDACTED

***Amended values for Canal 3 based on GDP Price Deflator | U.S. Bureau of Economic Analysis (BEA) (<https://www.bea.gov/data/prices-inflation/gdp-price-deflator>)

****Amended values for Grand River to assume published cost is in nominal 2026\$

References

- 1) <https://gasturbine-world.com/simple-cycle-350-mw-7ha-02-peaking-plant/>
- 2) <https://www.nsenergybusiness.com/news/burns-mcdonnell-canal-3-power-plant/>
- 3) <https://www.power-eng.com/gas/gas-and-diesel-fired-canal-3-station-completed-at-cape-cod/#gref>
- 4) <https://power.mhi.com/regions/amer/news/100323>
- 5) <https://www.readfrontier.org/stories/grand-river-dam-authority-looks-to-replace-its-last-coal-fired-generator-with-a-new-410-million-project/#:~:text=The%20Grand%20River%20Dam%20Authority,River%20Energy%20Center%20in%20Choteau.>

Rebuttal Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, Michael B. Robinson, and Michael A. Bush
On behalf of Georgia Power Company
Docket No. 55378
Exhibit 2 - Page 1

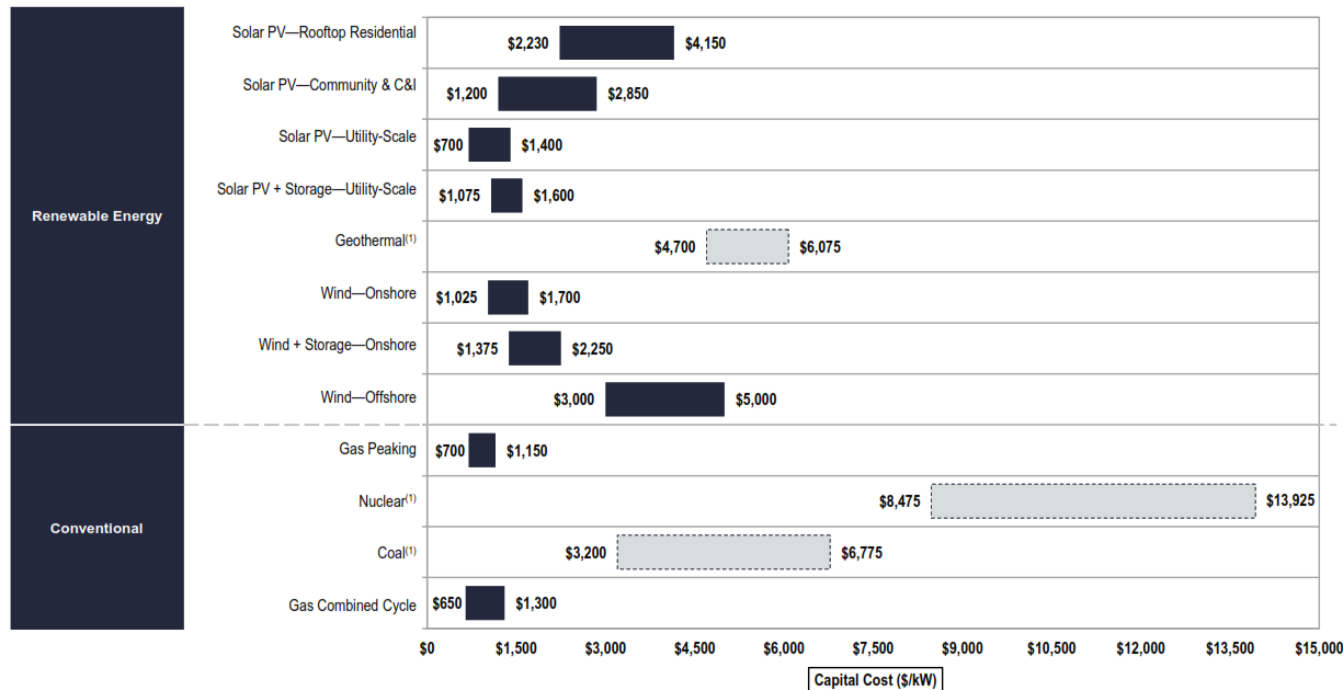
EXHIBIT 3 – Capital Cost Comparison from Lazard’s 2023 Levelized Cost of Energy Analysis



I LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 16.0

Levelized Cost of Energy Comparison—Capital Cost Comparison

In some instances, the capital costs of renewable energy generation technologies have converged with those of certain conventional generation technologies, which coupled with improvements in operational efficiency for renewable energy technologies, have led to a convergence in LCOE between the respective technologies



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Source: Lazard and Roland Berger estimates and publicly available information.

Notes: Figures may not sum due to rounding.

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

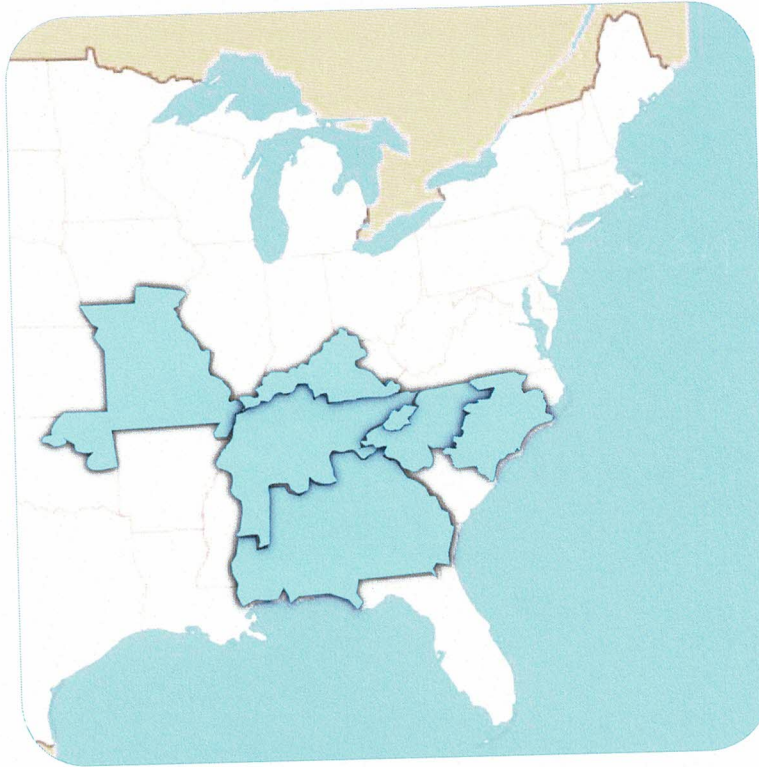
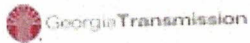
11 |

Rebuttal Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, Michael B. Robinson, and Michael A. Bush
On behalf of Georgia Power Company
Docket No. 55378
Exhibit 3 - Page 1

SERTP Southeastern Regional Transmission Planning

Economic Planning Studies Final Results

Associated Electric
Cooperative Inc.



November 27, 2023

Update Posted: 12/04/2023

2. Study Request 2 Results

***South Georgia to North Georgia – Summer
2028***

1600 MW

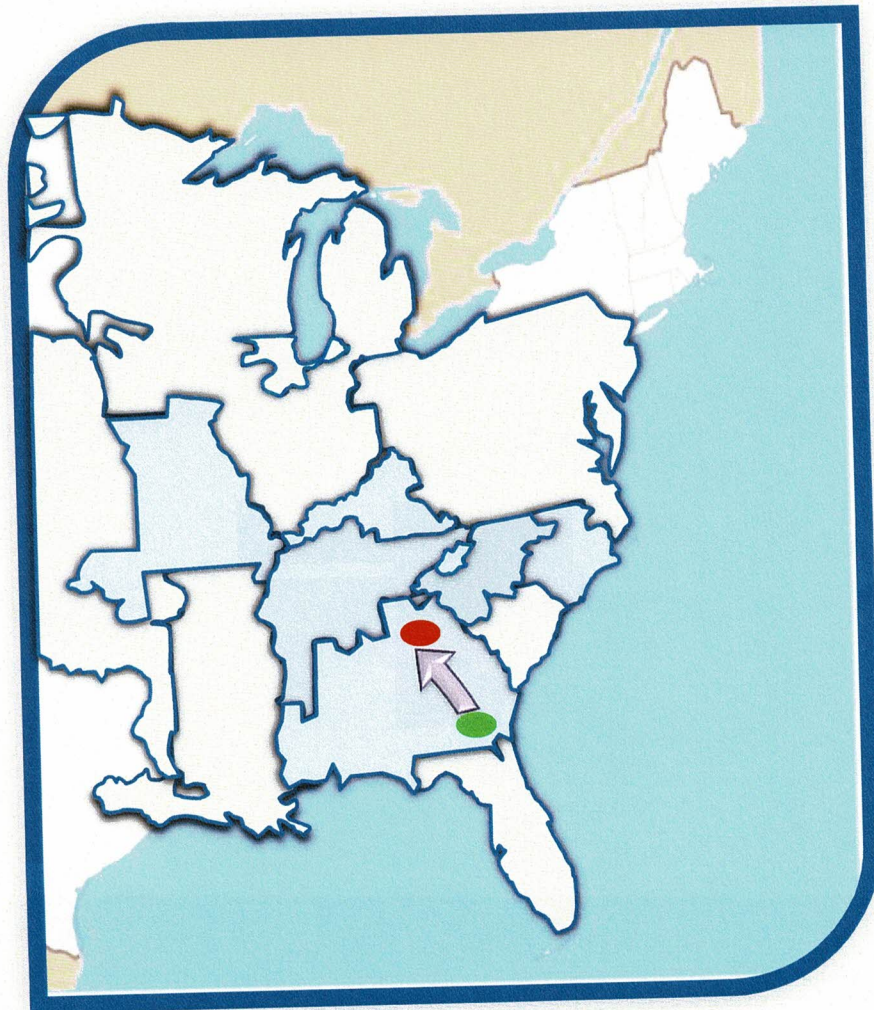
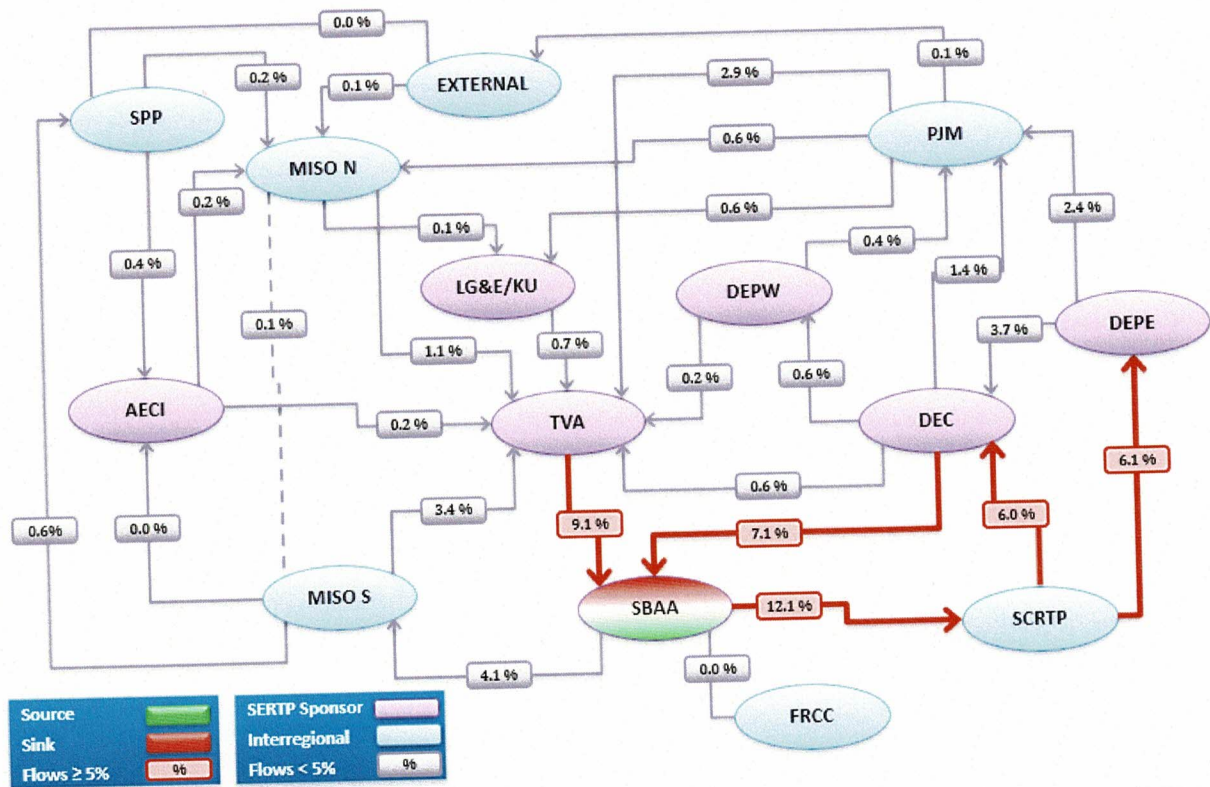


Table II.1.1.1. Total Cost Identified by the SERTP Sponsors

Balancing Authority Area	Planning Level Cost Estimate
Associated Electric Cooperative (AECI)	\$0
Duke Carolinas (DEC)	\$0
Duke Progress East (DEPE)	\$0
Duke Progress West (DEPW)	\$0
Louisville Gas & Electric and Kentucky Utilities (LG&E/KU)	\$0
PowerSouth (PS)	\$0
Southern (SBAA)	\$94,990,000
Tennessee Valley Authority (TVA)	\$925,000
TOTAL (\$2023)	\$95,915,000

Diagram II.1.1. Transfer Flow Diagram (% of Total Transfer)



Associated Electric Cooperative Balancing Authority Area (AECI) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.2.1. Pass 0 – Transmission System Impacts with No Enhancements – AECI

The following table identifies significant *AECI* thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
AECI	None Identified	–	–	–	–	–	–

Scenario Explanations:

1. N/A

Table II.2.2. Pass 1 – Potential Future Transmission System Impacts – AECI

The following table depicts thermal loadings of **AECI** transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
AECI	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.2.3. Potential Solutions for Identified Problems – AECI

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
--	None Required	--	--
AECI TOTAL (\$2023)			\$0 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

Duke Carolinas Balancing Authority Area (DEC) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.3.1. Pass 0 – Transmission System Impacts with No Enhancements – DEC

The following table identifies significant *DEC* thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
DEC	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.3.2. Pass 1 – Potential Future Transmission System Impacts – DEC

The following table depicts thermal loadings of **DEC** transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
DEC	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.3.3. Potential Solutions for Identified Problems – DEC

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
--	None Required	--	--
DEC TOTAL (\$2023)			\$0 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

Duke Progress East Balancing Authority Area (DEPE) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.4.1. Pass 0 – Transmission System Impacts with No Enhancements – DEPE

The following table identifies significant **DEPE** thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
DEPE	None Identified	–	–	–	–	–	–

Scenario Explanations:

1. N/A

Table II.4.2. Pass 1 – Potential Future Transmission System Impacts – DEPE

The following table depicts thermal loadings of **DEPE** transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
--	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.4.3. Potential Solutions for Identified Problems – DEPE

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
--	None Required	--	--
DEPE TOTAL (\$2023)			\$0 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

Duke Progress West (DEPW) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.5.1. Pass 0 – Transmission System Impacts with No Enhancements – DEPW

The following table identifies significant *DEPW* thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
DEPW	None Identified	–	–	–	–	–	–

Scenario Explanations:

1. N/A

Table II.5.2. Pass 1 – Potential Future Transmission System Impacts – *DEPW*

The following table depicts thermal loadings of *DEPW* transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
DEPW	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.5.3. Potential Solutions for Identified Problems – DEPW

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
--	None Required	--	\$0
DEPW TOTAL (\$2023)			\$0 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

Louisville Gas & Electric and Kentucky Utilities Balancing Authority Area (LG&E/KU) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.6.1. Pass 0 – Transmission System Impacts with No Enhancements – LG&E/KU

The following table identifies significant LG&E/KU thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
LG&E/KU	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.6.2. Pass 1 – Potential Future Transmission System Impacts – LG&E/KU

The following table depicts thermal loadings of **LG&E/KU** transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
LG&E/KU	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.6.3. Potential Solutions for Identified Problems – LG&E/KU

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
--	None Required	--	--
LG&E/KU TOTAL (\$2023)			\$0 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

PowerSouth Planning Authority Area (PS) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.7.1. Pass 0 – Transmission System Impacts with No Enhancements – PS

The following table identifies significant **PS** thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
PS	None Identified	—	—	—	—	—	—

Scenario Explanations:

1. N/A

Table II.7.2. Pass 1 – Potential Future Transmission System Impacts – PS

The following table depicts thermal loadings of **PS** transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
PS	None Identified	--	--	--	--	--	--

Scenario Explanations:

1. N/A

Table II.7.3. Potential Solutions for Identified Problems – PS

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
--	None Required	--	--
PS TOTAL (\$2023)			\$0 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

Southern Balancing Authority Area (SBAA) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.8.1. Pass 0 – Transmission System Impacts with No Enhancements – SBAA

The following table identifies significant **SBAA** thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
SBAA	380084 6FAIRBURN 1 230.00 382709 6UNIONCTY B2 230.00 1	602	89.0	106.4	380023 8WANSLEY 500.00 383034 8HEARD CO 500.00 1	1	P1
SBAA	380084 6FAIRBURN 1 230.00 381932 6LINE CREEK 230.00 1	596	90.6	108.2	380023 8WANSLEY 500.00 383034 8HEARD CO 500.00 1	1	P2
SBAA	381932 6LINE CREEK 230.00 382708 6UNIONCTY B1 230.00 1	602	89.9	107.4	380023 8WANSLEY 500.00 383034 8HEARD CO 500.00 1	1	NA*
SBAA	380147 6BRANCH 230.00 381689 6FORREST LK 230.00 1	596	91.4	101.0	380152 6EATONTON SW 230.00 382436 6OASIS 230.00 1	2	P3
SBAA	380152 6EATONTON SW 230.00 382436 6OASIS 230.00 1	602	93.8	103.2	380147 6BRANCH 230.00 381689 6FORREST LK 230.00 1	1	P4
SBAA	384403 3CROOK CK 115.00 385200 3SWAGG 115.00 1	140	73.3	101.5	380010 8FORTSON 500.00 383033 8TENASKA GA 500.00 1	1	P5

*Project not in version 1 models, but is in the 2023 Expansion Plan

Scenario Explanations:

- McDonough Unit 6 Offline
- Wansley Unit 7 Offline

Table II.8.2. Pass 1 – Potential Future Transmission System Impacts – SBAA

The following table depicts thermal loadings of **SBAA** transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
SBAA	381331 3SIGMAN RD 115.00 381914 3CORNISH MTN 115.00 1	188	88.1	93.9	380096 6CONYERS 230.00 380465 3CONYERS 115.00 1	1	--
SBAA	380288 3FAYTVL RD J 115.00 380289 3MURRAY LK J 115.00 1	140	86.2	92.4	380297 3MORROW B1 115.00 381237 3FT GILLEM 115.00 1	1	--
SBAA	380289 3MURRAY LK J 115.00 382707 3MORROW B3 115.00 1	135	89.4	95.8	380297 3MORROW B1 115.00 381237 3FT GILLEM 115.00 1	1	--
SBAA	380300 3BARNETT RD 115.00 382701 3MTN VIEW B2 115.00 1	138	83.5	92.0	380028 6WELCOME ALL 230.00 382708 6UNIONCTY B1 230.00 1	1	--
SBAA	380734 3BERNHARD RD 115.00 381296 3HARP RD 115.00 1	174	79.5	94.4	380023 8WANSLEY 500.00 383034 8HEARD CO 500.00 1	2	--
SBAA	382480 6YELLOW DIRT 230.00 382485 6HICK LVL B1 230.00 1	776	80.1	93.8	380023 8WANSLEY 500.00 383034 8HEARD CO 500.00 1	2	--
SBAA	382028 3JEFFERSN RD 115.00 382036 3RUSSELL 115.00 1	124	92.0	97.7	380430 3WINDER P B1 115.00 382758 3WINDER P B2 115.00 1	1	--
SBAA	381579 6MULBERRY GR 230.00 381598 6HOPEWELL CH 230.00 1	509	75.9	91.0	380010 8FORTSON 500.00 383033 8TENASKA GA 500.00 1	2	--
SBAA	381579 6MULBERRY GR 230.00 382231 6FORTSON B1 230.00 1	509	78.1	93.1	380010 8FORTSON 500.00 383033 8TENASKA GA 500.00 1	2	--
SBAA	380604 3W PT DAM 115.00 380605 3PITTMAN RD 115.00 1	124	86.9	93.1	380603 3W POINT 2 115.00 384459 3W PT DS 115.00 1	1	--
SBAA	380159 6EATONTON AB 230.00 381689 6FORREST LK 230.00 1	596	88.3	97.9	380152 6EATONTON SW 230.00 382436 6OASIS 230.00 1	1	--
SBAA	380153 3ROBINS SP 115.00 381613 3KAOLIN J 115.00 1	115	83.2	92.5	380317 8ROCKVILLE 500.00 383052 8WARTHEN 500.00 1	1	--
SBAA	380137 6PITTS 230.00 381603 6KATHLEEN 230.00 1	433	65.4	92.0	380013 8BONAIRE 500.00 380014 8HATCH 500.00 1	1	--
SBAA	380137 6PITTS 230.00 383201 6RED PEBBLE 230.00 1	433	76.7	98.0	380013 8BONAIRE 500.00 380014 8HATCH 500.00 1	1	--
SBAA	380159 6EATONTON AB 230.00 382368 6NEWBORN RD 230.00 1	602	85.2	94.6	380152 6EATONTON SW 230.00 382436 6OASIS 230.00 1	1	--
SBAA	384404 3MORR XRD 115.00 384405 3RANBURNE 115.00 1	135	67.4	96.4	380010 8FORTSON 500.00 383033 8TENASKA GA 500.00 1	1	--
SBAA	384404 3MORR XRD 115.00 385200 3SWAGG 115.00 1	140	70.8	98.9	380010 8FORTSON 500.00 383033 8TENASKA GA 500.00 1	1	--
SBAA	384924 3MTVMILTP 115.00 385116 3TUSK TAP 115.00 1	138	75.6	92.3	382500 8RACCOON CK 500.00 384600 8FARLEY 8 500.00 1	1	--
SBAA	384924 3MTVMILTP 115.00 385947 3THURLOW B2 115.00 1	138	80.0	96.7	382500 8RACCOON CK 500.00 384600 8FARLEY 8 500.00 1	1	--
SBAA	317096 6CHATOM 6 230.00 318001 6WAYNE230 230.00 1	335	85.0	90.8	317105 6LOWMAN6 230.00 384586 6W MCTSH6 230.00 1	2	--

Scenario Explanations:

1. McDonough Unit 6 Offline
2. Wansley Unit 7 Offline

Table II.8.3. Potential Solutions for Identified Problems – SBAA

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
P1	SOCO: Rebuild the line with bundled 200C 1351 ACSS Martin conductor. Replace the 2000A line trap at Union City with 4000A line trap. Replace switches at Union City with 4000A switches. Replace switch at Fairburn #1 with 4000A switch.	Summer 2028	\$8,750,000
P2	SOCO: Rebuild the line with bundled 200C 1351 ACSS Martin conductor. Replace switch at Fairburn #1 with 4000A switch. Replace the 1590 AAC jumper at Fairburn #1 with 3-1590 AAC jumper.	Summer 2028	\$10,650,000
P3	SOCO: Rebuild the line with 160C 1351 ACSS conductor. Replace the 2-750 AAC jumper at Eatonton Primary with 2-1590 AAC.	Summer 2028	\$3,691,000
P4	SOCO: Rebuild the line with 160C 1351 ACSS conductor. Replace the 1590 AAC jumper at Branch with 2-1590 AAC.	Summer 2028	\$71,905,000
P5	SOCO: Project to reconductor the line from 397 30/7 ACSR 100°C to 795 26/7 ACSR 100°C from Crooked Creek TS to Indian Creek Metering Station planned for 2029 cannot be advanced.	Summer 2028	--
SBAA TOTAL (\$2023)			\$94,990,000 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

Tennessee Valley Authority Balancing Authority Area (TVA) Results

Study Structure and Assumptions

Transfer Sensitivity	Amount	Source	Sink	Year
South Georgia to North Georgia	1600 MW	South Georgia	North Georgia	2028
Load Flow Cases				
2023 Series Version 1 SERTP Models: Summer Peak				

Transmission System Impacts

The following tables below identify any constraints attributable to the requested transfer for the contingency and scenario that resulted in the most significant loadings for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

Table II.9.1. Pass 0 – Transmission System Impacts with No Enhancements – TVA

The following table identifies significant **TVA** thermal constraints without any enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
TVA	Charleston-Hiwassee River 161 kV	289.5	108.7	118.6	Sequoyah-Bradley 500 kV	1	1
TVA	Hiwassee River-East Cleveland 161 kV	289.5	99.6	109.6	Sequoyah-Bradley 500 kV	1	1
TVA	Chickamauga-Hawthorne 161 kV	226.7	103.2	108.4	Bradley-Conasauga 500 kV	1	2
TVA	Chickamauga-Hawthorne 161 kV	226.7	103.2	108.4	Conasauga-Mosteller 500 kV	1	2

Scenario Explanations:

1. No Unit Out of Service

Table II.9.2. Pass 1 – Potential Future Transmission System Impacts – TVA

The following table depicts thermal loadings of **TVA** transmission facilities that could become potential constraints in future years or with different queuing assumptions but are not overloaded in the study year with all proposed enhancements to the transmission system.

Area	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
TVA	Sequoyah-Concord 161 kV	350.0	89.7	97.2	Sequoyah-Bradley 500 kV	1	
TVA	Trafford-Fultondale 115 kV	92.8	90.5	95.9	East Point 500/161 kV	1	
TVA	Trafford-Fultondale 115 kV	92.8	90.2	95.6	East Point-Fairview Tap 161 kV	1	
TVA	Oglethorpe 161/230 kV	289.5	88.2	95.0	Concord 161/230 kV	1	
TVA	Oglethorpe 161/230 kV	289.5	88.0	94.8	West Ringgold-Concord 230 kV	1	
TVA	Trafford-Fultondale 115 kV	92.8	88.9	94.2	Fairview Tap-Arab 161 kV	1	
TVA	Trafford-Fultondale 115 kV	92.8	88.0	93.5	Lowndes-Valley View 500 kV	1	
TVA	Trafford-Fultondale 115 kV	92.8	87.0	92.0	Decatur-Priceville Tap 161 kV	1	
TVA	Trafford-Fultondale 115 kV	92.8	83.3	91.7	Arab-Guntersville 161 kV	1	
TVA	Trafford-Fultondale 115 kV	92.8	85.7	90.8	Priceville Tap-Winton 161 kV	1	

Scenario Explanations:

1. No Unit Out of Service

Table II.9.3. Potential Solutions for Identified Problems – TVA

The following table lists any potential solutions that were identified to address the attributable constraints based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
1	Upgrade terminal equipment at Charleston and East Cleveland 161 kV substations.	2028	\$775,000
2	Upgrade terminal equipment at Chickamauga Hydro Plant.	2028	\$150,000
TVA TOTAL (\$2023)			\$925,000 ⁽¹⁾

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

January 1 of the following year. The update will reflect the split between revenues collected from inside city limits, on the one hand, and outside city limits, on the other, based on the most recent twelve months of actual data. As proposed, the MFF tariff will collect an additional \$20 million in 2023 and will continue to apply as a percentage of total revenues, including the revenues generated from all tariffs incorporated into the standard base tariffs (which include, without limitation, the DSM, FCR, ECCR, and NCCR tariffs). The percentage that is ultimately applied to total revenues will depend upon customer location (i.e., whether the customer is located inside or outside the limits of a city with which the Company has a franchise agreement).

Q. WHAT IS THE IMPACT OF THE COMPANY'S PROPOSED RATE INCREASE ON EACH OF THE EIGHT RATE GROUPS?

A. As proposed in the Company's ARP, the average increase on an after-fuel basis across all rate groups is approximately 10.2% in 2023 (including ECCR, DSM and MFF). The bill impact for a typical residential customer using an average of 1,000 kilowatt hours per month is \$14.32. The impact to each of the Company's eight rate groups on an after-fuel basis is as follows:

Rate Group	2023 Bill Impact*
Domestic	11.4%
Small Business	12.0%
Medium Business	10.9%
Large Business	9.8%
Agriculture	10.5%
Government / Institution	9.9%
Outdoor Lighting	12.3%
Marginally Priced	6.3%

*All impact percentages include the effects of base rate increases and updated ECCR, DSM and MFF tariffs.

1 The variation in percentage increases is due, in part, to the differences in the ratio of
2 fuel costs to the total bill for each group. Moreover, consistent with existing practice,
3 the base rate increase is not applied to incremental RTP usage.

4 For years 2024 and 2025, the projected average increases for the adjustments to rates
5 for CCR ARO compliance costs, DSM, and MFF (as discussed above) are
6 approximately 1.2% and 0.5% respectively, with estimated monthly bill impacts for a
7 typical residential customer of \$1.35 and \$0.62.

8 **III. PROPOSED CHANGES TO EXISTING PRICING PROGRAMS**
9 **AND TARIFFS**

10 **Q. IS GEORGIA POWER PROPOSING ANY CHANGE TO EXISTING PRICING**
11 **PROGRAMS AND TARIFFS?**

12 A. Yes. The Company is proposing changes to the following programs and tariffs:
13 Residential Service ("R"), FlatBill ("FLAT"), FlatBill General Service ("FLAT-GS"),
14 Income-Qualified Senior Citizen Discount program, Roadway Lighting Governmental
15 ("RLG"), Demand Plus Energy Credit ("DPEC"), RNR, Community Solar ("CS"), and
16 Simple Solar ("SS").

17 **Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO THE R**
18 **TARIFF.**

19 A. The Company proposes to modify the R tariff to make the rate unavailable to newly
20 constructed residential premises that are established on Georgia Power's system after
21 December 31, 2022. This proposal is the logical next step in the Company's ongoing
22 efforts to encourage residential customers to move toward more modern rate structures.
23 As initially discussed in the Company's 2019 base rate case, utilities across the country
24 are proactively moving away from more antiquated volumetric rate designs (such as
25 the R tariff) and toward more modern rate designs that send price signals that more
26 appropriately reflect the cost of service.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
Hearing Request Set Number 1

AS UPDATED BY GEORGIA INTERFAITH POWER & LIGHT

HR-1-5

Information requested by: Georgia Interfaith Power & Light – Whitfield (Tr. 364)

Question:

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. But, again, we would have to go back and look at what the outages were and those types of things. But, again, not saying that they don't ever perform, but at the end of the day, there is a different reliability responsibility.

MS. WHITFIELD: Chairman Shaw, could we make that a hearing request that they provide that PPA information?

CHAIRMAN SHAW: Yes.

MR. HEWITSON: Well, can I confirm what the hearing request is?

MS. WHITFIELD: For evidence that PPAs have been unable to perform as they're contractually required in order to meet customer load.

MR. HEWITSON: Based on what statement? Mr. Grubb said that there's a difference in reliability. I don't think he said that they're unable to perform. So I'm just trying to figure out how we respond to it. It's an allegation made, asking us to respond. If there's data that we can provide, I mean, is there --

MS. WHITFIELD: It's not an allegation. It's a question. He said he wasn't sure. Seems pretty important if this is sort of the legal basis of your request.

MR. HEWITSON: Yeah. But I'm asking for what is the data that we would need to refer -- I mean, a hearing request is for data.

MS. WHITFIELD: Yes. For the instances, the times when PPAs have been unable to perform, as contractually required and that's endangered customer load, the company's ability to meet customer load.

Response:

See the tables below for unavailable capacity, total capacity, and percentage of total capacity for which an unavailability event occurred during the periods of highest reliability risk during two recent winter storm events: Winter Storm Elliott in December 2022 and Winter Storm Heather in January 2024. This information is provided for Georgia Power's aggregated capacity power purchase agreement ("PPA") resources and Georgia Power's owned capacity resources.

Contact: Jeff Grubb



Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
Hearing Request Set Number 1

AS UPDATED BY GEORGIA INTERFAITH POWER & LIGHT

Please note that an Energy Emergency Alert was declared by the Southern Balancing Authority in each winter storm event.

Winter Storm Elliott (December 24, 2022, Hours 1-13 CST)

	Unavailable Capacity (MW)	Total Capacity (MW)	Percentage with Unavailability Event
GPC Capacity PPA Resources	1,031	4,145	25%
PPA with “Payment Reduction”¹	267	4,145	6%
GPC Owned Capacity Resources	2,061	14,092	15%

Winter Storm Heather (January 17, 2024, Hours 4-9 CST)

	Unavailable Capacity (MW)	Total Capacity (MW)	Percentage with Unavailability Event
GPC Capacity PPA Resources	523	4,145	13%
PPA with “Payment Reduction”	171	4,145	4%
GPC Owned Capacity Resources	602	14,666	4%

¹ Email chain between S. Hewitson to J. Whitfield, RE Hearing Request – GIPL 1-5:

Q: [H]ow many of the “unavailable” megawatts listed in GPC’s response to HR-1-5 were unavailable due to contractual violations of the relevant PPA? ... If [GPC] can’t make that determination w/o a case-by-case evaluation, a proxy question could be – how many times (involving how many MWs) did they seek damages for non-delivery of PPA power (for these two events)?

A: “One way to find the information for you was to determine how many of the PPAs had payment reductions for being unavailable. That information is as follows:

- 267 MW of the 1,031 MW unavailable had PPA payment reductions during Winter Storm Elliott; and
- 171 MW of the 523 MW unavailable had PPA payment reductions during Winter Storm Heather.”

From: Hewitson, Steven J. <steven.hewitson@troutman.com>
Sent: Wednesday, February 14, 2024 2:57 PM
To: Jennifer Whitfield <jwhitfield@selcga.org>
Cc: Bob Sherrier <bsherrier@selcga.org>
Subject: RE: Hearing Request - GIPL - 1-5

Sure, we can do that. Not entirely certain when, but we can get to it soon.

Steven J. Hewitson

Partner

troutman pepper

Direct: 404.885.3475 | Mobile: 404.202.7807 | Internal: 11-3475
steven.hewitson@troutman.com

From: Jennifer Whitfield <jwhitfield@selcga.org>
Sent: Wednesday, February 14, 2024 2:56 PM
To: Hewitson, Steven J. <steven.hewitson@troutman.com>
Cc: Bob Sherrier <bsherrier@selcga.org>
Subject: RE: Hearing Request - GIPL - 1-5

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This is helpful. Thanks. Will you supplement your formal response?

From: Hewitson, Steven J. <steven.hewitson@troutman.com>
Sent: Wednesday, February 14, 2024 9:14 AM
To: Jennifer Whitfield <jwhitfield@selcga.org>
Cc: Bob Sherrier <bsherrier@selcga.org>
Subject: RE: Hearing Request - GIPL - 1-5

Jennifer –

One way to find the information for you was to determine how many of the PPAs had payment reductions for being unavailable. That information is as follows:

- 267 MW of the 1,031 MW unavailable had PPA payment reductions during Winter Storm Elliott; and
- 171 MW of the 523 MW unavailable had PPA payment reductions during Winter Storm Heather.

Please let me know if that provides the information you were seeking.

-Steve

Steven J. Hewitson

Partner

troutman pepper

Direct: 404.885.3475 | Mobile: 404.202.7807 | Internal: 11-3475

steven.hewitson@troutman.com

From: Jennifer Whitfield <jwhitfield@selcga.org>

Sent: Friday, February 9, 2024 5:35 PM

To: Hewitson, Steven J. <steven.hewitson@troutman.com>

Cc: Bob Sherrier <bsherrier@selcga.org>

Subject: RE: Hearing Request - GIPL - 1-5

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Makes sense. Thanks. If they can't make that determination w/o a case-by-case evaluation, a proxy question could be – how many times (involving how many MWs) did they seek damages for non-delivery of PPA power (for these two events)?

From: Hewitson, Steven J. <steven.hewitson@troutman.com>

Sent: Friday, February 9, 2024 5:31 PM

To: Jennifer Whitfield <jwhitfield@selcga.org>

Cc: Bob Sherrier <bsherrier@selcga.org>

Subject: RE: Hearing Request - GIPL - 1-5

Let me check with the Company to see if they can determine that information without reviewing every PPA and every instance where the generator delivered less than the contracted amount to determine whether it was a violation of the PPA.

Steven J. Hewitson

Partner

troutman pepper

Direct: 404.885.3475 | Mobile: 404.202.7807 | Internal: 11-3475

steven.hewitson@troutman.com

From: Jennifer Whitfield <jwhitfield@selcga.org>
Sent: Friday, February 9, 2024 4:43 PM
To: Hewitson, Steven J. <steven.hewitson@troutman.com>
Cc: Bob Sherrier <bsherrier@selcga.org>
Subject: Hearing Request - GIPL - 1-5

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Hey Steve,

Georgia Power has not yet completed its response to our hearing request. In an effort to get closer to an answer, could you please let us know how many of the “unavailable” megawatts listed in GPC’s response to HR-1-5 were unavailable due to contractual violations of the relevant PPA?

Thanks,
Jennifer

Jennifer Whitfield
Senior Attorney

Southern Environmental Law Center
10 10th St NW, Suite 1050
Atlanta, GA 30312

Office (404) 521-9900
Direct (678) 277-4821
Fax (404) 521-9909

southernenvironment.org
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From: [Johnson, Cheryl](#)
To: [Robert Trokey](#)
Subject: RE: 2029 - 2031 Capacity RFP
Date: Wednesday, March 29, 2023 1:06:31 PM

Hi, Rob. Following up with you, we do not currently have a schedule for the Capacity RFP, but we are having internal discussions on all of our upcoming procurements issued from the 2022 IRP. We anticipate communicating with Staff on the Capacity RFP no later than June.

Thanks,



Georgia Power

Cheryl Johnson | Georgia Power Regulatory Affairs | Regulatory Affairs Manager
Office: 404.506.6837 | Cell: 404-353-9316 | Email: cljohnso@southernco.com

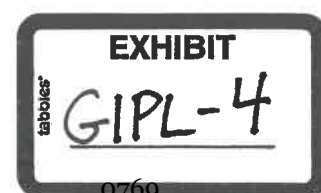
From: Robert Trokey <rtrokey@psc.ga.gov>
Sent: Thursday, March 2, 2023 2:11 PM
To: Johnson, Cheryl <cljohnso@southernco.com>
Subject: 2029 - 2031 Capacity RFP

EXTERNAL MAIL: Caution Opening Links or Files

Does the Company have a tentative schedule for the RFP?

Thanks.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284



From: [Pryor, Allison](#)
To: [Robert Trokey](#); [Johnson, Cheryl](#)
Cc: [Tom Newsome](#); [Preston Thomas](#); [Jamie Barber](#)
Subject: RE: RFI Document and IM Contract
Date: Friday, August 25, 2023 5:34:26 PM
Attachments: [GPC RFP Certification Chart.docx](#)
[GPC RFP Evaluation Schedules.xlsx](#)

Rob,

As the Company continues its review of the draft All-Source RFP Schedule Staff sent over, we wanted to share our initial feedback. Our primary concern is that the amount of time allotted for the evaluation period is much too short, especially given the vast amount of MW that will need to be procured in the All-Source RFP for 2029 – 2031. The other concern is trying to finish the RFP in time to have resources certified as part of the 2025 IRP. We don't think it is necessary or advantageous to do so.

To help provide some context for the Company's concerns, please find attached information that we hope will be of assistance as we continue to discuss the All-Source RFP in the coming weeks. One is the history of certification filings for competitively procured resources since 2006 and the other is a chart identifying the duration of the evaluation periods for several of the Company's past solicitations compared to the evaluation durations proposed by Staff. As you see in the attached, and as we have mentioned in our past meetings, the 2022 IRP was the only time in the last 17 years where PPAs were certified within an IRP and the specific intent from the get-go of the 2022-2028 Capacity RFP was to have resources in hand for evaluation alongside the 2022 IRP. While this was the most recent Capacity RFP presented to the Commission, the 2022-2028 RFP schedule was atypical by comparison to the Company's other RFP processes.

We wanted to provide you this initial concern, but fully intend to meet with Staff in the coming weeks to discuss these and any other concerns further as well as pros and cons with Staff's recommendations, etc.

A few more thoughts we wanted to share on the schedule and a few other items.

- **RFP schedule:** As mentioned above, please note our concern with the evaluation timeframe, and specifically the time needed for transmission evaluations. Transmission is a major component and most complicated part of the evaluation and is only getting more complicated. Given that this is an all-source RFP and that many if not most of the resources to be proposed will be new facilities (rather than existing); along with the huge amount of resources to be evaluated, we foresee quite a lengthy evaluation for the bids proposed in this RFP.
- **RFP Schedule and the IE Contract:** The RFP Schedule is not typically included within or known in advance of entering the IE Contract. The RFP Process begins with the selection of the IE. The Company is then tasked with preparing the first draft of the RFP documents, which includes the solicitation schedule. The RFP Rule contemplates that Staff and the IE will then weigh in and provide feedback on the RFP Documents and schedule. The IE must be hired first for the RFP process to run as intended. Hopefully, we can move forward with the IE Contract as Staff and the Company continue to discuss the All-Source RFP Schedule.

Certification history: As you will see, the only RFP certified in the triennial IRP was the previous 2022-2028 Capacity RFP. As we have discussed in our prior meetings, that RFP was approved in the 2019 IRP specifically for identifying replacement generation for potential coal retirements. Aligning the 2022-2028 RFP to the IRP was important because the IRP is the appropriate forum for recommendations to retire the coal units and certify the replacement. The All-Source RFP is about serving load growth and therefore, like all prior RFPs, the schedule is based on the process to meet need years and not an IRP filing. Also note that traditionally, multiple RFPs were conducted for needs spanning many years, and an RFP was done for each year of need.

- **2023 IRP Update filing:** The Company is evaluating both a second half of September filing or second half of October filing. We will communicate a draft schedule and PSO (including issues involved) as soon as possible once a decision is made in the coming weeks.

We will continue to work with Staff on the many issues we are facing but per your request wanted to share our initial concern on the RFP schedule.

Thanks,
Allison

Allison Pryor

Partner

troutman pepper

Direct: 404.885.3779 | Mobile: 770.851.4199 | Internal: 11-3779

allison.pryor@troutman.com

From: Robert Trokey <rtrokey@psc.ga.gov>

Sent: Thursday, August 24, 2023 3:27 PM

To: Pryor, Allison <Allison.Pryor@troutman.com>; Johnson, Cheryl <cljohnso@southernco.com>

Cc: Tom Newsome <tnewsome@psc.ga.gov>; Preston Thomas <pthomas@psc.ga.gov>; Jamie Barber <jbarber@psc.ga.gov>

Subject: RE: RFI Document and IM Contract

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Allison,

Thanks for sending this back. Staff will review and provide additional questions tomorrow.

I spoke with Cheryl and we will await feedback on Staff's proposed RFP schedule.

Rob Trokey

Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

From: Pryor, Allison <Allison.Pryor@troutman.com>
Sent: Thursday, August 24, 2023 10:29 AM
To: Robert Trokey <rtrokey@psc.ga.gov>; Johnson, Cheryl <cjohnso@southernco.com>
Cc: Tom Newsome <tnewsome@psc.ga.gov>; Preston Thomas <pthomas@psc.ga.gov>; Jamie Barber <jbarber@psc.ga.gov>
Subject: RE: RFI Document and IM Contract

Rob,

Georgia Power has reviewed Staff's additional feedback on the RFI and IM/IE Contract and provided responses in the attached documents. Harry has provided a revised Scope of Work (Attachment A). If Staff is agreeable with the proposed changes, I have also attached a clean copy of the IM/IE Contract for review that includes this new Attachment.

The Company is still reviewing Staff's proposed RFP Schedule and will need additional time to digest it before providing feedback.

Let us know if you have any questions or would like to discuss.

Best,
Allison

Allison Pryor

Partner

troutman pepper

Direct: 404.885.3779 | Mobile: 770.851.4199 | Internal: 11-3779
allison.pryor@troutman.com

From: Robert Trokey <rtrokey@psc.ga.gov>
Sent: Tuesday, August 22, 2023 12:17 PM
To: Pryor, Allison <Allison.Pryor@troutman.com>; Johnson, Cheryl <cjohnso@southernco.com>
Cc: Tom Newsome <tnewsome@psc.ga.gov>; Preston Thomas <pthomas@psc.ga.gov>; Jamie Barber <jbarber@psc.ga.gov>
Subject: RE: RFI Document and IM Contract

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Allison,

Thanks for the responses. Staff has incorporated additional comments (files attached). I've also attached a potential schedule for the RFP. Note that the Committee cycle at the end of this year may be Consent-items only. The accommodation would be to push the approval request back to the first Energy Committee in January 2024.

Please reach out to me or Preston if you have any questions or would like to discuss further.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

From: Pryor, Allison <Allison.Pryor@troutman.com>
Sent: Friday, August 18, 2023 6:51 PM
To: Robert Trokey <rtrokey@psc.ga.gov>; Johnson, Cheryl <cljohnso@southernco.com>
Cc: Tom Newsome <tnewsome@psc.ga.gov>; Preston Thomas <pthomas@psc.ga.gov>; Jamie Barber <jbarber@psc.ga.gov>
Subject: RE: RFI Document and IM Contract

Rob,

The Company has had a chance to review and respond to Staff's comments and suggested revisions to the RFI. The attached draft includes the Company's feedback. In addition, I've attached a draft of the revised IE Contract, which covers Accion's services for the RFI (as an IM), the All Source RFP, and the ESS RFP.

Thanks again for the quick review. Please let Cheryl or I know if you all have questions or would like to discuss further.

Best,
Allison

Allison Pryor
Partner
troutman pepper
Direct: 404.885.3779 | Mobile: 770.851.4199 | Internal: 11-3779
allison.pryor@troutman.com

From: Robert Trokey <rtrokey@psc.ga.gov>
Sent: Thursday, August 17, 2023 3:29 PM
To: Johnson, Cheryl <cljohnso@southernco.com>; Pryor, Allison <Allison.Pryor@troutman.com>
Cc: Tom Newsome <tnewsome@psc.ga.gov>; Preston Thomas <pthomas@psc.ga.gov>; Jamie Barber <jbarber@psc.ga.gov>
Subject: RE: RFI Document and IM Contract

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Cheryl and Allison,

The attached document contains Staff's feedback on the RFI.

Please let me or Preston know if you have questions. Thanks.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

From: Johnson, Cheryl <cljohnso@southernco.com>

Sent: Friday, August 11, 2023 1:36 PM

To: Robert Trokey <rtrokey@psc.ga.gov>

Subject: RFI Document and IM Contract

Rob,

As previewed in the Company's meeting with Staff on July 26th, the Company is moving forward with issuing a Request for Information (RFI). The RFI seeks information on planned or existing capacity resources that could commence delivery between 2026 and 2030 to meet the Company's capacity needs. The Company intends to issue the RFI early next week with responses due by September 1, 2023. The Company views the RFI as a necessary gauge on the availability of market resources and logical next step in the Company's exploration of all available options to meet its updated capacity needs. A copy of the RFI is attached.

In addition, the Company has engaged Harry Judd and Accion Group to serve as an Independent Monitor and to manage the IM Website as the communication portal and host platform for the RFI. Since the RFI will likely collect a lot of the same information as the upcoming All Source RFP, Harry has agreed that his IM Professional Services Fee can be credited toward Accion's professional services fee under the IE Contract for the All Source RFP. A copy of the executed IM Contract is also attached.

We wanted to provide Staff a copy of both documents since although they are separate from the RFP process, they are related pre-cursors to the Commission approved All Source RFP. If you have any questions, please let me know.

Thanks,



Cheryl Johnson | Georgia Power Regulatory Affairs | Regulatory Affairs Manager
Office: 404.506.6837 | Cell: 404-353-9316 | Email: cljohnso@southernco.com

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From: [Robert Trokey](#)
To: [Pryor, Allison](#); [Johnson, Cheryl](#)
Cc: [Tom Newsome](#); [Preston Thomas](#); [Jamie Barber](#)
Subject: RE: RFI Document and IM Contract
Date: Monday, August 28, 2023 3:53:49 PM
Attachments: [IM IE Agreement for RFI All-Source and ESS RFPs \(Clean\).docx.pdf](#)
[20230823_Final ATTACHMENT A SCOPE OF WORK.pdf](#)

Harry, Allison and Cheryl:

As mentioned earlier today and in prior conversations, Staff has concerns with the length of the IM/IE contract. Will the Company or Accion provide an updated contract and scope of work to reflect an 18-month RFP process, concluding in Q1-2025?

Thank you.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

From: [Robert Trokey](#)
To: [Johnson, Cheryl](#)
Cc: [Story, Tyrance J. \(Ty\)](#); [Tom Newsome](#)
Subject: RE: Capacity Needs Meeting Agenda
Date: Friday, September 8, 2023 1:38:31 PM

Thanks.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

From: Johnson, Cheryl <cljohnso@southernco.com>
Sent: Friday, September 8, 2023 1:17 PM
To: Robert Trokey <rtrokey@psc.ga.gov>
Cc: Story, Tyrance J. (Ty) <TJStory@southernco.com>; Tom Newsome <tnewsome@psc.ga.gov>
Subject: RE: Capacity Needs Meeting Agenda

Rob – To answer your question, we have an updated needs chart so we can discuss.

From: Robert Trokey <rtrokey@psc.ga.gov>
Sent: Friday, September 8, 2023 9:55 AM
To: Johnson, Cheryl <cljohnso@southernco.com>
Cc: Story, Tyrance J. (Ty) <TJStory@southernco.com>; Tom Newsome <tnewsome@psc.ga.gov>
Subject: RE: Capacity Needs Meeting Agenda

Cheryl,

The date and time proposed work for Staff. I'll find a conference room at the Commission and ask Operations Support to set up equipment to enable hybrid participation.

Staff did not see anything about the Company's estimated 2027 and 2028 capacity shortfall on the agenda.

What is Georgia Power's plan for 2027 and 2028 capacity shortfall? It seems this needs to be part of the conversation, since it impacts both the all-source RFP and the IE/IM contract.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

From: Johnson, Cheryl <cljohnso@southernco.com>
Sent: Thursday, September 7, 2023 3:07 PM

To: Robert Trokey <rtrokey@psc.ga.gov>
Cc: Story, Tyrance J. (Ty) <TJStory@southernco.com>
Subject: Capacity Needs Meeting Agenda

Rob,

As requested, see below the agenda for the Capacity Needs Meeting with Staff. Also, is Staff available to meet on **September 12th from 10am to 11:30am?**

Agenda:

GPC and Staff Introductions

Purpose of Meeting:

- To provide an overview of the GPC Resource Planning process and review from the 2022 IRP to now
- To engage in deep dive discussions regarding details and timeframes for an RFP schedule to meet capacity needs, specifically the 2029-2031 All-Source RFP

GPC Planning Overview

2022 IRP to Now

Increasing Loads

Timelines Discussion

- Discuss GPC's 2029-2031 All-Source RFP Schedule
- RFP Timelines Comparison (Renewables, Biomass, and Capacity RFPs)
- Discuss pros and cons of Staff's All-Source RFP Schedule
- Evaluation process deep dive

Thanks,



Cheryl Johnson | Georgia Power Regulatory Affairs | Regulatory Affairs Manager
Office: 404.506.6837 | Cell: 404-353-9316 | Email: cljohnso@southernco.com

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From: [Robert Trokey](#)
To: [Johnson, Cheryl](#)
Cc: [Tom Newsome](#)
Subject: Capacity RFP - IE Contract
Date: Tuesday, September 19, 2023 11:21:53 AM

Cheryl,

Do you have an estimate for when the Company will provide feedback on the Capacity RFP schedule? As noted, Staff believes Georgia Power needs to expedite the process.

Looking ahead to next steps, which agenda would the Company like Staff to target for the IE contract approval request?

Thanks.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284