

1 BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

2 STATE OF GEORGIA

3
4 In Re:

5 Georgia Power Company's 2022)
6 Application for Approval of its) Docket No. 44160
7 Integrated Resource Plan)

8 In Re:

9 Georgia Power Company's 2022)
10 Application for Approval of its)
11 Amended DSM Plan and Certification) Docket No. 44161
12 and Decertification of Certain DSM)
13 Programs)

14 VOLUME I

15 Hearing Room 110
16 244 Washington Street
17 Atlanta, Georgia

18 Tuesday, May 24, 2022

19 The above-entitled matter came on for hearing

20 Pursuant to Notice at 9:30 a.m.

21 PRESENT WERE:

22 TRICIA PRIDEMORE, Madam Chair
23 TIM ECHOLS, Vice-Chairman
24 FITZ JOHNSON, Commissioner
25 LAUREN "BUBBA" MCDONALD, Commissioner
 JASON SHAW, Commissioner

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I N D E X

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1 P R O C E E D I N G S

2 MADAM CHAIR PRIDEMORE: Okay. Good morning.
3 This is Docket No. 44160 and Docket No. 44161
4 regarding Georgia Power Company's 2022 application
5 for approval of its integrated resource plan and
6 their application for approval of its amended
7 DSM plan and certification and decertification of
8 certain DSM programs.

9 Appearances.

10 Georgia Public Service Commission.

11 MR. WALSH: Thank you. On behalf of the Public
12 Interest Advocacy Staff, I'm Daniel Walsh with the
13 Georgia Attorney General's Office. And with me
14 today, Preston Thomas and Alex Davis from the Public
15 Service Commission.

16 MADAM CHAIR PRIDEMORE: Georgia Power.

17 MR. MARZO: Thank you, Chair Pridemore,
18 Commissioners. Brandon Marzo, Steve Hewitson, and
19 Allison Pryor for Georgia Power Company.

20 MADAM CHAIR PRIDEMORE: Americans for
21 Affordable Clean Energy.

22 MR. GALLOWAY: Good morning, Madam Chair.
23 Newton Galloway and Terri Lyndall on behalf of AACE.

24 MADAM CHAIR PRIDEMORE: Commercial Group.

25 MR. JENKINS: Good morning, Madam Chair. Alan

1 Jenkins, Commercial Group.

2 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
3 for Georgia.

4 MR. PRENOVITZ: Good morning, ma'am. Steve
5 Prenovitz, Concerned Ratepayers of Georgia.

6 I also have a few administrative issues to --

7 MADAM CHAIR PRIDEMORE: Not time for that yet.
8 We'll come back to you, Mr. Prenovitz.

9 MR. PRENOVITZ: Thank you.

10 MADAM CHAIR PRIDEMORE: Cypress Creek
11 Renewables, LLC.

12 MR. STAIR: Good morning, Commissioners. Jeff
13 Stair on behalf of Cypress Creek Renewables.

14 MADAM CHAIR PRIDEMORE: Georgia Association of
15 Manufacturers.

16 MR. JONES: Clay Jones for GAM.

17 MADAM CHAIR PRIDEMORE: Georgia Center for
18 Energy Solutions.

19 MR. HUBBARD: Good morning, Madam Chair. Peter
20 Hubbard for Georgia Center for Energy Solutions.

21 MADAM CHAIR PRIDEMORE: Georgia Coalition of
22 Local Governments.

23 MS. BROWN: Good morning, Madam Chair. Alicia
24 Brown, John Seydel, David Nifong for the Georgia
25 Coalition of Local Governments.

1 MADAM CHAIR PRIDEMORE: Georgia Interfaith
2 Power & Light and Partnership for Southern Equity.

3 MS. KYSOR: Good morning. Jill Kysor and Nicha
4 Rakpanichmanee for GIPL and PSE.

5 MADAM CHAIR PRIDEMORE: Georgia Large Scale
6 Solar Association and Advanced Power Alliance.

7 MR. CARVER: Brad Carver on behalf of Georgia
8 Large Scale Solar Association and Advanced Power
9 Alliance.

10 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
11 Industries Association, Solar Energy Association, and
12 Vote Solar.

13 MR. THOMASSON: Madam Chair, Scott Thomasson on
14 behalf of GASEI, SEIA and Vote Solar.

15 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
16 Association a/k/a GA Solar.

17 (No response.)

18 MADAM CHAIR PRIDEMORE: Do we have a Donald
19 Moreland with us?

20 (No response.)

21 MADAM CHAIR PRIDEMORE: No, not present.

22 MADAM CHAIR PRIDEMORE: Georgia Watch.

23 (No response.)

24 MADAM CHAIR PRIDEMORE: Ms. Coyle? Did anybody
25 see Ms. Coyle?

1 (No response.)

2 MADAM CHAIR PRIDEMORE: Okay. Interstate Gas
3 Supply.

4 MR. CARVER: Brad Carver and Adam Wise for
5 Interstate Gas Supply.

6 MADAM CHAIR PRIDEMORE: Adam Wise is not listed
7 on the appearance list. Will we be seeing him on the
8 stand?

9 Will he be appearing?

10 MR. CARVER: He is -- he is -- he's part --
11 he's been filed as part of this.

12 MADAM CHAIR PRIDEMORE: Okay. He's not on the
13 appearance list. Check with the executive
14 secretary's office.

15 Resource Supply Management.

16 (No response.)

17 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
18 Coalition.

19 MR. S. JONES: Steven Jones on behalf of RCG.

20 MADAM CHAIR PRIDEMORE: Sierra Club.

21 MS. ARIZA: Good morning. Isabella Ariza, Zach
22 Fabish, and Robert Jackson on behalf of the Sierra
23 Club.

24 MADAM CHAIR PRIDEMORE: Southern Alliance for
25 Clean Energy and Southface Energy Institute.

1 MR. BAKER: Good morning, Commissioner. Robert
2 Baker on behalf of Southface and SACE.

3 MADAM CHAIR PRIDEMORE: Southern Renewable
4 Energy Association.

5 MR. MAHAN: Simon Mahan on behalf of SREA.

6 MADAM CHAIR PRIDEMORE: Glad to see you up and
7 healthy, Mr. Mahan.

8 MR. MAHAN: Thank you.

9 MADAM CHAIR PRIDEMORE: All right. Is there
10 anybody who expects to be on the appearance list, but
11 was not -- I did not call your name?

12 Speak now.

13 (No response.)

14 MADAM CHAIR PRIDEMORE: All right. Do we have
15 any housekeeping matters before us?

16 MR. PRENOVITZ: I do, Madam Chairman.

17 MADAM CHAIR PRIDEMORE: Mr. Prenovitz, go
18 ahead.

19 MR. PRENOVITZ: Three things. One, I'd like to
20 do a medical update on my colleague, Ben Stockton.
21 What happened was he went in to do the preop for
22 rotator cuff surgery. They said: We need to check
23 your heart first.

24 They did. They put that off. Anyway, he had
25 heart surgery three weeks ago. He's recovering. I

1 spoke with him. His voice is strong. So he's doing
2 better. So I'm glad to hear that.

3 MADAM CHAIR PRIDEMORE: Thank you,
4 Mr. Prenovitz. That's good.

5 MR. PRENOVITZ: Thank you, ma'am.

6 The second point is I had a very simple data
7 request for Georgia Power to provide a hard copy of
8 their 2021 annual report, 10K report.

9 They refused saying that basically no
10 intervenor is entitled to any kind of discovery
11 information, which at least wasn't true in the old
12 days, in the 1980s, because we did ask and we got a
13 report. As a matter of fact, we have a deposition of
14 that.

15 So I'd like clarification on that. I would
16 like Georgia Power to comply with that very simple
17 request.

18 MADAM CHAIR PRIDEMORE: Mr. Prenovitz is
19 seeking the 2021 Georgia Power annual report.

20 MR. PRENOVITZ: And 10K.

21 MADAM CHAIR PRIDEMORE: And 10K.

22 Mr. Hewitson.

23 MR. HEWITSON: Madam Chair, as I noted to
24 Mr. Prenovitz in a -- in a response to his request,
25 intervenors do not have discovery rights in this

1 proceeding. Although, I did, as a courtesy, provide
2 him a link to the report.

3 MR. PRENOVITZ: I -- may I respond?
4 Mr. Hewitson knew I had the link to that report
5 because of the previous cross with McKinney and
6 Kuczynski. We referenced that. We have copies of
7 that.

8 Also, I'd also like to draw the attention,
9 Commissioner, again, in the 1980s --

10 MADAM CHAIR PRIDEMORE: Whoa, whoa, whoa.
11 Let's stop. Let's stop here for a second.

12 Now, let's keep ourselves -- you and I, let's
13 keep ourselves in check.

14 MR. PRENOVITZ: Yes.

15 MADAM CHAIR PRIDEMORE: So you asked for
16 publicly available information where intervenors
17 don't have discovery rights to, but it's public.
18 I've looked at it. It's just public. And they sent
19 it to you anyhow.

20 What's the complaint when you already have it?

21 MR. PRENOVITZ: No. I asked for a hard copy.
22 All I had was the internet copy.

23 It is hard to navigate a 500-page document
24 online. It's much easier if you have it in front of
25 you, to answer your question.

1 A hard of the report that they publish
2 anyway --

3 MADAM CHAIR PRIDEMORE: But you have -- but you
4 have the information, Mr. Prenovitz.

5 Do me a favor and speak into your microphone,
6 Mr. Prenovitz.

7 MR. PRENOVITZ: Yes, ma'am. Can you hear me
8 okay?

9 MADAM CHAIR PRIDEMORE: A little better. There
10 you go.

11 MR. PRENOVITZ: Thank you. Okay.

12 You asked --

13 MADAM CHAIR PRIDEMORE: Anything else?

14 MR. PRENOVITZ: I have the internet, but I
15 don't have the hard copy.

16 MADAM CHAIR PRIDEMORE: Well, I only looked at
17 the internet copy, as well.

18 MR. PRENOVITZ: Okay.

19 MADAM CHAIR PRIDEMORE: Okay.

20 MR. PRENOVITZ: I'm just asking.

21 MADAM CHAIR PRIDEMORE: Okay. Anything else?

22 MR. PRENOVITZ: Yes. Two more points.

23 Second, basically the policy is if somebody
24 does testimony, they cannot do cross. Or if they do
25 cross, they cannot do testimony.

1 My question is this: This was made for the --
2 the VCMs, which was basically Georgia Power only had
3 one set of witnesses and they never filed rebuttal.

4 My question is: If they file rebuttal
5 testimony, since one does not have the response to
6 provide testimony to the rebuttal testimony, will
7 they then be able to cross-examine a panel on the
8 rebuttal phase for them if they've already testified?
9 Just a question.

10 MADAM CHAIR PRIDEMORE: Mr. Prenovitz, I do
11 believe that your question is germane to these
12 proceedings in the respect that in my four years as a
13 Commissioner I've never seen Georgia Power have the
14 same person issue cross as somebody who's on the
15 stand, so...

16 MR. PRENOVITZ: Okay.

17 MADAM CHAIR PRIDEMORE: Okay.

18 MR. PRENOVITZ: Apparently the panel requested
19 that since I'm testifying, I appear in person. I was
20 wondering would it be okay if -- if we try to
21 coordinate the time.

22 Could I come in, like, tomorrow afternoon?
23 Would that work for you people?

24 MADAM CHAIR PRIDEMORE: Unfortunately, I have
25 not been able to allow any special scheduling for any

1 intervenor. And I've had many intervenors that you
2 see out before you that have asked. People taking
3 flights, et cetera, and we just can't do it.

4 We have a long docket to get through today.
5 We've got a lot of witness testimony. And I can't do
6 schedules.

7 MR. PRENOVITZ: Okay. So --

8 MADAM CHAIR PRIDEMORE: No exceptions. No
9 exceptions.

10 MR. PRENOVITZ: -- I don't have to be there
11 today. So just kind of watch to see where we are on
12 the sequence and try to guess when to come?

13 MADAM CHAIR PRIDEMORE: Yes, uh-huh. Yeah.

14 MR. PRENOVITZ: That's all I have.

15 MADAM CHAIR PRIDEMORE: You can -- you can come
16 sit here all four days like we do.

17 MR. PRENOVITZ: I'm sorry?

18 MADAM CHAIR PRIDEMORE: Or you can come sit
19 here all four days like we do.

20 MR. PRENOVITZ: Not today.

21 Let me ask you this. Are you planning to break
22 a little early today because it's election day?

23 MADAM CHAIR PRIDEMORE: All right,

24 Mr. Prenovitz.

25 What else -- anybody else with housekeeping

1 matters?

2 MR. PRENOVITZ: Thank you, ma'am.

3 MADAM CHAIR PRIDEMORE: You're welcome.

4 Anybody else with housekeeping matters?

5 (No response.)

6 MADAM CHAIR PRIDEMORE: Okay. Speak now or
7 forever hold your peace.

8 All right. We have a lot of parties here today
9 and a lot of material to get through. My request for
10 all of you, listen to the questions. Listen to the
11 answers.

12 If your question has already been asked and
13 answered, please don't ask it again. It's okay. I
14 love the sound of your voice. It is delightful to
15 me. Sometimes I lay in bed at night and dream about
16 just how delightful the sound of your voice is, but
17 say something new or don't say anything at all.

18 All right. With that, let's get started.

19 Mr. Walsh, you want to swear in your witnesses?

20 MR. WALSH: Thank you, Madam Chair.

21 At this time Public Interest Advocacy Staff
22 would like to call to the -- call the panel of Tom
23 Newsome, Philip Hayet, Stephen J. Baron, and Leah
24 Wellborn.

25 Please raise your right hands.

1 Thereupon,

2 TOM NEWSOME,
3 PHILIP HAYET,
4 STEPHEN J. BARON,
5 LEAH WELLBORN,
6 having been duly sworn, testified as follows:

7 DIRECT EXAMINATION

8 MR. WALSH: Thank you. You may be seated.

9 For the record, Madam Chair, Philip Hayet is
10 testifying over Zoom and I just want to make -- make
11 that clear for the record.

12 BY MR. WALSH:

13 Q I will start with Mr. Baron. Could you
14 please state your full name for the record and by whom
15 you're employed.

16 And then we'll just go down the -- down the
17 list and then go to Mr. Hayet.

18 A (Witness Baron) Stephen Baron, president of
19 J. Kennedy and Associates, Inc. 570 Colonial --

20 COMMISSONER MCDONALD: Sir, would you speak up,
21 please.

22 MADAM CHAIR PRIDEMORE: Speak into your mic for
23 us.

24 WITNESS BARON: Is that better?

25 MADAM CHAIR PRIDEMORE: Yes.

WITNESS BARON: Okay. Stephen Baron. I am
president of J. Kennedy and Associates, Inc. Address

1 is 570 Colonial Park Drive, Suite 305, Roswell,
2 Georgia 30075.

3 BY MR. WALSH:

4 Q Thank you.

5 Ms. Wellborn.

6 A (Witness Wellborn) Leah Wellborn, manager of
7 consulting at J. Kennedy and Associates.

8 Q Mr. Newsome.

9 A (Witness Newsome) Tom Newsome, Georgia Public
10 Service Commission Staff.

11 Q Mr. Hayet.

12 A Philip Hayet, vice-president of J. Kennedy and
13 Associates. And I apologize for not testifying in person.

14 Q Thank you, Mr. Hayet.

15 Mr. Newsome, I'm going to direct the next
16 questions to you on behalf of the panel. Mr. Newsome, on
17 May 6, 2022, did the panel prefile or cause to be prefiled
18 125 pages of public disclosure testimony in question and
19 answer form?

20 A (Witness Newsome) Yes.

21 Q Are there any corrections that you would like
22 to make to the prefiled direct testimony at this time?

23 A (Witness Newsome) Yes. We have three
24 corrections.

25 Q Please give them.

1 A (Witness Newsome) All right. First correction,
2 page 71, line 9: Since there are limits to how much solar
3 can be added staff per year, strike the word staff.

4 Second correction, page 102, Table 21. Under
5 Staff Plan 2, Bowen 1-2, Retired 2027 case average. Zero
6 CO2 delta value should be changed from a negative 101.7 to a
7 positive 60.8. That's the second change.

8 Third change is also page 102, Table 21, strike
9 the dollar symbol and three zeroes with the title of the
10 table.

11 Q Thank you. Noting the corrections you just
12 made, if I were to ask you the same questions that are
13 presented in your prefiled testimony, would the panel's
14 answer be the same?

15 A (Witness Newsome) Yes.

16 MR. WALSH: Madam Chair, I would ask that the
17 prefiled public disclosure version of the direct
18 testimony of the panel be copied into the record as
19 if read from the witness stand.

20 MADAM CHAIR PRIDEMORE: So moved.

21 (Whereupon, the prefiled direct testimonies
22 of Mr. Tom Newsome, Mr. Philip Hayet, Mr. Stephen J.
23 Baron and Leah Wellborn follows:)

24 //

25 //

I. BACKGROUND AND QUALIFICATIONS

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

A. My name is Tom J. Newsome. I am the Director of Utility Finance with the Georgia Public Service Commission ("Commission"). My business address is 244 Washington St., Atlanta, Georgia 30334.

My name is Philip M. Hayet. I am a Vice President and a Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

My name is Stephen J. Baron. I am President and a Principal of Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

My name is Leah J. Wellborn. I am Manager of Consulting at Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. MR. NEWSOME, WHAT ARE YOUR PRIMARY RESPONSIBILITIES WITH THE COMMISSION STAFF?

A. I am responsible for economic, financial, and cost of equity analysis and evaluations at the Commission.

1 **Q. WHAT CONSULTING SERVICES DOES KENNEDY AND ASSOCIATES**
2 **PROVIDE?**

3 A. Kennedy and Associates provides consulting services related to electric utility system
4 planning, resource analysis, production cost modeling, ratemaking, finance, accounting,
5 and industry policy issues.

7 **Q. PLEASE PROVIDE SUMMARIES OF YOUR EDUCATIONAL BACKGROUND**
8 **AND EXPERIENCE.**

9 A. Summaries of our education, experience, professional certifications, and testimony
10 appearances are provided in Exhibits STF-NHBW-1, STF-NHBW-2, STF-NHBW-3, and
11 STF-NHBW-4 for Mr. Newsome, Mr. Hayet, Mr. Baron, and Ms. Wellborn, respectively.

13 **Q. HAVE YOU ALL PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

14 A. Yes, we have all testified before this Commission. Most recently, Mr. Hayet and Mr.
15 Newsome testified in the Vogtle Construction Monitoring ("VCM") 25 proceeding
16 (Docket No. 29849) on December 16, 2021. Ms. Wellborn last testified in the VCM 19
17 proceeding (Docket No. 29849) on December 18, 2018, and Mr. Baron last testified in the

2019 IRP proceeding (Docket No. 42310) on May 13, 2019. Mr. Hayet and Mr. Newsome also testified in the 2019 IRP proceeding.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. We are presenting testimony on behalf of the Commission's Public Interest Advocacy Staff ("Staff").

II. SUMMARY AND RECOMMENDATIONS

Q. WHAT ARE THE SPECIFIC ISSUES THAT YOU ADDRESS IN YOUR TESTIMONY?

A. The issues we address, which are identified in the Conclusion Section of Georgia Power's 2022 IRP Main Document, Section 1.14, beginning at page 1-11, include:

- 1. The Reserve Margin Study and its associated outputs, including the continued use of a 16.25% Summer Target Reserve Margin, a 26% Winter Target Reserve Margin, and the associated short-term Target Reserve Margins for each season.*
- 8. The permanent cessation of coal combustion Effluent Limitation Guidelines ("ELG")¹ compliance plan through retirement for Plant Bowen Units 1-2 and the associated decertification effective upon the completion of the*

¹ Effluent Limitation Guidelines refers to EPA regulations addressing the treatment of wastewater streams, including from flue gas desulfurization scrubbers.

necessary transmission system improvements, which is projected to be no later than December 31, 2027.

9. The permanent cessation of coal combustion ELG compliance plan through retirement for Plant Scherer Unit 3 and the associated decertification effective by December 31, 2028.

10. The permanent cessation of coal combustion ELG compliance plan through retirement for Plant Gaston Units 1-4 and the associated decertification effective by December 31, 2028.

11. Decertification of Plant Gaston Unit A effective by December 31, 2028.

12. Decertification of Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1, effective by August 31, 2022.

16. A certificate of public convenience and necessity for six PPAs with a capacity of 2,356 MW² from Plant Wansley Unit 7, Plant Dahlberg Units 2 & 6, Plant Harris Unit 2, Plant Dahlberg Units 1, 3, & 5, Plant Monroe Units 1-2, and Plant Dahlberg Units 8-10 procured in the 2022-2028 Capacity RFP.

19. The capital and O&M costs the Company will incur for the modernization of Plant Burton, Plant North Highlands, and Plant Sinclair hydro facilities (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume I.

26. Certification of 88 MW of wholesale capacity from Blocks 2-4 and Blocks 5&6 to be placed in retail rate base effective January 1, 2024 and January 1, 2025, respectively.

28. The capital and O&M costs the Company will incur for the Integrated Hydrogen Microgrid pilot project (but not yet the recovery of such costs),

² Capacity listed in winter terms.

*as set out in the Selected Supporting Information section of Technical
Appendix Volume 1.*

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S
PROPOSAL TO ADOPT 26% AS ITS WINTER TARGET RESERVE MARGIN
AND 16.25% AS ITS SUMMER TRM (ISSUE 1)?**

A. Staff recommends use of a lower Winter Target Reserve Margin ("TRM"), but does not object to 16.25% being used as the Southern Company System's Summer TRM. Staff has identified a problem with the Company's 2022 Reserve Margin analysis associated with the Load Forecast Error ("LFE") assumptions and recommends use of 24.5% as the Winter TRM.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING UNIT RETIREMENTS,
INCLUDING THE BOWEN COAL UNITS 1-2, SCHERER 3 COAL UNIT,
WANSLEY COAL UNITS 1-2, GASTON UNITS 1-4 GAS-FIRED STEAM
TURBINE, AND THE GASTON UNIT A, WANSLEY UNIT 5A, AND
BOULEVARD UNIT 1 COMBUSTION TURBINE UNITS (ISSUES 8-12)?**

A. With regard to the coal units, Staff confirms that the economics of those units are challenged, considering the availability of reasonably available low-cost replacement

1 capacity, and possibility of future environmental legislation. However, Staff also concludes
2 that it may be reasonable for the Commission to decide to require Bowen 1-2 to continue
3 operating beyond 2028, along with Bowen 3-4, given the uncertainty that exists with
4 respect to the North Georgia transmission system and the Company's capacity needs that
5 will arise beginning in the 2029 time frame. Staff's economic analysis found that Bowen
6 1-2 is a close call, and Staff presents two alternative plans for the Commission's
7 consideration, one in which the Bowen 1-2 units are retired by 2028, and the other in which
8 Bowen 1-2 continue to operate through 2035.

9 Staff accepts that the Company's other coal unit retirements, the Gaston Units 1-4
10 steam turbine units, and the three relatively small oil-fired combustion turbine unit requests
11 are reasonable and should be retired with certain caveats discussed below.

12
13 **Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S**
14 **REQUEST TO ACQUIRE 2,356 MW OF POWER PURCHASE AGREEMENT**
15 **("PPA") CAPACITY BASED ON THE 2022 – 2028 CAPACITY REQUEST FOR**
16 **PROPOSAL ("RFP") (ISSUE 16)?**

17 **A.** Staff agrees with the Company's proposal to acquire the six PPAs that the Company
18 identified as being the final short-listed bids on October 1, 2021 in the 2022-2028 Capacity
19 RFP.

1

2 **Q. WHAT IS STAFF'S RECOMMENDATION ON THE COMPANY'S HYDRO**
3 **MODERNIZATION PROPOSAL (ITEM 19)?**

4 **A.** Staff recommends the Commission reject the Company's proposal at this time. The
5 Company has not provided any economic analyses to justify the capital expenditures to
6 modernize hydro plants Burton, North Highlands, and Sinclair. The Company is currently
7 making substantial capital expenditures to modernize 16 turbines at five hydro plants which
8 will not be completed until 2029. Given the Commission has approved a robust hydro
9 modernization program and the Company has provided no economic justification for Plants
10 Burton, North Highlands and Sinclair the Commission should wait until the 2025 IRP to
11 consider expansion of the hydro modernization program and only if Georgia Power
12 provides requested economic analysis that justifies modernization of the three additional
13 hydro plants.

14

15 **Q. WHAT IS STAFF'S RECOMMENDATION ON THE COMPANY'S OFFER TO**
16 **TRANSFER 65 MW OF PLANT YATES UNITS 6 & 7 CAPACITY (BLOCKS 2-4)**
17 **AND 23 MW OF PLANTS MCMANUS AND WILSON OIL-FIRED COMBUSTION**
18 **TURBINES (BLOCKS 5&6) FROM WHOLESALE TO RETAIL (ISSUE 26)?**

1 A. Staff found the Company's offer to transfer the Yates, McManus, and Wilson capacity
2 from wholesale to retail rates to be uneconomic, and recommends the Commission reject
3 the offer. Staff notes that there were other blocks of wholesale capacity, including Scherer
4 3 and Gaston 1-4 that normally would have been offered to retail customers, however,
5 given the Company's proposed plans to retire those units, blocks of capacity from those
6 units were not included in the Company's offer.

7
8 **Q. WHAT IS STAFF'S RECOMMENDATION ON THE COMPANY'S HYDROGEN**
9 **MICROGRID PROJECT (ISSUE 28)?**

10 A. Staff recommends the Commission approve the project if costs are shared with Alabama
11 Power Company and Mississippi Power Company on a pro rata share basis.

12
13 **Q. DOES STAFF HAVE ANY RECOMMENDATIONS REGARDING THE**
14 **COMPANY CONDUCTING A CAPACITY RFP FOR ADDITIONAL CAPACITY?**

15 A. Yes. Staff's analysis indicates the Company would have a resource need in the 2029-2031
16 time-period even with the approval of resources sought in this IRP. Given the long lead
17 time to build new capacity Staff believes the Company should initiate an all-source RFP
18 now for the Company's need for the 2029-2031 timeframe.

III. ANALYSIS

Target Reserve Margin Issues

Q. WHAT IS A RESERVE MARGIN AND HOW DOES IT IMPACT CUSTOMER BILLS?

A. A reserve margin is the amount of generation capacity, in excess of expected utility system peak load, that is required to ensure that a utility can provide reliable service in the event of a loss or disruption of generation resources or higher than expected loads due to weather events or other factors. From a planning perspective, the higher the reserve margin the more generation capacity the utility must obtain. While this additional reserve capacity provides reliability to the system, it also has a cost, which will increase customer bills. Therefore, it is important that the appropriate balance is struck between having sufficient generation reserves without unnecessarily increasing customer bills.

Q. HOW IS THE AMOUNT OF RESERVE GENERATION CAPACITY DERIVED FROM A RESERVE MARGIN?

A. In a simple example a utility assumes a maximum demand or load of 20,000 MW for a certain time period. However, the utility will need to plan for generation reserve capacity for the reasons outlined above. If reserve margin is set at 20%, then the utility would need

1 reserve capacity of 4,000 MW (20,000 MW x 20%) and have total installed generation
2 capacity of 24,000 MW (20,000 MW + 4,000 MW).
3

4 **Q. PLEASE SUMMARIZE THE STAFF'S FINDINGS AND RECOMMENDATIONS**
5 **ON THE COMPANY'S 2022 RESERVE MARGIN STUDY.³**

- 6 • The Company is continuing its current dual Planning Target Reserve Margins: a
7 16.25% summer peak TRM and a 26% winter peak TRM. As in the 2019 IRP, the
8 Company finds that the winter season is the constraining season for reliability on the
9 System. Even though the Southern Company system continues to be summer peaking,
10 the higher winter TRM applied to the winter peak provides more than sufficient
11 capacity in the summer season to meet a 16.25% TRM.
12
13 • The Staff's analysis of the Company's 2022 Reserve Margin Study has identified a
14 problem with one of the important input factors that results in an overstatement of the
15 optimal winter TRM. The Staff concludes that a winter TRM of 24.5% will provide
16 reliability at the 80% Value at Risk level ("VaR") that is recommended by the
17 Company. The Staff supports the continuation of a 16.25% summer TRM, as proposed
18 by the Company.
19
20 • The Staff accepts the Company's recommendation to establish the Short-Term winter
21 and summer TRMs using a 0.5% adjustment to the long term TRMs. Based on this
22 differential, the Short-Term winter TRM would be 24% and the summer TRM would
23 be 15.75%.
24
25

26 **Q. PLEASE SUMMARIZE THE STAFF'S FINDINGS AND CONCLUSIONS IN ITS**
27 **EVALUATION OF THE 2022 PLANNING RESERVE MARGIN STUDY.**

³ "An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System," January 2022.

A. Our findings and conclusions are as follow:

- A summer target reserve margin of 16.25% is appropriate and should be approved by the Commission.
- Seasonal summer and winter reliability planning should continue to be implemented by the Company.
- The Company's request for a 26% winter target reserve margin should not be approved. Staff has identified a significant problem with the Company's load forecast error ("LFE") assumptions used in the Company's reserve margin analysis. The historic distribution of load forecast errors is one of the inputs into the reserve margin analysis. Though the Company's actual forecasts for the past 18 years have all been too high, the Company used an adjusted⁴ load forecast error distribution that assumes its forecasts follow a more normal distribution (both too high and too low). Using this adjusted LFE distribution produces a winter TRM (26%) that is not consistent with actual history on the Southern Company system. The Staff's correction of this input factor results in a winter TRM of 24.5%.
- The Company has reasonably responded to recent extreme winter weather events in Texas and Oklahoma, as well as the 2014 polar vortex, by making improvements to its existing generating resources to withstand the effects of extreme cold weather. As a result, the Company has reduced the threshold temperature from 17 degrees to 13 degrees at which its incremental cold weather forced outage factors are activated in the SERVVM modeling. This reduced threshold reduces the need for planning reserve capacity during cold weather events.
- The Company's 2022 Reserve Margin Study has improved its modeling of historic load and weather relationships by utilizing statistical regression modeling rather than its prior use of neural net modeling. The Staff has reviewed the Company's new approach and believes that it is appropriate.

**Q. PLEASE EXPLAIN WHY STAFF'S RECOMMENDED WINTER TARGET
RESERVE MARGIN OF 24.5 PERCENT IS REASONABLE AND THE**

⁴ The Company refers to this adjustment as "recentering".

COMPANY'S PROPOSED 26 PERCENT IS EXCESSIVE.

A. Historically, electric utilities have determined TRMs by calculating the reserves needed to maintain a loss of load expectation ("LOLE") of at least 1 day in 10 years. Using this criterion would result in a winter TRM of 20 percent for the Company. A Staff survey of winter reserve margins of other utilities and RTOs had an average of approximately 18 percent. Staff's recommended winter TRM of 24.5 percent is conservative relative to the historical LOLE standard and typical winter TRM of other utilities and Regional Transmission Organizations ("RTOs") and would provide the Company ample generation reserve capacity. The Company's 26 percent winter TRM would result in 227 MW of additional reserve capacity in 2025 for Georgia Power Company, compared to the Staff's recommendation.

Q. THE COMPANY ALSO RECOMMENDED A 26% WINTER TRM IN THE 2019 IRP CASE. DID THE COMMISSION APPROVE THIS REQUESTED WINTER TRM IN THAT PROIR CASE?

A. No. In the last IRP, the Commission did adopt the Company's request to begin use of seasonal planning in the 2019 IRP, and Staff supported that request. However, while Staff recognized that planning for reliability is important, Staff did not agree that 26% should be the appropriate winter TRM for the Company's System. Staff based its recommendation in the 2019 IRP on its findings that the Company's Reserve Margin Study in that IRP was

1 flawed. Given the disagreement between Staff and the Company, a settlement was reached
2 that recognized the Commission did not have to act on the proposed winter TRM in the
3 2019 IRP, as no new resources were being proposed pursuant to a need for capacity. The
4 settlement, however, allowed the Company to use the 26% winter TRM for planning
5 purposes, but it noted that the Company would have to justify use of the 26% Winter TRM
6 the next time it proposed new resource additions.

7
8 **Q. PLEASE DESCRIBE THE METHODOLOGY THAT THE COMPANY USED IN**
9 **THIS CURRENT 2022 IRP CASE TO DEVELOP ITS RECOMMENDED**
10 **SUMMER AND WINTER SEASONAL PLANNING RESERVE MARGINS.**

11 **A.** For the 2022 IRP, the Company has used similar methodologies to those that it used in both
12 the 2019 and 2016 IRPs to develop recommended TRM, though the Company has changed
13 its load/weather modeling methodology and the methodology used to measure LFE. As in
14 the 2018 Reserve Margin Study, the Company is focusing primarily on a seasonal
15 analysis.⁵ In fact, because the winter TRM drives the need for capacity additions on the
16 Southern Company system, the focus in the 2022 Reserve Margin Study is almost entirely
17 on the winter TRM.

18

⁵ The reserve margin study used in the 2019 IRP is referred to as the 2018 Reserve Margin Study.

As was the case in prior Georgia Power Company IRPs, the 2022 Reserve Margin Study is performed on a total Southern Company system basis, which includes all of the loads and capacity resources of Alabama Power Company, Georgia Power Company, Mississippi Power Company, and the portion of Southern Power Company included in the IIC (collectively, the "Operating Companies").⁶ The Company concludes that the results of the 2022 Reserve Margin Study are consistent with the reserve margin targets it recommended in the 2019 IRP of 26% in the winter and 16.25% in the summer and recommends adopting those planning targets in this IRP.⁷

Q. DOES THE STAFF AGREE THAT MAINTAINING SYSTEM RELIABILITY IS AN IMPORTANT FUNCTION OF THE COMPANY'S PLANNING PROCESS?

A. Yes. Maintaining reliability is extremely important to customers and therefore a critical aspect of the IRP process. To that end, Staff supported the Company's desire to move to a seasonal planning approach in the last IRP, recognizing that it would provide greater visibility into the System's capacity needs in both the summer and winter seasons.

⁶ The IIC is the Southern Company Intercompany Interchange Contract.

⁷ It should be noted that while the Georgia Public Service Commission approved the Company's 16.25% summer TRM, the Commission did not approve the 26% winter TRM due to concerns raised by the Staff on certain aspects of the Company's analysis.

1 Q. IS THE COMPANY'S PLANNING APPROACH DESIGNED TO IDENTIFY A
2 RESERVE MARGIN THAT BOTH MEETS RELIABILITY REQUIREMENTS
3 AND IS ALSO ECONOMICALLY OPTIMAL?

4 A. Yes. While the Company states that the purpose of the Reserve Margin Study is to
5 "determine the amount of reserve capacity – or the TRM that should be maintained on the
6 System,"⁸ the Company also recognizes that cost of maintaining reliability to avoid the
7 possibility of all outage risks would be extremely expensive. The Company's 2022
8 Reserve Margin Study states that:

9 "...maintaining such high levels of capacity reserves comes at significant expense
10 and may only eliminate very low probability events. A more appropriate approach
11 to setting the TRM is to minimize the combined expected costs of maintaining
12 reserve capacity, System costs, and customer costs associated with service
13 interruptions, and adjust for the value at risk. A proper evaluation of these costs
14 will result in the Economic Optimum Reserve Margin ("EORM"), properly
15 adjusted for risk."⁹
16

17 This was also confirmed by Company witness Jeffrey Weathers at the hearing on April 4,
18 2022. Mr. Weathers testified that "if you have too much capacity on the system, you may
19 be really, really reliable, but that's expensive for customers. On the other hand, if you have
20 too little capacity on the system, there's significant reliability costs that customers see."¹⁰

⁸ An Economic Reliability Study of the Target Reserve Margin for the Southern Company System, Submitted with Georgia Power's 2022 IRP, January 2022, pg. i.

⁹ Id, pg. iii.

¹⁰ Hearing Transcript page 138, April 4, 2022.

1

2 **Q. DOES THE STAFF AGREE WITH THE COMPANY'S APPROACH TO SET THE**
3 **TARGET RESERVE MARGIN LEVEL SO THAT IT MEETS AN APPROPRIATE**
4 **LEVEL OF RELIABILITY AND MINIMIZES THE COST TO CUSTOMERS AT**
5 **THAT LEVEL OF RELIABILITY?**

6 **A. Yes.**

7

8 **Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S RESERVE MARGIN**
9 **STUDY METHODOLOGY.**

10 **A. First, as noted previously, the TRM analysis is performed on a total Southern Company**
11 **System ("SOCo") basis, not on a standalone Georgia Power Company basis. This is**
12 **appropriate since the system's reliability is based on the full SOCo load and capacity and**
13 **optimizes the joint capability of each SOCo Operating Company.**

14

15 **As in prior reserve margin studies, the 2022 Reserve Margin Study utilizes a sophisticated**
16 **economic modeling approach using the Strategic Energy and Risk Valuation Model**
17 **("SERVM"), a proprietary software product from Astrapé Consulting. In addition to**
18 **SOCo, several other utilities use the SERVM model to develop economically optimal**

1 reserve margin targets.¹¹

2
3 **Q. HOW HAVE ELECTRIC UTILITIES TRADITIONALLY CALCULATED A**
4 **PLANNING RESERVE MARGIN?**

5 A. Historically, electric utilities have determined TRMs by calculating the reserves needed to
6 maintain a LOLE of at least 1 day in 10 years. This “1 day in 10 years” LOLE criterion
7 means that the utility has sufficient reserve capacity, over and above its expected system
8 peak demand, so that a loss of load event (not meeting customer load) will only occur 0.1
9 times in a single year. Over a 10-year period, there would be “1 event” in which the system
10 could not meet customer load, hence a 1 day in 10-year event. Many utilities continue to
11 use a 1 day in 10-year planning reserve criterion, as do major Regional Transmission
12 Organizations, such as PJM Interconnection and MISO. In many LOLE-based reserve
13 margin analyses conducted by other electric utilities, the risk of failing to meet customer
14 loads is generally developed by modeling a utility system’s generator forced outage factors.
15 All other sources of risk, such as load deviations due to extreme weather events and load
16 forecast errors are not specifically modeled – these factors are reflected in the analysis at
17 their expected values (for example, normal weather). Many of the studies conducted by
18 other utilities also do not consider other factors such as the economic cost to customers in

¹¹ Some of the other utilities that use SERVIM include Duke Energy Carolinas, Duke Energy Progress, Louisville Gas & Electric Company and The Tennessee Valley Authority.

1 the event of a failure to meet customer load (Value of Lost Load or "VOLL"). As noted
2 previously, using a 1 day in 10-year LOLE criterion, the winter TRM would be 20%. The
3 Staff's 24.5% winter TRM is therefore a conservative recommendation. For the summer
4 season, a 1 day in 10-year LOLE is only 14%, compared to the Staff's recommended
5 16.25% TRM.

6
7 **Q. HOW DOES SERVVM DETERMINE AN OPTIMAL TRM?**

8 A. In SERVVM, and other more sophisticated reserve margin models, the objective is to
9 determine the optimal, least cost, reserve margin (the Company refers to this as the
10 Economically Optimal Reserve Margin or EORM). In addition to generator forced outage
11 assumptions, the SERVVM model considers such factors as the risk of under or over-
12 forecasting system load, the cost of unserved energy (i.e., the cost to customers of an
13 outage) and the incremental cost of capacity that would be incurred to increase system
14 reserves. These factors, as well as the production costs (fuel, purchased power energy,
15 emergency energy purchases) are simulated under alternative assumptions about generator
16 availability, load forecast errors and weather conditions using Monte Carlo simulation.¹²

¹² Monte Carlo simulations are used to model the probability of different outcomes in a process that cannot easily be predicted due to the intervention of random variables (in this case, random events would include different weather outcomes or random generator forced outages). A Monte Carlo simulation calculates the combined effects of multiple factors on a specific variable – in this case, the Company's optimal reserve margin. The Monte Carlo simulation uses random numbers that are selected in a computer program to simulate an outcome of each factor on the target variable.

1 The objective is to determine the reserve margin that has the lowest total cost, considering
2 all of factors listed above. The analysis considers the tradeoff of spending more on capacity
3 to achieve lower customer costs (outage costs incurred by customers when their load is
4 interrupted and production costs). While it is possible to add enough capacity to the system
5 to almost ensure that there would be no customer outages, it doesn't make economic sense
6 to do so if the cost is so high that customers would not voluntarily pay this extra cost to
7 avoid an outage.

8
9 **Q. IS THE COMPANY PROPOSING SEPARATE TRMS FOR THE SUMMER AND**
10 **WINTER SEASONS?**

11 **A.** Yes. As was the case in the 2019 IRP, the Company determines separate winter and
12 summer season TRMs based on individual seasonal analyses. In fact, in this current 2022
13 IRP, the Company focuses primarily on the winter TRM because capacity needed to meet
14 the winter peak will be sufficient to meet the capacity required during the summer season.
15 In other words, the winter TRM controls capacity requirements on the system. This is true
16 even though the SOCo system continues to have a summer annual peak that exceeds the
17 winter peak, under expected weather conditions. Because extreme winter weather causes
18 significant increases in the expected winter peak and causes higher generator forced
19 outages, the Company has concluded that it needs to plan resource additions to meet the
20 winter peak. Doing so will satisfy reliability during the summer season without any

additional resources.

Q. WHAT IS THE RESULT OF THE COMPANY'S EORM ANALYSIS?

A. The Company's EORM analysis determined the winter TRM should be 24.25% and the summer TRM should be 20.5%.

Q. DOES THE COMPANY ALSO USE OTHER CRITERIA TO DETERMINE THE WINTER TARGET RESERVE MARGIN BESIDES THE EORM ANALYSIS?

A. Yes. The Company's actual reserve margin criterion also requires that the TRM meet or exceed a traditional 1 day in 10 years LOLE criterion. As in the 2019 IRP, the Company's recommended 26% winter/16.25% summer TRMs greatly exceed a 1 day in 10-year reliability level. Based on a 26% winter TRM, the SOCo system achieves a 1 day in 20-year LOLE reliability level (twice as high as industry standards). The winter reserve margin required to satisfy a 1 day in 10-year LOLE criterion would just be 20%.

Finally, as in the 2018 Reserve Margin Study, the Company relies on a third reliability criterion to determine its winter target reserve margin, which is that it recommends a TRM based on minimizing costs based on an assumed higher risk avoidance using a Value at Risk ("VaR") construct. This increases the winter TRM from 24.25% to 26.00% in the Company's 2022 study. The VaR construct relies on the same EORM derivation approach

but includes a measure of risk that reflects the least cost result based on outcomes (e.g. weather, load, generator outages) that have only a 20% chance of being exceeded ("VaR80"), and another case that has only a 15% chance of being exceeded ("VaR85").

Q. WHAT ARE THE WINTER AND SUMMER TRMS CALCULATED BY THE COMPANY IN THE 2022 RESERVE MARGIN STUDY USING EACH OF THE THREE RESERVE MARGIN CRITERIA?

A. Table 1 below shows these results.

Table 1				
Company Winter and Summer Reserve Margins				
(Base Case Analysis)				
1 Day/10 Yr.				
	LOLE	VaR 80%	VaR 85%	EORM
Winter	20.00%	26.00%	29.50%	24.25%
Summer	14.00%	22.75%	23.25%	20.50%

As can be seen, a traditional 1 day in 10-year LOLE criterion would require a winter TRM of 20%, compared to the EORM economically optimal TRM of 24.25%. Then when the value at risk TRM is derived at the 80% confidence level (VaR 80%), the winter TRM increases further to 26%. Finally, if the 85% confidence level is used (VaR 85%), the winter TRM increases to 29.50%. In this IRP, the Company is recommending use of the

1 VaR 80% winter TRM value of 26%, because it believes the increase in TRM only results
2 in a small increase in expected cost of \$4.1M/year. In the summer- based analysis, the
3 SERVVM results show a need for a 22.75% TRM using the VaR80 criterion. However, in
4 reaching a decision concerning its recommended summer TRM, the Company stated,¹³

5 “....it is not recommended to increase the summer TRM at this time. This
6 is because the combination of the 26% Winter TRM and 16.25% Summer
7 TRM provides an adequate level of reliability and increasing the TRM in
8 the summer would have little impact on the planning process, as winter is
9 the driving season. It is therefore recommended that the current, approved
10 16.25% TRM (which is already stated in summer terms) remain in place as
11 the Summer TRM.”
12

13 **Q. PLEASE PROVIDE MORE DETAILS ABOUT HOW THE THREE RELIABILITY**
14 **CRITERIA ARE DEVELOPED.**

15 **A.** The objective of the SERVVM EORM analysis is to find the optimal TRM value that results
16 in the sum of production costs, the cost of capacity resource additions, and the cost of
17 outages to customers being minimized. Many inputs are required to perform this analysis.
18 One of the critical inputs into the SERVVM analysis is the relationship between load and
19 weather. In the 2022 study, the Company uses 58 years of weather data to represent a
20 comprehensive distribution of possible weather events. The SERVVM model uses Monte
21 Carlo simulations to develop a probability weighted cost for 13 different winter reserve

¹³ 2022 Reserve Margin Study, Executive Summary at page xi.

1 margins that is driven by possible system outcomes under each of the 58 weather years. A
2 Monte Carlo simulation reflects a random occurrence of these weather years, coupled with
3 a random occurrence of other input factors that simulate the ability of the system resources
4 to meet loads each hour. While the simulation is driven by a computer selected random
5 number, each input (e.g., weather, load forecast errors, etc.) follows a pre-developed
6 probability distribution. For example, the weather distribution reflects an assumption that
7 each of the 58 years of weather has an equal probability of occurrence. The load forecast
8 error probability distribution is supposed to reflect the historic experience of either over or
9 under-forecasting hourly loads by the Company over the 20-year planning horizon.

10
11 Some of these factors influence the load that occurs in a simulation – weather and load
12 forecast errors, while other factors influence the availability of the resources themselves –
13 forced outages, cold weather forced outage increments.¹⁴ For each simulation, a set of
14 costs are calculated, which include production costs (e.g., fuel expense, purchased power
15 expense), the costs of new combustion turbine capacity needed to add capacity to the
16 system in order to meet each of the 12 reserve margins above the 20% minimum analyzed
17 in the modeling,¹⁵ and the cost of reliability, as measured by the cost of customer outages

¹⁴ The incremental forced outage factors are themselves driven by a particular weather event that occurs in the simulation.

¹⁵ The 13 reserve margins modeled range from 20% to 32%.

(cost of expected unserved energy or EUE), emergency purchases, interruptible load and the cost of shortfalls in non-spinning reserves.¹⁶

The probability weighted results of the Monte Carlo simulation over each of the 58 weather years and load forecast error probabilities is shown for each reserve margin in the EORM chart shown on page 38 in Figure III.1 of the Company's report. The chart is a U-shaped curve that depicts the cost to customers over a range of winter reserve margins. At low reserve margin levels, costs are high because the higher production costs and EUE costs (due to more frequent customer outages) is not enough to offset the lower capacity costs. At the highest reserve margins modeled, the opposite is true. The higher capacity costs needed to meet the 30%-32% reserve margins more than offsets the lower production costs and lower EUE customer outage costs produced by higher reserve margins. The minimum value on this curve, at 24.25% represents the least cost reserve margin (the EORM).

Q. IF THE COMPANY'S ANALYSIS SHOWS THAT A 24.25% WINTER RESERVE MARGIN IS THE LEAST-COST PLANNING CRITERION, WHY IS THE COMPANY RECOMMENDING A 26% WINTER RESERVE MARGIN?

A. The Company uses a risk adjusted least-cost analysis to calculate its recommended winter

¹⁶ EUE is an estimate of the cost of an outage to residential, commercial and industrial customers based on a sample survey of customers. These estimates are typically referred to as the Value of Lost Load ("VOLL").

1 TRM. As discussed earlier, the 26% winter TRM reflects the least cost result based on
2 outcomes (for example, weather, load, generator outages) that have only a 20% chance of
3 being exceeded ("VaR80"). While the EORM reflects the least cost reserve margin on an
4 average basis, given variations in weather, load forecast errors and generator outages, the
5 VaR80 analysis sets the reserve margin based on an outcome that is assumed to have only
6 a 20% chance of being worse (for example, more extreme winter weather, greater than
7 expected generator outages). The value at risk construct is an attempt to plan for lower
8 probability events that, if they occurred, would cause a greater chance of customer outages
9 (loss of load) and higher production costs. If the cost of such low probability events is
10 more than the cost of the capacity needed to achieve that higher level of reliability, then it
11 is economically rational to use the higher VaR80 based reserve margin.

12
13 **Q. BASED ON YOUR REVIEW OF THE COMPANY'S ANALYSIS, WHAT ARE**
14 **THE KEY DRIVERS THAT PRODUCED A 26% WINTER RESERVE MARGIN?**

15 **A.** The Company's reserve margin analysis incorporates a number of key inputs that drive the
16 ultimate calculation of an optimal winter TRM. In order to better understand the factors
17 that influence the Company's 26% reserve margin, it is helpful to identify the impact of
18 these key factors on the result. The following three factors strongly influence the need for
19 winter season capacity reserves on the Southern Company system:

20 1. The impact of generator forced outage rate assumptions.

2. The impact of weather on customer loads, which in turn drives the need for capacity and reserves.
3. Extreme winter cold weather events that cause a reduction in the reliability of the Company's generation plants as forced outage rates increase.

The Staff analyzed the impact of these factors in our evaluation of 2022 study. In particular we looked the impact of some extreme winter temperature years (1982, 1985) on the reserve margin results. The Staff also evaluated the winter reserve margin based on a 20-year weather data set, rather than the full 58 years of weather used in the Company's analysis. The Company itself presented a number of sensitivity analyses designed to provide insight on the effect of extreme winter weather on generator forced outages, as well as changes in the basic forced outage rate assumptions used in the base case study. We will discuss these scenarios later in this testimony.

Q. WHY HAS THE COMPANY FOCUSED ALMOST EXCLUSIVELY ON THE WINTER TRM IN ITS 2022 RESERVE MARGIN STUDY?

A. Even though the Southern Company system and Georgia Power Company continue to be summer peaking in the 2025 base year used in the reserve margin study, the need for capacity is driven by a shortage of capacity to maintain a 26% reserve margin applied to the winter peak. In other words, if the winter peak reserve margin is satisfied, the summer peak reserve TRM will always be met. Therefore, the focus of the 2022 study is on the

winter TRM.

Q. AS IN PRIOR RESERVE MARGIN STUDIES, THE COMPANY HAS ALSO CALCULATED AN ADJUSTMENT TO ITS WINTER AND SUMMER PLANNING TRMS THAT WOULD CONVERT THEM TO SHORT-TERM PLANNING RESERVE MARGINS. DOES THE STAFF AGREE WITH THE COMPANY'S ADJUSTMENT?

A. Yes. While the basis for the Company's adjustment is a sensitivity scenario in which the load forecast errors are calculated for a period less than the 4-year ahead error calculation used in the base case SERVIM analysis, the Staff accepts the Company's proposed 0.5% reduction in the winter and summer long-term TRMs to determine the corresponding short-term reserve margins. Based on the Staff's recommended 24.5% winter and 16.25% summer TRMs, the short-term winter and summer TRMs would be 24% and 15.75%.

Q. PLEASE DISCUSS THE SIGNIFICANT CHANGES THAT THE COMPANY HAS MADE IN ITS 2022 STUDY IN MORE DETAIL.

A. As discussed previously, the Company made two important changes in the 2022 Reserve Margin Study. The first involved the methodology used to develop the relationship between hourly system load and weather. In the prior 2018 Reserve Margin Study, the Company used a neural net modeling methodology to develop the load/weather model. In

1 this 2022 study, the Company has used a traditional statistical regression modeling that
2 more closely reflects the methods used in Georgia Power Company's load forecasting. One
3 of the problems with the prior neural net modeling approach was that the resulting model
4 was essentially a "black box" that could not easily be evaluated by the Staff and other
5 parties. The new methodology that uses statistical regression modeling can easily be
6 reproduced and evaluated, which the Staff has done in this case.

7
8 The second change that the Company has made in the 2022 study is to use actual historic
9 load forecast errors in the Southern Company system energy forecast to develop the load
10 forecast error distribution. In the prior 2018 study, the Company used a methodology that
11 calculated the forecast error in the Congressional Budget Office ("CBO") gross domestic
12 product forecast ("GDP") as a proxy for the Company's load forecast errors. As the Staff
13 discussed in our 2019 IRP testimony, this proxy approach significantly underestimated the
14 actual load forecast errors that have occurred historically for Georgia Power Company and
15 the other SOCo Operating Companies.

16
17 **Q. DOES THE STAFF BELIEVE THAT THESE CHANGES IMPROVE THE 2022**
18 **RESERVE MARGIN STUDY?**

19 **A. Yes. Both of these changes are beneficial and provide greater transparency in the analysis.**
20 **However, while the Staff agrees that using the new approach to calculate the load forecast**

error distribution, which relies on actual historic load forecast errors in the Company's forecasting models, is an improvement, the Staff has some significant concerns with the actual methodology used by the Company to develop the probability distribution of load forecast errors in the 2022 study.

Q. BEFORE DISCUSSING THE STAFF'S SPECIFIC CONCERNS WITH THE COMPANY'S LOAD FORECAST ERROR METHODOLOGY, PLEASE BRIEFLY EXPLAIN HOW THESE LFE'S FIT INTO THE OVERALL SERVVM RESERVE MARGIN ANALYSIS.

A. The LFE is one of the factors that is used in the SERVVM analysis to develop the total cost curve (EORM curve) that shows the total costs to customers at each reserve margin. The LFE factors are a set of load forecast percentage errors and their respective probability of occurrence. SERVVM begins with Southern Company's 2025 load and energy forecast. Based on the load and weather regression models (discussed subsequently), the Company develops an estimated 2025 hourly load forecast that reflects each of the 58 weather years.¹⁷ In hotter summer and colder winter weather years, the expected 2025 load forecast is increased, while in cooler summer and warmer winter weather years, the 2025 load

¹⁷ As discussed in the Company's 2022 Reserve Margin Study, there are actually 116 separate 2025 hourly load curves reflecting both a weekday and a weekend start date for the weather year. See 2022 Reserve Margin Study at page 2.

forecast is decreased, compared to the weather normalized 2025 forecast. The regression models make the adjustments in the hourly loads for each weather year, based on that year's weather data. Each alternative weather/load curve is separately simulated in the SERVIM Monte Carlo simulation, after adjustment for one of 5 load forecast error assumptions, which will be discussed subsequently. For any given LFE assumption, the 2025 weather hourly loads that are simulated in the Monte Carlo analysis will be higher than or lower than the assumed normal weather-based forecast that has no assumed load forecast error. In extreme weather years (years that are much colder or hotter than normal during the past 58 years), the loads used to determine the total customer costs (production, EUE) at each reserve margin level will be higher. At lower reserve margin levels this will result in higher costs, even after accounting for the lower capacity costs at lower reserve margins. As you move along the U-Curve, costs will decrease even though the reserve margin is increasing, even after accounting for the higher capacity costs at higher reserve margins. However, at some point, the costs begin increasing due to the cost of adding additional capacity, with little additional benefit from lower customer outage costs and lower production costs (thus, the U-shape of the EORM curve).

Q. HOW ARE THE LFE'S USED IN THE SERVIM ANALYSIS?

A. The LFE factors are used in this calculation to adjust the load curves for each weather year to reflect an over- or under-forecast by either increasing or decreasing the hourly loads.

1 The combination of each weather-load year/LFE assumption forms a case that is then
2 simulated in the SERVIM Monte Carlo model.¹⁸ In theory, by modeling these forecast
3 errors, the assumption is that the EORM U-Curve will be a more accurate representation
4 of actual behavior. If it is assumed that in some years, the Company's load forecast will
5 overstate actual (after accounting for weather impacts), then it is expected that there will
6 be a higher probability of customer outages due to inadequate capacity. On the other hand,
7 if the load forecast is too high, then there would be a lower chance of outages – however,
8 in that event there may be unneeded capacity on the system. By modeling the entire
9 historical distribution of load forecast over and under-performance (along with a weather
10 year and a day of the week start assumption), compared to weather normalized actual load,
11 the SERVIM analysis attempts to measure the additional risk associated with errors in the
12 assumed load forecast. This risk includes both the risk of under-forecasting load due to
13 factors other than weather, which would result in a higher level of unserved energy and
14 customer outages and the risk of over-forecasting load, which would result in higher costs
15 due to overstated reserve margins.

16
17 **Q. HOW DID THE COMPANY CALCULATE ITS LFE DISTRIBUTION IN THE**
18 **2022 STUDY?**

¹⁸ As discussed earlier, there is an additional element in the weather-load/LFE case to reflect either a weekday or weekend day start for the year.

1 A. The Company did a comparison of its energy forecast for each of the past 18 years to the
2 weather normalized actual system energy requirements in the fourth year of the forecast.
3 For example, if the forecast in 2003 was 1,000 MWh in 2007, this is compared to the
4 weather normalized actual energy in 2007 to determine a percent forecast error. This
5 calculation was performed for each forecast developed for the years 2000 through 2017.
6 These percent forecast errors were then summarized to create a forecast error/probability
7 table.

8
9 **Q. DID THE COMPANY USE THIS TABLE AS THE BASIS FOR ITS LFE**
10 **DISTRIBUTION IN THE SERVING ANALYSIS?**

11 A. No. The Company discovered that in every single year during the past 18 years, the
12 Southern Company energy forecast four years out over-forecasted energy. There was never
13 any under-forecast. This is consistent with the Staff's findings in the 2019 IRP case, based
14 on an analysis of Georgia Power Company's historic load forecasts – that is, the history is
15 consistently an over-forecast, not balanced under/over forecasts. Table 2 below shows the
16 Southern Company 4-year ahead load forecast errors produced by each of the Company's
17 forecasts for the past 18 years (2000 through 2017). It is similar to Table 1-3 of the
18 Company's Public Disclosure version of the report, except that Table 1-3 has been sorted
19 by the size of the load forecast error, rather than being chronological. As can be seen, the
20 Company's load forecast exceeded weather normalized actual values for each of the past

1 18 years. Over the entire 18-year period, the average annual four year ahead over-forecast
2 error was 6.8%. The average over-forecast error for the 9 best years was [REDACTED]%. The table
3 shows that the over-forecast error rose significantly during the period 2009 through 2012,
4 which was a significant recessionary period in the U.S. If these years are excluding, as
5 well as 2020 when the COVID 19 pandemic substantially impacted economic activity, the
6 historical over-forecast error was [REDACTED]% on a 4-year ahead basis.

Table 2		
Southern Company 4-Year Ahead Load Forecast Error (Forecast vs. Weather Normalized Actual)		
Year Forecast Prepared	4-Year Ahead Comparison Year	Forecast Error (% Forecast Exceeds Actual)
2000	2003	
2001	2004	
2002	2005	
2003	2006	
2004	2007	
2005	2008	
2006	2009	
2007	2010	
2008	2011	
2009	2012	
2010	2013	
2011	2014	
2012	2015	
2013	2016	
2014	2017	
2015	2018	
2016	2019	
2017	2020	
Avg. Over-Forecast Error -All Years		6.8%
Avg. Over-Forecast Error - Best 9 Years		
Avg. Over-Forecast Error - Excluding years 2009-2012 and 2020		
Source: 2021 Reserve Margin - LFE Worksheet (TS).xlsx		

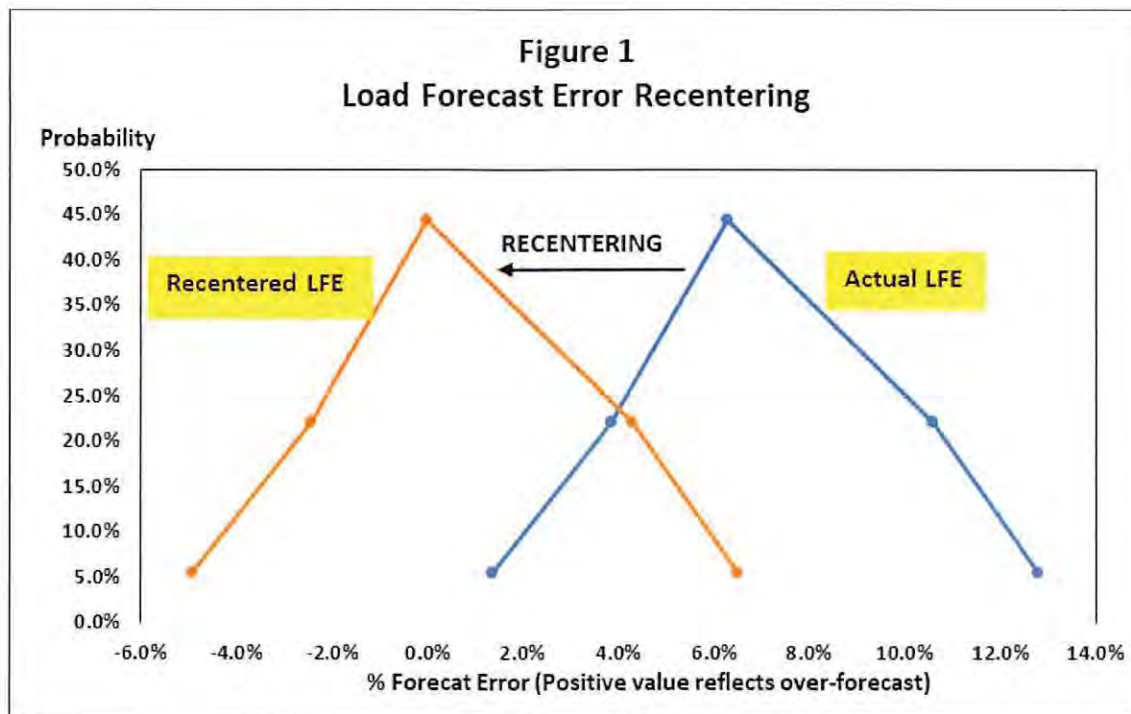
1

2

3 Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE ACTUAL

**HISTORICAL LOAD FORECAST ERRORS TO OBTAIN AN ALTERNATIVE
LFE DISTRIBUTION?**

A. Yes. The Company recentered the actual LFEs by subtracting the median percentage forecast error from the actual forecast error each year. This adjustment had the effect of creating an entirely new, and unsupported load forecast error distribution that shows both under-forecast years and over-forecast years. Another way of looking at this is that the Company shifted the actual load forecast error probability curve to the left. Figure 1 below compares the actual forecast error distribution to the recentered distribution used in the 2022 Reserve Margin Study.



1 As can be seen, while the actual distribution showed that there was a 100% probability of the
2 Company's forecast exceeding the four-year ahead weather normalized actual system energy
3 requirement, the recentered LFE distribution shows probabilities of both over and under-
4 forecasts.¹⁹ The expected value of the actual forecast error on a percentage basis during the
5 past 18 years is 6.8%, while the expected value of the recentered forecast error is about 0.5%
6 (close to "0").
7

8 **Q. WHAT IS THE IMPACT OF USING THIS ADJUSTED, RECENTERED, LFE**
9 **DISTRIBUTION INSTEAD OF THE ACTUAL LFE DISTRIBUTION IN THE**
10 **SERVM BASED 2022 RESERVE MARGIN STUDY?**

11 A. The LFE distribution is used in the SERVM Monte Carlo analysis to adjust the 2025 hourly
12 load forecast up or down for each weather/load year. By using the recentered LFE
13 distribution, the hourly load curve was increased in some simulation instances and decreased
14 in other instances. This had the effect of creating higher costs, on average, for each reserve
15 margin studied. In simulation instances in which the LFE shows an under-forecast, the costs
16 increase, while in simulation instances in which the LFE shows an over-forecast, total costs
17 decrease. However, because total costs are not a linear function of these load changes (the

¹⁹ To measure load forecast error, the Company compared its 4-year ahead system energy forecast to weather normalized energy. This assumes that energy forecast errors are a reasonable proxy for the annual load curve, which includes peak demands.

changes due to applying an LFE factor in the Monte Carlo simulation), the overall impact of the recentering adjustment is a large increase in costs at lower reserve margins, than at higher reserve margins on the winter EORM U-Curve. As a result, the optimal winter reserve margin is now at a higher reserve margin value, resulting in a higher winter TRM.

Q. HAVE YOU CALCULATED THE WINTER TRM USING THE ACTUAL 18-YEAR LOAD FORECAST ERROR DISTRIBUTION, WITHOUT THE COMPANY'S RECENTERING ADJUSTMENT?

A. Yes. Because the Staff does not have access to the SERVVM software, the Staff was only able to perform an approximate analysis of the impact. The Company provided SERVVM output data for each weather/LFE combination at each reserve margin level simulated through the Monte Carlo analysis. The total number of cases in the Monte Carlo output is 7,540, based on two groups of 58 load/weather years (weekday, weekend start dates), 5 LFE scenarios simulated for each of 13 winter reserve margins ($2 \times 58 \times 5 \times 13 = 7,540$). In order to approximate the impact on the EORM U-Curve of an actual LFE distribution, the Staff applied a "0" probability to the over-forecast scenarios in the Monte Carlo output and recalculated the total cost for each reserve margin level. Table 3 below shows the original recentered LFE distribution used by the Company in its analysis and the Staff's proxy LFE distribution to reflect the actual 18-year forecast error.

Table 3
Staff Approximation of Actual LFE Distribution

	Actual 18-Year LFE		Company Recentered LFE		Staff Proxy Actual LFE	
	Forecast Error*	Probability	Forecast Error*	Probability	Forecast Error*	Probability
95th +	12.8%	5.6%	6.5%	5.6%	6.5%	7.7%
95th to 75th	10.6%	22.2%	4.3%	22.2%	4.3%	30.8%
25th to 75th	6.3%	44.4%	0.0%	44.4%	0.0%	61.5%
5th to 25th	3.9%	22.2%	-2.4%	22.2%	-2.4%	0.0%
5th +	<u>1.4%</u>	<u>5.6%</u>	<u>-4.9%</u>	<u>5.6%</u>	<u>-4.9%</u>	<u>0.0%</u>
Wtd. Average	6.8%	100.0%	0.5%	100.0%	1.8%	100.0%

* A positive value indicates that the forecast overstated weather normalized actual load.

As shown in Table 3, the actual average 18-year Southern Company forecast error was an over-forecast of 6.8% each year. The Company's SERVIM analysis, which used a recentered forecast error distribution, changed this actual forecast error into an assumed 0.5% average annual over-forecast. While there was a 100% probability of the Company over-forecasting load 4-years ahead using actual Southern Company data, the SERVIM analysis assumed that there was a 28% chance of an under-forecast and 28% chance of an over-forecast. This is a substantially different result from the actual experience during the past 18 years. The Staff's proxy actual forecast error distribution, which was used to develop a corresponding winter TRM is an over-forecast of 1.8% annually, still quite different from the actual experience.

Q. WHAT IS THE WINTER TRM BASED ON THE STAFF'S PROXY ACTUAL

LOAD FORECAST ERROR DISTRIBUTION?

A. Table 4 below shows the results of the modified SERVIM winter reserve margin calculations using the Staff's load forecast error distribution compared to the Company's analysis. The only change made to the Company's winter TRM analysis is the change in the LFE distribution.

Table 4 Impact on Winter Target Reserve Margin Due to Incorrect Load Forecast Error Distribution		
Scenario	EORM	80% VAR
SOC Co Base Case	24.25%	26.00%
Correction to Load Forecast Error*	22.00%	24.50%
* This scenario shows the Staff's optimal winter TRM based on using the actual load forecast errors, rather than using the recentered LFE.		

The Economically Optimal Reserve Margin for the winter season drops from the Company's 24.25% to 22% and the Value at Risk 80% winter TRM drops from 26% to 24.5%.

Q. IS A 24.5% WINTER TRM A MORE REASONABLE ESTIMATE OF THE ECONOMICALLY OPTIMAL, RISK ADJUSTED RESERVE MARGIN THAN THE COMPANY'S PROPOSAL?

1 A. Yes. Staff's proxy actual LFE distribution produced a weighted average over-forecast of
2 1.8%, while the actual 18-year average over-forecast for Southern Company is 6.8%. The
3 Staff believes that our adjustment produces a reasonable and conservative result, given the
4 history of the Company's over-forecasting errors, even after accounting for periods such
5 as the 2009 to 2012 recession and the 2020 COVID 19 economic impacts. As such, the
6 Staff believes that its 24.5% winter TRM, based on actual load forecast errors, is a
7 reasonable estimate of the level of reserves appropriate for the Company.²⁰

8
9 **Q. THE COMPANY IS RECOMMENDING A CONTINUATION OF THE CURRENT**
10 **16.25% SUMMER RESERVE MARGIN TARGET. IF A WINTER RESERVE**
11 **MARGIN OF 24.5% IS ADOPTED, WOULD THAT PROVIDE SUFFICIENT**
12 **RESERVES IN THE SUMMER?**

13 A. Yes. Even though the winter peak is expected to be less than the summer peak, if the
14 Southern system's capacity meets a 24.5% winter reserve margin, that will provide more
15 capacity in the summer than is needed to meet a 16.25% summer reserve margin. The 2025
16 summer and winter Southern Company weather normalized system peak forecasts used in
17 the SERVIM analysis are 33,346 MW and 32,710 MW.²¹ The 2025 summer and winter
18 weather normalized peak load forecasts for Georgia Power Company are 16,177 MW and

²⁰ As discussed earlier, the Staff's actual LFE distribution is an approximation.

²¹ See Public Disclosure Version of 2022 Reserve Margin Study at page 10.

1 15,636 MW. A 24.5% reserve margin applied to the winter peak would provide sufficient
2 system capacity in the summer to produce a reserve margin of 22.13%, which exceeds the
3 Company's requested 16.25% summer TRM.
4

5 **Q. HAVE YOU CALCULATED THE IMPACT OF THE STAFF'S PROPOSED**
6 **WINTER TRM ON THE MW'S OF RESERVE CAPACITY NEEDED BY**
7 **GEORGIA POWER COMPANY?**

8 **A.** Yes. Table 5 below compares the MW of reserves using both the Company's and Staff's
9 reserve margin recommendations. Also shown are the reserves required if the reserve
10 margin is based on an LOLE construct.
11

12 As shown in the table, the MW of reserve capacity for Georgia Power vary substantially,
13 depending on the methodology used to develop the target reserve margin. As discussed
14 earlier, the cost associated with this capacity is included in the Company's revenue
15 requirements and paid for by customers. In 2025, the difference between the Company's
16 recommended winter TRM of 26% and the Staff's 24.5% winter TRM recommendation is
17 ■ MW of reserve capacity.
18

Table 5 Impact of Alternative Reserve Margins on Reserve Capacity MW - 2025			
	Company Base Case 1:10 LOLE 20.00%	Company Base Case (VaR80) 26.00%	Staff LFE Corrected (VaR80) 24.50%
<u>Winter</u>			
GPC MW	3,029	3,938	3,711
<u>Summer*</u>			
GPC MW	2,488	3,397	3,170
* The summer MW's of reserves are the MW's in excess of the summer peak based on the capacity needed to meet the winter peak plus winter TRM.			

1
2 Q. THE COMPANY REVISED ITS METHODOLOGY IN THE 2022 IRP TO
3 ESTIMATE THE HISTORIC RELATIONSHIP BETWEEN WEATHER AND
4 LOAD. HAS THE STAFF EVALUATED THE COMPANY'S NEW
5 METHODOLOGY?

6 A. Yes. To quantify load variability due to weather the Company constructed a linear
7 regression model that related historical weather within their service territory to historical
8 load. The Company then used the results of this model to estimate the effects of potential
9 future weather shapes on their expected load.
10

**Q. HOW DID THE COMPANY DEVELOP THE WEATHER DATA USED IN THE
LOAD/WEATHER STATISTICAL REGRESSION ANALYSIS?**

A. The weather data in the Company's model came from observations at five weather stations within the Company's service areas. This data was seasonally weighted (summer and non-summer) by the portion of load that was closest to each weather station. The five stations were located in Atlanta, Birmingham, Macon, Mobile, and Montgomery. The Atlanta station was given the highest weight, as Atlanta represents the largest load draw of the five.

**Q. PLEASE BRIEFLY SUMMARIZE THE LOAD/WEATHER STATISTICAL
MODEL THAT THE COMPANY DEVELOPED.**

A. The Company's regression model estimated the relationship between weather and load by relating historical weather to historical observed load. The Company used two historical weather periods within its model: 2014-2019 (the "Training Set") and 1962-2019 (the "Test Set").

First, the historic weather and load values from the Training Set were used to estimate the model coefficients. The Company used the Metrix ND software to estimate the relationship between the historic weather observations and actual load from that time period, along with additional variables that adjust for seasonal and weekly variations. Metrix ND and the variables used are discussed in more detail in sections below.

1
2 The Company estimated separate models for each hour using data for the 2014-2019
3 period. For example, the Hour_12 model included variables and predictions for every day
4 of each year in the study for the 12:00 – 1:00 hour. A similar model was built for each hour
5 of the day. By building independent models, the Company was able to avoid the need for
6 additional variables to adjust for time-of-day effects. The Company did account for weekly
7 and seasonal variations in load, however, by including variables corresponding to the day
8 of the week and time of the year. The Company excluded 2020 data from the estimation
9 period to eliminate the potential impact of COVID-19 effects.

10
11 **Q. DID THE STAFF EVALUATE THE COMPANY'S MODELING?**

12 A. Yes. The Staff obtained the Metrix ND software and re-estimated a sample of the hourly
13 models to confirm the Company's results and to examine the summary statistics. The Staff
14 also ran alternative models to test the robustness of the Company's modeling.

15
16 **Q. BASED ON THE STAFF'S REVIEW AND ANALYSIS, WHAT ARE THE STAFF'S**
17 **FINDINGS ON THIS ISSUE?**

18 A. The Staff believes that the Company's analysis is reasonable and appropriate. The models
19 appear to reasonably measure the relationship between load and weather and are a

reasonable basis to develop a set of 2025 hourly load curves based on 58 different weather years.²²

Q. IN ITS EVALUATION OF THE 2018 RESERVE MARGIN STUDY DURING THE 2019 IRP, STAFF NOTED THAT EXTREME WINTER TEMPERATURES OCCURRED IN ONLY A COUPLE OF YEARS IN THE WEATHER DATA BASE, THAT EXTENDED FOR THE PERIOD 1962 TO 2015. HAS THE STAFF PERFORMED SIMILAR ANALYSES OF THE IMPACT OF WEATHER ON THE RESERVE MARGIN RESULTS IN THE 2022 STUDY?

A. Yes. In order to assess the sensitivity of the results to extreme winter temperatures and also to test the impact of more recent weather temperatures, Staff evaluated two scenarios. The first scenario is a recalculation of the winter EORM and winter VaR80 reserve margins using only weather data for the period 2000 to 2019 (the most recent 20 years). The second scenario is a recalculation of the winter EORM and VaR80 reserve margins using the Company's weather data set for 58 years, but excluded the two extreme winter temperature years, 1982 and 1985 from the analysis. Table 6 below shows the results of these alternative weather scenarios on the winter EORM and VaR80 reserve margin calculations using the Staff's corrected LFE distribution.

²² As noted earlier in the Staff's testimony, there are actually 116 load curves, reflecting 58 years of weather data with Tuesday and Saturday yearly starts.

Table 6
Weather Impacts on Winter Reserve Margin

Scenario	With LFE Correction	
	EORM	80% VAR
SOCo Base Case*	22.00%	24.50%
Use Most Recent 20-Years of Weather**	21.75%	23.50%
Base Case W/O 1982 and 1985***	21.50%	24.00%

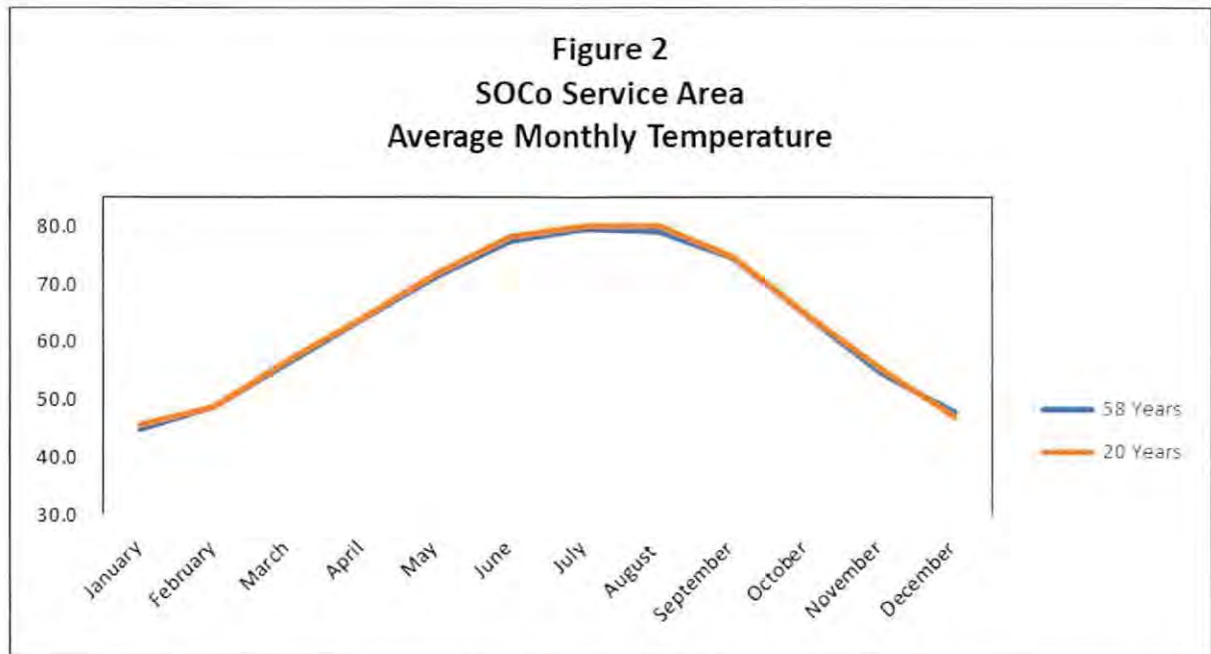
* The Company's Base Case uses weather for the 58 years (1962-2019).

** Company Base Case using only weather for the years (2000-2019).

*** Company Base Case using weather for the years 1962-2019, excluding 1982, 1985.

1
2
3 **Q. WHAT IS THE STAFF'S INTERPRETATION OF THESE WEATHER RESULTS?**

4 **A.** Based on the EORM and VaR80 reserve margin results, it appears that there is relatively
5 little difference in the results in the two alternative weather scenarios compared to the full
6 58-year data set. On average, the monthly average temperatures are similar, whether a 58-
7 year, 20-year weather data set is used. Figure 2 below shows the monthly comparison
8 between the three distributions.
9



To evaluate the extreme weather events, the Staff analyzed the average annual number of hours in each of the three weather data sets in which temperatures dropped below 20 degrees and exceeded 90 degrees. Table 7 below summarizes these results. It appears that there were significantly more hours, on average annually, that temperatures exceeded 90 degrees during the past 20-year period than during the entire 58-year period used in the Company's analysis. Even though the analysis is a winter season reserve margin evaluation, the SERVVM model results are based on all hours of the year, including the summer period.

Table 7		
Historic Temperature Comparisons		
Average Annual Hours		
	Temperature	
	Below 20°	Above 90°
1962-2019	19.5	145.5
2000-2019	9.6	175.0

1
2
3 **Q. YOU INDICATED EARLIER IN YOUR TESTIMONY THAT A KEY FACTOR**
4 **INFLUENCING THE OPTIMAL RESERVE MARGIN IS GENERATING UNIT**
5 **FORCED OUTAGE ASSUMPTIONS. HAS THE COMPANY PROVIDED ANY**
6 **INFORMATION ON THE SENSITIVITY OF THE WINTER RESERVE MARGIN**
7 **TO THESE FORCED OUTAGE RATE ASSUMPTIONS?**

8 **A.** Yes. The Company performed two sensitivity analyses in which generating unit forced
9 outage rates were increased by 50% and reduced by 50%. Table 8 below shows the results
10 of the Company's forced outage rate sensitivity analyses.

Table 8
Winter Reserve Margin Sensitivity Comparisons

Scenario	EORM	80% VAR
SOCco Base Case	24.25%	26.00%
Higher EFOR*	25.00%	27.25%
Lower EFOR**	23.25%	24.75%

* Generating Unit forced outage rates increased by 50%

** Generating Unit forced outage rates decreased by 50%

As can be seen from the table, a 50% decrease in forced outage rates reduces the required level of winter TRM by 1%, based on EORM and 1.25% using the VaR80 construct. Similar impacts, in the opposite direction, are produced if forced outage rates are increased by 50%.

Q. IN THE 2018 RESERVE MARGIN STUDY, THE COMPANY RELIED ON RESULTS FROM A 2012 SURVEY TO DEVELOP ESTIMATES OF THE VALUE OF LOST LOAD (THE COST TO CUSTOMERS OF OUTAGES). DID THE COMPANY DEVELOP ANY UPDATES OF ITS ESTIMATE OF THE COST TO CUSTOMERS OF OUTAGES IN THIS 2022 RESERVE MARGIN STUDY?

A. Yes. The Company retained the Brattle Group to develop an update using a statistical

1 analysis of the original survey data.²³ The Staff has reviewed the Brattle Group study and
2 does not have any objections or concerns with the results.
3

4 **Q. DID THE COMPANY ADDRESS THE IMPACTS OF EXTREME COLD**
5 **WEATHER TARGET RESERVE MARGIN STUDY?**

6 **A.** Yes, it did. As mentioned previously, the Company approach to deriving its EORM target
7 relies on a complex analysis using its SERVIM modeling tool that requires numerous
8 modeling inputs. Generating unit outage rates play an important factor that influences the
9 determination of the Company's Target Reserve Margin, and the Company has found that:

10 "…under extremely cold conditions, outage rates can increase as coal piles
11 and pipes begin to freeze. These situations do not materialize until weather
12 conditions are extreme, and such extreme weather conditions are less
13 common. When they occur, though, the outage impacts can be significant
14 and can increase in an exponential manner."²⁴
15

16 **Q. HOW DID THE COMPANY ACCOUNT FOR THE IMPACTS OF COLD**
17 **WEATHER OUTAGES IN ITS RESERVE MARGIN STUDY?**

18 **A.** The Company's Reserve Margin Study includes a "base" level of generating unit outages
19 expected across the year in its SERVIM modeling. In addition, based on historical data, the
20 Company also includes an incremental amount of generating unit outages that occur in

²³ Southern Company Value of Lost Load (VoLL) Study Update, The Brattle Group, September 27, 2021.

²⁴ Public Disclosure version of 2022 Reserve Margin Study at pages 17-18.

1 hours when system temperatures drop below 13 degrees Fahrenheit, which happens during
2 the winter, though it happens infrequently.
3

4 **Q. IN GENERAL, WHAT IS THE IMPACT OF MODELING AN INCREMENTAL**
5 **AMOUNT OF GENERATING UNIT OUTAGES DURING WINTER MONTHS IN**
6 **ITS SERVUM MODELING?**

7 **A.** The result of modeling an incremental amount of generating units during winter months is
8 that the winter Target Reserve Margin ends up being higher than it would be if only the
9 base level of generating unit outages were modeled, and that leads to the need to install a
10 greater amount of reserve capacity to serve load during the few cold weather hours of the
11 year.
12

13 **Q. HAS THE COMPANY TAKEN STEPS TO MITIGATE THE IMPACTS OF COLD**
14 **WEATHER OUTAGES?**

15 **A.** Yes. Since the 2014 Polar Vortex that affected utilities across the Midwest, South Central,
16 and East Coast regions of the US, the Company has invested capital and spent money on
17 operating and maintenance ("O&M") expenses to harden its generating units and prepare
18 for extreme winter events. Utilities, including Georgia Power have relied on industry
19 reports including one published in September 2014 by the North American Electric

1 Reliability Corporation ("NERC") to address cold weather issues. The Company noted
2 that NERC.²⁵

3 "....recommended that utilities review and update power plant
4 weatherization programs as a result of lessons learned from the 2014 Polar
5 Vortex and limit planned outages during possible winter peak periods,
6 among other things."
7

8 The Company described the actions it has taken since the Polar Vortex to address cold
9 weather outages, which include:

- 10 • Implementing a freeze protection program for non-nuclear generating plants.
- 11 • Conducting winter preparedness meetings with power plants as winter approaches.
- 12 • Incorporating extreme weather scenarios into the Winter Operational Readiness
13 assessments.
- 14 • Significantly reducing planned maintenance in January and February.
15

16
17 The Company has taken further actions since the winter of 2021 events that affected Texas,
18 Louisiana, and other western states. The Company explained it has taken actions to
19 proactively address combustion turbine ("CT") and combined cycle ("CC") generating
20 units that could be impacted by conditions of zero-degree Fahrenheit temperatures for a
21 72-hour period with 25 mile per hour winds. Previously, the Company's design standards
22 required plants to withstand conditions of 10 degrees Fahrenheit for a 72-hour period with
23 12.3 mile per hour winds. The Company has identified modifications necessary to address

²⁵ STF-JKA-I-1.

1 the lower weather condition requirements at many of its CT and CC units and is currently
2 working to implement the modifications to its units.²⁶

3
4 **Q. HAVE THESE CAPITAL EXPENDITURES AND O&M EXPENSES BEEN**
5 **TAKEN INTO ACCOUNT IN THE COMPANY'S ANALYSIS?**

6 **A.** The actual expenditures that have been made are not reflected in the SERVIM analysis
7 itself, but the additional weatherization has resulted in lower forced outage rates as extreme
8 low temperatures in the reserve margin modeling. In the 2022 Reserve Margin Study, the
9 Company has been able to lower the temperature at which it assumes that incremental cold
10 weather outages need to be considered in its SERVIM modeling analysis. Previously, in
11 the 2019 IRP, the Company began to include additional generating unit outages when
12 temperatures dropped below 17 degrees Fahrenheit, but in the 2022 IRP, the Company is
13 now including the additional generating unit outages when temperatures drop below 13
14 degrees. The result is that the System has been hardened and should be more resilient to
15 cold weather outages. The Company in fact, conducted a sensitivity study to determine the
16 impact of the incremental cold weather outages on the winter EORM. The analysis found
17 that when the incremental cold weather outages were removed, the winter EORM only
18 dropped from 24.25% to 24.00%, which is a negligible impact. In fact, there was no impact

²⁶ STF-JKA-1-2.

on the winter TRM using a VaR80 risk criterion as a result of removing the incremental cold weather outage adjustment.

Q. WHAT ARE THE STAFF'S CONCLUSIONS WITH REGARD TO THE COMPANY'S RESPONSE TO COLD WEATHER OUTAGE RELIABILITY IMPACTS?

A. The Company has hardened its System, and this should greatly mitigate the impacts of cold weather outages. Staff commends the Company on the steps it has taken and encourages it to continue to be vigilant in implementing winter preparedness programs. In doing so, the Company should be able to reduce forced outages during extremely weather events, which should save customers money by resulting in less back-up capacity needs during the winter months.

Q. HOW DO THE SOCO WINTER AND SUMMER TARGET RESERVE MARGINS COMPARE TO THOSE USED BY OTHER UTILITY SYSTEMS IN THE U.S.?

A. Table 9 below summarizes a survey prepared by the Staff of selected U.S. electric utility systems and Regional Transmission Organizations.

State	Utility/RTO	Study Name (+hyperlink)	RESERVE MARGIN		
			ANNUAL ICAP RM%	SUMMER ICAP RM%	WINTER ICAP RM%
CA, ID, OR, UT, WA, WY	Pacificorp	2021 IRP	13.0%	13.0%	13.0%
PJM*	NERC	2021 Summer Reliability Assessment	14.7%	14.7%	14.7%
SERC-C	NERC	2021 Summer Reliability Assessment	15.0%	15.0%	15.0%
SERC-E	NERC	2021 Summer Reliability Assessment	15.0%	15.0%	15.0%
ID	Idaho Power	Idaho Power 2021 IRP	15.5%		
LA	Entergy	2023 IRP Assumptions	12.7%		
LA	CLECO	2023 IRP Assumptions	20.7%		
MISO*	MISO	2021-2022 PRM LOLEWG	20.7%		
LA	SWEPSCO	2023 IRP Assumptions			12.0%
SPP*	SPP	2021 SPP Adequacy Report	12.0%		
SC	Duke Energy Carolinas	2020 IRP Update			17.0%
SC	Duke Energy Progress	2020 IRP Update			17.0%
SC	Dominion Energy South Carolina	2021 IRP Update		14.0%	21.0%
MN	Xcel Energy Minnesota	2019 IRP Alternate Plan (2021)	18.0%	18.0%	18.0%
FL	FPL	2021 FRCC Load and Resource Reliability Assessment	20.0%		
FL	Tampa Electric	2022 FRCC Load and Resource Reliability Assessment	20.0%		
FL	Duke Energy Florida	2023 FRCC Load and Resource Reliability Assessment	20.0%		
TN	TVA	2019 IRP		17.0%	25.0%
KY	Louisville Gas & Electric/Kentucky Utilities	2021 IRP		17%-24%	26%-35%

* Regional Transmission Organizations ("RTOs").

Based on this survey, only one other utility uses a winter reserve margin of 26% or greater – Louisville Gas & Electric/Kentucky Utilities ("LGE/KU"). As noted earlier, LGE/KU also use the SERVIM model to develop their planning reserve margin.

Q. What does the Staff conclude from these survey results?

A. The average winter period reserve margin of the utilities and RTOs included in the Staff's survey is 18%. This is substantially lower than the Company's recommended winter TRM of 26% or the Staff's recommended winter TRM of 24.5%. Based on this comparison, the

Staff's recommendation is very conservative.

Results of the 2019 IRP and Need for Capacity RFPs

Q. HOW DID THE RECENTLY COMPLETED CAPACITY RFP COME ABOUT?

A. As the result of a stipulation in the 2019 IRP, the Commission ordered the company to "initiate a 2022-2023 and a 2026-2028 capacity based RFP" that "will require a level of capacity firmness and dispatchability" and that "accommodate[s] bids from renewable resources paired with storage."²⁷ The Company sought in the 2022 RFP to fill capacity needs in the event that the Company were to decide to retire coal units early in 2022. The 2026-2028 RFP was based on the recognition in 2019 that the Company would have a capacity need in the 2026-2028 time period.

Q. WHAT TRANSPIRED IN THE CAPACITY RFP?

A. The Company began the IRP seeking to possibly procure 1,000 – 3,000 MW of capacity resources. After the IRP 2019 completed, the Company decided to combine the two RFPs into one, largely because of changes the Environmental Protection Agency ("EPA") made to the ELG rule, which pushed certain deadlines out from 2023 to 2025, and due to changes

²⁷ 2019 IRP Stipulation, June 6, 2019, Item #11, pg. 4.

1 in the Company's load forecast, which moved the need date forward from 2029 to 2028 at
2 that time. As a result, the Company revised its plans to conduct a single RFP for capacity
3 needs for the 2022 – 2028 period.

4 **Q. WHAT WERE THE RESULTS OF THE RFP?**

5 A. As a result of the RFP, the Company decided to seek approval of six PPAs totaling 2,356
6 MW of winter reliable capacity in this IRP. As will be discussed in more detail below, Staff
7 evaluated the six PPAs with the Company's Aurora model, including costs, benefits, and
8 timing issues.

9
10 **Review of Generation Mix Study**

11 **Q. WHAT IS THE PURPOSE OF THE RESOURCE MIX STUDY?**

12 A. The purpose of the Company's Generation Resource Mix Study is for the Company to
13 develop a long-term resource addition schedule that "provides an informative roadmap for
14 long-term decisions."²⁸ The Company performs a 20-year study using its Aurora
15 Optimization model that considers the status of its existing system, derives forecasts of
16 peak demand and energy, considers fuel prices and carbon dioxide emissions costs,
17 evaluates its need for capacity, and includes various types of resources that would satisfy

²⁸ TS 2022 IRP Mix Study.docx, pg. 2.

its reliability requirements, including conventional resources, renewable resources, and demand-side options. The Company states that the cases developed in the Resource Mix study do not “reflect commitments but instead are generic expansion plans used for planning to support analyses.”²⁹ Staff has certain disagreements with the Company’s Generation Resource Mix Study discussed below.

Q. WHAT ASPECTS OF THE GENERATION MIX STUDY DID YOU EXAMINE?

A. The primary areas of review in the context of the mix study and the Aurora modeling are an assessment of inputs and the reasonableness of outputs.

Fuel and Carbon Forecast

Q. HAS STAFF EVALUATED THE COMPANY’S NATURAL GAS PRICE FORECAST?

A. Yes. Staff evaluated the Company’s latest natural gas price forecasts, B2022, used in various studies in the IRP, including the Resource Mix Study, and compared them to other publicly available, recently published gas price forecasts. Staff developed its own independent Low, Mod, and High natural gas forecasts from public sources. Staff’s natural gas forecasts were similar to the Company’s forecasts. Staff adopted the Company’s

²⁹ *Id.* at pg. 2.

forecast for efficiency purposes in this proceeding. The following graphs compare the data for the company's Low, Mod, and High Henry Hub forecasts. Natural gas is priced in dollars per million BTUs (\$ / MBTUs) and measured in nominal dollars.

Figure 3: Low Henry Hub (Base) Gas Price Forecast Comparison (\$/MBTU)

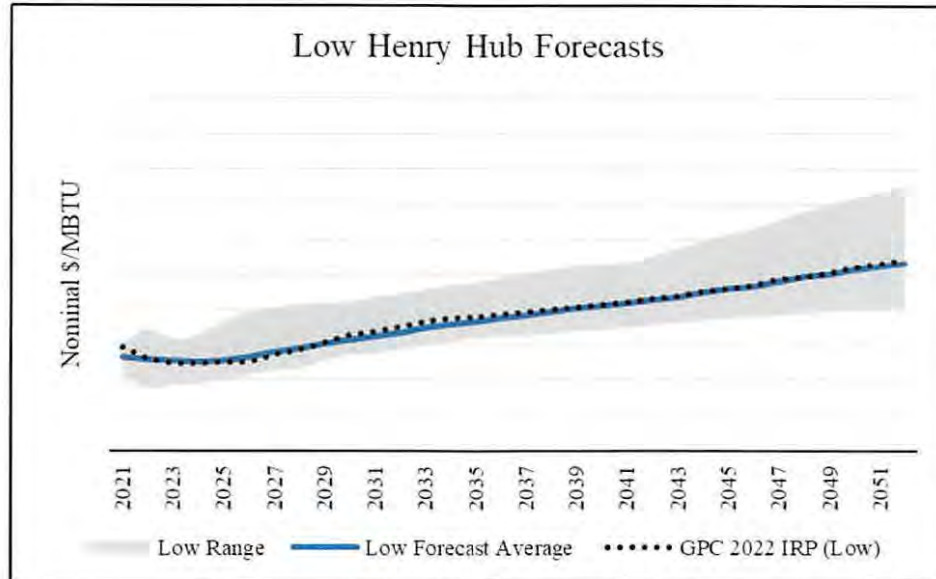


Figure 4: Moderate Henry Hub Gas Price Forecast Comparison (\$/MBTU)

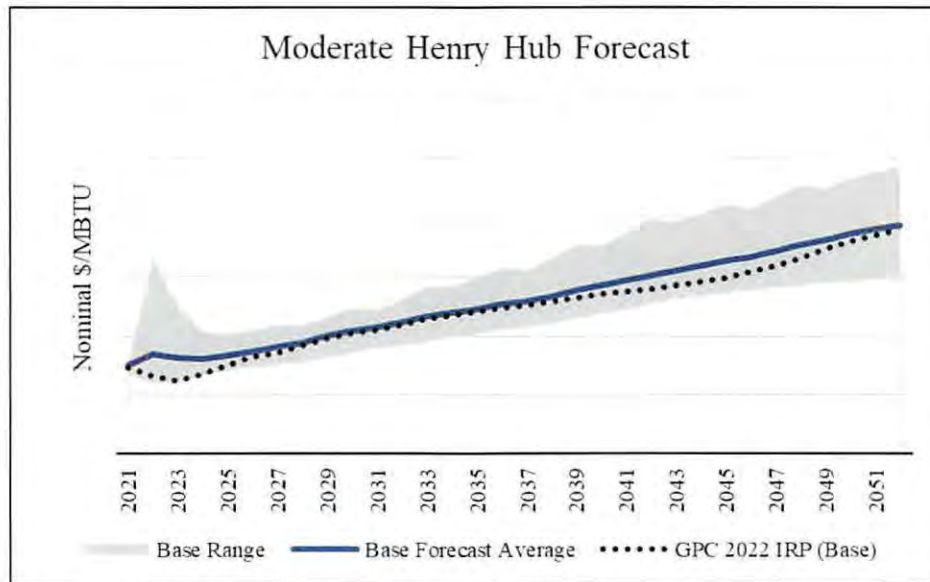
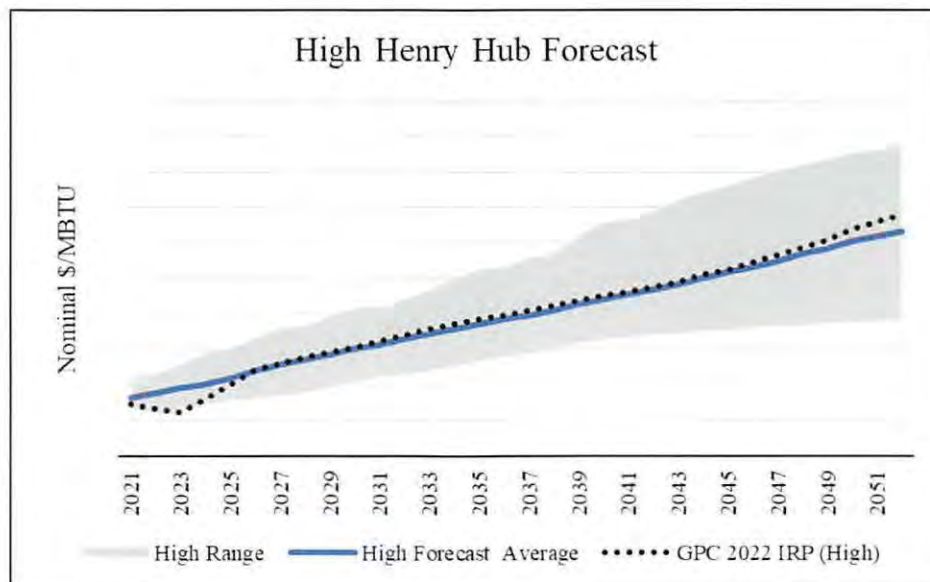


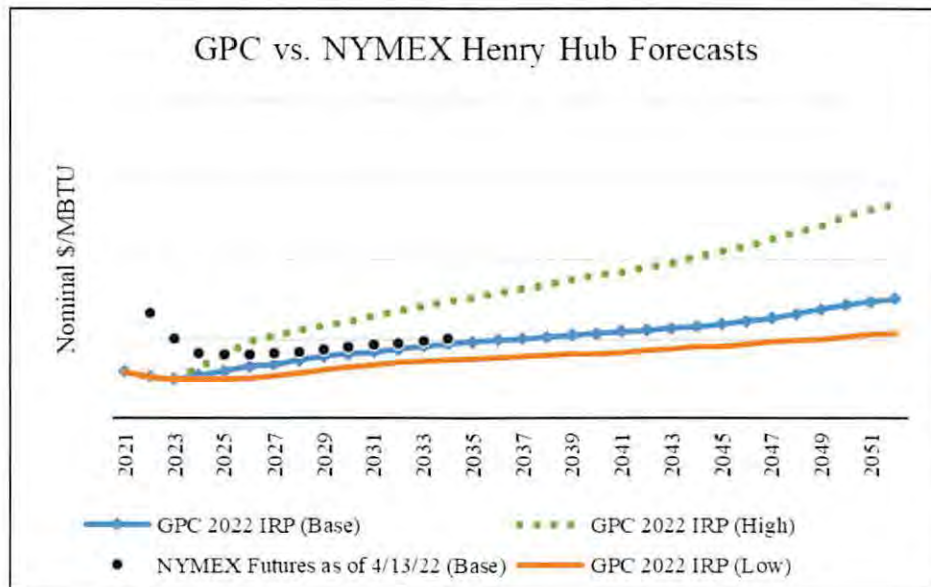
Figure 5: High Henry Hub Gas Price Forecast Comparison (\$/MBTU)



1
2 **Q. DID YOU ACCOUNT FOR RECENT UPWARD PRESSURE ON NATURAL GAS**
3 **PRICE FORECASTS?**

4 A. Yes. Staff included a NYMEX futures projection from April 13, 2022, in its Mod Gas
5 forecast. This NYMEX futures projection shows a fairly dramatic increase in the price of
6 natural gas in the 2022 and 2023 period, however, after that, the difference in gas prices
7 are not significantly different, and over the long-term the NYMEX price and the other
8 forecasts, including the Company's forecast, are not far out of line with each other. Staff
9 notes that increased cost pressures on natural gas prices have arisen in response to investor
10 pressure for domestic drillers to become profitable on an ongoing basis, recent inflationary
11 pressures, and the Russia/Ukraine conflict. Figure 6 below shows that, although long-term
12 price expectations have risen in recent months, the market continues to expect the current
13 high gas price pressures to ease within a few years, and long-term price expectations to
14 remain closer to the Company's moderate forecast than its high forecast. While the
15 NYMEX forecast was included in the Mod natural gas comparison above, the following
16 figure indicates that even if there is continued price pressure on natural gas, the Company's
17 Mod and High gas price forecasts still provide reasonable cases for current analyses.

Figure 6: GPC Natural Gas Price Forecasts vs. NYMEX



Q. HAS STAFF EVALUATED THE COMPANY'S CARBON DIOXIDE (CO₂) EMISSION PRICE FORECAST?

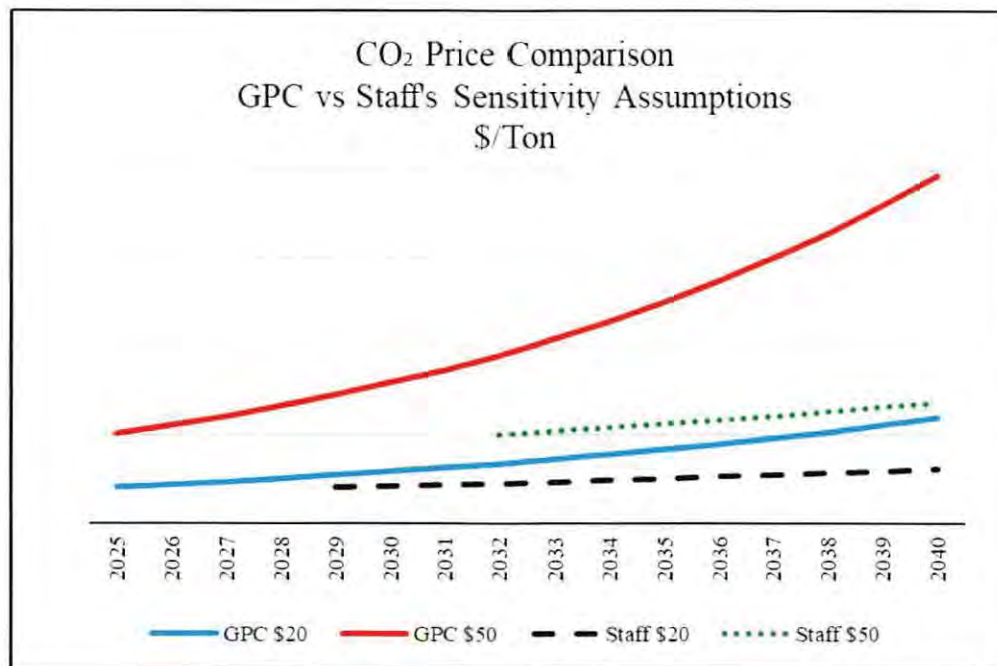
A. Yes. The Company's two main carbon pricing scenarios both begin in 2025. The \$20/Ton scenario escalates at █% per year, while the \$50 scenario escalates at █% per year on a constant nominal basis.

Q. SINCE THE 19TH VCM PROCEEDING AND IN THE 2019 IRP, STAFF HAS EXPRESSED CONCERN ABOUT CO₂ EMISSION PRICES. PLEASE ELABORATE ON STAFF'S CONCERN.

1 A. Staff recognizes there are many points of view regarding CO₂ concerns, and what CO₂
2 prices may be in the future. Staff also understands that there is tremendous uncertainty
3 over what form greenhouse gas policy will ultimately take, if and when it will go into
4 effect. Staff continues to have concern about the Company's forecasts, particularly the
5 assumption that CO₂ prices will begin in just a few years (2025) and that prices will escalate
6 at a constant high rate over time. The Company used different CO₂ forecasts in the 2022
7 IRP than in the 2019 IRP for its scenario analysis. The Company is no longer using \$0/Ton,
8 \$10/Ton and \$20/Ton CO₂ forecast assumptions, but instead is now using \$0/Ton, \$20/Ton,
9 and \$50/Ton CO₂ assumptions.

10 As in the prior IRP, and VCM proceedings, Staff developed its own CO₂ forecasts
11 for sensitivity analysis. Staff's \$20/Ton forecast begins in 2029, and its \$50/Ton forecast
12 begins in 2032, and both escalate at a constant nominal rate of 4.0% per year. The following
13 figure shows the difference in Staff's forecast and the Company's forecast.

Figure 7: CO₂ Forecast Comparison



Staff's analyses relied on the Company's CO₂ forecasts, however, Staff also performed additional analyses using Staff CO₂ forecast sensitivities. It should be noted that under Staff's assumed CO₂ emission prices the annual cost of CO₂ to ratepayers would initially be approximately \$480 million and \$1.2 billion under the \$20 and \$50 scenarios, respectively.³⁰ This cost to ratepayers would grow over time as the CO₂ prices increase,

³⁰ Carbon dioxide emissions are estimated to be 24 million metric tons per year based on 2021 and 2020 10-K filings on page II-45.

though some of the costs charged could ultimately be distributed back to customers depending on the tax legislation.

Q. WHAT SCENARIOS DID THE COMPANY EVALUATE IN ITS RESOURCE MIX STUDY?

A. The Company provided a summary of the cases it evaluated in Section 4.1 of the Resource Mix Report. For convenience the table is reproduced here. The table indicates that depending on the case, the Company relied on different assumptions for fuel, CO₂, and technology costs, as well different load forecast assumptions.

Table 10: GPC Planning Scenarios

	Natural Gas Price Path	Greenhouse Gas Pressure	Technology Cost & Performance	Load	Short Name
1	Moderate	\$0 fee	Tech Application Stds	Reference	MG0
2	Moderate	\$20 fee	Tech Application Stds	Reference + MG20 delta	MG20
3	\$50 CO ₂	\$50+ fee	Tech Application Stds	Reference + \$50 delta	\$50
4	Low	\$0 fee	Tech Application Stds	Reference + LG0 delta	LG0
5	Low	\$20+ fee	Tech Application Stds	Reference + LG20 delta	LG20
6	High	\$0 fee	Tech Application Stds	Reference + HG0 delta	HG0
7	High	\$20+ fee	Tech Application Stds	Reference + HG20 delta	HG20
8	Moderate	\$0 fee	Tech Application Stds	High Electrification	HL
9	Moderate	\$0 fee	Tech Application Stds	High EE & DER adoption	LL
10	Moderate	\$0 fee	Low cost zero-CO ₂ tech	Reference	Tech
11	Moderate	CO ₂ Intensity	Tech Application Stds	Reference	CI

The CO₂ intensity view assumes that no CO₂ costs would be imposed, but based on other actions taken across the industry, CO₂ would decline to 10% of 2020 CO₂ levels by

2050.³¹ The Technology Application Standards refers to cost and performance summaries the Company provided in the IRP Technology Screening Document.³²

Generic Resources

Q. HOW DID THE COMPANY ARRIVE AT THE RESOURCES IT CONSIDERED IN ITS RESOURCE MIX STUDY?

A. The Company conducted a technology screening process to reduce resource types down to a smaller set that could be used in the expansion planning analysis study. The technology screening process included three steps, 1) Technology Identification, 2) Preliminary Screening, and 3) Detailed Qualitative Screening Analysis. The Technology Identification Step determined many supply-side technologies that were categorized as Fossil Fuel, Nuclear, Renewable and Energy Storage. The second and third steps eliminated resources that the Company considered to be commercially unviable based on factors such as safety, technical development, commercial availability, and performance uncertainties.

Q. WHAT RESOURCES DID THE COMPANY IDENTIFY FOR USE IN ITS EXPANSION PLAN OPTIMIZATION ANALYSES?

³¹ 2020 IRP Main Document, pg. 7-41.

³² TS 2020 IRP Tech Screening.docx.

A. The table below contains a list of resources that were evaluated in the predominant number of expansion plan studies the Company performed. The data was taken from a table in the Company's Resource Mix Study.³³

Table 11: Summary of Company Modeled Generic Resources

Resource Name	Short Name	Capacity Equivalence (%)	Build Time (Yr)	Asset Life (Yr)
Combined Cycle	CC	100%	■	■
Combined Cycle with Carbon Capture & Sequestration	CC w CCS	100%	■	■
Combustion Turbine	CT	100%	■	■
Combustion Turbine with Future Emission Controls	CT w SCR	100%	■	■
Reciprocating Internal Combustion Engines	RICE	100%	■	■
Solar Photovoltaic - Single Axis Tracker (\$25PPA)	Solar	0%	PPA ³⁴	■
Onshore Wind Power	Wind	41%	■	■
Lithium-ion Battery Energy Storage System	BESS	Declining Tranches ³⁵	■	■

³³ 2022 IRP, Resource Mix Study Report, Table 2: Candidate Technology Assumptions, pg. 15.

³⁴ The lead time for solar is the required time for conducting an RFP.

³⁵ In the Resource Mix Study tranches were modeled as follows: 0-600 MW: 75%; 601-1200 MW : 60%; 1201-3300 MW : 50%; 3301+ MW : 25%

1 Q. DID STAFF COMPARE THE COSTS AND OPERATIONAL
2 CHARACTERISTICS MODELED BY THE COMPANY TO INDUSTRY
3 VALUES?

4 A. Yes. We compared the costs to the National Renewable Energy Laboratory ("NREL"),
5 Lazard, and a selection of other utilities to assess the reasonableness of assumptions. Staff
6 provides this assessment as Generic Resource Comparison Exhibit NHBW-6. Staff notes
7 that this is the first IRP in which the Company used the Aurora production cost model,
8 which has provided the opportunity to evaluate renewable resources as selectable resource
9 options along with traditional fossil resources. Previously, challenges arose attempting to
10 use Strategist for this purpose, such as runtime issues.

11 Q. DOES STAFF HAVE ANY CONCERNS ABOUT THE RESOURCES OPTIONS
12 MODELED IN THE RESOURCE MIX STUDY?

13 A. Staff has three concerns. First, the Company did not evaluate paired solar and battery
14 resource options in the Resource Mix Study, which could provide additional economic
15 benefits to System ratepayers. Staff recommends that for future Resource Mix Studies, the
16 Company should model paired solar and battery generating units as selectable resources in
17 its optimization analysis.

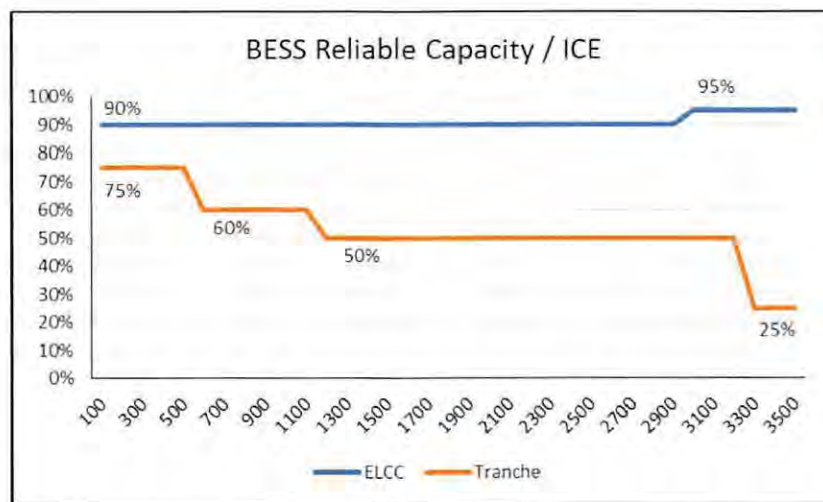
18 Second, Staff has some concerns about the Company's cost decline assumption for
19 battery storage resources, which the Company presented in Figure 10 of its Resource Mix

1 Study Report. Staff is generally aware that, like Solar and Wind resources, battery storage
2 resources are expected to drop in price over time. However, given that utility scale adoption
3 is relatively new, it is difficult to assess the reasonableness of the Company's forward
4 projections. Future all-source RFPs would help provide more clarity about battery storage
5 economic benefits. Staff Panel Barber-Cook-Bower will also address other issues
6 regarding battery storage resources in their testimony.

7 Third, the Company provided a study that utilized the Effective Load Carrying
8 Capability ("ELCC") methodology to determine the capacity value of battery and solar
9 resources. The ELCC study was reviewed by the Barber-Cook-Bower panel as well, in the
10 context of the Renewable Cost Benefit Framework, but our primary concern relates to a
11 lack of consistency between the results the Company determined in the ELCC study, and
12 the assumptions it used in the Resource Mix Study in terms of modeling the capacity value
13 of solar and battery resources. The Company did not rely on the ELCC results when it
14 performed the Resource Mix Study.³⁶ The following graph provides a comparison of the
15 Company's assumed tranche modeling compared to the ELCC results for 4-hour BESS.
16

³⁶ STF-JKA-3-3.

Figure 8: Capacity Value of BESS (Winter)



Q. HOW DID STAFF ADDRESS ITS CONCERNS?

A. Staff included adjustments in its Aurora Optimization analyses to account for the capacity equivalence value results that were derived in the ELCC study for modeling solar and battery storage resources. Staff assumed 90% for BESS, and 5% for Solar based on the winter study results from the ELCC Study.

Q. DID STAFF ADDRESS ANY OTHER CONCERNS IN ITS AURORA MODELING?

A. Yes. Staff reviewed the Company's Renewable Integration Study, which was performed to derive the cost of maintaining additional operating reserves to ensure reliability of the Company's system with increasing penetrations of solar resources. In collaboration with

1 the Barber-Cook-Bower panel, we concluded it was appropriate to capture an integration
2 cost in modeling solar resources in our Aurora expansion plan modeling process. Staff is
3 concerned about the Company's assumption for integration costs being set too high, and
4 Staff decided, for our modeling purposes, to include an integration cost of \$2.50/MWh in
5 its analysis. This was based on the Company's Renewable Integration Study derivation of
6 the cost to mitigate up to 8,000 MW on the Southern Company System.³⁷ For purposes of
7 testimony, the Barber-Cook-Bower panel ultimately settled on a lower solar integration
8 cost of \$1.93/MWh after our modeling had been completed. Since there are limits to how
9 much solar can be added Staff per year, and Staff only recommends that 2,300 MW of solar
10 be added by 2029, Staff believes that \$2.50/MWh was reasonable for this analysis, but
11 Staff will use a lower solar integration cost in the future.

12 **Scenarios, Resource Need, and Expansion Plan Development**

13
14 **Q. PLEASE DISCUSS THE CAPACITY NEED SITUATION FOR SOUTHERN**
15 **COMPANY AND GEORGIA POWER.**

16 **A.** On behalf of each operating company, Southern Company performs joint resource planning
17 analyses to identify optimal resources for the System, which are then allocated to each
18 operating company, including Georgia Power.³⁸ As one of the first steps, the process

³⁷ Table 15, pg. 23, 2022 IRP Renewable Integration Study.

³⁸ Operating companies are Alabama Power, Georgia Power and Mississippi Power.

1 begins with a determination of the System's capacity needs, which are derived based on
2 the obligation for the System to meet certain reliability targets. As discussed earlier,
3 Southern Company Services conducts a System TRM Study to assess the reliability of its
4 system and to determine TRMs for both the winter and summer seasons. After establishing
5 the System TRM, Southern Company Services derives corresponding TRM values that
6 apply to Georgia Power, which are determined by accounting for the diversity of Georgia
7 Power's peak demand compared to the System's peak demand. For purposes of this
8 section, all discussion focuses on the Winter TRM, as the winter season currently drives
9 the capacity need for the Company.

10
11 **Q. PREVIOUSLY, YOU DISCUSSED STAFF'S CORRECTION TO THE SYSTEM**
12 **WINTER TRM. DID YOU PREPARE A TABLE SHOWING SOUTHERN**
13 **COMPANY'S TRM VALUES FOR BOTH THE SYSTEM AND GEORGIA**
14 **POWER AND COMPARE THAT TO STAFF'S ADJUSTED VALUES?**

15 **A.** Yes. The following table compares long-term TRMs that the Company derived to the
16 corrected targets that Staff derived that was previously discussed. The System TRM and
17 Georgia Power TRM values effectively lead to the same need for capacity, the difference
18 is that one is used to derive requirements using the Southern Company System Peak
19 demand and the other is used to derive requirements using the Company's peak demand.

Table 12: Target Reserve Margin

	Derived by Company (%)	Derived by Staff (%)
System TRM	26.0	24.5
Georgia Power TRM	25.18	23.7

Q. BASED ON THE STAFF'S CORRECTED TRM DERIVED FOR THE COMPANY, AND ASSUMING THERE WOULD BE NO RETIREMENTS OF COAL UNITS AND NO ACQUISITIONS OF PPA RESOURCES, WHEN DOES STAFF EXPECT THE COMPANY'S NEXT NEED FOR CAPACITY WOULD BE?

A. Using Staff's calculated TRM of 23.7% for Georgia Power, the Company's next need for capacity would not be until 2030, as shown in the following table. That is the year that Georgia Power's TRM falls below 23.7% for the first time, creating a small shortfall in capacity that would need to be addressed.

Table 13: GPC Reserve Margin – No PPAs, No Retirements

GPC Territorial Base Case Load vs. Existing Capability MG0 (Winter) No Generic Additions, Staff TRM, No Retirements, No PPAs						
	Peak Demand (MW)	Target Reserve Margin	Target Capacity	Total Installed Capacity (MW)	Total Installed Capacity Above Target Capacity (MW)	GPC Reserve Margin (%)
2022	15,490	23.24%	19,090	20,121	1,031	29.9%
2023	15,550	23.24%	19,164	20,620	1,456	32.6%
2024	15,581	23.24%	19,202	21,334	2,132	36.9%
2025	15,636	23.70%	19,342	20,383	1,042	30.4%
2026	15,657	23.70%	19,368	20,024	656	27.9%
2027	15,674	23.70%	19,389	20,134	745	28.5%
2028	15,659	23.70%	19,370	20,151	781	28.7%
2029	15,760	23.70%	19,495	19,827	332	25.8%
2030	15,799	23.70%	19,543	19,472	(71)	23.2%

Q. GEORGIA POWER IS PROPOSING TO RETIRE WANSLEY 1-2 LATER IN 2022, WOULD THAT RESULT IN AN EARLIER NEED FOR CAPACITY?

A. Yes. Retiring just the Wansley Units 1-2 units would accelerate Georgia Power's need for capacity to 2026 assuming no other retirements take place and no capacity PPAs are acquired.

Q. ASSUMING THE COMPANY'S REQUEST TO RETIRE CERTAIN COAL UNITS AND ACQUIRE PPA CAPACITY IS APPROVED AS PROPOSED, WHEN WOULD THE COMPANY'S NEXT NEED FOR CAPACITY OCCUR?

A. With the Company's plan to retire coal units and acquire PPAs, Georgia Power's next need for capacity would be in 2029, which is one year earlier than it would be if no retirements

1 were to occur. The following table identifies the proposed retirements and PPA
2 acquisitions that are part of the Company's proposed decertification and certification
3 requests. Positive values in the Change MW column reflect additions to the Company's
4 resources, and negative values reflect retirements or PPA contract expirations. The table
5 indicates that in addition to coal retirements and PPA additions, there will also be other
6 changes to Georgia Power's generating units including the addition of the Vogtle 3-4 units,
7 unit upgrades, PPA expirations, and solar additions. The bottom of the final column to the
8 right shows that with all of the changes, the Company will next have a need for capacity in
9 2029.

Table 14: Georgia Power Additions vs. Retirements Winter Ratings (MW)³⁹

Year	Units	Change MW	Installed Capacity	Staff TRM Capacity	Capacity Excess (Need)
2022	GPC POSITION		20,121	19,090	1,031
2023	Fleet (Vogtle U3, etc.)	499	20,620	19,164	1,456
2023	Wansley 1-2	(933)	19,687	19,164	523
2024	Fleet (Vogtle U4, etc.)	714	20,401	19,202	1,199
2025	PPA – Wansley	622	21,023	19,341	1,682
2025	PPA – Harris	690	21,713	19,341	2,371
2025	PPA - Monroe CT	(309)	21,404	19,341	2,062
2025	PPA - Monroe CT	360	21,764	19,341	2,422
2025	Fleet (Walton, Washington Co, etc.)	(642)	21,121	19,341	1,780
2026	Fleet (Dahlberg 2,6, 8, 10, etc.)	(359)	20,763	19,368	1,394
2026	PPA - Dahlberg 2,6	171	20,934	19,368	1,566
2026	PPA - Dahlberg 8-10	258	21,192	19,368	1,824
2027	Mossy Branch	65	21,257	19,389	1,868
2027	McGrau Ford	270	21,527	19,389	2,138
2027	Fleet (RTP, sales, etc.)	45	21,572	19,389	2,183
2028	Bowen 1-2	(1,432)	20,140	19,370	769
2028	PPA - Dahlberg 1,3,5	256	20,396	19,370	1,025
2028	750 MW Solar @ 5% ICE	38	20,433	19,370	1,063
2028	Fleet	(13)	20,420	19,370	1,050
2029	Scherer 1-2	(144)	20,276	19,495	781
2029	Scherer 3	(504)	19,772	19,495	277
2029	Gaston 1-4	(460)	19,312	19,495	(183)
2029	Fleet (Mid GA CoGen, Sales, New Solar)	(333)	18,980	19,495	(515)
2029	GPC POSITION		18,980	19,495	(515)

³⁹ Regarding Scherer 3, the total unit capacity is 860 MW, and Gulf Power's share is 215 MW or 25%. Of Georgia Power's 75% (645 MW), 504 MW can be counted toward retail customer's firm requirements. The remainder is not in retail rate base and cannot be counted towards the Company's firm capacity.

1 **Q. IF ANY OF THE CANDIDATE RETIREMENT UNITS CONTINUE TO OPERATE**
2 **INSTEAD OF RETIRING, WOULD THAT CHANGE THE DATE OF THE NEXT**
3 **NEED FOR CAPACITY?**

4 A. Yes. For example, if Bowen Units 1-2, continued to operate beyond the end of 2027, the
5 Company's next need for capacity would be pushed out to 2031, assuming all of the
6 proposed PPAs were acquired as planned. The Company currently has four other PPAs that
7 will terminate in 2031.

8
9 **Q. WHAT HAS STAFF CONCLUDED REGARDING THE COMPANY'S**
10 **RESOURCE NEEDS?**

11 A. Staff concludes that the Company will likely have a need for capacity in the 2029-2031
12 time-period. Staff believes an all-source capacity RFP should be initiated following this
13 IRP to address future capacity needs. An all-source capacity RFP should include
14 traditional fossil fuel resources, stand-alone battery, and solar plus battery resources as was
15 permitted in the most recent capacity RFP. In the next capacity RFP Demand-Side
16 resources could also be treated as eligible resources. The timing for conducting this RFP
17 would be similar to the timing that occurred in planning the last RFP. After the 2019 IRP
18 concluded, the Company initiated an RFP for 2026 – 2028 capacity needs, which was also
19 seven to nine years after the IRP completed. This longer time frame would allow the
20 Company time to bid in new capacity that it could own, including the battery storage

resources that the Company would like to add in the future. As with the most recent capacity RFP, Company and third-party proposals would be evaluated against each other to identify the most economic capacity additions.

Georgia Power's Unit Retirement Study

Q. PLEASE DESCRIBE GEORGIA POWER'S UNIT RETIREMENT STUDY ("URS").

A. Georgia Power's URS was performed as a stand-alone analysis, designed to determine whether it would be economic to continue to operate coal units and oil-fired CT units versus whether it would be economic to retire those units and replace them with a set of PPA units. In contrast, Staff performed a full optimization analysis that considered capacity and fuel cost in a comprehensive manner, and resulted in a more accurate estimate of the optimal expansion plan. The Company used a separate spreadsheet analysis to evaluate each of the retirement candidate units. The analyses considered whether the candidate resources should continue to operate between 2025 and 2052, or whether they should be retired and replaced with alternative PPA resources that operate during that time frame. Since the study period extended well beyond the length for when the PPA resources would expire, the Company hand-selected resources that would fill in the expansion plan at the later end of the study period. The Company conducted analyses for six groups of candidate retirement

coal and gas-fired steam turbine units as identified in the table below, and it evaluated the retirement of three oil-fired CT resources. The following table provides the characteristics of the candidate retirement units.

Table 15: Candidate Retirement Units

Units	GPC Retail Capacity (MW)	Earliest Transmission Retirement Date	ELG Compliance Strategy	Proposed Decertification Date	Modeled Retirement Date
Wansley 1-2	933	2022	Retire by 2028	August 31, 2022	August 31, 2022
Bowen 1-2	1,432	2027	Retire by 2028	December 31, 2027	December 31, 2027
Gaston 1-4	460	2027	Retire by 2028	December 31, 2028	December 31, 2028
Scherer 3	504	2022	Retire by 2028	December 31, 2028	December 31, 2028
Scherer 1-2	144	2028	ELG spend 2025/2028	N/A	December 31, 2028
Bowen 3-4	1,768	2030+	ELG spend 2025	N/A	December 31, 2035
Wansley 5A	32	2022		August 31, 2022	August 31, 2022
Boulevard 1	19	2022		August 31, 2022	August 31, 2022
Gaston A	10	2022		December 31, 2028	December 31, 2028

Q. PLEASE EXPLAIN THE COMPANY'S EVALUATION METHODOLOGY.

A. The Company performed a series of economic analyses comparing a case with an evaluation unit continuing to operate, versus a case with the evaluation unit no longer operating and replaced with a portfolio of alternative resources. Coal units (Wansley 1-2, Bowen 1-2 and Scherer 3) were generally replaced by the portfolio of six Capacity RFP

PPAs proposed in this IRP. Since the PPAs mostly will only be available for 10 years, the Company assumed that further out in the study period, generic CT, Solar, and Battery Storage resources would be the replacement for the retired coal units. The Company conducted its analysis considering combinations of natural gas and CO₂ tax forecasts, including the price-policy scenarios of LG0, MG0, HG0, LG20, MG20, HG20, and MG50.

Q. WHAT COSTS AND BENEFITS WERE INCLUDED IN THE COMPANY'S URS STUDY?

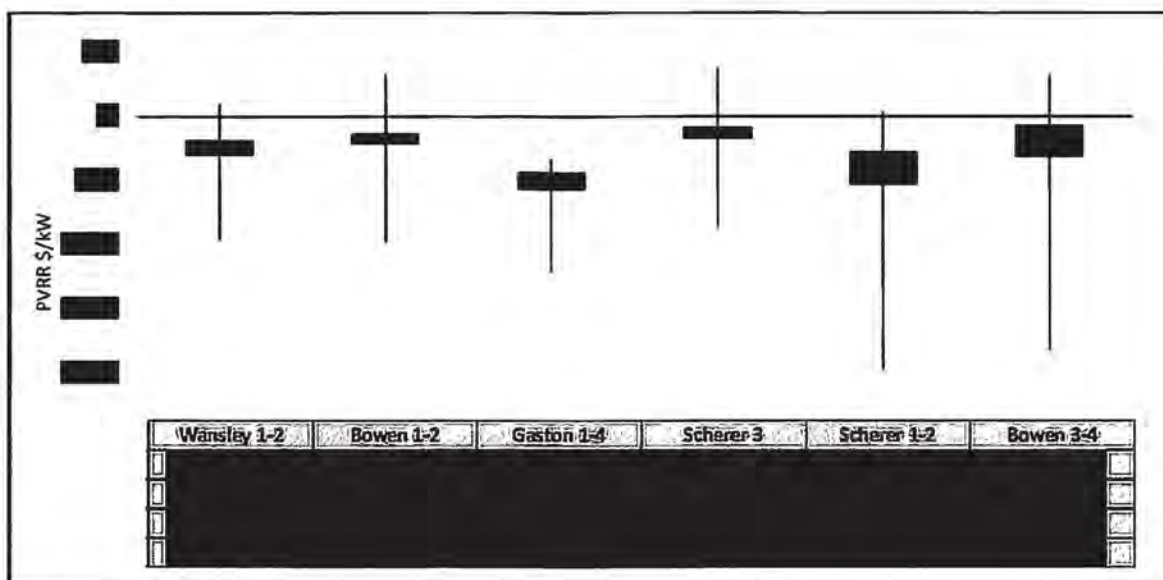
A. The Company's analysis captured, energy, capacity, and avoided transmission benefits. With regard to costs, the analysis included fuel costs, fixed and variable O&M expenses, and incremental capital expenditures. The analysis was structured to derive the on-going costs and benefits of continuing to operate candidate retirement units. The net benefit of continuing to operate candidate units, was compared to the net benefit of retiring the candidate units, and acquiring replacement PPA capacity. The contractual PPA costs were included in the economic analysis.

Q. PLEASE DISCUSS THE COMPANY'S URS RESULTS.

A. The Company's analysis determined that it was economic to retire all of the identified units. Tables 8 through 13 in Section 4 of the Company's Unit Retirement Study Report

(Technical Appendix Volume 2) contain the Company's results. The results are presented in a matrix format containing the net present value benefit of continuing to operate the evaluation unit associated with a given natural gas/CO₂ case. Numerous tables were provided, and Staff presents the same information but condensed into a single figure. Figure 9 below contains the results for each retirement grouping and expresses the results on a net present value revenue requirement or NPVRR per kW basis for each fuel/CO₂ case that the Company provided. These results were analyzed over the 2025-2052 study period, and the graph shows the economics of replacing the candidate retirements with replacement capacity. This metric is useful for normalizing the results to compare units of different sizes.

Figure 9: Summary of Georgia Power's Unit Retirement Study Results



1 Positive values in the chart indicate it would be more economic to continue to operate the
2 target unit through 2052, and conversely, negative values indicate it would be more
3 economic to replace the candidate units. For its study, the way the Company structured its
4 analysis, it essentially assumed a 2025 retirement date despite requesting decertification
5 for most of the units in 2028. Even in the case of Wansley 1-2, the Company's modeling
6 assumed a retirement date of 2025, while the Company in fact is seeking decertification of
7 those units in 2022. For the portion of the analysis that considered continuing to operate
8 the candidate units, by conducting the analysis through 2052, the Company assumed that
9 the candidate units would stay online all the way through 2052, which is unlikely even if
10 those units remain online beyond 2028. Staff believes the Company's methodology was
11 flawed by assuming that if candidate retirement units in fact continue to operate, they
12 would operate all the way through 2052. Assuming certain coal units operate until 2052 is
13 not realistic assumption as the older units (Bowen and Wansley) may have to be rebuilt in
14 their entirety, which would be quite expensive. By assuming the coal units run until 2052,
15 and not evaluating alternative retirement years, the Company's analysis may have been
16 biased towards a retirement decision. Staff believes an earlier retirement date should have
17 been considered.

18 In the table above, the "Average (\$/kW)" value is an average of the results of all
19 seven natural gas and CO₂ combinations. The "Median (\$/kW)" value represents the mid-
20 point of the seven natural gas price/CO₂ scenarios that the Company analyzed. The "Min.

1 (\$/kW)" (Minimum) and "Max. (\$/KW)" (Maximum) values represent the lowest and
2 highest cost natural gas/CO₂ cases, respectively.

3 For coal plants, typically, the Max result is the High Gas Price, Zero CO₂ tax
4 scenario, while the Min result is for the highest CO₂ scenario (MG50). Negative values in
5 the chart indicate that it would be more economic to retire the target units in 2025 than to
6 continue operating them until 2052.

7 The Company concluded that it was economic to retire all of the candidate
8 retirement units, but determined a schedule for phasing out the coal units over time such
9 that it could make necessary transmission investments.

10
11 **Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S**
12 **MODELING APPROACH?**

13 **A.** Yes. Staff has concerns about the Company's use of the avoided cost methodology and the
14 Company's choice to hand-select the replacement unit portfolio rather than utilizing an
15 optimization modeling process which considers all costs and evaluates replacement
16 resources in a comprehensive manner. Using an avoided cost shape for dispatch is an
17 inaccurate representation of how units are actually dispatched. In day-to-day operations,
18 units are dispatched economically to serve load while considering operational constraints.
19 The Company indirectly used its production cost model in developing avoided costs that
20 were used in its analysis, but that approach does not directly capture dynamic impacts such

1 as resource curtailments and the influence of operating reserves that are captured when
2 direct analyses are performed within a production cost model.

3 Also, the Company's avoided cost methodology doesn't accurately reflect the fact
4 that marginal costs will change as units are retired and replacement resources are added.
5 As resources are added or removed from the system, the marginal unit may be different,
6 which could change dispatch price signals. This possible change to the dispatch price
7 signals is not captured in the Company's avoided cost analysis. The following table
8 provides an indication of the problem with the Company's approach. The table shows the
9 projected Bowen 1-2 generation derived in the Company's URS based on its avoided cost
10 analysis for the MG0 scenario. It compares that to the amount of unit generation that was
11 produced in an Aurora production cost analysis (Zonal Dispatch) with the same generation
12 assumptions, but with the full dispatch process modeled.⁴⁰ The results are vastly different.

⁴⁰ Data Response STF-JKA-4-9 explains that the URS avoided cost approach does not capture factors such as unit minimum up and down times, operating reserves, known local reliability constraints, etc., which are captured in Aurora production cost modeling.

Table 16: Bowen 1-2 Projected Generation MWh per Year

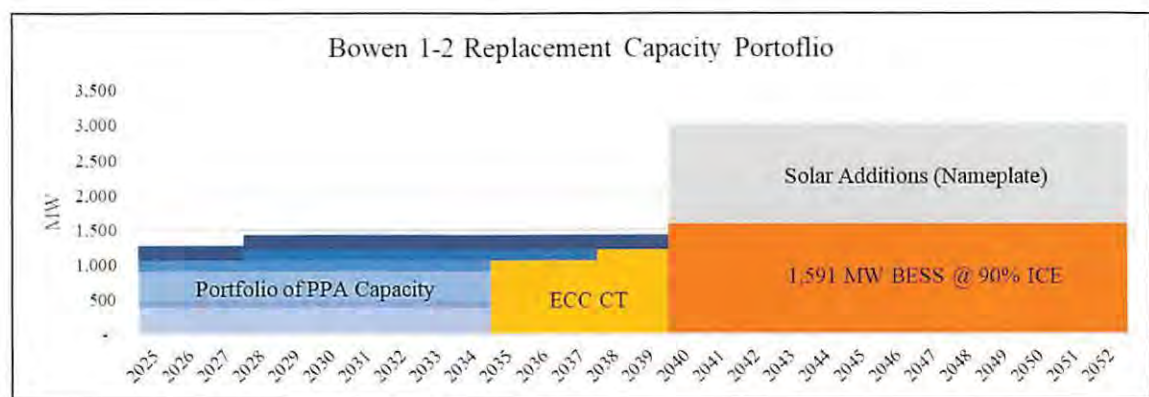
MG0	Avoided Cost (against Price)	Zonal Dispatch (against Load)
2025	-	
2026	-	
2027	-	
2028		
2029		
2030		
2031		
2032	-	
2033	-	
2034	-	
2035	-	

The table indicates that the Company's avoided cost analysis produces significantly less Bowen 1-2 energy compared to what was produced using the zonal dispatch production cost model, which performs a more accurate simulation of how the System would operate. The Zonal Dispatch approach is more accurate because it dispatches resources using proper dispatch pricing signals, accurately reflects generating unit operating characteristics, and includes operating reserve modeling impacts.

Finally, the Company developed a replacement portfolio by "hand-selecting" resources by simply assuming what the replacement resources would be rather than performing an optimization to determine the most economical replacement resources. The

following figure shows the capacity the Company assumed would replace Bowen 1-2 in a retirement scenario.

Figure 10: Bowen 1-2 Replacement Portfolio



These hand selected resources are not consistent with the resource plan the Company has proposed. For example, the Company's Action Plan is to add 2,300 MW of solar capacity by 2030, but the replacement portfolio utilized in the URS shows solar only beginning in 2040. While the Company's approach to deriving a potential expansion plan and performing its URS is one way that an evaluation could be conducted, that approach is inferior to using a resource optimization methodology. The advantage of an optimization methodology is that it would identify the optimal ordering of unit retirements and would more accurately select replacement units. Staff believes that the unit retirement study would be best conducted consistent with the way the Company's Resource Mix Study was

1 performed, and not as a separate study, in which dispatch and optimization dynamics are
2 ignored.

3
4 **Q. PLEASE DESCRIBE YOUR CONCERNS REGARDING THE USE OF**
5 **DIFFERENT MODELING ASSUMPTIONS THROUGHOUT THE COMPANY'S**
6 **IRP MODELING ANALYSES.**

7 **A.** Staff is concerned that different studies used different modeling assumptions, which could
8 lead to incompatible results. In this IRP, the Company performed five analysis
9 frameworks, and they were structured utilizing different modeling assumptions and
10 methodologies. A summary of the studies is included in the following table.

Table 17: GPC Supply Side Studies in 2022 IRP

Study	Analysis Structure	Corporate Budget Inputs
Solar Study / Renewable Expansion Plan	Expansion Plan Optimization Study (Aurora)	B2021
Renewable Integration Study / Battery Flexibility Analysis	SERVM Analysis	B2021
Ford McGrau / BESS Study	Production Cost Valuation to derive avoided costs (Aurora + Spreadsheet)	B2022 ⁴¹
Unit Retirement Study	Production Cost Valuation to derive avoided costs (Aurora + Spreadsheet)	B2022 (URS)
Capacity RFP – PPA Acquisition	Production cost valuation to derive avoided costs (Aurora + Spreadsheet). Also, relied on the RFP Evaluation (Strategist)	B2022 (URS)
Generation Resource Mix Study	Expansion Plan Study (Aurora)	B2022

Many of these studies were performed at different times, with different assumptions, and the results were fed into each other. Though these studies were not integrated, individually, they led to decisions about how much battery storage resources to acquire, how much solar resources to acquire, what coal and CT resources to retire, what PPA resources to acquire, etc. Staff is concerned that so many Company studies were conducted in a disjointed manner and that discrepancies exist in the modeling assumptions that were used in the various analyses the Company performed. Based on its review, Staff adjusted the Company's assumptions in order to use recent and consistent assumptions.

⁴¹ STF-JKA-3-21

Staff's Unit Retirement Study

Q. PLEASE PROVIDE AN OVERVIEW OF STAFF'S MODELING APPROACH.

A. As in prior IRP cases, Staff conducted its own independent modeling analysis using a production cost and resource optimization modeling tool. In this IRP, Staff utilized the Aurora model to conduct an integrated analysis to *concurrently* evaluate coal retirements, proposed capacity RFP PPAs, as well as additions of future generic resource options including CTs, CCs, BESS and Solar.

Q. WHAT CHANGES DID STAFF MAKE TO THE STRUCTURE OF THE COMPANY'S ANALYSIS?

A. Staff conducted its evaluation as a two-stage analysis. In the first stage, all pertinent decisions the Company proposes to make were modeled as selectable options that could be evaluated and optimally selected within the Aurora optimization model. Staff's studies were performed for each fuel/CO₂ price/policy scenario, and analyses were performed over a shorter study period through 2039 versus through 2052, as the Company assumed in its URS. This shorter study period allowed for Staff to evaluate the near-term impacts of the coal unit retirements against the six capacity PPAs. Staff's modeling generally compared a resource that could 1) retire early such as in 2022 for Wansley 1-2, 2) retire in 2028, or 3) incur ELG and other environmental costs and continue to operate until 2039. By limiting

1 the study period to 2039 Staff partially addressed the unrealistic assumption of coal units
2 operating until 2052 in the Company's analysis.

3 Although, no one knows exactly which fuel price/CO₂ scenario will ultimately
4 occur in the future, certain resource decisions must be reached in this IRP, such as whether
5 to set retirements dates for Wansley 1-2, Bowen 1-2, Scherer 3 and Gaston 1-4. Therefore,
6 in the second stage of its analysis, Staff analyzed potential action plans with certain near-
7 term decisions locked down for analysis across the different fuel price/CO₂ scenarios.

8
9 **Q. WHAT COAL UNIT RETIREMENTS DID STAFF CONSIDER IN ITS URS?**

10 A. Staff set up its analysis of candidate resources that could either retire by 2028 in compliance
11 with ELG requirements or operate beyond that with ELG controls implemented. In the case
12 of Bowen 3-4, Staff assumed the Company would not be able to avoid incurring ELG
13 capital investment costs, and would continue to operate until 2035. Staff based this on the
14 Company's concern that necessary transmission upgrades would take a long time to
15 construct and would require Bowen 3-4 to operate beyond 2028. Although it appears
16 reasonable for the Company to continue to operate Bowen 3-4 beyond 2028 for
17 transmission reliability reasons, which means that ELG upgrades selected by the Company
18 would have to be implemented by 2025 in compliance with EPA regulation, it is not clear
19 that the Company has sufficiently investigated transmission alternatives that could allow
20 Bowen Units 3-4 to be able to retire before 2035. Even after the ELG investment has been

1 made, the Company should continue to study if any economic transmission alternatives
2 could be identified that would allow Bowen 3-4 to be retired prior to 2035. This could
3 either be studied in the 2025 IRP or as part of an integrated analysis to address the North
4 Georgia reliability and resilience issues, including results from the Renewable RFP. See
5 Staff Witness Chiles' testimony for additional discussion of transmission issues.

6 In its analyses, Staff assumed that when Bowen 1-2 continues to operate, the
7 retirement dates for those units would be 2035 consistent with Staff's retirement
8 assumption for Bowen 3-4. Regarding Wansley 1-2, Staff assumed that in cases in which
9 it retires, it could retire in 2025, however, Staff also considered an early retirement option
10 in 2022.

11 **Q. WHAT ASSUMPTIONS DID STAFF REVISE IN ITS URS?**

12 A. Staff utilized the Company's B2022 vintage data assumptions, and relied on information
13 the Company provided in its Unit Retirement Study and Generation Resource Mix Study
14 for its analyses. However, as explained above, Staff identified adjustments in both the
15 structure of the analysis and the input assumptions it used. The following table compares
16 the input assumptions that Staff used in its analysis compared to the Company's
17 assumptions:
18

Table 18: Staff Study Assumption Summary

Data Assumption	Company Resource Mix Study	Staff
System TRM	26%	24.5%
Solar Integration Cost	\$0.0	\$2.50/MWh
Solar Capacity Value	0% (Winter) ⁴²	5% (Winter)
Battery Storage Capacity Value	Declining Tranches	90%
Solar Pricing	\$25/MWh	\$25/MWh + \$2.3/kw-yr Additional Sum
Capacity RFP PPA	Committed resources with no capacity payment	Selectable, Include \$2.30 \$/kw-yr in additional sum
Coal Unit Maintenance and Capital Project Costs	Committed resources with no fixed costs	Selectable, to include fixed costs
2019 60 MW Biomass RFP Addition ⁴³	Included	Excluded

There were two reasons for these adjustments. First, these inputs assumptions were made in order to use the most recent data available, such as B2022 budgets and the Solar Integration Study/ELCC study results. Second, decisions were locked in place in the Company's Resource Mix study and therefore some costs could be excluded from the

⁴² GPC attributed zero capacity value to solar resources in its Resource Mix study, however, in its Effective Load Carrying Capability Study it determined that solar resources would have capacity value. The Company also assumed that it's proposed 6,000 MW of solar would have █% peak capacity value when added as a committed resource, per its Aurora modeling.

⁴³ Staff excluded the 2019 IRP Biomass addition because the RFP that followed the 2019 IRP did not economically select 60 MW of biomass capacity to add to the System.

analysis. For example, the Company excluded capacity payments associated with PPA acquisitions in Resource Mix Studies, since the PPA acquisitions were included in every Resource Mix study the Company performed. Therefore, in the Company's studies it did not matter whether the Company included the capacity payments or not. In Staff's analyses, PPA resources were treated as selectable resources, and therefore, the capacity payments had to be included in the modeling assumptions.

Q. WHAT DID STAFF DETERMINE FROM ITS STAGE 1 ANALYSIS?

A. Staff identified different optimal expansion for each fuel/CO₂ price/policy scenario. While different expansion plans were developed for the different fuel/CO₂ scenarios, ultimately a single resource will have to be settled on, especially for the short-term time period that lies immediately ahead. We refer to this as the action plan the Company would have to follow.

At the end of Stage 1, Staff developed results from each of the price-policy scenarios that it used to determine which capacity options (candidate units and PPAs) would be most economic. The following table describes the optimal selections by fuel scenario – assuming decisions could fluctuate depending on the scenario. A “1” indicates it would be economic to continue operating a generating unit and a “0” indicates it would be economic to retire the unit.

Table 19: Staff Stage 1 results – Aurora Optimal⁴⁴

Decision Resource(s)	LG0	MG0	HG0	GPC LG20	GPC HG20	GPC MGS0	Avg.
Bowen 3-4*	1	1	1	1	1	1	1.00
Bowen 1-2	1	1	1	0	0	0	0.50
Scherer 3	1	1	1	0	0	0	0.50
Scherer 1-2	0	0	1	0	0	0	0.17
Gaston 1-4	0	0	0	0	0	0	0.00
Wansley 1-2	0	0	0	0	0	0	0.00
PPA 1: Wansley 7	1	0	0	1	0	1	0.50
PPA 2: Dahlberg 2&6	1	1	1	1	1	0	0.83
PPA 3: Harris 2	1	1	0	1	0	1	0.67
PPA 4: Dahlberg 1,3,5	1	1	1	1	1	1	1.00
PPA 5: Monroe CT*	1	1	1	1	1	1	1.00
PPA 6: Dahlberg 8-10	1	1	0	0	1	0	0.50
GPC MW Solar by 2030	1260	1440	4680	4680	5400	5400	3810
GPC MW Solar by 2035	3780	5940	9180	9180	9900	9900	7980
GPC Battery ESS by 2030	0	0	0	0	540	360	150
Generic CT/CC MW by 2030	180 CT			540 CC			

Based on the results provided above reflecting the Company's CO₂ price forecasts, Staff concluded that many of the candidate fossil retirement units were not economic to continue to operate beyond 2028. Staff will provide additional context below on each unit retirement decision. Based on the table, Staff determined that the PPA's were generally economic,

⁴⁴ Key:

Candidate Retirement Units, 1 = retrofit (operate past 2028), 0 = retire by 2028
(*Bowen 3,4 force in per reliability assumption)
PPA, 1 = accept, 0 = reject
(*PPA 5: Monroe CT forced in for modeling convenience)
BESS shows cumulative MW by 2030 (at 60% of system, allocated to GPC)
Solar shows cumulative MW by 2030 and 2035 (at 60% of system, allocated to GPC)
Generic CT/CC MW cumulative MW by 2030 (at 60% of system, allocated to GPC)

1 with each PPA being selected in half or more than half of the fuel/CO₂ scenarios.
2 Additionally, Staff's integrated approach provided insights regarding the Company's
3 request for Battery and Solar procurements by 2030.⁴⁵

4
5 **Q. WHAT INSIGHTS WERE GAINED FROM STAFF'S STAGE 1 ANALYSIS**
6 **REGARDING SOLAR AND BATTERY RESOURCES?**

7 A. In general, Staff found that the Company's proposal to acquire 1,000 MWs of battery
8 energy storage by 2030 is uneconomic. Staff believes it is premature at this time to approve
9 the acquisition of 1,000 MWs of capacity, without further evaluating battery storage units
10 and considering other alternatives that may be more economic through a competitive RFP.

11 Staff's analysis shows that Solar provides economic value to the system under
12 different fuel and CO₂ cases, and Staff agrees with the Company's recommendation to
13 conduct an RFP to identify economic solar in the near term.

14 Staff Panel Barber-Bower-Cook provides further recommendations regarding future
15 BESS procurement, consideration of Solar+BESS projects that may be eligible for ITC,
16 and Staff's review of the Company's Renewable Cost Benefit (RCB) Framework, and other
17 renewable resource recommendations.

18

⁴⁵ The Company's solar study assumed a fixed allocation percentage of approximately 58% to determine the GPC share of new economic solar. Staff ultimately received the Company's modeling for allocating system selected resources to GPC in response to STF-JKA-2-18 and STF-JKA-4-12.

1 Q. WERE SENSITIVITY CASES RUN USING STAFF'S CO₂ EMISSION COST
2 ASSUMPTIONS?

3 A. Yes. Staff performed sensitivity cases with its adjusted CO₂ emission cost assumptions,
4 which helped Staff differentiate its recommendations for Bowen 1-2 and Scherer 3. The
5 results in Table 19, using the Company's CO₂ assumptions, show both Bowen 1-2 and
6 Scherer 3 as potentially borderline decisions. However, Staff's lower CO₂ forecast led to
7 the conclusion that continuing to operate Bowen 1-2 was preferred over continuing to
8 operate Scherer 3. In these Staff CO₂ Sensitivity cases, Bowen Units 1 and 2 were selected
9 to continue to operate beyond 2028 in two out of the three Staff \$20/ton CO₂ cases – the
10 higher gas cases, and Scherer 3 was only selected to continue to operate in the low gas
11 \$20/ton case. Additionally, Bowen 1-2 and Scherer 3 were not selected together in any of
12 Staff's CO₂ scenario optimization analyses, therefore Staff concluded that Scherer 3 and
13 Bowen 1-2 would not be economic to continue to operate together over the long term.
14 Based on this information derived from Staff's Stage 1 optimization analysis, Staff
15 concluded that it would be reasonable to further evaluate Bowen 1-2 for consideration of
16 retirement versus continued operation in Stage 2. At the same time, from its Stage 1
17 analysis, Staff concluded that Scherer Units 1-3 would be retired in any further analyses.

18
19 Q. WHAT DID STAFF CONCLUDE REGARDING BOWEN 1-2 FROM ITS STAGE
20 1 RESULTS?

A. Staff concluded that the retirement decision for Bowen 1-2 could be made either way, and Staff conducted its Stage 2 analyses by creating two Action Plans, one with and one without the 2028 retirement of Bowen Units 1-2. The following table summarizes Staff's proposed Action Plans that were created based on the Stage 1 results and compares those to the Company's Action Plan. These Action Plans were then further evaluated in Stage 2.

Table 20: Staff vs. Company Proposed Action Plans

Decision Resource(s)	GPC Decision	Staff Plan Bowen 1-2 Retire	Staff Plan Bowen 1-2 Continue
Bowen 1-2	Retire 2027	Retire 2027	Retire 2035
Bowen 3-4	Retire 2035	Retire 2035	
Scherer 3	Retire 2028	Retire 2028	
Scherer 1-2	Retire 2028	Retire 2028	
Gaston 1-4	Retire 2028	Retire 2028	
PPA 1: Wansley 7	Accept	Accept	
PPA 2: Dahlberg 2&6	Accept	Accept	
PPA 3: Harris 2	Accept	Accept	
PPA 4: Dahlberg 1,3,5	Accept	Accept	
PPA 5: Monroe CT	Accept	Accept	
PPA 6: Dahlberg 8-10	Accept	Accept	
Solar by 2030	RFP for 2,100 MW by 2029	RFP for 2,100 MW by 2029	
Solar by 2035	6,000 MW by 2035	No Target, economic amount taken	
McGrau Ford	Force ~300 MW	Selectable – Uneconomic	
Battery by 2030	600 MW additional	No Target, economic amount taken	
Total Battery by 2030	~1,000 MW	No Target, economic amount taken	

The table above shows that with the exception of Bowen 1-2, and with regard to the coal retirement units and PPA acquisitions, Staff's and the Company's Action Plans match completely. In Stage 2, Staff analyzed one Action Plan with Bowen Units 1-2

retiring in 2027, and another with Bowen Units 1-2 retiring in 2035. With respect to solar and battery storage resources, Staff's Action Plans differed from the Company's in that Staff found battery storage resources to be uneconomic in Stage 1. Therefore, Staff did not assume that 1,000 MWs of battery storage resources would be locked into Staff's Action Plans by 2030, as the Company assumed. In its Stage 2 modeling, Staff did allow for economic selections of battery storage resources, but again, Staff did not force-in 1,000 MWs of battery storage resources by 2030, as the Company assumes should be acquired. With respect to Solar resources Staff agrees with the Company that it would be reasonable for it to acquire 2,100 MWs by 2029. In its Stage 2 analyses, Staff locked-in 2,100 MWs of solar resources by 2029 in its Action Plans. However, as opposed to the Company, Staff did not lock-in its Action Plans the assumption that up to 6,000 MWs of solar resources would definitely be taken by 2035. Staff did, however, allow the model to economically select solar above 2,100 MWs in its Stage 2 analyses. Staff developed reserve margin views for each of the three action plans that were evaluated further in Stage 2, which are:

- GPC Plan
- Staff Plan – Bowen 1-2 Retire in 2027
- Staff Plan – Bowen 1-2 Continue through 2035.

Three tables are presented in Exhibit STF-NHBW-5 showing these three reserve margin views.

Q. WHAT WAS THE PURPOSE OF STAFF'S STAGE 2 ANALYSIS?

1 A. In Stage 1, optimal resource selections were always made for each of the fuel/CO₂
2 scenarios evaluated. In Stage 2, Staff locked-in specific decisions for modeling purposes
3 in the form of an Action Plan to reflect the decisions that have to be made today, without
4 the foresight of knowing which fuel and CO₂ scenario will actually occur. The purpose of
5 the Stage 2 analysis is to measure the value of the proposed decisions across all the
6 fuel/CO₂ scenarios.

7
8 **Q. PLEASE EXPLAIN THE DIFFERENCES IN THE GPC ACTION PLAN AND**
9 **STAFF'S TWO ACTION PLANS?**

10 A. The major difference between the Action Plans relates to the decision regarding Bowen
11 Units 1-2, the amount of solar being acquired, and the acquisition of battery storage
12 resources. While the Company determined that it would retire all the candidate coal units,
13 Staff determined from its Stage 1 analysis that Bowen 1-2 was a close call, and Staff,
14 therefore, created the two Action Plans. The Company's Action Plan includes 1,000 MWs
15 of battery storage resources fixed in the resource plan by 2030, however, Staff's Stage 1
16 analysis did not find battery storage resources to be economic, and Staff did not assume in
17 its Action Plans that 1,000 MWs of battery storage resources would be fixed in the plans
18 by 2030. However, Staff did allow Battery Storage resources to be selected economically
19 and they were selected in some of the high gas/CO₂ scenarios. Finally, with regard to solar

resources, Staff's Stage 1 analysis indicated that it was reasonable to acquire up to 2,100 MW of solar by 2029, and therefore, the same 2,100 MW solar assumption was fixed in the Company and Staff's two Action Plans through 2029. After that, in the GPC case, Staff continued to force in Solar to reach 6,000 MW in total by 2035, as the Company identified that amount as being reasonable to add to the System. Staff does not agree that 6,000 MW is necessarily reasonable at this time, and Staff allowed solar to be selected economically in both of its Action Plan cases.

Q. STAFF'S STAGE 1 ANALYSIS INDICATED BATTERIES ARE UNECONOMIC WITH LITTLE TO NO BATTERY ADDITIONS. ARE THESE RESULTS CONSISTENT WITH THE MOST RECENT CAPACITY RFP?

A. Yes. In the most recent capacity RFP standalone battery resources found to be uncompetitive and were not selected by the Company.

Q. HAS STAFF PERFORMED SUPPLEMENTAL ECONOMIC ANALYSIS OF BATTERIES AND WHAT WERE THE RESULTS?

A. Yes. Staff ran simulations to calculate battery revenue requirements based on cost data for battery projects that the Company provided. The purpose of the simulations is to provide an estimate of the cost of batteries rather than calculate the revenue requirements for

specific battery projects. Staff simulations indicate energy from batteries would be 2 to 3 times more expensive than energy from Georgia Power's existing fleet when measured in dollars per megawatt-hour, and that batteries are much more expensive than alternative capacity and support the results of Staff's optimization modeling.

Q. WHAT ARE THE RESULTS OF THIS ANALYSIS?

A. The NPV total Southern System cost revenue requirement results of each of the Action Plans are included in the following table. Note that the titles of each column indicate the status of Bowen Units 1-2 in each of the cases, however, there are also other differences between the cases, as discussed above. These values represent the value to the Southern Company system over the study horizon conducted by Staff (2022-2039).

Table 21: NPV \$000 Comparison of GPC Plan vs. Staff Plans

Fuel Scenario	GPC All Coal Retired (\$M NPV)	Staff Plan 1 Bowen 1-2 Operates (\$M NPV)	Staff Plan 2 Bowen 1-2 Retired 2027 (\$M NPV)
CASE RESULTS			
LG0	\$50,280	\$50,134	\$50,167
MG0	\$52,954	\$52,789	\$52,831
HG0	\$59,829	\$59,652	\$59,882
LG20	\$59,069	\$59,155	\$59,055
HG20	\$69,764	\$69,817	\$69,688
MG50	\$76,266	\$76,552	\$76,369
Average 0 CO2	\$54,354	\$54,192	\$54,293
Average All Cases	\$61,360	\$61,350	\$61,332
DELTA		GPC - Staff	GPC - Staff
LG0		\$145.6	\$112.7
MG0		\$164.7	\$122.9
HG0		\$177.5	(\$53.3)
LG20		(\$85.6)	\$14.7
HG20		(\$52.8)	\$75.9
MG50		(\$285.5)	(\$102.4)
Average 0 CO2		162.7	(101.7)
Average All Cases		\$10.7	\$28.4

Q. PLEASE DISCUSS THE RESULTS.

A. The results indicate that the difference in NPV cost between any of the cases is relatively small, however, certain trends are apparent. These results support the finding that the decision to continue to operate or to retire Bowen Units 1-2 is a close call. In cases in

which CO₂ emission cost is considered, retiring Bowen Units 1-2 is the economic choice, based on the Company's set of CO₂ assumptions. That is especially true in high CO₂ cases. In cases in which CO₂ is not included or under Staff CO₂ sensitivity assumptions, then it is economic to continue to operate the coal units, and that is especially true in higher natural gas price cases.

Q. DID STAFF CONDUCT ANY SENSITIVITY ANALYSIS?

A. Yes. Staff conducted numerous sensitivities analyses during its investigations to determine the reasonableness of its modeling approach and results. Staff evaluated cases with alternative CO₂ assumptions, revised avoided transmission cost assumptions, allowing Bowen 3&4 to be selectable, an alternative Target Reserve Margin value, extended study period, with and without additional sum assumptions included in the database, and other cases. The results of the sensitivity cases that Staff performed contributed to Staff reaching decisions regarding its ultimate Action Plan recommendations. The next section provides Staff's final recommendations based on results derived in Staff's Stage 1 and Stage 2 analyses.

Coal Retirements – Bowen Units 1-2 and 3-4

Q. PLEASE DESCRIBE STAFF'S RECOMMENDATION REGARDING BOWEN UNITS 3-4.

1 A. Staff agrees with the Company that Bowen Units 3-4 should not be considered for
2 retirement in 2028 since alternative transmission solutions were not evaluated by the
3 Company, and given the significant amount of transmission investment and capacity
4 additions assumed to be necessary, before the units could be retired.

5
6 **Q. WHAT DID STAFF CONSIDER IN REACHING A RECOMMENDATION**
7 **REGARDING BOWEN UNITS 1-2?**

8 A. Staff considered results from the Company analyses, Staff's Stage 1 and 2 cases, and
9 Staff's sensitivity cases. The Company's URS results indicated that it would only be
10 economic to continue operating Bowen Units 1-2 in higher gas/zero CO₂ cases. Staff's
11 results in both stages were mixed. Staff believes retiring or continuing to operate Bowen
12 1-2 are both reasonable outcomes in minimizing the economic impact on ratepayers.

13
14
15 **Q. HOW DOES THE ELG INVESTMENT AT BOWEN 3-4 IMPACT BOWEN 1-2?**

16 A. Once ELG controls are added to address Bowen 3&4, no other ELG investment would be
17 required to continue operating Bowen Units 1-2. The only other significant and known
18 Bowen 1-2 cost that would be incurred are O&M expenses and maintenance capital costs.

19
20 **Q. WHAT IS STAFF'S RECOMMENDATION REGARDING BOWEN UNITS 1-2?**

1 A. Given that ELG controls implemented for Bowen 3-4 would address Bowen 1-2, it would
2 not be unreasonable for the Commission to consider aligning the retirement dates of Bowen
3 1-2 with Bowen 3-4 in 2035. Bowen 1-2 could provide economic value, reliability support,
4 and fuel diversity benefits in a time of fleet transition.

5 However, there are other costs, including carbon taxes, costs due to other
6 environmental impacts, and costs associated with environmental regulations that are
7 unknown today, but may be imposed in the future that should be considered in reaching a
8 decision as to whether to continue operating Bowen Units 1-2. Establishing definitive
9 retirement dates would provide certainty that specific near-term maintenance capital and
10 O&M costs could be avoided. Staff believes that the decision on Bowen 1-2 may be more
11 of a policy decision than an economic one, and Staff provides its results and analysis
12 assuming this decision could be made either way.

13
14 **Q. ARE THERE ANY OTHER FACTORS THE COMMISSION MAY WANT TO**
15 **CONSIDER IN REACHING ITS DECISION REGARDING BOWEN UNITS 1-2?**

16 A. Yes. As a final matter, Staff notes that a decision regarding Bowen 1-2 does not need to be
17 made in this IRP, as the Company is not recommending retirement until the end of 2027.
18 Georgia Power has a significant resource need in the 2030-2031 timeframe, and until a
19 clear path is defined for filling that capacity need, the Commission may want the Company
20 to maintain flexibility and make a decommissioning decision in a future IRP. Another

benefit of deferring a retirement decision is that continuing to operate Bowen 1&2 beyond 2027 could postpone the need for additional capacity. However, as mentioned, a decision to retire Bowen Units 1-2 now would allow the Company to reduce its capital maintenance spending over the next few years based on a commitment to retire the units by the end of 2027. The Company estimates the savings on maintenance capital spending would equal approximately \$[REDACTED] million over the next 6 years if a decision to retire the units were made now. It should be noted that even with these capital expenditures, the Bowen 1&2 capacity revenue requirement is equivalent to the capacity payments of the six PPAs.

Coal Retirements - Scherer

Q. WHAT IS STAFF'S UNDERSTANDING REGARDING THE CONTINUED OPERATION OF PLANT SCHERER 1&2?

A. Georgia Power has a minority 8.4 percent interest in Scherer 1 and Scherer 2. Therefore, the majority co-owners will decide whether to install ELG controls on those two units. It is Staff's understanding from a site visit to Scherer on April 12, 2022, that the majority owners of Scherer 1&2 will install ELG controls. A decision regarding the type of controls to be installed (physical/chemical/biological versus membranes) is scheduled to be determine by the end of May 2022.

1 **Q. HOW DOES THE INSTALLATION OF ELG CONTROLS FOR SCHERER 1 AND**
2 **SCHERER 2 IMPACT SCHERER 3.**

3 A. The ELG controls for Scherer 1-2 will also address Scherer 3. There would be no
4 incremental ELG control capital investment for Scherer 3. However, it is Staff's
5 understanding that capital costs are allocated across all owners at Plant Scherer. Therefore,
6 Georgia Power would be responsible for their pro rata share of cost attributed to Scherer 3
7 regardless of whether Scherer 3 continues to run or is retired.

8 **Q. PLEASE DESCRIBE STAFF'S ANALYSIS AND RECOMMENDATION FOR**
9 **PLANT SCHERER UNIT 3.**

10 A. After conducting its Stage 1 and 2 analyses, Staff is not recommending that Scherer 3
11 continue to operate beyond 2028. It is true that Scherer 3 is among the youngest of the
12 coal units in the Company's fleet, but it still cannot be considered a recent addition to the
13 System as it will have operated for 42 years by the time it retires in 2028.⁴⁶ However, the
14 same issue with regard to maintenance capital costs that was discussed with regard to
15 Bowen Units 1-2 would also apply to Scherer 3. In other words, customers could save
16 approximately \$■ million by making the decision to retire Scherer 3 now as the Company
17 would be able to spend less on maintenance capital over the next few years, compared to
18 what it otherwise would have to spend if it were to wait and make the same decision in the

⁴⁶ As with Bowen 1&2 deferring a Scherer 3 retirement decision could postpone the need for additional capacity.

2025 IRP. It should be noted that even with these capital expenditures, the Scherer 3
capacity revenue requirement is equivalent to the capacity payments of the six PPAs.

Coal Retirements – Wansley 1-2

Q. PLEASE DESCRIBE STAFF'S RECOMMENDATION FOR WANSLEY 1-2.

A. Staff recommends the Commission accept the Company's decertification request to retire
Wansley Units 1-2 in 2022 based on the following four factors. First, the Company's
analysis showed that Wansley Units 1-2 were uneconomic in all but the High Gas/Zero
CO₂ case. Second, Staff's Stage 1 analysis confirmed that Wansley Units 1-2 were never
selected to continue to operate in any of the cases, including the zero CO₂ cases. Third,
Wansley Units 1-2 could be retired in 2022 and there would be no impact on the Company's
need for Capacity until 2026, and the PPA resources that the Company proposes to acquire
would be able to fill the capacity need at that time. Fourth, there would be considerable
savings before the new PPA contracts start, including \$■ million in maintenance capital
costs, and \$■ million in Maintenance O&M costs prior to and including 2025.

**Q. ALTHOUGH THE COMPANY CONDUCTED ITS ECONOMIC ANALYSIS
ASSUMING THAT IT WOULD RETIRE WANSLEY UNITS 1-2 IN 2025, IT IS
PROPOSING TO RETIRE THE UNITS IN 2022. DID STAFF CONDUCT AN**

**ANALYSIS TO DETERMINE IF IT WOULD BE ECONOMIC TO RETIRE
WANSLEY 1-2 IN 2022?**

A. Yes. Although the Company did not perform any economic analysis to support its decision to retire Wansley 1-2 in 2022, Staff conducted such an analysis, and determined that it would be economic to retire Wansley 1-2 in 2022. In addition to performing its modeling analyses using its Stage 1/Stage 2 approach, Staff also performed additional evaluations comparing Wansley's forecasted O&M costs versus its projected energy benefits based on capacity factor assumptions that were consistent with historical operations results. Staff concluded from these analyses that the costs of continuing to operate the units beyond 2022 would exceed their benefits, and agreed it would be reasonable to decertify Wansley 1-2 in 2022.

Coal/Gas Retirement – Gaston 1-4

Q. PLEASE DESCRIBE STAFF'S RECOMMENDATION FOR GASTON UNITS 1-4.

A. Staff recommends the Commission accept the Company's decertification request for Plant Gaston Units 1-4. The Gaston Units 1-4 currently utilize coal as a back-up fuel, and coal is being phased out at the Gaston plant entirely, as Alabama Power has announced it will

1 be converting the remaining coal unit, Unit 5, to natural gas by 2028.⁴⁷ The Company's
2 fuel policy requirements for gas-fired steam turbine units call for the units to have an annual
3 firm transportation contract in place.⁴⁸ According to the Company's response to STF-JKA-
4 3-7, the cost of a firm transportation contract for Gaston Units 1-4, beginning in 2028 will
5 be approximately \$■ million per year, which results in the Gaston Units being uneconomic
6 to continue operating beyond 2028 in all fuel/CO₂ scenarios. The Company and Staff's
7 Unit Retirement Studies are consistent and Gaston Units 1-4 should be retired beginning
8 in 2028.

9
10 **Oil Fired CT Retirements – Gaston A, Wansley 5A, and Boulevard 1**

11 **Q. PLEASE DESCRIBE STAFF'S RECOMMENDATIONS REGARDING PLANT**
12 **GASTON UNIT A.**

13 **A.** The Company requested decertification of Plant Gaston Unit A effective December 31,
14 2028. Staff recommends accepting the Company's request given that Gaston A is a 10
15 MW (Georgia Power share) oil burning CT that was initially installed 52 years ago (1970)
16 and hardly operates today. Historic data from FCR 25 indicates that from August 2015 to

⁴⁷ STF-JKA-3-7-d.

⁴⁸ Georgia Power FCR-25, Docket No. 43011, March 9, 2020, Minimum Filing Requirements, MFRH-6, Attachment MFRH-6E TS.docx, Exhibit B, pg. 16, states that firm transportation will be "...■"

December 2019, Gaston A hardly produced any energy and operated at a very high heat rate. Georgia Power has excess capacity currently and the unit is not needed to satisfy capacity requirements. Staff agrees with the Company's recommendation to retire Gaston A.

Q. PLEASE DESCRIBE STAFF'S RECOMMENDATIONS REGARDING PLANT WANSLEY UNIT 5A AND PLANT BOULEVARD UNIT 1.

A. The Company requested decertification of these two oil-fired CT units effective August 31, 2022. Staff recommends accepting the Company's request given that Plant Wansley Unit 5A is a 42-year old, 32 MW oil burning CT, and if the other Wansley units are retired in 2022, it would not make sense to continue to operate an old inefficient oil-fired CT at the site. Likewise, Plant Boulevard 1 should also be retired, as it is an inefficient, 19 MW oil burning CT unit that was constructed 52 years ago (1970). Boulevard Unit 1's is the only remaining unit operating at the Boulevard site and is not needed for to satisfy capacity requirements.

PPA Resources

Q. WHAT PPA CAPACITY IS THE COMPANY SEEKING TO CERTIFY IN THIS IRP?

A. The Company has requested approval of six Capacity RFP PPAs, as listed in the following table.

Table 22: Capacity RFP PPA SUMMARY

PPAs	Type	MW	Start	Term
Wansley 7	CC	625	12/1/2024	10 years
Dahlberg 2&6	CT	171	6/1/2025	10 years
Harris 2	CC	690	12/1/2024	10 years
Dahlberg 1,3,5	CT	256	1/1/2028	10 years
Monroe CT	CT	360	12/1/2024	15 years
Dahlberg 8-10	CT	258	6/1/2025	10 years

Q. WHAT IS THE CURRENT OWNERSHIP STRUCTURE OF THESE UNITS?

A. Five of the six PPA resources are owned by Southern Power (all but Monroe CT), and three (Monroe CT, Dahlberg 2&6, and Dahlberg 8 and 10) are currently under contract already with Georgia Power and will expire just prior to when the new contracts begin. Harris Unit 2, Wansley Unit 7 and Dahlberg 1, 3 and 5 will be new contracts.

Q. WHAT DID THE COMPANY CONCLUDE REGARDING THE PPA CAPACITY AND COAL UNITS IN THE UNIT RETIREMENT STUDY?

A. The Company concluded that the PPA resources were economic replacements for the majority of the coal units.

Q. WHAT DID STAFF CONCLUDE IN ITS ANALYSES?

1 A. Staff's conclusions were similar. In addition to the Stage 1/Stage 2 optimization analyses
2 that Staff performed, Staff also evaluated components of the costs and benefits of the
3 individual PPA resources in the Company's evaluation, and determined that the PPA's
4 range in a net benefit from approximately \$[REDACTED]/kw-year to \$[REDACTED]/kw-year over the 10 –
5 15 year terms of the PPA's. For the candidate retirement units, studied through 2052 in
6 the case where the units continue to operate, the Company determined that net benefits
7 would range from a negative \$[REDACTED]/kw-year for Gaston to a positive \$[REDACTED]/kw-year for
8 Bowen 1-2.⁴⁹ The Company's analysis showed that of all the candidate retirement units,
9 Bowen Units 1-2 were the most competitive to continue to operate, and the net benefit
10 results for Bowen 1-2 compared reasonably well to the range of benefits of the PPA units.

11
12 **Q. PLEASE DESCRIBE STAFF'S FINAL RECOMMENDATION REGARDING THE**
13 **SIX PPA RESOURCES?**

14 A. Staff recommends that all six of the PPAs be acquired. Staff concludes that all six PPAs
15 are economic, though the economics vary depending on the fuel price/CO₂ policy case
16 considered. The LG0 scenario was the only case in which all 6 of the PPAs were accepted
17 simultaneously. The PPAs were selected by the model as optimal resource selections over
18 generic resource alternatives in the majority of the scenarios Staff ran, and Staff observed

⁴⁹ Note that negative net benefits imply that the resource is uneconomic.

1 overall System NPV savings in the cases where selected PPAs were included compared to
2 when they removed. Considering the resource needs of the system with coal retirements
3 and future purchase power expiration in the 2029-2031 time period, Staff recommends that
4 all six of the PPAs be acquired.

5
6 **Q. DOES STAFF HAVE ANY CONCERNS ABOUT THE COMPANY'S REQUEST**
7 **TO CHARGE RATEPAYERS FOR AN ADDITIONAL SUM AMOUNT OF \$7.50**
8 **PER KILOWATT-YEAR?**

9 A. Staff has two concerns. First, Staff notes that the Company excluded its proposed
10 Additional Sum amount from the economic evaluations it performed.⁵⁰ Exclusion of the
11 Additional Sum from PPAs creates a potential bias in the analysis, because evaluations of
12 other capital investment projects, like new build resources and coal unit environmental
13 upgrades, include return on equity cost components. To remedy this concern, Staff
14 included the current Additional Sum amount of \$2.30/kW-year in its Aurora modeling.

15 Second, Staff disagrees with the Company's attempt to increase the Additional Sum
16 amount to \$7.50/kw-year from \$2.30/kW-year that it charged customers for on prior
17 capacity PPAs. No additional risk has been identified in this IRP compared to previous
18 IRPs to support an increase in the Additional Sum amount. As mentioned above, the

⁵⁰ Data Response JKA-3-2.

1 Company is already familiar with several of the resources as they are under contract with
2 Georgia Power at the present time. The additional requested revenue of \$[REDACTED] million
3 (nominal, over the duration of the PPAs) is not a reasonable risk premium that reflects the
4 risk the Company is taking above the risk the Company took on PPA acquisitions in prior
5 years. Staff Panel Trokey-Smith address this issue further.
6

7 **Wholesale to Retail Acquisition**

8 **Q. HAS THE COMPANY OFFERED WHOLESALE CAPACITY TO RETAIL**
9 **CUSTOMERS IN THIS IRP?**

10 **A.** Yes. As the Company notes,

11 *Pursuant to the Commission's July 30, 2008 Order in Docket No. 26550,*
12 *Georgia Power must offer certain blocks of available wholesale capacity to the*
13 *retail jurisdiction to serve retail customers when the capacity becomes*
14 *available. The Company evaluates when to offer the wholesale capacity blocks*
15 *to the retail jurisdiction as additional wholesale contracts are set to expire.⁵¹*
16

17 The Company has prepared an offer to sell wholesale capacity from Blocks 2-4 (converted
18 gas units), Blocks 2-4 (coal resources), and Blocks 5-6 (oil fired CTs), and the Company
19 made the following certification request listed as item 26 in the Conclusion section of the
20 2022 Main Document.(Section 1.14):

⁵¹ Direct Testimony of Jeffrey R. Grubb, A. Wilson Mallard, Michael B. Robinson, and Jeffrey B. Weathers, Georgia Power 2022 IRP, Docket No. 44160 & 44161, pg. 54, ln. 15.

26. Certification of 88 MW of wholesale capacity from Blocks 2-4 and Blocks 5&6 to be placed in retail rate base effective January 1, 2024 and January 1, 2025, respectively.⁵²

The table below shows the capacity that has been offered and requested for certification.⁵³

Table 23: Wholesale to Retail Offer Summary

Wholesale Blocks	Available MW	Offered MW	Units	Available to Retail	GPC Offer
Blocks 2-4 Converted Gas Unit Resource	115.6		Gaston 1-4 Gas Steam	1/1/2024 ⁵⁴	Not recommending with decertification request
		65.4	Yates 6 & 7 Gas Steam	1/1/2024	Offering to Retail
Blocks 5&6	23.0		Gaston Unit A Oil CT	1/1/2025	Not recommending with decertification request
		22.7	McManus 3A-3C, 4A-4F & Wilson 1A-1F Oil CTs	1/1/2025	Offering to Retail
Blocks 2-4 Coal Block Resource	60.8		Scherer 3 Coal Steam	1/1/2026	Not recommending with decertification request
TOTAL	199.4	88.1	Offer to Retail		

⁵² IRP Main Document, page 1-15.

⁵³ IRP Main Document, tables 10 and 11 in Section 16 include this detail (page 16-124 through 16-127).

⁵⁴ GPC Provided document, 1 TS 2022 IRP Wholesale-to-Retail Offer.docx indicates, "The existing wholesale contract for the Blocks 2-4 Converted Units Resource is scheduled to terminate on December 31, 2025, but it provides the counterparty with an early termination option as soon as December 31, 2023. Based on feedback from the counterparty, this offer assumes the early termination option is struck."

1 **Q. ARE THE COMPANY'S OFFERS TO THE COMMISSION REGARDING THE**
2 **BLOCKS OF CAPACITY BASED ON ACTUAL OFFERS TO A MARKET**
3 **PARTICIPANT?**

4 A. No, it does not appear that any party has expressed interest to the Company in wanting to
5 buy these blocks of capacity.
6

7 **Q. DID THE COMPANY PROVIDE AN ECONOMIC ANALYSIS IN SUPPORT OF**
8 **THE WHOLESALE TO RETAIL OFFER?**

9 A. Yes. The Company is required to offer the capacity at market value. The Company
10 provided an analysis calculating the Market Differential Adjustment ("MDA"), which
11 represents the difference between the revenue requirement of the resource and the assumed
12 market value of the resources, expressed on a dollar per kilowatt-month basis for the MG0
13 fuel case scenario. This evaluation serves to determine an MDA that increases or decreases
14 the revenue requirement of the offered resources so that customers pay no more and no less
15 than the market value of the offered resource.
16

17 **Q. WHAT ARE THE RESULTS OF THE COMPANY'S MDA CALCULATION**
18 **ASSOCIATED WITH THE YATES 6 & 7 UNITS?**

19 A. The Company's results indicate that the majority of the benefits for the Yates resource are
20 associated with the capacity value over the contract period of 2024-2034, which the

Company determined based on the last winning bid in the 2022-2028 Capacity RFP. The Company determined that the market value of the Yates resource is [REDACTED] the revenue requirement to equal the market value. The Company's analysis derives an MDA that adjusts the costs customers would have to pay so that benefits of the resources would essentially equal the costs of the resources. A summary of Staff's interpretation of the cost/benefit analysis is shown in the following table. Because the intention is for customers to pay no more and no less than market value, the MDA has been derived such that the Net Cost/(Benefit) results in a value that is reasonably close to zero, that is assuming the Company's assessment of the market value of Yates 6 & 7 is reasonable, which Staff does not think that it is.

Table 24: Block 2-4 Converted - Yates 6 & 7 Value (NPV 2024 \$000)
GPC Assumed

Fuel Scenario	Fixed O&M	Capital Cost	MDA	Capacity Value	Energy Value	Net Cost (Benefit)
MG0	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Q. DOES STAFF AGREE WITH ALL OF THE COMPANY'S ASSUMPTIONS?

A. No. Staff does not agree with the capacity value the Company assigned to the Yates resource. The Company's next need for capacity is not until 2029. If customers were to acquire the resource, the Company would have even more excess capacity beyond its needs through 2029, and under that situation, there is little to no value to customers for acquiring

1 this capacity. Staff revised the Company's analysis to assume no capacity value in years
2 prior to 2029. In addition, Staff not only reviewed the Company's MG0 analysis, but also
3 performed analyses using additional fuel scenarios. Finally, Staff recomputed energy
4 benefits using updated data from the Company's IRP Aurora modeling. The Company's
5 analysis appears to have been performed using data that was associated with the 2022 –
6 2028 Capacity RFP that was conducted using Strategist. Since the Company has updated
7 its assumptions since the capacity RFP in the 2022 IRP, Staff relied on that data in its
8 analysis.

9
10 **Q. WHAT DO STAFF'S RESULTS INDICATE?**

11 **A.** Staff's results indicate that if the capacity value of the Yates resource is less than the
12 Company assumed, as Staff determined it will be, the MDA adjustment the Company has
13 proposed will be too small to ensure that customers will pay no more than the market value
14 of the Yates resource. The table below indicates that customers will actually incur a net
15 cost in every fuel scenario case based on the Company's assumed MDA.
16
17

Table 25: Block 2-4 Converted - Yates 6&7 Value (NPV 2024 \$000)

Fuel Scenario	Fixed O&M	Capital Cost	MDA	Capacity Value	Energy Value	Net Cost (Benefit)
LG0						9,968
MG0						11,374
HG0						11,872
LG20						9,720
MG20						10,370
HG20						11,837
MG50						8,581
AVERAGE						10,532

Q. HAS STAFF EVALUATED THE OFFER FOR THE MCMANUS 3A-3C, 4A-4F & WILSON 1A-1F OIL CT (BLOCK 5&6) CAPACITY?

A. Yes. Staff reviewed the Company's analysis. Staff recommends against acquiring the CT units as well. Staff's recommendation is based on the following factors:

- The CTs are only being offered for a period of five years (2025-2029).⁵⁵
- The CTs are old inefficient oil burning CTs,
- The Company already has sufficient capacity to meet its Target Reserve Margin and this capacity would only increase the Company's excess resources.
- There would be no energy benefits associated with these resources.

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATIONS REGARDING THE COMPANY'S WHOLESALE TO RETAIL CAPACITY RESOURCES.

⁵⁵ The Company describes the term for this contract to be the remaining lives of the assets, and for computing the MDA, assumes that the assets will be unavailable beginning December 31, 2029. See pg. 7 of 1 TS 2022 IRP Wholesale-to-Retail Offer.docx

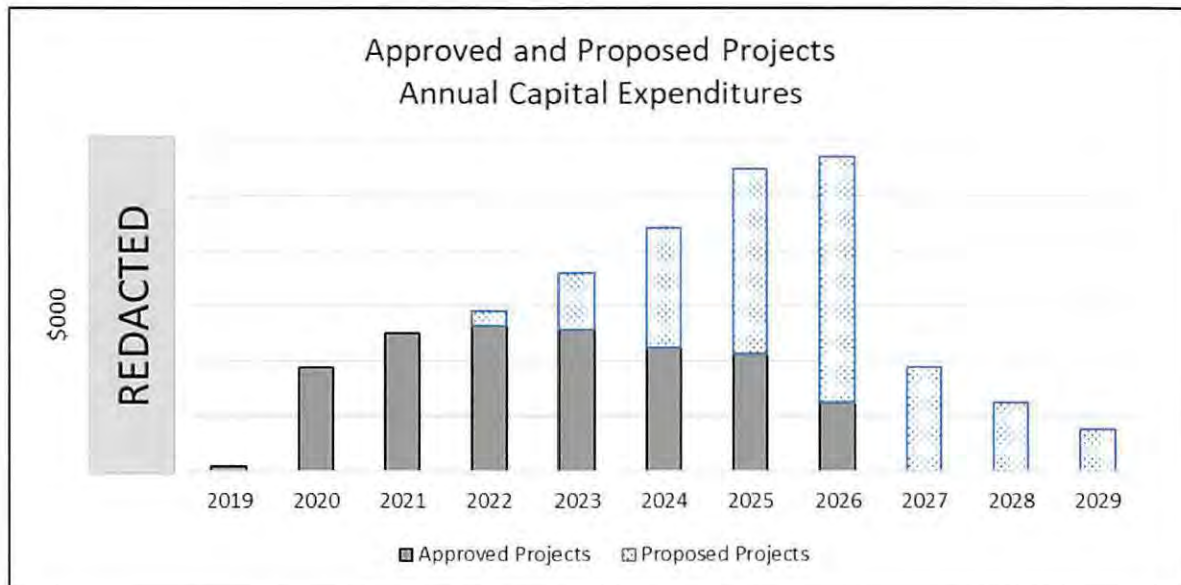
A. Staff recommends that the Commission reject all of the wholesale to retail offers as proposed by the Company.

Proposed Hydro Modernization

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED HYDRO MODERNIZATION PLAN AND THE CURRENT STATUS OF THE 2019 APPROVED PROJECTS.

A. In this IRP and in the 2019 IRP, the Company presents an extensive series of hydro modernization projects that it plans to undertake over the next 12 years, which it estimates will cost over \$1.4 billion dollars. The following table summarizes the costs that have been spent to date, and the expected future costs to be spent by year.

Figure 11: Approved and Proposed Hydro Modernization Spend



The Company has not completed the already approved projects at Tugaloo, Bartletts Ferry, Nacoochee and Oliver, which will require hundreds of millions of dollars in capital investment and will not be complete the projects until after the 2025 IRP. The Company should be required to complete the modernization of these four hydro plants and demonstrate efficient and economic project management before undertaking modernization of three additional hydro plants (Burton, North Highlands, and Sinclair) for hundreds of millions of dollars. The Company should also provide economic analysis to justify the modernization capital expenditure for these three hydro plants.

1 Q. HAS THE COMPANY PROVIDED AN ECONOMIC ANALYSIS TO EVALUATE
2 THE COSTS AND BENEFITS OF MODERNIZATION?

3 A. No. The Company has not provided an economic analysis to justify the extensive capital
4 expenditures that it would incur. In response to STF-JKA-4-31, part a, the Company states:

5 *The Company has not performed an economic analysis as the Company does not*
6 *consider retirement practical and a number of these investments are needed in*
7 *order to maintain the FERC licenses.*

8 Although Staff acknowledges that the hydro fleet provides energy and flexibility value to
9 the system, Staff notes that hydro units have been retired in various jurisdictions in the
10 past, including some Georgia Power hydro units. Staff continues to believe that the
11 Company should be required to provide more information, as well as an economic analysis
12 to justify that the additional Hydro Modernization capital investment would provide
13 reasonable economic benefits to ratepayers. Regarding additional information, Staff
14 recommends the Company provide an evaluation of the costs and benefits achieved to date
15 by modernization projects.

16
17 **Hydrogen Microgrid**

18 Q. HAS STAFF REVIEWED THE COMPANY'S HYDROGEN MICROGRID PILOT?

19 A. Yes. Staff has reviewed the Company's filed documentation. The overall project is nearly
20 \$65 million and is a collaboration of many parties, with the GPC/SCS share being

approximately \$6.6 million over the period from 2022-2025, with the largest expenditure forecasted in 2024.⁵⁶ The Company describes its project in the main document as follows⁵⁷:

"[...] the Company is partnering with key stakeholders to develop an integrated hydrogen microgrid. This project seeks to create hydrogen from an electrolysis system utilizing grid energy. The hydrogen produced will then be utilized in a fuel cell microgrid application as well as for a transportation fuel. The fuel cell component will create electricity that can be utilized to charge EVs, provide backup power, or provide peaking services. The transportation component will include six zero-emission utility trucks. Three trucks will be battery electric utility vehicles charged by the fuel cell. The remaining three trucks will directly consume hydrogen as their primary fuel source. This pilot project will provide new insights into the various capabilities of hydrogen to meet the needs of customers in the evolving energy landscape, while minimizing costs through key partnerships."

Q. DOES STAFF HAVE ANY CONCERNS?

A. Staff is concerned that the Company is proposing the costs not covered by United States Department of Energy ("DOE") be borne by Georgia Power customers, rather than be shared across the Southern Company System. The Company indicated the pilot was designed to answer a number of questions related to dispatchable load, peak shaving, back-up power, scalable long-duration energy storage, and microgrids with zero emissions

⁵⁶ Integrated Hydrogen Microgrid Pilot.docx, pages 3-4 and STF-JKA-6-12 part b.

⁵⁷ Page 11-86

vehicles. Clearly, these are issues that would be important to all of the Southern Company Operating Companies.⁵⁸

Q. WHAT DOES STAFF RECOMMEND?

A. The Commission should approve the projects on a case-by-case basis, and when these projects would benefit all Southern Company Operating Companies, the costs should be shared across the system. Staff recommends the Commission approve only a Georgia Power ratio share of the net costs after the DOE portion of the costs have been accounted for and that Southern Company Services retain the ownership of the assets at the competition of the pilot.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

⁵⁸ STF-JKA-6-13

1 BY MR. WALSH:

2 Q Mr. Newsome, did the panel also prefile or
3 cause to be prefiled a trade secret version of the direct
4 testimony?

5 A (Witness Newsome) Yes.

6 Q Would you make the same corrections to the
7 trade secret version of the testimony that you made to
8 your public disclosure testimony?

9 A (Witness Newsome) Yes.

10 MR. WALSH: Madam Chair, I request that the
11 trade secret version of the panel's testimony be
12 marked for identification as Staff's Trade Secret
13 Exhibit No. 9.

14 MADAM CHAIR PRIDEMORE: So moved.

15 (The document referred to was marked for
16 identification as Staff Exhibit 9.)

17 MR. WALSH: Thank you.

18 BY MR. WALSH:

19 Q Mr. Newsome, along with your direct
20 testimony, did you prefile or cause to be prefiled six
21 public disclosure exhibits marked STF-NHBW-1 through
22 STF-NHBW-6?

23 A (Witness Newsome) Yes.

24 Q Do you have any changes or corrections to any
25 of your exhibits?

1 A (Witness Newsome) No.

2 MR. WALSH: Madam Chair, I ask that the public
3 disclosure exhibits NHBW-1 through NHBW-6 be marked
4 for identification as the next six staff exhibit
5 numbers, which I believe are Staff Exhibits 10
6 through 15.

7 MADAM CHAIR PRIDEMORE: So moved.

8 (The documents referred to were marked for
9 identification as Staff Exhibits 10-15.)

10 MR. WALSH: Thank you.

11 BY MR. WALSH:

12 Q Mr. Newsome, did you also -- did the panel
13 also prefile or cause to be prefiled a trade secret
14 version of STF-NHBW-6?

15 A (Witness Newsome) Yes.

16 Q Do you have any changes to make to that trade
17 secret exhibit?

18 A No.

19 MR. WALSH: Madam Chair, I ask that the trade
20 secret version of STF-NHBW-6 be marked for
21 identification as Staff Trade Secret Exhibit No. 16.

22 MADAM CHAIR PRIDEMORE: So moved.

23 (The document referred to was marked for
24 identification as Staff (Trade Secret) Exhibit 16.)

25 BY MR. WALSH:

1 Q Has the panel prepared a summary of its
2 testimony?

3 A (Witness Newsome) Yes.

4 MR. WALSH: Madam Chair, may the panel give its
5 testimony -- the summary of its testimony at this
6 time?

7 MADAM CHAIR PRIDEMORE: So moved.

8 BY MR. WALSH:

9 Q Mr. Newsome, please give the testimony.

10 A (Witness Newsome) Good morning, Commissioners.
11 Our testimony addresses supply side issues and certain other
12 issues in Georgia Power Company's 2022 integrated resource
13 plan filing.

14 In general, staff supports the company's
15 position on several supply side issues; however, staff does
16 not agree with all of the company's proposals. The primary
17 reasons for staff's disagreements are that the company's
18 proposed expenditures are not necessary for Georgia Power
19 system reliability or provide no economic benefit to
20 ratepayers or both.

21 The company performed an economic optimal
22 reserve margin study to calculate the appropriate amount of
23 reserve capacity necessary to provide reliable service.
24 Staff performed a detailed review of the company's reserve
25 margin study and concluded the Southern system winter target

1 reserve margin should be 24.5 percent, rather than the 26.0
2 percent recommended by the company. The lower winter
3 reserve margin recommended by staff was the result of a
4 correction of a flaw in the company's analysis. Staff's
5 reserve margin recommendation is conservative relative to
6 other utilities and industry standards and provides the
7 company with ample reserve capacity for reliable -- for
8 reliability purposes.

9 In the 2022 IRP, the company performed a series
10 of separate modeling analyses, including renewable energy --
11 renewable integration study, the solar study, the unit
12 retirement study, the battery storage study, the resource
13 mix study, the effective load carrying, capability study,
14 and the reserve margin study. These studies were disjointed
15 in that they were performed at different times using
16 different modeling techniques, using different modeling
17 assumptions.

18 For example, the company used the budget 2021
19 corporate load and fuel forecast assumptions for some
20 studies and used a budget 2022 load and fuel forecast
21 assumptions for others. Based on one study using an
22 optimization modeling approach, the company determined that
23 6,000 megawatts of solar should be added by 2035. But
24 another study connected in an entirely different way
25 determined that 1,000 megawatts of battery storage should be

1 added by 2030. These evaluations could have been performed
2 using the same modeling approach to develop a comprehensive
3 economically optimum expansion plan for these resources.

4 Staff performed an independent integrated
5 modeling analysis with consistent modeling assumptions using
6 the Aurora optimization model. Staff's analysis considered
7 a range of different natural gas and carbon dioxide emission
8 prices.

9 Staff supports the company's -- excuse me. The
10 staff supports the company's decertification request on an
11 economic basis with the exception of Bowen 1 and 2. Our
12 testimony explains we found the retirement decision for
13 Bowen 1 and 2 to be a close call. Staff believes the
14 Commission is best suited to evaluate the economics of these
15 units in conjunction with policy considerations, including
16 reliability, fuel diversity, and potential future carbon
17 dioxide emission costs. While the Commission is no doubt
18 aware that no federal carbon dioxide emission legislation
19 has passed, the question for the Commission to consider is
20 whether it should wait until Congress -- whether it should
21 wait for action from Congress prior to quantifying the
22 environmental externalities.

23 Staff determined that Bowen 1 and 2 could
24 provide economic value with no price on carbon dioxide
25 emissions under staff's carbon dioxide emission price

1 assumptions. However, continued operation of Bowen 1 and 2
2 appears to be uneconomic when evaluating the company's
3 carbon pricing scenarios.

4 There is another option available to the
5 Commission. Given that the decision for Bowen 1 and 2
6 concerns retirements that will take place in 2028, the
7 Commission could wait until 2025 IRP to make a final
8 decision. The Commission has that flexibility because the
9 EPA effluent limitation guideline requirements for flue gas
10 scrubber -- for flue gas scrubber wastewater at Bowen will
11 be implemented by 2025 to accommodate keeping Bowen 3 and 4
12 online.

13 These environmental upgrades will be sufficient
14 to address Bowen 1 and 2 wastewater stream -- wastewater
15 treatment requirements, as well. There may be some savings
16 of capital expenditures if the Commission makes a retirement
17 decision in this proceeding as opposed to waiting until
18 another IRP. However, the savings from a decision to retire
19 in this proceeding should be evaluated against the loss of
20 flexibility to continue to run Bowen 1 and 2.

21 Ultimately, a decision to wait until the 2025
22 IRP would offer maximum flexibility. And, for that reason,
23 staff developed two action plans for the Commission's
24 consideration, one in which Bowen 1 and 2 is retired in 2028
25 and one in which Bowen 1 and 2 continues to operate until

1 2035.

2 Staff found the company's six requested power
3 purchase agreement resources would be economic in
4 conjunction with the company's proposed coal unit
5 retirements, but that was not universally the case in every
6 fuel and carbon pricing scenario. Staff's recommendation is
7 that all six PPAs be accepted, considering the resource
8 needs of the system with coal retirements and the expiration
9 of existing PPA contracts in the 2029 to 2031 time period.

10 Staff identified a significant resource
11 shortfall during the 2029 to 2031 time period as
12 approximately 2000 megawatts of PPA capacity under contract
13 will expire. Staff recommends that an all-source request
14 for proposal be conducted to identify future resource
15 additions in the 2029 to 2031 time period to fill that need.

16 Staff believes an all-source RFP would be the
17 best venue for determining the most economic capacity
18 additions. And an all-source RFP would allow traditional
19 policy sources -- resources, solar, battery, and demand-side
20 management to be examined on a head-to-head basis.

21 Staff commends the company for including some
22 renewable resources as a selectable mixed study, but
23 recommends further improvement in future IRPs. Staff
24 recommends that the company model battery storage -- battery
25 plus storage as a resource option relying on the results of

1 its effective load carrying capability study in determining
2 the appropriate capacity contribution and include
3 integration costs for tranches and renewable resources.

4 In staff's independent modeling, staff found --
5 generally found solar to be an economic resource addition,
6 assuming some carbon pricing, but believes the economics of
7 battery storage resources have not been proven to date.
8 Staff recommends that battery acquisitions be considered on
9 a case-by-case basis within a competitive procurement
10 process to help ensure only economic projects are added to
11 the system.

12 Staff recommends the Commission reject the
13 proposed wholesale to retail capacity offer proposed by the
14 company. Staff determined that these small capacity
15 additions were not economic for the customers, nor to the
16 resource need date of the company.

17 Staff recommends the Commission reject the
18 company's hydro modernization proposal given that the
19 company has provided no economic analysis to support its
20 request and the Company is in the process of modernizing 16
21 turbines at 5 hydro plants, which will not be completed
22 until 2029.

23 Staff recommends the Commission reject the
24 company's requested hydro micro grid project as proposed
25 with 100 percent of the cost assigned to Georgia Power.

1 Staff recommends accepting the project only if the costs are
2 shared costs across the Southern Company operating
3 companies.

4 This concludes our summary.

5 MR. WALSH: Madam Chair, the panel is available
6 for cross-examination and questions from the
7 Commissioners.

8 Thank you.

9 MADAM CHAIR PRIDEMORE: Questions from
10 Commissioners?

11 Commissioner Echols.

12 COMMISSIONER ECHOLS: Yes.

13 Tom, just on a couple of things. On the two
14 scenarios that you devised for Bowen Units 1 and 2,
15 one for the -- I guess for an extension to '35 to
16 match Units 3 and 4, and then the other to wait until
17 2025 IRP to make a decision.

18 Now, the company had said that wasn't really an
19 option, but you're saying it is. Let me ask you this
20 question: Is it -- what might happen between then
21 and now that would trigger us in 2025 keeping the
22 plant open until -- for a later date?

23 What could happen?

24 WITNESS NEWSOME: Well, there's no carbon
25 legislation. That would definitely do it. That

1 would be the primary thing.

2 The argument about making a decision now versus
3 waiting until 2025, the company correctly points out
4 they have got to put some more money. If they don't
5 know they're going to retire in 2028, they're going
6 to put some more money in the plant capital because
7 they don't have a retirement date.

8 But that's -- but that needs to be balanced, as
9 I point out in the summary, against the ability to
10 keep the plant open -- have the flexibility to keep
11 the plant open.

12 Another point is even if you put that capital
13 incremental capital into the plant above what they
14 would do if you were going to retire early, the
15 plant's still competitive against the PPAs. So it's
16 still a competitive asset.

17 VICE-CHAIRMAN ECHOLS: 1 and 2 are still
18 competitive?

19 WITNESS NEWSOME: Yes.

20 VICE-CHAIRMAN ECHOLS: Yeah. Regarding the
21 dams, we have an intervenor concerned about one
22 particular dam. Is there any -- is there any
23 reliability risk for, you know, not doing the -- you
24 know, the dam improvements that the -- you know, that
25 the company's recommended?

1 WITNESS NEWSOME: My understanding of the
2 improvements is they want to upgrade the -- the water
3 turbines.

4 VICE-CHAIRMAN ECHOLS: Yes.

5 WITNESS NEWSOME: So they're small. In terms
6 of the reliability of the system, that's not -- it's
7 not a big deal. But I think they've already
8 committed to spending money to upgrade those
9 turbines.

10 So we're kind of -- my understanding, they can
11 correct me on cross, is that we're already kind of --
12 in terms of upgrading the turbines, they've already
13 started spending money to do that, so...

14 VICE-CHAIRMAN ECHOLS: All right. Thank you.

15 WITNESS NEWSOME: You might have some -- you
16 might have to walk away some costs if you decide not
17 to move forward with it.

18 VICE-CHAIRMAN ECHOLS: All right. Thank you.

19 WITNESS NEWSOME: All right.

20 MADAM CHAIR PRIDEMORE: Other Commissioners?

21 I have a question for the panel. So,
22 Mr. Newsome, you mentioned an act of Congress to
23 begin carbon pricing or carbon markets.

24 WITNESS NEWSOME: Correct.

25 MADAM CHAIR PRIDEMORE: We've seen this White

1 House administration really like executive orders,
2 especially -- especially around the area of energy.
3 Walk us through, for the record, what this Commission
4 would do or could do to respond should there be an
5 executive order from this president establishing
6 carbon prices nationally.

7 WITNESS NEWSOME: I think that's a better
8 question for Tom Bond. I think that's a legal --
9 you're asking for a legal opinion there.

10 MADAM CHAIR PRIDEMORE: I'll ask him later.

11 WITNESS NEWSOME: Okay.

12 MADAM CHAIR PRIDEMORE: But I do want it on the
13 record because I think it's important. There's a
14 procedural matter that we have to consider.

15 WITNESS NEWSOME: Right. I mean, I think it
16 would be -- if they issue an executive order, it's
17 probably going to get tied up in litigation, too.

18 MADAM CHAIR PRIDEMORE: Yeah. The difference
19 is, is that Congress moves a lot slower than that
20 White House does.

21 WITNESS NEWSOME: Correct. But they still
22 could be tied up in litigation on it probably.

23 MADAM CHAIR PRIDEMORE: Yeah.

24 WITNESS NEWSOME: I mean, if it comes to -- my
25 understanding, if Congress passes something and the

1 President signs, it's a law. They can do whatever
2 they want to do, but --

3 MADAM CHAIR PRIDEMORE: Yeah.

4 WITNESS NEWSOME: -- then I think the executive
5 action would be kind of -- I'm not saying -- talk to
6 Tom Bond to get the full story. But it would be
7 civil litigation.

8 MADAM CHAIR PRIDEMORE: We'll get him on the
9 record.

10 All right. Any other Commissioners have
11 questions?

12 (No response.)

13 MADAM CHAIR PRIDEMORE: All right. Your
14 witnesses.

15 Let's see. Americans for Affordable Clean
16 Energy.

17 MR. GALLOWAY: No questions, Madam Chair.

18 MADAM CHAIR PRIDEMORE: All right. Commercial
19 Group.

20 MR. JENKINS: No questions.

21 MADAM CHAIR PRIDEMORE: Concerned Ratepayers of
22 Georgia.

23 (No response.)

24 MADAM CHAIR PRIDEMORE: Not present. I've got
25 this.

1 Cypress Creek Renewables.

2 MR. STAIR: No questions.

3 MADAM CHAIR PRIDEMORE: Georgia Association of
4 Manufacturers.

5 MR. C. JONES: Yes, ma'am.

6 Good morning, panel.

7 WITNESS HAYET: Good morning.

8 MR. C. JONES: Mr. Hayet, I hope you feel
9 better soon.

10 WITNESS HAYET: Thank you very much.

11 MR. C. JONES: Sorry you're not with us this
12 morning.

13 WITNESS HAYET: Yeah. A little under the
14 weather.

15 MR. C. JONES: Well, I do hope you feel better.

16 CROSS-EXAMINATION

17 BY MR. C. JONES:

18 Q Good morning. So I have a few questions
19 about your testimony. And I'll apologize in advance
20 because I am going to jump around from page to page. So
21 just have it handy. I would appreciate it.

22 And if I ask a question, I'm just going to ask
23 it generally to the panel and whoever is the best person to
24 respond, please do so.

25 So let's start with the target reserve margin

1 and start on page 5.

2 Now, staff recommends a lower long-term winter
3 target reserve margin than Georgia Power by one and a half
4 percent; correct?

5 24.5 versus 26 percent?

6 A (Witness Newsome) Yes.

7 Q And that's a long-term systemwide target; is
8 that correct?

9 A (Witness Newsome) Yes.

10 Q Okay. And then over on page 10, down on
11 lines 20 to 23, you have a short-term target would be 500
12 basis points lower than that; is that correct?

13 A (Witness Newsome) Correct.

14 Q All right. Now, in making your
15 recommendation, you didn't really object to the company's
16 economic planning methodology in determining the long-term
17 target reserve margin, did you?

18 A (Witness Baron) Yes.

19 Q Okay. Now, you --

20 A (Witness Baron) Please answer it -- ask it
21 again.

22 Q Correct. Yeah. I mean, in other words, you
23 didn't object to their methodology; correct?

24 A (Witness Baron) That -- that's correct. We had
25 some problem -- we had a significant problem, as we

1 discussed in the testimony, with one element -- an important
2 element that -- of an input assumption. But the overall
3 methodology of using an economically optimal reserve margin,
4 we -- we did not object to, consistent with our testimony in
5 2019 IRP case.

6 Q Okay. And so when the company used three
7 different metrics, the loss of load expectation, the EORM
8 or economic optimum reserve margin, and the -- I'll call
9 it value at risk methodology; would you agree?

10 A (Witness Baron) Yes.

11 Q And the loss of load expectation, which you
12 say on page 12 in your testimony -- I believe there you
13 say: Historically, electric utilities have determined
14 target reserve margins by calculating the reserves needed
15 to maintain a loss of load expectation of at least one day
16 in ten years; right?

17 A (Witness Baron) Yes. That has -- that's the
18 traditional method and it's commonly used by the utility
19 industry today.

20 Q And under that metric, the company produced a
21 20 percent winter target reserve margin; would you agree?

22 A (Witness Baron) Correct.

23 Q And then when they used the EORM, it pumps it
24 up to 24.25 percent?

25 A (Witness Baron) Yes.

1 Q And then the value at risk takes it up to 26;
2 would you agree?

3 A (Witness Baron) Yes.

4 Q Now, would you agree with me that EORM and
5 value at risk are not pervasive throughout the industry;
6 that they are unique to a few utilities, including
7 Southern Company?

8 A (Witness Baron) I -- I'd say anecdotally that's
9 correct. I'm familiar with -- I think we -- I listed -- we
10 listed a few utilities that we're familiar with that
11 actually use the same model as the company. Other utilities
12 may have and probably do use other economic evaluations
13 to -- to determine an optimal reserve margin. But I agree
14 that the predominant method does not rely on an economic
15 approach.

16 Q And so if I can refer you to page 55 of your
17 testimony. Again, I apologize. We're going to bounce
18 around a little bit.

19 There you've got Table 9. And if I understand
20 what the staff did here, you surveyed electric utilities and
21 RTOs on this issue. And would you agree with me that many
22 of them continue to use the loss of load expectation metric?

23 A (Witness Baron) I have -- well, I -- I'm
24 familiar with some utilities, for example, Duke Energy
25 Carolinas, Duke Energy Progress, Louisville Gas & Electric,

1 TVA actually use the SERVUM model the same as Southern
2 Company.

3 Q Right.

4 A (Witness Baron) How they actually develop their
5 recommendation for a reserve margin would differ, but the --
6 the modeling approach definitely looks at an economic
7 evaluation. Generally these utilities -- and I think
8 Southern Company is consistent with this -- would have as a
9 minimum a one day in ten year loss of load expectation
10 reliability target. To the extent that an economic
11 methodology would dictate a higher reserve margin based on
12 an evaluation of a lot of economic inputs, then those
13 utilities would tend to follow that result. So similar to
14 what Southern Company does.

15 Q But if you look at the -- the utilities that
16 you have reviewed here on Table 9, there's only one that
17 uses a 26 percent or higher winter target reserve margin
18 on this chart; would you agree?

19 A (Witness Baron) Yes. That is correct.

20 Q Okay.

21 A (Witness Baron) The -- as I said -- as we said
22 in the testimony, the average is 18 percent.

23 Q Right. But --

24 A (Witness Baron) For winter.

25 MR. C. JONES: We're moving right along, Madam

1 Chair. That was going to be my next question.

2 BY MR. C. JONES:

3 Q So, yeah. So the average of these is
4 18 percent.

5 Now, you mentioned earlier that you had made an
6 adjustment. Could you describe the adjustment for me?

7 You -- you talked about an adjustment.

8 A (Witness Baron) Yes.

9 Q Why did you do that? What is it?

10 A (Witness Baron) The load forecast error
11 adjustment.

12 Were you asking me the page reference?

13 Q No, no, no. I just generally wanted you
14 to --

15 A (Witness Baron) yes.

16 Q -- describe what the load forecast error
17 adjustment was.

18 A (Witness Baron) Yes. Are you asking me to --
19 to explain it or just to acknowledge --

20 Q I'll tell you what.

21 A (Witness Baron) -- that that is the error?

22 Q Let's -- let's -- let's just do this.

23 Because it's not important to get into the details of
24 that. Making that adjustment, though, let's -- let's try
25 this. Let's go to page 39.

1 And here on Table 4 you show this correction to
2 the EORM and the VAR methodologies. Will you agree?

3 A (Witness Baron) That's correct.

4 Q Okay. And under the EORM, it reduces -- in
5 staff's opinion, it reduces the target reserve margin to
6 22 percent, which is a 2.25 percent difference; right?

7 A (Witness Baron) That's correct.

8 Q And with the VAR, it reduces it 150 basis
9 points down to 24.5 percent?

10 A (Witness Baron) Yes. At an 80 percent
11 confidence level, which is the --

12 Q Okay.

13 A (Witness Baron) -- the level that's produced at
14 the company's 26 percent.

15 Q So if you were using the loss of load
16 expectation and starting at 20 percent, would that result
17 in similar adjustments somewhere in the range of 1.5 to
18 2.25 percent less than what the company would recommend
19 under a loss of load analysis?

20 A (Witness Baron) The -- there would be a -- I --
21 I can't say that it would be similar, but it would be --
22 certainly directionally it would be lower than the
23 20 percent.

24 Q And -- and the average, again, was 18
25 percent; right?

1 A (Witness Baron) The average of the utilities
2 they will be serving, yes.

3 Q Right. So those would be more. It would
4 be -- if you made the adjustment to the LOLE, the result
5 would be more akin to that average; would you agree with
6 that?

7 Is that fair to say?

8 A (Witness Baron) Well, it's -- the -- I think
9 that's reasonable that it would certainly be in that
10 neighborhood.

11 Q Okay. Over on page 20, you talk about on
12 lines 9 through 13 that the practical effect of setting a
13 26 percent winter target reserve margin is to achieve a
14 reliability level that's twice as high as industry
15 standards. Would you agree with that?

16 A (Witness Baron) That's -- that's correct.

17 Q Okay. Did staff conduct any analysis --
18 excuse me -- on whether having a system that's twice as
19 reliable as the industry is cost-effective for consumers?

20 A (Witness Baron) Could you restate that question
21 again?

22 Q Your analysis here says that using a 26
23 percent winter target reserve margin there is a
24 reliability level that is twice as high as the industry
25 standard. My question is: Did staff conduct an analysis

1 to determine whether having that level of reliability,
2 twice as high as the industry standard, is economically
3 beneficial or cost-effective for customers?

4 A (Witness Baron) Well, the -- I think the answer
5 is that that -- that's the analysis that the company did.
6 The 26 percent -- excuse me.

7 The 26 percent reserve margin that the company
8 is recommending using the value at risk methodology is based
9 on -- is the -- is an economic methodology. And so it is --
10 if you accepted the company's assumptions, which we did not
11 in the case of the load forecast error, you would conclude
12 that -- that on a risk-adjusted basis at the 80 percent risk
13 level that it was economic. So that -- that's really the --
14 the essence of the analysis of the -- the value at risk and
15 EOR methodology.

16 And so in -- in our analysis, we concluded that
17 the proper -- the correct reserve margin, using the same
18 metrics, the 80 percent risk level, would be 24 and a half
19 percent. And so that produces, you know, a different loss
20 of load value.

21 But in answer to your question, if you accept
22 the 26 percent value at risk result is economic, then the
23 LOLE at twice the industry standard would be economic as
24 well. The LOLE doesn't make -- there is no information in
25 the LOLE result that points to economics. It's not -- it

1 doesn't consider economics in its -- in its methodology, its
2 calculation.

3 Q But you can look at a target reserve margin
4 and make an analysis of whether -- at some point the
5 target reserve margin would be too high or higher than
6 necessary and would not provide benefits that are worth
7 the cost to consumers?

8 Would you agree --

9 A (Witness Baron) That's exactly correct.

10 Q -- with that general statement?

11 A (Witness Baron) And that is, in essence, what
12 the -- this methodology that the company uses and other
13 utilities who have adopted an economic approach. That's the
14 methodology, the essence of the methodology. That it's
15 designed to look at that trade-off between added reliability
16 benefits, which is, you know, in the form of lower
17 production costs, lower emergency purchases, potentially
18 lower outages of customers, on the one hand, and the
19 trade-off, which is you need to add more capacity. So
20 that -- that is exactly the essence of the economic
21 methodology.

22 Q So you made this adjustment -- this LFE
23 adjustment called load forecast error adjustment. Did you
24 note that there was any other witnesses in this proceeding
25 who made a similar adjustment?

1 A (Witness Baron) I saw in Mr. Wilson's testimony
2 that he identified the same problem that the staff
3 identified. My recollection is that he didn't make any
4 specific adjustments. He simply -- he identified that as a
5 problem, similar to what the staff did.

6 Q And his -- his recommended target reserve
7 margin was 17 percent; would you agree?

8 A (Witness Baron) Yes. But that was based on an
9 entirely different approach using an adjusted loss of load
10 expectation method.

11 Q All right. Let's talk about the unit
12 retirement study. Two key variables in the unit
13 retirement study are, you would agree, I hope, projected
14 natural gas prices and whether or how much of a carbon fee
15 or tax will be imposed on fossil fuel generation; would
16 you agree?

17 A (Witness Newsome) Correct. Yes.

18 Q Okay. And all other things being equal,
19 higher forecast natural gas prices would make, for
20 example, coal plants more economical, all things being
21 equal?

22 A (Witness Newsome) Correct. Yes.

23 Q Okay. And higher carbon taxes or fees would
24 make coal and all fossil fuel plants really, all things
25 being equal, less economical?

1 A (Witness Newsome) Correct. Yes.

2 Q All right. Now, let's look at page 58 of
3 your testimony. And, again, thank you for jumping around.

4 Very thorough testimony so we've got to find
5 what we're looking for. On page 58 at the bottom, line 16
6 and 17, you say that staff developed its own independent
7 low, moderate, and high gas forecasts using public sources;
8 correct?

9 A (Witness Newsome) Correct.

10 Q Those are shown on pages 59 and 60?

11 A (Witness Newsome) Correct.

12 Q Now, let's look just for an example at the
13 moderate Henry Hub forecast that is at the top of page 60.

14 Would you agree with me that it shows that the
15 Georgia Power's base case is below -- below the average?

16 A (Witness Newsome) Yes.

17 Q Okay.

18 A (Witness Newsome) I mean, a little bit.

19 Q But there's no numbers on the -- on the Y
20 axis, I guess, there. So we don't know -- it is difficult
21 to measure the dollar differences in that case, would you
22 agree, from -- from the way it appears there?

23 A (Witness Newsome) Correct.

24 Q Okay. And Georgia Power's base forecast uses
25 EIA GATS' forecast published in 2021. I think they call

1 it the Annual Energy Outlook.

2 Does that sound familiar?

3 A (Witness Newsome) Correct.

4 Q Okay. Are you aware that the 2022 Annual
5 Energy Outlook projects higher natural gas prices than in
6 2021, both in the short and long term?

7 A (Witness Newsome) That doesn't surprise me, no.

8 Q Okay. In fact, on your -- on the next page,
9 on 61, staff recognizes that -- I believe this is on lines
10 -- starting on line 9, that there are increased cost
11 pressures in response to invest -- investor pressures for
12 domestic drillers to be profitable on an ongoing basis,
13 recent inflation, and -- and the Russia/Ukraine conflict.
14 Would you agree?

15 A (Witness Newsome) Correct.

16 Q And then even though you believe this -- this
17 market will ease within a few years, still the '22
18 projections are higher than what Georgia Power has here?

19 A (Witness Newsome) Correct.

20 Q All right. Are you aware of any factors that
21 would result in lower gas prices in the near term?

22 A (Witness Newsome) Well, you know, to the extent
23 that high prices incentivize drillers to drill more, you
24 know, you might get a little more supply online.

25 Q Okay.

1 A (Witness Newsome) So you have something like
2 that, but --

3 Q But nothing concrete at the moment?

4 A (Witness Newsome) Correct.

5 Q Okay. And then on page 64, let's talk about
6 carbon taxes. Your carbon --

7 A (Witness Hayet) Could I -- could I add to that
8 answer, if you don't mind?

9 Q No, please.

10 A (Witness Hayet) I -- I noticed that you
11 mentioned in the -- in the short term. And the projection
12 is over a longer-term period. And the projections -- the
13 forecasts are for the -- a reversion back to the -- back to
14 the lower forecasts that we've been experiencing. So it's
15 expected to come back -- essentially, back to the mod
16 forecast, as the company has projected.

17 Q Right. And -- and the average is still
18 higher than on that, though; would you agree?

19 A (Witness Hayet) Yes. Slightly, though.

20 Q Okay. Well, it's just hard to tell a little
21 bit because of -- of the chart.

22 But in any event -- so regarding carbon on
23 page 64, this is Figure 7. Here we have staff's \$20 and \$50
24 carbon tax forecast and Georgia Power's 20 and \$50 forecast.

25 Is it fair to say -- I mean, just looking at

1 this without really getting into the details, but just
2 looking at it, is it fair to say that the staff's carbon
3 forecast is significantly below Georgia Power's for this
4 time period that you're showing here?

5 A (Witness Newsome) Correct.

6 Q All right. And are you aware of any pending
7 national legislation that would impose a carbon fee or tax
8 on fossil fuel generation?

9 A (Witness Newsome) Not at this time.

10 Q And has one ever been passed by Congress?

11 A (Witness Newsome) No.

12 Q And would -- in your view -- we have been
13 talking about that issue for a couple of decades now.
14 Would you -- is that fair or -- as I'm --

15 A (Witness Newsome) That's correct.

16 Q Okay. And, in fact, even in the Build Back
17 Better legislation that didn't pass, there was -- they
18 didn't have carbon taxes in there; it was tax incentives?

19 A (Witness Newsome) I will take that, subject
20 to --

21 Q Okay.

22 A (Witness Newsome) -- check.

23 Q All right.

24 A (Witness Newsome) I mean, that's kind of the
25 part why we -- in lines 6 and 7, we quantified the impact

1 with Georgia Power customers. And it's a big impact.

2 Q It is. But as of now, we -- we still don't
3 have a carbon --

4 A (Witness Newsome) Right. I think the point --
5 well, I'm saying the impact is it's a -- if you pass
6 legislation like that, it has a big impact on people.

7 Q Sure.

8 A (Witness Newsome) So it's -- I think that's one
9 of the reasons probably that they haven't had much success
10 passing one. Because when people figure out who's going to
11 pay for it, it can be quite expensive.

12 Q Would it be fair to summarize your testimony
13 that you have many concerns with the company's unit
14 retirement study?

15 A (Witness Newsome) Yes.

16 Q Okay. And then despite those differences,
17 though, the only change you really recommended is to keep
18 Bowen Units 1 and 2 in operation through 2035; would you
19 agree?

20 A (Witness Newsome) Well, we said that to -- on
21 Bowen 1 and 2, we said that's a Commission decision.

22 Q Okay. Let's see. Let's look at -- let's
23 look at page 94. And this is Table 19. And this is Stage
24 1 results.

25 Can you describe a little bit what this, just

1 generally what this chart is showing?

2 A (Witness Wellborn) Yes. So Table 19 is
3 intended to describe what resources would be selected
4 optimally under each of the various fuel and carbon
5 combinations. So across the top you see the fuel and carbon
6 combinations and then you see some of the key decision
7 resources we were evaluating in our modeling. And so a one
8 shows that it was selected and a zero shows that it was not
9 selected.

10 Q And Bowen 1 and 2 is shown here with an
11 average of .5; is that right?

12 A (Witness Wellborn) That's correct.

13 Q And Scherer 3, which you did not recommend
14 the Commission consider delaying the retirement of, is
15 also ranked at .5; would you agree?

16 A (Witness Newsome) Correct.

17 Q Okay. And further, if you go on down, I
18 think later in your testimony -- I think it's on 97. You
19 don't have to go there, unless you need to confirm.

20 But I believe that you're recommending that --
21 you said you're recommending accepting all the PPAs,
22 including Wansley 7 and Dahlberg 8 to 10. And those had the
23 same Stage 1 ranking here as Scherer; right?

24 A (Witness Wellborn) That's correct.

25 (Witness Newsome) Correct.

1 MR. C. JONES: All right. Madam Chair, I'd
2 like to show an exhibit to the witnesses, if I might.

3 MADAM CHAIR PRIDEMORE: You may. You may
4 approach.

5 MR. C. JONES: Thank you.

6 Madam Chair, because Mr. Pollock will be
7 testifying later and we've added exhibits, I'd like
8 to skip ahead in our sequence a little bit and mark
9 this as GAM 9 --

10 MADAM CHAIR PRIDEMORE: You may.

11 MR. C. JONES: -- for clarity in the record.
12 Thank you.

13 (The document referred to was marked for
14 identification as GAM Exhibit 9.)

15 WITNESS NEWSOME: Let me make a clarification
16 on Table 19.

17 BY MR. C. JONES:

18 Q Yes, sir.

19 A (Witness Newsome) This is -- this is Georgia
20 Power's assumptions.

21 Q Right.

22 A (Witness Newsome) Not staff. So that's --

23 Q Okay. But you're agreeing with their
24 ultimate recommendations, except on Bowen 1 and 2, where
25 you say it's a Commission decision and that it could be

1 economic to continue those units?

2 A (Witness Newsome) Correct.

3 Q Okay. So what I'm showing you is an
4 S&P Capital Plant Profile. And if you look through it,
5 it's for Plant Scherer, also Plant Bowen. And I apologize
6 for the pagination here because we'll -- we'll figure it
7 out. It won't take me long to do that. And also Plant
8 Miller. Plant Miller is a -- a plant on the Alabama Power
9 system.

10 A (Witness Newsome) Okay.

11 Q Are you familiar with that?

12 A (Witness Newsome) Okay.

13 Q So -- and we can go through -- I have this in
14 front of you so that we can refer back to it.

15 A (Witness Newsome) Okay.

16 Q We don't have to sit and go through all of
17 this. But the point I want to make with you, or am trying
18 to make is: Are you -- you're aware that the Scherer
19 Units 1, 2, 3 are even newer and more modern coal plants
20 than Bowen 1 and 2?

21 A (Witness Newsome) Correct.

22 Q Okay. Would you accept, subject to checking
23 this document, that the online dates for -- for the Bowen
24 units are '71, '72, '74, '75, and the Scherer units are
25 '82, '84, and '87; is that --

1 A (Witness Newsome) Correct.

2 Q Okay.

3 MR. WALSH: Madam Chair, I'm going to just make
4 a -- I guess a conditional objection here to this
5 exhibit just to the extent that if the panel is not
6 familiar with the information, I don't want them
7 being asked questions. If they're familiar with it,
8 then they can certainly ask. I just want that --

9 MR. C. JONES: Sure.

10 MR. WALSH: -- on the record so I don't have to
11 stand up --

12 MADAM CHAIR PRIDEMORE: Sustained.

13 MR. C. JONES: Sure. Absolutely.

14 MADAM CHAIR PRIDEMORE: Mr. Jones, make your
15 questions be about the content, please.

16 MR. C. JONES: We will.

17 BY MR. C. JONES:

18 Q And -- and certainly I don't want you to
19 testify to anything that you're not comfortable testifying
20 to. That's -- that's a valid point.

21 Scherer Units 1, 2, and 3 have over 20 years of
22 remaining life; is that about right?

23 A (Witness Newsome) That's fair.

24 Q And 13 years are left for -- for the Bowen
25 units; is that right?

1 A (Witness Newsome) Correct.

2 Q Okay. Now, I'll ask you to look at the --

3 it's really about the fifth page where it starts with the

4 plant profile of Plant Miller.

5 A (Witness Newsome) Give me a second.

6 Q Sure.

7 A (Witness Newsome) Okay.

8 Q And really maybe onto the next page, page --

9 A (Witness Newsome) Oh, I see them. Miller plant

10 profile?

11 Q Uh-huh. And then if you go to the second

12 page of that, you'll see the online dates to the right

13 there.

14 A (Witness Newsome) Okay.

15 Q October of '78, May '85, May '89, and 1991.

16 Do you see that?

17 A (Witness Newsome) Correct.

18 Q Okay. So that's a similar age plant to Plant

19 Scherer; would you agree? I mean --

20 A (Witness Newsome) Sure.

21 Q -- throughout the same era.

22 And the coal that is used at Plant Scherer is

23 sourced from the Powder River Basin. Would you agree with

24 that?

25 A (Witness Newsome) Correct.

1 Q That is also true for Plant Miller in
2 Alabama, if you look on --

3 A (Witness Newsome) I see.
4 Okay. I'll accept that.

5 Q Okay. You can go to the very last -- next to
6 last page.

7 MADAM CHAIR PRIDEMORE: Was that a question,
8 Mr. Jones?

9 MR. C. JONES: I'm sorry. It was a question.
10 It was meant to be: Do you agree? Sorry about that.
11 BY MR. C. JONES:

12 Q So the last page that shows the plant fuels
13 for Plant Miller, it shows as --

14 A (Witness Newsome) Okay.

15 Q -- southern Powder River Basin. Do you
16 agree?

17 A (Witness Newsome) I see that there, yes.

18 Q Okay. Great. So we've got two very similar
19 plants.

20 A (Witness Newsome) Okay.

21 Q Are you familiar with whether Alabama Power
22 is planning to retire Plant Miller any time soon?

23 A (Witness Newsome) I have no idea.

24 MR. JONES:

25 MR. C. JONES: Okay. Madam Chair, I think

1 that's all I have. Thank you.

2 I will move that the exhibit be entered into
3 the record.

4 (GAM Exhibit 9 was admitted into evidence.)

5 MADAM CHAIR PRIDEMORE: So moved.

6 Georgia Center for Energy Solutions.

7 MR. HUBBARD: No questions, Madam Chair.

8 MADAM CHAIR PRIDEMORE: Georgia Coalition of
9 Local Governments.

10 MS. BROWN: No questions, Madam Chair.

11 MADAM CHAIR PRIDEMORE: Georgia Interfaith
12 Power & Light and Partnership for Southern Equity.

13 Ms. Kysor.

14 MS. KYSOR: Thank you, ma'am.

15 CROSS-EXAMINATION

16 BY MS. KYSOR:

17 Q Good morning. I'm Jill Kysor. I'm here on
18 behalf of Georgia Interfaith Power & Light and Partnership
19 for Southern Equity.

20 And Mr. Jones started off by asking almost my
21 first full page of questions. So that should speed things
22 up.

23 A couple follow-up questions. Mr. Jones talked
24 to you about Table 9 on page 55 of your testimony.

25 A (Witness Newsome) That's the reserve margin?

1 Q Correct.

2 A (Witness Newsome) Okay.

3 Q And he noted that there was only one utility
4 in your survey that had a 26 percent reserve margin and
5 that was Louisville Gas & Electric; correct?

6 A (Witness Baron) Yes.

7 Q And would you accept, subject to check, that
8 LG&E is a very small utility with under 3,000 megawatts of
9 capacity?

10 A (Witness Baron) Well, LG&E and Kentucky
11 Utilities are essentially combined for planning purposes.
12 So I don't -- I don't remember the -- the megawatt capacity
13 for the combined system.

14 But it's obviously -- what I certainly can
15 agree with is it's not part of a -- a holding company
16 consolidated system. It's a standalone utility, even the
17 combination of Kentucky Utilities and Louisville Gas &
18 Electric.

19 Q And you talked with Mr. Jones about the
20 one-in-ten method being used fairly commonly by other
21 utilities; correct?

22 A (Witness Baron) Yes. And RTOs.

23 Q So would you agree that the one-in-ten method
24 would be a reasonable method to use here?

25 A (Witness Baron) Would it be reasonable?

1 Q Could be a reasonable method to use?

2 A (Witness Baron) Yes. I -- I would say it could
3 be reasonable. In fact, as I said, it's my understanding
4 that the Southern Company criteria or criterion is to use
5 the one day in ten as a minimum.

6 So to the extent that the loss of load
7 expectation analysis shows a higher reserve margin required
8 than, say, the economic analysis -- which certainly can
9 happen. In the Duke Energy cases, which I was involved in,
10 the economic results, at least for one of the companies, was
11 lower than the LOLE.

12 So it's -- so I think the way I'd answer your
13 question is: It is -- I think it is reasonable and I'm
14 aware that a number of utilities use the LOLE, as well as
15 other methodologies. But set a planning criterion and such
16 that they would always meet a one day in ten criterion.

17 Q And so to button that up, a 20 percent winter
18 target reserve margin could be reasonable using the
19 one-in-ten method?

20 A (Witness Baron) Yes. I -- I'd say it could be
21 reasonable. I'm not recommending it and -- because I think
22 that the economic approach is a reasonable methodology and
23 it should -- to the extent that it produces a higher reserve
24 target than an LOLE method, I think that is a reasonable
25 outcome and not -- so your -- your question -- if your

1 question really is: Is -- and I don't think it was.

2 Is the LOLE result of 20 percent just as
3 reasonable as an economic result for Southern Company? My
4 answer is, no, it is not because -- and we're not
5 recommending that. But certainly an LOLE result can be
6 reasonable.

7 Q And it is commonly used among other
8 utilities?

9 A (Witness Baron) Yes.

10 A (Witness Newsome) I mean, we're acknowledging
11 that our reserve margin to many is conservative. I mean, it
12 gives them ample reserve capacity for reliability.

13 Q Did staff conduct its own analysis into the
14 cost that ratepayers would incur if the company were to
15 adopt a 20 percent one-in-ten reserve margin and how those
16 costs might compare to the company's recommended
17 26 percent risk-adjusted EORM?

18 A (Witness Baron) Essentially the answer is we
19 did not conduct a specific analysis of that, but I think it
20 is important to understand that the economically optimal
21 reserve margin methodology analyzes the cost to customers.
22 And it doesn't just look at the revenue requirements in a
23 test year rate case, but it looks at the full compendium of
24 costs. The costs of additional capacity and -- that are
25 modeled in the analysis, higher production costs, lower

1 production costs, more reliance or less reliance on
2 emergency purchases, the cost to customers of lost load, and
3 other factors.

4 So when you ask: Do we look at the cost,
5 essentially that is exactly what the study looked at and we
6 looked at as well in our evaluation. And when we made
7 adjustments, for example, to the load forecast error, we
8 looked at the cost because the 24 and a half percent value
9 of risk result was the lowest cost at that 80 percent risk
10 level.

11 Q So did staff conduct -- staff did not conduct
12 a cost analysis of the 20 percent one-in-ten method?

13 A (Witness Baron) Well, it was implicit in the
14 analysis. In other words, we -- the company -- when we
15 reviewed all of the outputs -- and there were a tremendous
16 number of outputs from the SERV model, we -- that was what
17 we -- we looked at those. But the loss of load expectation
18 methodology is one of the outputs of the SERV results.

19 And the analysis that the company did, and that
20 we evaluated, was based on economics. And so -- but we did
21 not actually calculate for a particular year what the
22 economics -- the economic cost. And, again, if you're
23 talking about what it would be in a rate case, that's
24 entirely different than what is done in this type of
25 analysis. But we didn't make any specific calculation of

1 that.

2 A (Witness Hayet) If I could add --

3 MADAM CHAIR PRIDEMORE: Just a reminder --

4 WITNESS HAYET: If I could I add to that --

5 COMMISSIONER PRIDEMORE: Mr. Hayet, just a
6 reminder just to speak into your mic.

7 WITNESS BARON: Oh, okay. I'm sorry.

8 MADAM CHAIR PRIDEMORE: That's okay. Thank
9 you.

10 WITNESS BARON: Usually I talk too loud.

11 WITNESS HAYET: Could I -- could I add to that
12 answer? This is Phil Hayet.

13 The -- just -- just to be clear with what
14 Mr. Baron is saying is that while not performing a
15 calculation as -- as what would be done in a rate
16 case evaluation of a -- of a cost, the purpose of
17 that study is to look at a comparison of costs
18 between different reserve margin levels.

19 So, implicitly, as he said, 20 percent was
20 considered, and 26 percent, and 24 and a half. And
21 when we corrected to the 24 and a half, it was found
22 that 24 and a half was superior to the 20 percent
23 reserve margin level. And superior, meaning lower
24 costs than the 20 percent reserve margin level on an
25 economic basis.

1 WITNESS BARON: Just to follow -- just to
2 follow up and hopefully clarify. If you think of --
3 if you've seen the company's reserve margin study and
4 you've seen the U curve that they produce, it -- it
5 is a composite of all of the costs that I was
6 referring to, including the cost of additional
7 capacity at different reserve margins.

8 If you look at that curve for our adjusted
9 corrected load forecast error model, what you will
10 see is that the costs are higher at a 20 percent
11 reserve margin level than they are at the 22 percent
12 in the EORM analysis.

13 So, to that extent, we did look at a 20 -- what
14 the effect is of a 20 percent reserve margin and
15 it -- and based on that U curve, the 20 percent
16 produced a higher cost than a -- than the 22 percent
17 for EORM. And the corresponding value for value at
18 risk at 80 percent again was a lower cost than a --
19 an alternative reserve margin either 20 percent or 26
20 percent.

21 BY MS. KYSOR:

22 Q Thank you.

23 I'm turning to page 37 and 38 of your
24 testimony. And specifically looking at Table 3 on page 38.
25 And I think it ties in with the question that is on page 37

1 before it.

2 But did staff analyze what the risk-adjusted
3 EORM would have been with the actual average 18-year
4 Southern Company over forecast error of 6.8 percent?

5 A (Witness Baron) We did not. It would require
6 rerunning the SERVVM model, which we did not have available.
7 But I think there are other issues which we discussed a
8 little bit in the testimony, that there was some --
9 obviously during the 2008-2009 period when the economic
10 downturn was the greatest since the Great Depression, the
11 forecast -- it produced high forecast errors, but that is --
12 that's something that probably could be considered as an
13 anomaly, at least for long-term planning.

14 And so we think that the fact that our adjusted
15 or corrected load forecast error methodology produces a
16 slight -- you know, a somewhat higher, 1.8 percent average
17 over forecast is not unreasonable. That's why we believe
18 that the 24 and a half percent is a reasonable number.

19 But as Mr. Newsome said in his summary, and we
20 said in the testimony, it's -- it's -- it provides adequate
21 reserves, but -- and it's -- and we believe it is
22 reasonable.

23 Q And flipping now back to page 25 of your
24 testimony towards the bottom and then going on to 26, you
25 list some of the key assumptions, the impact of forced

1 outage rate assumptions, impact of weather on load, and
2 extreme cold weather events. Do you see what I'm talking
3 about?

4 A (Witness Baron) Yes.

5 Q Did staff determine to what extent each of
6 these assumptions drives the company's recommended
7 26 percent reserve margin?

8 A (Witness Baron) The company actually did a -- a
9 piechart in their reserve margin study which provides some
10 information about the breakdown of those elements. And
11 we -- we -- again, we did not -- we were not able to rerun
12 SERVVM, but we were able to analyze adjustments like the load
13 forecast error adjustment.

14 So on some of them, for example, the impact of
15 alternative forced outage rates, the company actually did a
16 sensitivity analysis and that was presented in their report.
17 I -- I may have put a table in this summary of some of those
18 results.

19 And, of course, we looked at -- we did actually
20 examine the impact of some alternative weather assumptions.
21 We were able to do that using the SERVVM output that we had
22 available to us.

23 So we looked at the effect of a 20-year weather
24 history, instead of 58 years. We removed some -- the two
25 most extreme winter years from the analysis. Not because

1 we're recommending that, but just to provide information to
2 the Commission as to the impact of those alternatives. But
3 the company study did do a sensitivity analysis on some of
4 those factors.

5 Q Does staff know whether and to what extent
6 the company's scarcity pricing assumptions impact the
7 winter reserve margin?

8 A We looked at scarcity assumptions and that is
9 an input. I saw a criticism of that by Mr. Wilson in his
10 testimony. But we did not find what the -- the company's
11 assumption to be unreasonable. It was based on historical
12 data and it -- we did not make an assumption of that.

13 And let me apologize for this, but I did see --
14 I do see on Table 8 at page 49 of my testimony I did -- I do
15 report the company's higher and lower forced outage rates
16 assumptions.

17 Q And just circling back to the scarcity
18 pricing assumption, would you characterize or could you
19 say is the scarcity pricing assumption -- does that have a
20 significant or insignificant impact on driving the winter
21 reserve margin?

22 A (Witness Baron) I would say it's a -- it's a
23 material impact. I don't -- I can't tell you the extent to
24 which a change in the scarcity pricing would change the
25 results.

1 Q Do you -- does staff know whether and to what
2 extent the company's DSM impacts the risk-adjusted EORM
3 reserve margin?

4 A (Witness Baron) Excuse me. The -- what was the
5 first part of your question?

6 Q Do you know whether and to what extent
7 demand-side management impacts the company's 26 percent?

8 A (Witness Baron) It's -- again, it's one of the
9 inputs into the SERVVM modeling process that determines the
10 optimum reserve margin. Economically optimal reserve
11 margin. There is really no -- there is no way that you
12 could answer that question except to rerun the entire
13 analysis and vary levels of demand-side management input
14 assumptions. And then you could -- from that you could
15 examine the incremental impact on the economically optimal
16 reserve margin. It certainly can be done, but it
17 requires -- it would require extensive analyses using SERVVM.

18 Q Thank you.

19 I'm shifting gears quite a bit now and turning
20 to page 21 of your testimony where you discuss gas price
21 forecasts and recent upward pressure on forecasts.

22 A (Witness Newsome) What page number?

23 Q Sixty-one and 62, generally.

24 A (Witness Newsome) Okay. We are there.

25 Q All right. Specifically page 61, lines 14

1 through 18. Even under continued gas price pressure, the
2 moderate and high gas price forecasts that the company
3 used still provide reasonable cases?

4 A (Witness Newsome) I see that, yes.

5 Q And at this point in time, given current gas
6 prices, would you characterize the low gas price forecast
7 as reasonable?

8 A (Witness Newsome) Well, it's a low forecast.
9 Now, given new information, you may bump it up, but still,
10 it's a low forecast so it's going to be lower than the other
11 two.

12 So your point is: Would it be higher now than
13 when we filed this testimony? Probably would be. But, I
14 mean, it's still a low forecast. It's going to be below the
15 other two.

16 Q And turning to page 62, I'm looking at
17 Figure 6.

18 A (Witness Newsome) Okay.

19 Q Do you think it's likely that gas prices will
20 be higher than they were projected to be at the time the
21 case -- or, excuse me, the RFP that resulted in the
22 proposed gas PPAs was issued and the -- during the
23 evaluation process?

24 A (Witness Newsome) Repeat the question. Give me
25 a time period you want those gas prices to change.

1 Q Sure. So thinking about the period of time
2 that the RFP, the 2022 to 2028 RFP.

3 A (Witness Newsome) Okay.

4 Q Thinking about that time frame.

5 A (Witness Newsome) Okay.

6 Q Do you think it's likely that gas prices will
7 be higher than they were projected to be at the time the
8 RFP was issued and during the evaluation process?

9 A (Witness Newsome) Over what time period?

10 Q The time period of the PPAs that were
11 selected, I guess. Over the next 10, 15 years.

12 A (Witness Newsome) They maybe a little -- a bit
13 little higher, yeah. Yes.

14 A (Witness Hayet) Let me just add to that. I
15 think it will be -- I think he's correct it will be a little
16 bit higher. But, again, as you could see from Figure 6,
17 there's an expectation of a reversion back to where it had
18 been.

19 So you can see the dotted lines that represent
20 NYMEX futures as four -- as of 4/13/22. And then NYMEX has
21 gone up a little bit even more even since then. But it
22 still comes back -- and if you looked at it today, it still
23 comes back down, reverts back down to where the expectation
24 was for the longer term.

25 So over the term of when the PPA contracts will

1 exist, it's about approximately where the company had
2 analyzed during the PPA evaluation.

3 Q In turning to Table 13 on page 74, a
4 clarification question. Does this table assume that
5 Vogtle 3 and 4 come online in 2023 and 2024?

6 A (Witness Newsome) Yes.

7 Q Okay. I just -- it was clear for the next
8 table, but I just wanted to clarify those.

9 A (Witness Newsome) Let me do subject to check on
10 that.

11 A (Witness Wellborn) Vogtle is in there.

12 A (Witness Newsome) Yes, Vogtle is in there.

13 Q Okay. And now I'm looking at Table 14 on
14 page 76.

15 A (Witness Newsome) Okay. We're there.

16 Q Okay. So in 2024, when Vogtle Unit 4 comes
17 online, there's a 714 megawatt capacity change?

18 A (Witness Newsome) Correct.

19 Q What makes up that 714 above and beyond the
20 Vogtle capacity?

21 A (Witness Wellborn) Yeah. It is a number of
22 smaller resources. Vogtle Unit 4 is the largest and so
23 that's the one that was called out in this table.

24 A (Witness Newsome) That's why it's listed as
25 fleet.

1 A (Witness Wellborn) Yeah, it's just intended to
2 quantify the fleet changes that are not changing based on
3 the various scenarios we're presenting. So those are almost
4 base case across what the company's provided, what we
5 provided.

6 A (Witness Newsome) And Vogtle Unit 4 is probably
7 about 500, so the rest of it's around 215.

8 Q Okay.

9 A (Witness Hayet) But to add to that, the fleet
10 has changes all the time, including up-rates. It has some
11 PPA adjustments. So we could go through and look at every
12 resource.

13 There are solar resources being added. And
14 some of the solar resources have capacity value that -- in
15 the company's analysis. So I think -- I think that would
16 explain it.

17 We'd have to go through and look at every
18 single resource and see what is going up to account for that
19 extra. But we lumped it together and just called it, you
20 know, fleet.

21 Q Sure. And I was mostly just clarifying that
22 the Vogtle capacity is, you know, approximately 500
23 megawatts and other capacity is something else?

24 A (Witness Newsome) Correct.

25 A (Witness Hayet) That's correct.

1 Q Okay. So I'm looking -- mainly the next set
2 of questions are about the Wansley PPA, but referring to
3 the same chart, Table 14.

4 So if the Commission hypothetically were to
5 reject the Wansley PPA and everything else stayed the same,
6 would you agree that the year of need, according to your
7 chart, would still be 2029?

8 A (Witness Newsome) Yeah, yeah. Approximately.
9 Based on what; Table 14?

10 Q Correct.

11 A (Witness Newsome) You're knocking out what?

12 Q Knocking out --

13 A (Witness Newsome) Wansley PPA, 6.2? Yeah, by
14 the math, yeah, that would be '29.

15 Q So it may be true that customers -- the
16 Wansley PPA or some capacity amount similar to that is not
17 needed for about four years out of a -- in that case, a
18 ten-year contract?

19 A (Witness Newsome) Yeah. Correct. In fact, you
20 don't need any of the PPAs initially. It's the -- it's
21 Bowen 1 and 2 that's driving -- driving the whole thing. I
22 mean, you're way over.

23 I mean, this excess is above their reserve
24 margin. So we've got -- you're way over through '27. And
25 then, again, Bowen 1 and 2 is what is driving them, yeah.

1 You know, is driving the PPAs. But before then, it's all --
2 it's way excess.

3 Q Thank you.

4 Turning now to page 113 of your testimony.

5 A (Witness Newsome) Okay. I'm there.

6 Q This is where you discuss the net benefits of
7 the gas PPAs proposed for certification.

8 Clarifying question: Did you include the
9 proposed additional sum in this analysis?

10 A (Witness Newsome) Yes.

11 A (Witness Wellborn) In the analysis on the top
12 of page 113, those actually are based on the company's MGO
13 results that were filed. So they do not have the additional
14 sum --

15 A (Witness Newsome) Okay.

16 A (Witness Wellborn) -- included.

17 Q Sorry. I think I'm actually turning on to
18 page -- it's kind of between 113 and 114 where --

19 A (Witness Newsome) Give us some -- yeah. We
20 need some line numbers so we --

21 Q Sure.

22 A (Witness Newsome) -- give you a correct answer.
23 In our analysis, we included the additional sum. Their
24 analysis tended to omit it.

25 So if you're referring to our analysis, it's

1 included. If you're referring to their analysis, it's not
2 included.

3 Q It looks like -- on page 114, did your
4 analysis include -- take into account an additional sum
5 that is lower than the additional sum sought by the
6 company?

7 A (Witness Newsome) Yes. We used 2.30, the
8 existing one.

9 Q So did you conduct an analysis of the net
10 benefits of the gas PPAs using the proposed additional sum
11 of \$7.50?

12 A (Witness Newsome) No.

13 A (Witness Wellborn) Yeah. No. The company's
14 proposed levelized 7.50 is based on a net benefit
15 calculation and we just used the 2.30 as a flat additional
16 sum.

17 Q And on page 13 -- 113, lines 16 and 17, you
18 note that the low-gas zero-carbon scenario was the only
19 scenario where all of the PPAs were selected
20 simultaneously; correct?

21 A (Witness Wellborn) That's correct. Our
22 Table 19 shows the specific results for each fuel price
23 scenario. And under the base set of assumptions, that's
24 correct. We run some other sensitivities that shows
25 economics with all six, but the -- consistent with Table 19,

1 LG0 is the only one with all six.

2 Q And did staff conduct an analysis if your
3 reserve -- if your proposed reserve margin, target reserve
4 margin were adopted; did you conduct any analysis on how
5 that would affect the need for the proposed PPAs?

6 A (Witness Newsome) It's included in -- our
7 entire analysis is based on the -- our reserve margin
8 recommendation of 24.5 percent. So the answer is yes.

9 MS. KYSOR: Okay. Thanks. That's all my
10 questions.

11 COMMISSIONER PRIDEMORE: Georgia Large Scale
12 Solar Association and Advance Power Alliance.

13 MR. CARVER: No questions.

14 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
15 Association, Solar Energy Association, and Vote
16 Solar.

17 MR. THOMASSON: No questions.

18 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

19 MR. CARVER: No question, Madam Chair.

20 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
21 Coalition.

22 MR. S. JONES: Madam Chair.

23 MADAM CHAIR PRIDEMORE: Okay.

24 CROSS-EXAMINATION

25

1 BY MR. S. JONES:

2 Q Good morning, panel. Steven Jones on behalf
3 of Restore Chattooga Gorge Coalition. All my questions
4 will focus on page 122 and 123 of your testimony.

5 A (Witness Newsome) Okay. We're there.

6 Q On those pages you state that the company has
7 not done an economic analysis for the three units that it
8 proposes to upgrade in this IRP; is that correct?

9 A (Witness Newsome) Correct.

10 Q Is the same true for the three units that
11 were approved in the 2019 IRP?

12 A (Witness Newsome) There was actually five units
13 approved by --

14 Q Sorry. Five units.

15 A (Witness Newsome) Five hydro plants, but that's
16 -- that's correct.

17 Q What would staff like to see in an economic
18 analysis?

19 A (Witness Newsome) The same thing we do for all
20 these fossil plants, these PPAs. Unit cost benefit
21 analysis.

22 Q And what -- and would that look at cost and
23 benefits to the entire system?

24 A (Witness Newsome) Yes, we'd look at the entire
25 system.

1 Q And to ratepayers?

2 A (Witness Newsome) Correct.

3 Q What about to -- what about extra analyses?

4 A (Witness Newsome) That's those guys up there,
5 the Commissioners.

6 Q To date -- and this is also in your
7 testimony. You have a graph regarding construction -- or
8 expenditures and efforts to date. What activities have
9 been conducted at the Tugalo facility as of the date of
10 this hearing?

11 A (Witness Newsome) I know they've done some
12 preliminary engineering. I'm not sure what they've done or
13 haven't done up there. I know they're starting work on it,
14 but I think they've got a ways to go, is my understanding.

15 Q Okay. Do you know if it's maintenance only
16 or has construction commenced?

17 A (Witness Newsome) I think they have -- I just
18 don't know.

19 A (Witness Hayet) It's my --

20 A (Witness Newsome) So I'll pass on that.

21 A (Witness Hayet) My understanding is planning,
22 but I don't have full, complete knowledge. But it's --
23 there are some delays because of the -- because of the
24 appeals that are going on at FERC.

25 Q Okay. Would an economic analysis look at

1 alternative generation resources?

2 A (Witness Newsome) Sure. I mean, with something
3 like this, this is smaller so you just say what's the --
4 what's the cost on the capacity, what's the cost on the
5 output. You compare it to the system and you could -- I
6 mean, that would be the shortcut way to do it, but you could
7 do that. Plus, you could do the full-blown analysis we do
8 on these PPAs.

9 Q Would the cost -- certainly.

10 A (Witness Newsome) Go ahead.

11 Q Would the cost benefit analysis also look at
12 ongoing maintenance over the life of a facility?

13 A (Witness Newsome) Of course.

14 Q And it would take into account the fact that
15 this is an upgrade to a facility, not a new facility?

16 A (Witness Newsome) Yes.

17 Q Okay. And the age of the facility?

18 A (Witness Newsome) Sure. But that's embedded in
19 the capital to upgrade it.

20 MR. S. JONES: No further questions. Thank
21 you, Madam Chair.

22 MADAM CHAIR PRIDEMORE: Sierra Club.

23 MR. FABISH: Thank you. I'm Zach Fabish for
24 the Sierra Club. I just have a couple of questions.

25 //

1 CROSS-EXAMINATION

2 BY MR. FABISH:

3 Q First, could you turn to page 94 and take a
4 look at Table 19. It's already come up once.

5 A (Witness Newsome) Okay.

6 Q So this table uses sort of a binary system of
7 assigning either a zero or a one based on whether or not
8 it's economic or uneconomic; is that correct?

9 A (Witness Newsome) Correct.

10 Q So that doesn't necessarily tell you how
11 economic or uneconomic a facility is in a given scenario;
12 is that right?

13 A (Witness Wellborn) That's correct.

14 Q Okay. So something could be extremely
15 uneconomic in many scenarios and in other scenarios it
16 would be marginally economic, and it would get the same
17 score as something that was more evenly above and below
18 the zero?

19 A (Witness Newsome) That's correct. It also
20 works the other way, too, though.

21 Q Yeah.

22 A (Witness Newsome) Okay.

23 Q Just clarifying. Thank you.

24 Can I ask you to take a look at Table 21 on
25 page -- I believe that's 102. And just as a quick

1 clarifying question, could you define NPV?

2 A (Witness Wellborn) Net present value.

3 Q Okay. Thank you.

4 Just to confirm, the Staff plan two in which
5 Bowen Units 1 and 2 are retired by 2027, that has the lowest
6 average NPV across all cases?

7 A (Witness Wellborn) That's correct.

8 A (Witness Newsome) Okay. But let's get a sense
9 of context here. It's pretty close to those other cases,
10 too. And we're taking a lot of data for a long period of
11 time and crunching it down.

12 So I understand on an absolute basis this is
13 what it shows. But another opinion could be: Well, they're
14 the same because they're so close. You're crunching down so
15 much data. So I want to make that point there.

16 Q Okay. Appreciate that.

17 It is true that for Bowen 1 and 2, in your
18 expansion analysis, they were uneconomic in every scenario
19 in which you included a carbon price; is that correct?

20 A (Witness Newsome) That's true.

21 Q Okay.

22 A (Witness Newsome) And they were economic in
23 every scenario that didn't include a carbon price.

24 Q Okay. Well, thank you. That was not going
25 to be my next question, but I appreciate it.

1 A (Witness Newsome) Yeah.

2 Q Okay. Now, in calculating potential future
3 costs as part of this analysis, did you look at any
4 environmental compliance costs, aside from those that
5 exist today and aside from the carbon price?

6 A (Witness Newsome) Yes. We included all the --
7 they got to do all the water treatment upgrades, the
8 sulphur, flue gas, wastewater. We've got all that put in
9 there. And then whatever other environmental upgrades they
10 found.

11 Q Uh-huh. Disposal -- sorry.

12 A (Witness Newsome) Go ahead.

13 Q Were you finished?

14 A (Witness Newsome) I'm finished.

15 Q Okay. Those are all for existing rules and
16 regulations?

17 A (Witness Newsome) Well, yeah. But that's what
18 we've got to deal with it.

19 Q So when projecting forward, the only
20 potential additional environmental compliance costs that
21 are represented in your analysis are in terms of carbon
22 pricing?

23 A (Witness Newsome) Repeat the question.

24 Q Yeah. You didn't add in any potential future
25 environment compliance costs, aside from carbon price

1 scenarios; is that right?

2 A (Witness Newsome) No. We did -- we -- we did
3 not. We accepted the company's assumptions. And part of
4 their assumptions is -- is that they are looking at all
5 the -- the longer term and seeing what environment regs
6 they've got to meet.

7 And then actually they have done that in
8 Scherer. They are going to put in a more advanced system to
9 treat the wastewater down there. They're going to put a
10 membrane system. So that's the example of them actually
11 anticipating more stringent -- potentially more stringent
12 environmental regulation. And they've accounted for it by
13 going through with a membrane system.

14 A (Witness Hayet) I would like to add to that.
15 We included 318B, CCR, and ELG costs for various -- the
16 various units that are candidate units for retirement.

17 Q But that's exactly the distinction I'm trying
18 to get to, which is that those are all -- and I don't know
19 which way to look because your monitor is up there and up
20 there. But they're -- those are all existing regulations?

21 A (Witness Hayet) Correct.

22 Q So you're affecting the future cost from
23 existing regulations?

24 A (Witness Newsome) Well, we don't have a crystal
25 ball.

1 Q Sure.

2 A (Witness Newsome) I don't think Southern does
3 either.

4 Q Yeah.

5 A (Witness Newsome) But they've tried to look
6 out -- like I'm saying on this wastewater treatment thing,
7 the ELG stuff, my conversations with them and inspection of
8 both Bowen and Scherer sites was that they were trying to
9 think ahead. Okay. This is what we've got to deal with
10 now. Is this systems that we're putting in here, are they
11 robust? So if EPA comes back and tweaks a little bit, do we
12 have some room? Either what we're putting in now takes care
13 of if they come back and tweak it, make the regulations more
14 restrictive; or, B, do we have enough room on the site to do
15 additional capital investment and modify the existing system
16 to account for more restrictions on the wastewater effluent?

17 Q Sure. And I certainly appreciate your point
18 about not having a crystal ball. And I think you would
19 probably agree, correct, that that is the point of this
20 exercise is to test different potential futures?

21 A (Witness Newsome) Well, That's exactly what we
22 did in our analysis.

23 Q And I'm trying to get some clarification.

24 The only nonexistent -- as of this day --
25 environmental compliance requirements that you factored in

1 was the carbon pricing; correct?

2 A (Witness Newsome) Right. And to the extent
3 Southern did it with the wastewater.

4 Q Yeah. Okay. Good.

5 So, I mean, is it fair to say that that carbon
6 pricing is a proxy for unknown future environmental
7 compliance costs?

8 A (Witness Newsome) Sure.

9 Q Okay. And so as a real -- just to close this
10 out a little bit. The scenarios without a carbon price
11 essentially -- well, let me back up.

12 So essentially the Bowen Units 1 and 2 are
13 economic in this analysis in future scenarios in which there
14 are no additional environmental compliance costs beyond what
15 are known today and factored into the company's planning
16 already?

17 A (Witness Newsome) That's correct. It's on
18 Scherer 3.

19 Q Okay. Is it the -- is it staff's position
20 that there are unlikely to be any significant future
21 environmental compliance costs --

22 A (Witness Newsome) Well --

23 Q -- over the planning horizon?

24 A (Witness Newsome) Well, what -- what particular
25 ones are you -- I mean, we picked up the CO2 price.

1 Q Sure. Yeah, yeah.

2 A (Witness Newsome) We vetted that.

3 Q Yeah.

4 A (Witness Newsome) And so Commissioners are

5 going to have to make a decision on what they really think,

6 whether there's going to be the CO2 tax or what have you.

7 Q Sure. But --

8 A (Witness Newsome) And we've done the same

9 thing. Southern did the same thing. Georgia Power --

10 Q Uh-huh.

11 A (Witness Newsome) -- did the same thing on the

12 water, on that flue gas ELG regulation. They've tried to

13 give themselves a little cushion on that. So I think

14 they've covered the -- covered the waterfront.

15 Q Okay.

16 A (Witness Newsome) I mean, we can't -- I mean, I

17 don't know what they are going to be doing in 2040, but

18 we're here in 2022. So --

19 Q Sure.

20 A (Witness Newsome) -- we have to deal with what

21 we know in 2022.

22 A (Witness Hayet) And let me -- let me add to

23 that. I'm sorry you have to turn your head.

24 Q It's okay. I'm all right.

25 A (Witness Hayet) The -- nobody knows what's

1 going to happen tomorrow. Everything could change between
2 today and tomorrow as we know it. But I think the notion is
3 that the costs that are being included in the analysis are
4 the most significant costs expected to -- environmental
5 costs expected.

6 CO2 is a significant cost that could occur and
7 so it's been accounted for. The ELG CCR and 316B costs that
8 are known are the most significant costs that are -- that
9 are known and expected. So if there are other costs -- and
10 certainly we're aware that there have been discussions -- we
11 don't know how far along that is. But we don't think that
12 those costs are as significant as the ones that have been
13 accounted for in the analysis.

14 A (Witness Newsome) There is another -- let me
15 add on what he said.

16 Q Absolutely.

17 A (Witness Newsome) If you're just going to throw
18 in hypothetical costs that may occur and then we retire
19 these units prematurely, you open the door for Southern --
20 excuse me -- for Georgia Power to come in and do a new
21 build. That's a lot more money than these PPAs or
22 continuing to run Scherer 3 or Bowen 1 and 2.

23 So we need to be careful about the
24 hypotheticals where they take you. Because they can take
25 you to a place where it actually gets much more expensive.

1 So I wanted to make that point there.

2 That's one reason we need to deal with the
3 world we're living in, make reasonable projections. We know
4 the carbon dioxide emission pricing on the table. And the
5 ELG stuff is on the table.

6 But, again, if you're just going to start
7 adding everything in, we're going to retire plants, you open
8 the door for them to put in something much more expensive.

9 Q Well, to be clear, I'm not asking you to add
10 in everything or anything. I'm just trying to get some
11 clarity as to whether or not the scenarios in which Bowen
12 Units 1 and 2 are economic, or scenarios in which the
13 assumption is there are no future environmental compliance
14 costs, aside from those that already exist from
15 regulations today.

16 A (Witness Newsome) That's -- that's correct,
17 but -- plus what margin they have built on the effluent
18 guidelines.

19 Q Sure, sure. And the planning horizon for
20 that Aurora analysis is 17 years; is that right?

21 A (Witness Wellborn) 2022 to 2039.

22 Q Okay. Yeah. So roughly 17 years?

23 A (Witness Wellborn) Uh-huh.

24 Q Appreciate you confirming my arithmetic
25 there.

1 Okay. I have a question about Plant Scherer.

2 A (Witness Newsome) Page number?

3 Q Yeah. It's on page 106, lines 13 through 14,
4 if you want to get precise.

5 A (Witness Newsome) Okay. We're there.

6 Q Yeah. So the testimony states that the
7 majority co-owners will decide whether to install ELG
8 controls at Scherer 1 and 2; is that right?

9 A (Witness Newsome) Correct.

10 Q Can I ask a clarifying question as to what
11 the role is of the Commission in approving or disapproving
12 that decision?

13 A (Witness Newsome) Ask them. Or ask Dan.

14 MR. WALSH: Yeah. That may be calling for a
15 legal conclusion.

16 MR. FABISH: Okay.

17 COMMISSIONER PRIDEMORE: Sustained.

18 BY MR. FABISH:

19 Q Is it staff's position that whatever decision
20 is made by those other owners, that's automatically a
21 decision that gets made here?

22 A (Witness Newsome) They own the majority of the
23 plant. So they're going to -- my understanding, talking
24 with Georgia Power, is that they -- the majority owners --
25 the way the agreement is set up, if they decide to put in

1 the controls, Georgia Power gets to play -- you know, has to
2 throw in their money with it.

3 Q Okay. So --

4 A (Witness Newsome) So -- and the same thing
5 happened on Wansley. They are a majority owner. If they
6 want to retire early, I -- that's my understanding of how
7 that works.

8 Q Okay.

9 A (Witness Newsome) And the money they're putting
10 down on these ELG controls, it's not relative to the size of
11 those plants. Because, I mean, what's Scherer, like 3,200.
12 It's like 860 times four, or three, whatever it is. It is
13 almost like 2,700 megawatts. The capital expenditure on
14 these for these ELG controls is -- is small.

15 MADAM CHAIR PRIDEMORE: Mr. Newsome.

16 WITNESS NEWSOME: Yes, ma'am.

17 MADAM CHAIR PRIDEMORE: Is it Georgia Power's
18 decision to put the ELG controls in it or is it --
19 are the ELG controls coming down from Washington?

20 WITNESS NEWSOME: Oh, the regulation is coming
21 down from Washington.

22 COMMISSIONER PRIDEMORE: Thank you.

23 BY MR. FABISH:

24 Q To clarify, the decision is to retire by 2028
25 or install controls; is that right?

1 A (Witness Newsome) That's -- that's the way the
2 regulation works.

3 Q Okay. And that is the decision of the owners
4 of the facility?

5 A (Witness Newsome) On 1 and 2.

6 Q Got it. If I may ask just one follow-up
7 question on -- I believe you said the capital cost for ELG
8 controls.

9 Is it staff's position that the control costs
10 for ELGs at Plant Bowen are the same, regardless of whether
11 or not some units retire without having to install those
12 controls?

13 A (Witness Newsome) That's correct.

14 Q Okay.

15 A (Witness Newsome) That's based on how the
16 plant's set up. Because all their scrubber effluent goes to
17 a common -- common basin. It is not piped separately.

18 Q Yeah.

19 A (Witness Newsome) So it's they do it for one,
20 they do it for all.

21 Q So are ELG controls the same cost, regardless
22 of the size of the plant?

23 A (Witness Newsome) Of course not. But they
24 can't repipe the plant. There's also a permitting issue.
25 It's all -- my understanding, and Georgia Power's attorneys

1 will correct me if I'm wrong, is that it's basically a
2 common basin up there for all four units.

3 And so they're not -- they're separate to start
4 with, but all that effluent, it's run to a common basin. So
5 you're fixing one, you're fixing it all.

6 Q So there is no savings associated with
7 retiring the two units earlier that go into the unit --
8 your analysis?

9 A (Witness Newsome) No. Because -- repeat the
10 question.

11 Q Yeah. Let me clarify -- rephrase that.

12 So in your -- your retirement analysis, there
13 are no savings -- ELG savings associated with retiring Units
14 1 and 2?

15 A (Witness Newsome) No.

16 Q Okay.

17 MR. FABISH: I think that's all of my
18 questions. So thank you very much.

19 COMMISSIONER PRIDEMORE: Southern Alliance for
20 Clean Energy and Southface Energy Institute.

21 CROSS-EXAMINATION

22 BY MR. BAKER:

23 Q Good morning, panel.

24 A (Witness Newsome) Good morning.

25 Q My name is Robert Baker. I represent the

1 Southern Alliance for Clean Energy and the Southface
2 Energy Institute. I have some questions for you here.

3 Referring to page 6 of your prefiled testimony,
4 the staff agrees with the company's proposal to acquire the
5 six PPAs, but you also conclude that it might be reasonable
6 to require Bowen Units 1 and 2 to continue operating beyond
7 2028 at the discretion of the Commission.

8 Isn't that a little inconsistent?

9 A (Witness Newsome) If the Commission said Bowen
10 1 and 2 keeps rolling, then you would probably need to
11 re-evaluate whether you need all those PPAs. I'm not
12 necessarily going to do that from the stand up here, but if
13 they -- if the Commission said Bowen 1 and 2 stays open,
14 then you would need to re-evaluate whether you need all
15 those PPAs.

16 VICE-CHAIRMAN ECHOLS: Hold on, Mr. Baker.
17 Just a second.

18 The gas PPAs?

19 WITNESS NEWSOME: Yeah. The six -- the six
20 they're requesting approval of.

21 VICE-CHAIRMAN ECHOLS: Yes.

22 WITNESS NEWSOME: So if you keep Bowen 1 and 2,
23 we're going to keep that up, we need to come back
24 because that means you're going to have a massive
25 amount of overcapacity.

1 VICE-CHAIRMAN ECHOLS: Yeah. And we've been
2 down this road before. Early, I guess, 2012 we were
3 looking at four PPAs for gas and we only did three, I
4 think, so --

5 WITNESS NEWSOME: Right.

6 VICE-CHAIRMAN ECHOLS: -- this is not unusual?

7 BY MR. BAKER:

8 Q Okay. Thank you, Mr. Newsome.

9 If the Commission adopts the recommendation by
10 the Georgia Association of Manufacturers and others in this
11 docket to set the company's winter target reserve margin at
12 20 percent, would staff continue to recommend that the
13 Commission approve the six gas PPAs?

14 A (Witness Newsome) I think you need to look at
15 it. I'm not sure. We have to run the math.

16 You might drop one or two, but we would need to
17 look at -- we need to redo the analysis at the lower reserve
18 margin capacity to see how much excess you've got.

19 A (Witness Wellborn) Yeah. There's a number of
20 moving parts. If certain recommendations are, you know,
21 accepted, there's a capacity RFP. We have a number of --
22 you know, we recommend the solar gets some capacity value.
23 There's a number of values that move around that would
24 change what that buildup looks like.

25 Q Correct. But if you -- Mr. Hayet, you had

1 something?

2 A (Witness Hayet) Yeah. If I -- if I can add. I
3 think the bottom line of what we're trying to say is that a
4 decision had to be made. We made the decision that six PPAs
5 made sense to accept. It was economic. We found accepting
6 it as economic.

7 We recognize that there could be excess
8 capacity. But given that there is a time period where in
9 the '29 to 2031 period there's going to be a big need for
10 capacity, we felt as if -- and at that time in 2028, the ELG
11 rule kicks in. There's going to be retirements. We felt it
12 reasonable to accept all six.

13 However, I think that, as Mr. Newsome has said,
14 we are open to the idea that one PPA could be considered
15 being removed. We looked at Wansley 7. I think it was
16 suggested Wansley 7 earlier in questioning to us.

17 So we're not entirely opposed to the notion of
18 not accepting one of the PPAs. But that was the basis --
19 the basis was -- for our testimony was that we believed it
20 was not unreasonable to take all six PPAs.

21 Q I understand what you're saying, and you have
22 to make assumptions in your review, but what I'm also
23 suggesting is that the Commission has some options that
24 they could consider that might have an impact on that
25 final decision to approve the six PPAs. And one of them

1 is if the target reserve margin is reduced down to
2 20 percent, wouldn't that have a direct impact on the need
3 for all six PPAs?

4 A (Witness Hayet) It would. Just like
5 Mr. Newsome said, we'd have to run the numbers. We think it
6 most likely would have a need to increase excess capacity,
7 reducing the need to have all six of the PPAs. So I think
8 I'm agreeing with what you're saying.

9 Q Thank you.

10 At page 8, you recommend the company should
11 initiate an all-source RFP now for the company's need for
12 the 2029-2031 time frame.

13 Would this all-source RFP include solar with
14 storage and DSM options?

15 A (Witness Newsome) Yes.

16 Q Does staff have any guidance to offer the
17 Commission for what would constitute a true all-source
18 procurement process?

19 A (Witness Newsome) I mean, we -- I mean, we
20 established that it needs to include everything, the fossil,
21 solar, battery, standalone battery, solar plus battery, DSM.
22 So you consider everything. That's as far as we got on this
23 panel.

24 Q Okay.

25 A (Witness Newsome) The actual mechanics of how

1 you qualify all that stuff would be a separate panel, I
2 believe.

3 Q Okay. Consider everything and let the
4 economics decide what is the best outcome; right?

5 A (Witness Newsome) Correct. Let them go
6 head-to-head.

7 Q Okay. Pages 58 through 62 of your prefiled
8 testimony includes comparison of the company's gas price
9 forecast with other publicly available forecasts. I mean,
10 what is your reaction?

11 Do you have a reaction to Witness Ron Binz's
12 assertion that it's better to be wrong high than wrong low?

13 I think you may have actually referenced this
14 thought in a few questions previously --

15 A (Witness Newsome) I need some clarification on
16 what he said. I scanned the testimony, but I'm not familiar
17 with that point.

18 Q I think if -- are you familiar with Mr.
19 Binz's testimony by any chance? Prefiled testimony.

20 A (Witness Newsome) I mean, I scanned it. I'm
21 not really -- I mean, if you want to describe his point more
22 fully, maybe we can debate it, but --

23 Q I -- his point is that he is arguing that
24 it's a lower risk for consumers if the Commission errs on
25 the side of looking at a higher gas price, rather than

1 taking a lower gas price.

2 A (Witness Newsome) I think you need to consider
3 all -- all -- I mean, he's entitled to his opinion. I just
4 think -- I think we've done it correctly in that we're
5 looking at all -- all -- the three different scenarios of
6 gas. So I don't necessarily agree with what he's saying
7 there. I think we've done a fair job and we need to look at
8 all scenarios. I mean --

9 Q In a -- excuse me. In response to your -- a
10 question you got on ELG for the company from -- Mr. Fabish
11 gave you regarding preparing for ELG upgrades, I think --

12 A (Witness Newsome) Correct.

13 Q You indicated that the company was erring on
14 the high side of -- of preparing -- expending the extra to
15 make sure that they have the capacity to -- ability to
16 facilitate all ELG improvements?

17 A (Witness Newsome) I mean, that's what's
18 happening in Scherer. They're going to run a membrane
19 system. And I think it was a little bit more money, but I
20 won't call it -- I mean, it's a small amount of money for
21 some -- for the ability to meet tighter regulations. So
22 they went that way. And, I mean, staff is fine with it.

23 A (Witness Hayet) Plus, it gives the flexibility
24 of making a decision later. Rather than having to have the
25 upgrades done by 2025, they can make a decision to have

1 upgrades done by 2028 under -- under that situation.

2 Q Thank you.

3 Your prefiled testimony starting at page 79
4 describes the unit retirement study performed by the -- by
5 the PIA staff, which differs from the company's unit
6 retirement study. What alternate resources were considered
7 in the unit retirement study performed by the advocacy
8 staff?

9 A (Witness Wellborn) Staff's modeling in Aurora
10 was fundamentally the PPAs as alternatives and the company's
11 generic resource option. So solar, CT, CCs. I think we
12 have a table that describes the generic resources that were
13 included.

14 A (Witness Newsome) I mean, I think a critical
15 point is staff's analysis stuff was selectable; whereas, in
16 the company's analysis a lot of stuff just got forced in.
17 So our analysis was more comprehensive and everything was --
18 we're trying to let the economics make the right selection
19 of resources.

20 Q Okay. Thank you.

21 Was an aggregated demand response considered?

22 A (Witness Wellborn) No. The company does not
23 have that model. That's a generic resource in there, a
24 mixed study, which was our starting point.

25 Q Was solar paired with storage one of the

1 alternative resources considered?

2 A (Witness Wellborn) Solar and batteries were
3 considered independently. There was no paired battery and
4 solar.

5 A (Witness Hayet) And -- and to add to that, we
6 pointed that out and -- and that's a recommendation for
7 improvement that we have for our -- in our testimony.

8 Q So, Mr. Hayet, staff's recommending that the
9 pairing of storage and solar next time in the next RFP?

10 A (Witness Hayet) Yeah. Yes.

11 Q Okay. And why is that?

12 A (Witness Hayet) Because we -- because if the
13 ITC is extended, which is -- has been considered, then there
14 could be benefits to having solar and storage that lowers
15 the cost.

16 Q Okay. At the bottom of page 86 and the top
17 of page 87 you say that staff believes the unit retirement
18 study would be best conducted consistent with the way the
19 company's resource mix study was performed and not as a
20 separate study in which dispatch and optimization dynamics
21 are ignored.

22 Did the company's resource mix study consider
23 solar paired with storage? And your answer was --

24 A (Witness Wellborn) No.

25 Q No. And it was considered separately?

1 The storage was considered separate -- a
2 separate item and solar was considered a separate item?

3 A (Witness Wellborn) That's correct.

4 Q Okay. Since you recommended the unit
5 retirement study be conducted like the resource mix study,
6 does staff think the company was correct to model solar
7 and storage resources separately?

8 A (Witness Wellborn) We think the resource mix
9 study was an improvement over their hand-selected portfolio
10 optimization methodology. That line you just pointed to,
11 the dispatch dynamics in the resource mix Aurora modeling is
12 very appealing for a unit retirement study.

13 Q Okay. And why did staff apply a \$2.50
14 megawatt-hour solar integration cost in its unit
15 retirement study when the company applied a different
16 figure? This is page 92, Table 18.

17 A (Witness Newsome) We just -- we knew there
18 was -- there is some cost there and we went back and forth
19 with internal analysis and came up with a different figure.
20 I think Phil may have a better answer on that.

21 A (Witness Hayet) Yeah. In fact, we -- we --
22 this is something that we developed in conjunction with
23 discussions with the renewable team -- staff's renewable
24 team. That's an issue that Jamie Barber and Jeff Bower
25 addressed in their testimony. In fact, I think they looked

1 at it and they have a recommendation that does differ from
2 what we used.

3 We used a value at a certain point in our
4 considerations and discussions with that team that 2.50
5 would be a value -- in other words, we don't agree with the
6 company. We all agree that the integration costs should be
7 lower than what the company set it to. We disagree with the
8 company on that point.

9 In our discussions with the renewable team, we
10 concluded that 2.50 for our modeling purposes would be
11 reasonable. And we understand -- and the final point is we
12 understand, in fact, that the renewable team has used a
13 value that they believe should be even lower than 2.50,
14 1.93.

15 We don't think that would necessarily change
16 the results that much because our results still show
17 significant acquisition of solar resources, but we do -- we
18 do -- staff does believe that integration costs are
19 important. However, we disagree with the company on the
20 level of what that integration cost should be. We think it
21 should be lower than what the company has set it to.

22 Q And does your -- the staff's integration cost
23 make a difference in the evaluation?

24 A (Witness Hayet) Would you repeat that? I
25 didn't hear the entirety.

1 Q Does the staff's \$2.50 integration cost make
2 a difference in the evaluation?

3 A (Witness Hayet) Yeah. It -- it reduces a
4 little bit by the amount of solar that would be acquired,
5 but not a lot.

6 Q Okay. You indicated staff's renewable team
7 used a figure of -- an amount of \$1.93. And I believe
8 Sierra Club used a \$2 figure. It -- would the -- sorry.
9 Between the 2.50 and 1.93, is there a level
10 that was preferred or better?

11 A (Witness Hayet) I think -- I think I still
12 believe the lower the value, the better, meaning that --
13 that 2.50 could even be too high. I think the 1.93 value
14 and -- and the basis I have for that is looking around the
15 country.

16 These integration studies have been done for 20
17 years and they keep dropping. I'm very familiar with the
18 integration studies done out in Pacific Corp. and the
19 numbers that are used here are way higher than those.
20 They -- it varies by the characteristics of the utility.

21 But to answer your question, I don't think
22 there is a significant difference between 1.93 and 2.50.
23 But I'd prefer in the future to -- to -- we'd probably use
24 the 1.93 estimate that the renewable team came up with.
25 There was just a timing difference, I'd say, in our having

1 to develop an input that we used for modeling and their
2 final decision as to what value they believed is reasonable.

3 Q Thank you.

4 You stated at pages 102 through 103 that in
5 cases in which CO2 emission cost is considered, retiring
6 Bowen Units 1 and 2 is the economic choice.

7 Does staff consider it more likely that a CO2
8 emission cost will or won't apply within the next 20 years?

9 A (Witness Newsome) I think that's why we -- I
10 mean, we really don't know. That's why we showed it both
11 ways.

12 Q Okay.

13 A (Witness Hayet) And also I think it is
14 important to get -- you know, as Mr. Newsome said in his
15 summary, that, you know, a lot of what this is going to have
16 to come down to, you know, the Commission's aware that no
17 federal carbon legislation has been passed. The Commission
18 is going to have to consider whether it should wait for
19 action from Congress prior to quantifying the environmental
20 analysis. That we believe that's for the Commission to
21 decide as a policy matter.

22 Q I hear you. But isn't it true that the EPA
23 has authority to regulate carbon under the Clean Air Act
24 and has had it since 1970?

25 A (Witness Newsome) That's -- that may be true,

1 but there's also -- EPA has also enacted other -- other
2 regulation and it gets tied up in litigation. I think it's
3 going to -- you know, if Congress passes a bill and the
4 President signs it, then it's clear-cut.

5 Q Right.

6 A (Witness Newsome) You know -- you know what you
7 got.

8 Q Right.

9 A (Witness Newsome) But EPA, I mean, they're
10 being challenged on -- I looked at that Waters of America
11 thing that was passed in the Obama administration and they
12 can declare what's a stream or not. So I think EPA can
13 issue all the regulations they want, but whether it's going
14 to pass muster with the courts I think is a separate
15 question. So I think that's more of a questionable thing
16 there relying on the EPA.

17 Q I hear you that it's not a sure thing, but it
18 is -- it is a -- a potential occurrence and the EPA has
19 taken action under the Clean Air Act to regulate carbon,
20 you know, for automobiles, vehicles; correct?

21 A (Witness Newsome) Subject to check.

22 Q Right. And you mentioned that there is
23 litigation -- federal litigation going on that includes
24 carbon rules under the Clean Air Act.

25 Are you also aware of the fact that -- that the

1 federal regulatory agencies have to make annual -- regular
2 reports of proposed regulations they are considering so that
3 parties have some -- can prepare and have advanced notice of
4 what potential regulations may be coming from the federal
5 government?

6 A (Witness Newsome) I will accept that, subject
7 to check.

8 Q Okay. And do you know -- subject to check,
9 do you know that for the next four to five years that EPA
10 plans to do on the regulatory side -- I mean, do you know
11 or not know what they're --

12 A (Witness Newsome) I'm not sure.

13 MR. WALSH: Madam Chair, I'm going to object on
14 the subject to check. That's a little bit subjective
15 about EPA plans. Usually subject to check is, you
16 know, a specific number.

17 He -- counsel can ask whether the panel knows.
18 I just don't want to accept a kind of vague subject
19 to check, so...

20 COMMISSIONER PRIDEMORE: Sustained.

21 WITNESS NEWSOME: I think the EPA has got all
22 kind of plans and we'll see what they -- they come up
23 with. But, I mean, ultimately, can they enforce a
24 rule? Again, a lot of it is subject to litigation.

25 BY MR. BAKER:

1 Q Right. So --

2 A (Witness Newsome) That's why we're saying you
3 may not have it. You may not have a carbon tax for a while.

4 A (Witness Hayet) Excuse me. And -- and I agree
5 with what he just said. As we know, there has been two
6 renditions of EPA environmental rules that have come into
7 existence and have gone out -- out of existence. And so
8 right now there is no carbon rule from the EPA at this
9 moment. And a lot -- whatever happens, it could be subject
10 to litigation.

11 So it's really -- you know, it's somewhat --
12 well, I will just leave it at what I said.

13 Q Okay. Let me move on. At page 114, staff
14 expressed a concern that exclusion of the additional sum
15 from the PPAs creates a potential bias in the analysis
16 because evaluations of other capital investment projects,
17 like new build resources and coal unit environmental
18 upgrades include return on equity cost components. And
19 you indicate you remedied that by including a \$2.30 per
20 kilowatt a year additional sum in your modeling.

21 Why didn't you include the \$7.50
22 kilowatt-hour-per-year figure -- amount that is proposed by
23 the company?

24 A (Witness Newsome) Well, we're choosing the
25 modeling assumptions and we didn't -- we didn't agree with

1 the 7.50 so we weren't going to -- we thought the 2.30 needs
2 to stay at 2.30. I think Trokey panel gets into why on that
3 a little bit more, but -- so we used what we thought was
4 appropriate.

5 Q If -- do you know if any of the PPAs would be
6 uneconomic if the Commission approves the requested
7 \$7.50-per-kilowatt-year additional sum requested by the
8 company?

9 A (Witness Newsome) Ask the question again,
10 please.

11 Q Okay. Would any of the six gas PPAs be
12 uneconomic if the Commission approves the requested
13 \$7.50-per-kilowatt-year additional sum requested by the
14 company?

15 A (Witness Newsome) I don't think it's that
16 material, but I will defer to Phil and Leah on that one.

17 A (Witness Wellborn) Yeah. We didn't run that
18 analysis so we don't know. But the company's development of
19 the 7.50 was -- was not considered either in their analysis
20 of the PPAs against the coal retirements.

21 Q And so did you -- so the -- excuse me.
22 Mr. Hayet.

23 A (Witness Hayet) But like Mr. Newsome said, we
24 don't think it's material.

25 A (Witness Newsome) Yeah. I mean, to not --

1 you're saying you change it from 2.30 to 7.50 and it makes
2 the -- the PPA clearly uneconomic. I don't think that's the
3 case.

4 There's -- I mean, there's money there. I'm
5 not going to say it doesn't matter or what have you. But in
6 terms of the capacity payments with -- of the PPA, it's
7 pretty small. The additional sum relative capacity payment
8 to the PPA is pretty small.

9 Q Okay. While it wouldn't make it uneconomic,
10 it would have a cost impact?

11 A (Witness Newsome) Oh, yeah.

12 Q It wouldn't make it less cost-effective?

13 A (Witness Newsome) Correct. Yes.

14 A (Witness Hayet) And it has an impact on the
15 ratepayer.

16 Q And then that ratepayer has to pay the higher
17 amount, or whatever the amount that's approved?

18 A (Witness Hayet) That's correct. And that's why
19 we recommended it should be the 2.30 a KW a year value.

20 MR. BAKER: Thank you, panel. Thank you,
21 Commission.

22 MADAM CHAIR PRIDEMORE: Southern Renewable
23 Energy Association.

24 MR. MAHAN: Good morning, Commission.

25 //

CROSS-EXAMINATION

BY MR. MAHAN:

Q Good morning, panel.

A (Witness Newsome) Good morning.

Q On page 95, lines 7 and 8, you said the 1,000 megawatts of batteries evaluated by the staff and the company are uneconomic based on your analysis. But with the questions you just had with Mr. Baker, you suggested that the 1 gigawatt of batteries might be economic if paired with renewables; is that correct?

A (Witness Newsome) I don't think -- I don't think we said that.

Q Okay. But you would agree that you said it would be cheaper if paired with renewables?

A (Witness Newsome) I think the whole discussion on that was us not including battery plus solar in the analysis. So I'm not quite sure where you're going with all this, but I think that whole conversation was saying we had solar analysis, we had battery, standalone battery analysis, but we didn't have it combined.

Q Right. And, Mr. Hayet, you explained that the investment tax credit could be applied to batteries if they're conjoined with renewable resources; is that correct?

A (Witness Hayet) Yes. I think we said that it

1 could be cheaper and it wasn't exactly modeled, but we're
2 recommending that an RFP be conducted. And through the --
3 so what we're saying is that a thousand megawatts of battery
4 storage shouldn't be approved necessarily, but it should be
5 based on economics and knowing exactly what the costs are
6 going to be and seeing if the IATC is going to be extended.
7 And, therefore, doing it through the RFP is the best
8 approach, rather than arbitrarily saying: Hey, a thousand
9 megawatts, we think you should accept it based on no
10 economic analysis.

11 Q Okay. But your testimony does say that you
12 believe that the 1,000 megawatts is currently uneconomic;
13 right?

14 A (Witness Newsome) Correct.

15 Q And that's based off of the Aurora capacity
16 expansion modeling work that you did?

17 A (Witness Newsome) Correct. But there's also
18 other market indications. In this capacity RFP the company
19 just conducted where they selected the six PPAs, you know,
20 battery plus solar was allowed to bid in. It just wasn't
21 selected. So when you also --

22 Q We'll get to that in a second.

23 Aurora is a capacity expansion model, though;
24 right? It's not an energy expansion model?

25 A (Witness Newsome) Well, it measures the energy,

1 too.

2 Q But which one does it prioritize?

3 A (Witness Newsome) It does both. That's the
4 reason it's so --

5 Q At the exact same time?

6 A (Witness Newsome) Yes.

7 A (Witness Hayet) Yes.

8 Q Okay. If you give Aurora a low-cost energy
9 resource, it will select that resource, regardless of
10 whether or not it provides capacity?

11 A (Witness Newsome) Repeat the question.

12 Q So if you provide Aurora with a low-cost
13 energy resource --

14 A (Witness Newsome) Define low-cost.

15 Q \$25 per megawatt-hour.

16 A (Witness Newsome) So it's just the energy
17 product?

18 Q Sure.

19 A (Witness Newsome) Not capacity?

20 Q Yep.

21 A (Witness Newsome) Okay.

22 Q You provide that to the -- into the model,
23 will the model select that if there's no capacity need?

24 A (Witness Hayet) Yes.

25 A (Witness Wellborn) Yes. You can set the model

1 to make those selections. The company's resource mix study
2 included solar with no capacity value as selectable. And it
3 was selected.

4 Q Was that generally earlier or later in the
5 model runs, in the model years?

6 A (Witness Wellborn) It was consistent with the
7 economics of the inputs. The prices change over time. And
8 so how the system is being dispatched influences what's
9 getting selected when. I would say generally later than
10 earlier.

11 A (Witness Newsome) When you say later, what --
12 what in your mind --

13 Q Post 2030.

14 A (Witness Hayet) It selected it prior to 2030.

15 Q Was that often?

16 A (Witness Wellborn) I might point us back to
17 Table 19, which includes staff's Stage 1 results from
18 Aurora. And you can see the solar selected in those model
19 runs.

20 Q Okay. Can batteries act as a transmission
21 alternative?

22 A (Witness Newsome) They could, yeah.

23 Q Does Aurora model that option?

24 A (Witness Wellborn) There is no transmission
25 modeling in Aurora.

1 Q Can batteries provide frequency and voltage
2 support?

3 A (Witness Hayet) Yes.

4 Q And does Aurora model that?

5 A (Witness Hayet) It doesn't model frequency and
6 voltage support, no.

7 Q And did you run Aurora on an hourly basis or
8 a sub-hourly basis?

9 A (Witness Hayet) We didn't run it on a
10 sub-hourly basis.

11 Q Okay. So it was an hourly basis then?

12 A (Witness Hayet) Depending on the study
13 actually, but -- but --

14 Q Okay. And can batteries provide services on
15 a sub-hourly basis?

16 A (Witness Hayet) They can provide -- so can
17 other resources. But, yes, batteries can provide benefits
18 on a sub-hourly basis.

19 Q So is it possible, then, the Aurora runs that
20 both the company and the staff performed doesn't consider
21 the full value stack of battery resources?

22 A (Witness Hayet) Yes, I'd say that's true. But
23 I think that you've got to consider the full value stack
24 with batteries, as well as other resources. But I
25 definitely agree that it doesn't account for the full value

1 stack.

2 MR. MAHAN: All right. That's it. Thank you.

3 COMMISSIONER PRIDEMORE: Georgia Watch.

4 Georgia Watch was missing before. Is she still
5 missing?

6 There she is.

7 MS. COYLE: No questions. Thank you.

8 COMMISSIONER PRIDEMORE: No questions, okay.

9 All right. I believe I got everybody for this
10 panel, except Georgia Power.

11 MR. MARZO: Thank you, Madam Chair. I promise
12 this is not all for them.

13 COMMISSIONER PRIDEMORE: He brought a box,
14 folks.

15 MR. MARZO: It's not all for you, gentlemen,
16 and ladies.

17 CROSS-EXAMINATION

18 BY MR. MARZO:

19 Q First of all, Brandon Marzo on behalf of
20 Georgia Power Company. I echo the sentiments earlier,
21 Mr. Hayet. I hope you get better soon.

22 A (Witness Hayet) Thank you.

23 Q I appreciate the panel's patience. I do have
24 some questions for you, though. The good part of going
25 last is I think a number of them have already been asked.

1 So I can try to summarize some of my questions about some
2 of the topics that have been covered earlier.

3 I want to ask you first about your unit
4 retirement analysis. And as we talked about in prior cases,
5 in this case the company recommended a number of
6 retirement -- or the company recommended a number of
7 retirements based upon our analysis.

8 And it's my understanding that staff did an
9 independent analysis and reached very similar conclusions;
10 is that correct?

11 A (Witness Newsome) In some cases, yes.

12 Q Okay. And I think it is fair to say that you
13 came up with your own, as has been discussed significantly
14 today. So I won't go into a lot of detail, but you came
15 up with your own fuel forecast, you had your own carbon
16 forecast.

17 You did analysis separate and different than
18 what the company provided in its analysis; correct?

19 A (Witness Newsome) Correct.

20 Q Okay. And at the end of the day, you
21 concluded, at least as pertains to these particular
22 recommendations, at Scherer Unit 3, Wansley Unit 1 and 2,
23 Gaston Units 1 through 4 and Unit A, and Wansley Unit 5
24 and Boulevard Unit 1 CT should be retired; is that --

25 A (Witness Newsome) That's correct.

1 Q Okay. And the one difference, as it pertains
2 at least to the retirements, pertains to Bowen 1 and 2.
3 And it's my understanding the recommendation that's been
4 discussed today that your proposal is really two
5 alternatives: One, to either retire the unit by 2028 as
6 proposed by the company, or to allow the unit to operate
7 until 2035; is that correct?

8 A (Witness Newsome) Well, actually, our
9 recommendation is to punt it to the Commissioners.

10 Q That's right.

11 A (Witness Newsome) But that's -- so they need to
12 decide whether to retire it or not.

13 Q And you answered my very next question. Is
14 that your two alternatives really provide a policy
15 decision for the Commission to ultimately be made; is that
16 fair?

17 A (Witness Newsome) Correct.

18 Q Okay. And it's also true that as it pertains
19 to the gas PPAs that have been talked about quite a bit in
20 the last few lines of cross, currently your recommendation
21 is to acquire all six purchase power purchase agreements;
22 is that correct?

23 A (Witness Newsome) That's -- yes. Contingent
24 with the retirements and --

25 Q Okay.

1 A (Witness Newsome) -- the other stuff y'all
2 proposed. The company -- I'm sorry. The company proposed.

3 Q Yeah. And I understand some parties are
4 suggesting that there should be maybe less procurement
5 depending on the retirements, but there are a couple of
6 points I do want to get your views on.

7 Would you agree with me that one of the
8 benefits of the PPAs in this particular solicitation is that
9 it was done early on enough that we've seen very favorable
10 pricing as compared to historical pricing?

11 A (Witness Newsome) I mean, that's y'all's
12 characterization. I don't know. Maybe Hayet's got a better
13 handle on the historical pricing we got on this.

14 I admit the -- the PPAs, the price and the
15 capacity payments are roughly equivalent to keeping, you
16 know, the Bowen 1 and 2 and Scherer 3. Those are existing
17 plants that you just keep running. So, I mean, all of those
18 are a lot cheaper than a new build. So that's relative to a
19 new build for sure.

20 A (Witness Hayet) I -- and I think that was the
21 point. When you compare it to new build, I think it's
22 attractive pricing.

23 Q Yeah. And it's one of the concerns that if
24 we don't procure, for example, all the PPAs that we have
25 the opportunity to procure at this point in time, if we're

1 out into the future and we need to get new capacity, what
2 we may be looking at is a new build, which I think you're
3 both saying would be more expensive?

4 A (Witness Newsome) That's a possibility.

5 Q Okay.

6 A (Witness Newsome) But, I mean, there's also --
7 there may be capacity available, too.

8 Q Okay. And that's one of the risks that I
9 think both -- at least the company has identified is it's
10 a risk that it won't be available. And I think you and
11 Mr. Hayet are saying that is also a risk; right?

12 A (Witness Newsome) No. It is. But it could go
13 the other way. I mean, there may be capacity available. I
14 mean, that's y'all's position. But --

15 Q Yeah.

16 A (Witness Newsome) -- that's not necessarily the
17 way it's going to turn out.

18 Q And what we do know is as more utilities are
19 looking towards making retirement decisions, there's a
20 good chance that the capacity could get snatched up across
21 the various system in order to meet other utilities needs,
22 right, other than Georgia Power's?

23 A (Witness Newsome) Depends what they replace it.
24 Maybe they're replacing it with solar. I don't know.

25 Q Yeah.

1 A (Witness Newsome) I agree with your basic
2 point, but they could be replacing it with something besides
3 fossil.

4 Q And that's -- that's fair enough.
5 I'm sorry, Mr. Hayet. Were you --

6 A (Witness Hayet) Yes, Mr. Marzo. What I was
7 going to add is that we're also recommending that there be a
8 movement -- or an action taken to have an RFP conducted.
9 And through an early action of conducting an RFP, I think it
10 would be known what capacity is going to be available in the
11 market. And I think also that it would allow time for new
12 capacity to be built if that's more economic. So I think
13 that's one of the considerations that we're having and why
14 we're, you know, open to the notion that one of the PPAs
15 could perhaps be, you know, possibly eliminated.

16 Q And maybe one final question at this point,
17 Mr. Hayet. Would you agree with me, though, that if we do
18 another RFP, we're likely to see or could see pricing
19 that's higher than what you've seen previously; correct?

20 A (Witness Hayet) You could.

21 Q Okay.

22 A (Witness Newsome) But that's the whole point,
23 doing the PPA to find out what the pricing is. I mean,
24 that's the whole point to do it. You may get favorable
25 pricing again, which is why we want to do it.

1 Q And it's just -- I think we're agreeing on
2 the uncertainty of it, though; right, Mr. Newsome?

3 A (Witness Newsome) Well, of course.

4 Q Yeah. Okay.

5 A (Witness Newsome) But, I mean, you're saying
6 the certainty as it goes all back. It may go the other way
7 and be beneficial to the ratepayer.

8 Q Fair enough.

9 A (Witness Hayet) And the earlier you conduct
10 that RFP, the better -- you know, the more flexibility
11 you're going to have, depending on what the price is coming
12 out.

13 Q Well, let me ask this question: You were
14 asked a number of questions in the context of the natural
15 gas forecasts that you provided in your testimony. I
16 think the cross-examiners asked you about that.

17 Isn't it also true, though, that currently
18 there is volatility in coal prices?

19 A (Witness Newsome) That's true. But they
20 haven't spiked as much as the -- I looked at the fuel prices
21 last night. And over the last year, coal's jumped up a
22 little bit, but nothing like the gas. So there's -- your
23 point is coal goes up.

24 Q Yeah.

25 A (Witness Newsome) It has, but nowhere near

1 what's happened with the gas. And I also think you've got
2 those things under contract a little bit more. I mean, the
3 gas you buy on market.

4 Q Yeah.

5 A (Witness Newsome) Whatever the market is that
6 day, you buy it. So you've definitely got volatility on
7 that. My understanding of how coal contracts work is that
8 it's a little more -- it's a little more subtle to more
9 long-term contracts.

10 Now, you may have some clauses in there that
11 let the prices move about. But it's not like the gas, it
12 can go (indicating) every day. I think the coal is more
13 straightened out. I mean, it's more steady, more stable
14 with the contracts. Hayet may have a better insight on
15 that.

16 A (Witness Hayet) Well, yeah, I think Mr. Newsome
17 is right that the coal contract -- the coal prices, they
18 have gone up from more of a -- if you're looking at a spot
19 market. However, there is not really a spot market when it
20 comes to coal.

21 Coal is bought over longer-term contracts and
22 so, therefore, it has a little bit more stability, depending
23 on if there's these short-term increases. Plus, Powder
24 River Basin coal is bought by the company and that's a
25 little bit more stable than the eastern coal, in terms of

1 prices than the eastern coal.

2 So I don't -- I'm not sure if I'm answering
3 your question, but I think that's the response I believe I'm
4 providing to your question.

5 Q I think you may be, Mr. Hayet. And I guess
6 my question is: You and Mr. Newsome were asked a lot of
7 questions about sort of near-term spikes. And the point I
8 was trying to make, and I think you confirmed,
9 Mr. Newsome, is that we see increases in coal prices near
10 term, as well.

11 So if we're going to look at near-term
12 equivalents, there's been volatility in both coal and gas;
13 correct?

14 A (Witness Newsome) Right. But it's been much
15 less in the coal than the gas. And the gain -- the increase
16 is a lot less, too, both in percentage and on the absolute
17 basis, too.

18 Q And at the end of the day, what I understood
19 your testimony is that as pertains to the gas forecast,
20 that, ultimately those forecasts tend to merge back to
21 what the conclusions or assumptions have been that the
22 company's had in its forecasts and I think your forecast
23 shows the same thing; correct?

24 A (Witness Newsome) Well, you got a lot in there.
25 I think what we did was we did our own independent forecast,

1 you know, for high, mid, and low. And it was pretty -- we
2 used public sources and we came up with our own numbers, our
3 own forecasts, and it was really close to what you guys did.
4 Or, excuse me, what the company did.

5 And so we just adopted the company's forecast
6 for efficiency purposes. So that's what we did. I don't
7 know if that's consistent with what you're asking.

8 Q Well, I think your testimony -- it
9 specifically states that you see those -- you see the
10 near-term spikes disappearing and actually the merge --
11 the prices start to merge back to the levels that were
12 within the company's ranges of assumptions. I think
13 that's --

14 A (Witness Newsome) That's fair.

15 Q -- pretty consistent with your testimony.

16 A (Witness Newsome) That's fair, yes.

17 Q Okay. So I just wanted to make that point.
18 I don't think --

19 A (Witness Newsome) That's fine.

20 Q -- I'm making an inconsistent point with your
21 testimony.

22 Now, I did want to point you to one thing that
23 was raised by Mr. Jones. And I think I probably need to ask
24 you this question because he used it with this panel. And
25 I'm going to refer you to GAM No. 9, which was the exhibit

1 he handed out. I don't know if you still have that --

2 A (Witness Newsome) Yes.

3 Q -- Mr. Newsome.

4 Phil -- you don't have that, Mr. Hayet, I don't
5 think.

6 A (Witness Hayet) I do not.

7 Q Okay. And what Mr. Jones showed you was a
8 comparison between the Miller plant at Alabama Power and
9 the Scherer plant in Georgia Power.

10 A (Witness Newsome) Okay.

11 Q And I think he was trying to make the
12 connection that somehow they're both very similar and so
13 why aren't they being treated similar. And one thing I
14 wanted to point you to, if you would look at the delivered
15 contract price in coal transportation costs for Miller,
16 which, unfortunately, by pagination I believe is about --

17 A (Witness Newsome) Okay.

18 Q It's the last page, Mr. Newsome.

19 A (Witness Newsome) Okay. It's primary coal
20 deliveries for Miller?

21 Q Yeah. It says delivered contract price and
22 coal -- yeah. Exactly. Under that category.

23 A (Witness Newsome) Yeah.

24 Q And if you were to look at that category for
25 Miller, but then you were to look at the same category for

1 Plant Scherer, which is about two pages over --

2 MR. WALSH: Madam Chair, I'll just restate my
3 earlier conditional objections. But I don't want to
4 be in the situation where the panel is just going to
5 be reading numbers off a page that they're not
6 familiar with. I know this isn't counsel's --

7 MR. MARZO: It's not -- yeah.

8 MR. WALSH: I know not it's not Counsel's
9 exhibit. I just want to make sure that the panel is
10 not being asked to testify to numbers that they're
11 not familiar with.

12 COMMISSIONER PRIDEMORE: Sustained. Ask your
13 next question.

14 MR. MARZO: And, Madam Chair, I'm only going to
15 ask them if the numbers reflect a higher cost for
16 Scherer versus Plant Miller. And the numbers will be
17 what they are. I'm not having Mr. Newsome attest to
18 their accuracy at all.

19 MR. WALSH: That's probably --

20 COMMISSIONER PRIDEMORE: I think what solves
21 the problem is just put the numbers in your question.

22 MR. MARZO: Yeah. Well, if I can ask that
23 about the exhibit.

24 BY MR. MARZO:

25 Q I mean, if you look at the Scherer primary

1 coal deliveries, would you agree with me -- and I think I
2 can get to the point fairly quickly here, Mr. Newsome.

3 Would you agree with me that delivered contract
4 price and coal transportation costs are significantly
5 higher?

6 A (Witness Newsome) Right.

7 Q Yeah.

8 A (Witness Newsome) But -- yeah.

9 Q Okay. Thank you.

10 A (Witness Newsome) But that's taken into account
11 when we do our economic analysis of Scherer.

12 Q Exactly. And I just wanted to make that
13 point in light of the comparison that was made to Plant
14 Miller.

15 Now, Mr. Baron, you have received a lot of
16 questions today. You're very popular, in terms of the
17 target reserve margin. And I just have a few. A lot of
18 them might have been asked.

19 A (Witness Baron) All right.

20 Q Now, there's several things that the company
21 and staff agree on as it pertains to the target reserve
22 margin. One is that the target reserve margin for the
23 summer should be set at 16.25 percent; is that correct?

24 A (Witness Baron) Yes.

25 Q Okay. And seasonal planning should continue;

1 is that correct?

2 A (Witness Baron) Absolutely, yes.

3 Q And the company has made the appropriate
4 improvements to the existing generation resources to
5 withstand the effects of cold weather; is that --

6 A (Witness Baron) Yes. That was our conclusion.

7 Q Okay. And, finally, I understand that we
8 made some adjustments to our study and staff has been
9 fairly supportive of those adjustments that we've made to
10 our study; correct?

11 And I'm referring to the regression modeling
12 and the use of actual historical load forecasts.

13 A (Witness Baron) Yes, yes. That was -- we
14 testified to that in our prefiled testimony.

15 Q Now, there is -- there is one disagreement
16 that we have had, particularly one part of the analysis,
17 which is the load forecast, a portion of the analysis.
18 I'm going to ask you some questions about that.

19 Before I get there, I do want to ask you: Now,
20 you agree -- would you agree with me that this Commission
21 has, over the course of the IRPs that it's conducted, has
22 not endorsed or adopted reserve margins that have been
23 simply planned a loss of load expectations?

24 A (Witness Baron) Based on my understanding
25 certainly of recent history, that's correct.

1 Q Okay.

2 A (Witness Hayet) And if I can add to that. I
3 know for a fact that the use of the economic optimal reserve
4 margin-type approach has been used for at least 15 years.

5 Q Thank you. And I think you just cut through
6 a few more of my questions, Mr. Hayet. So I won't revisit
7 that issue.

8 Now, on this one issue that is a difference
9 between the staff and the company on the analysis. Staff
10 offers a critique of the low forecast error used for the
11 reserve margin study; is that correct?

12 A (Witness Baron) Repeat that again, please.

13 Q Yeah. Staff offers a critique of the low
14 forecast error used in the reserve margin study; correct?

15 A (Witness Baron) Yes.

16 Q Okay. And that's based on the fact that the
17 company's adjusted the error to be both under- and
18 overforecasting; is that correct?

19 A (Witness Baron) That's correct.

20 Q Okay.

21 A (Witness Baron) The company took the actual
22 history, which was a -- in our view, was an improvement from
23 the prior methodology which relied on the congressional
24 budget office GDP forecast. The company used actual
25 forecast errors for the Southern system, but restated it so

1 that it would produce under- and overforecast probability or
2 likelihoods contrary to what the actual distribution was.

3 Q Okay. And I think to unwrap that a little
4 bit for me, who's not living it daily like you are,
5 Mr. Baron, the company essentially recentered and allowed
6 for there to be both an over- and an underforecast
7 analysis; is that a fair, simplistic summation of --

8 A (Witness Baron) Yes. Well, recentering doesn't
9 perhaps describe it. But, yes, that's what the company did.
10 The actual data for 18 years showed for the Southern system,
11 which is the basis for this entire analysis, that on a
12 four-year-ahead basis, the company's low energy forecast was
13 consistently an overforecast for each of the 18 years. And
14 the company converted that actual data into an alternative
15 history, an alternative distribution by effectively shifting
16 the curve -- the probability curve to the left so that it
17 would produce -- it would change the history to a data that
18 showed underforecasts and overforecasts.

19 Q And so essentially would you agree with me
20 that -- well, let me ask the question this way. While
21 there has been an overforecast trend, wouldn't it be
22 reasonable to study the risk associated with
23 underforecasting, as well?

24 A (Witness Baron) It would be -- certainly, if
25 the history -- if there was data that supported a

1 likelihood, a certain probability of an underforecast, that
2 would certainly make sense. The facts, though, in this case
3 are that the history doesn't support that.

4 And so when you're trying to -- the load
5 forecast error is basically an adjustment that's built into
6 the reserve margin model. It takes the company's 2025
7 forecast and in a particular case, and there were hundreds
8 of cases evaluated in the overall simulation, it adjusts it
9 either up or down based on an assumed error in the forecast.
10 And I don't mean error computationally, but an error that
11 simply occurs in any kind of projection.

12 But the problem is that the history in this
13 case is for 18 consecutive years there has been an
14 overforecast of varying magnitudes. And it -- at that
15 point, based on history, it doesn't support the type of
16 distribution that you're referring to.

17 Q I mean, would you -- or are you aware that
18 Georgia has had a lot of economic development activity in
19 recent times, a lot of large load customers coming to
20 Georgia?

21 A (Witness Baron) Yes, I would agree with that.

22 Q And wouldn't you agree with me, new economic
23 loads have the potential to result in increased load
24 forecasts or result in the company underforecasting a
25 load?

1 A (Witness Baron) Would you repeat that again,
2 please.

3 Q Sure. Wouldn't you agree with me that new
4 economic development loads have the potential to result in
5 an increased load forecast and result in the company
6 underforecasting load?

7 A (Witness Baron) Well, certainly anything could
8 occur. In other words, if load growth grows faster than the
9 forecast, you're going to have an underforecast. That's
10 simple arithmetic.

11 The issue, though, is that for -- as I said,
12 for 18 years in a row, that hasn't occurred. And you can
13 speculate that: Well, in the future, that might occur. And
14 I acknowledge that. It's certainly possible.

15 But to the extent we're basing this analysis,
16 and the company based its analysis on trying to use actual
17 information, actual data on forced outage rates, on
18 temperature and so forth and so on, it makes sense to use
19 the actual data. And the actual data doesn't support what
20 you're suggesting.

21 Q Thank you, Mr. Baron. I appreciate that.

22 I do want to turn to one thing that has been
23 discussed a great deal, your Table No. 9.

24 A (Witness Newsome) What's the page number?

25 Q And I was just trying to get to that. It is

1 on page 55.

2 A (Witness Baron) That's the survey you said;
3 correct?

4 Q Yeah, it is. It's the "Staff Survey of
5 Selected U.S. Electric Utilities and Regional Transmission
6 Organizations." And I think you received a -- some
7 questions about this already, but I have a few questions I
8 want to ask about it, as well.

9 And basically the staff just used this table as
10 a sort of -- I guess, a check, for lack of a better word,
11 against what the recommendations are in this case as to
12 what's going on generally across the country; is that fair?

13 A (Witness Baron) Yes. It's a -- that's correct.
14 It's a -- sort of a sanity check to see what other utilities
15 are doing. It's certainly not a survey of every utility in
16 the United States or every regional transmission
17 organization. But it is a sanity check. It certainly
18 includes utilities in the southeast and others that we're
19 aware of. So that's correct.

20 Q And I took your testimony, Mr. Baron, being
21 so technical that you would agree that in the absence --
22 in terms of actually setting the reserve margin, you
23 wouldn't just look at an average, you would actually do an
24 analysis like you've done --

25 A (Witness Baron) Absolutely.

1 Q -- in this case?

2 A (Witness Baron) Absolutely. It's -- as I said,
3 this is a sanity check. But the actual reserve margin,
4 regardless of the methodology that you would use, should be
5 based on a particular system. In this case, Southern
6 Company's system. It reflects their outages, the weather
7 impacts and other -- and load characteristics.

8 A (Witness Newsome) The purpose of the table is
9 to provide context to the Commissioners. That's the purpose
10 of it, to see whether the utility -- I mean, the natural
11 question would be that if you're not doing all those
12 calculations for the reserve margin, what do other utilities
13 do? This gives them a -- this table provides that.

14 Q And that's fair. And I think for certain
15 things we do look across the country to see what other
16 utilities are doing for at least information. In that
17 regard, I do want to present you with a couple of things,
18 if I can first show your counsel.

19 This is a February 2021 FERC and NERC regional
20 staff report. It was provided to staff in response to
21 JKA-1-6.

22 MR. MARZO: Madam Chair, I would like to have
23 it marked as Georgia Power No. 4.

24 (The document referred to was marked for
25 identification as Georgia Power Exhibit 4.)

1 MADAM CHAIR PRIDEMORE: Yes, you may approach.

2 MR. MARZO: I'm sorry, Madam Chair. May we
3 approach the bench, as well? We've got copies for
4 Commissioners.

5 COMMISSIONER PRIDEMORE: Just trying to keep it
6 moving.

7 BY MR. MARZO:

8 Q And, Mr. Baron, I'll give you a chance to
9 look at the report. And I realize it's a very lengthy
10 report, and so I apologize for the length of it. And even
11 though this was provided in discovery, I know it's 250
12 pages.

13 For the record, I will identify that I am going
14 to ask you about page 38 of that report. And I think
15 Mr. Hewitson hopefully gave you a copy of page 38. It
16 should be the same page 38 that's in the full report that I
17 handed you.

18 And there is a table -- did he give you an
19 individual copy? Mr. Baron, do you have --

20 A (Witness Wellborn) We have a copy up here.

21 Q You do have -- okay.

22 MR. MARZO: Madam Chair, can I approach the
23 panel?

24 COMMISSIONER PRIDEMORE: Yes, you may.

25 WITNESS BARON: And before you go on, Mr. Hayet

1 actually worked on some of this and I want to make
2 sure that -- see if he has access in case there's
3 something he may want to add.

4 BY MR. MARZO:

5 Q Yeah. Mr. Hayet, if you have access to data
6 request responses, it's Staff JKA-1-6.

7 A (Witness Hayet) I will pull that up.

8 Q Okay. We can give Mr. Hayet a moment to do
9 that.

10 A (Witness Hayet) Almost there.

11 Okay. I think I've got it pulled up.

12 Q It's the 2022 -- '21, I'm sorry, FERC and
13 NERC regional staff report.

14 A (Witness Hayet) Yes. I -- it's big. It's
15 pulling open right now.

16 Q Yeah.

17 A (Witness Hayet) I've got it open.

18 Q Yeah. I had asked the panel to focus on
19 page 38 of that report. So I know you will have to flip
20 to that to get to that.

21 A (Witness Hayet) I'm at page 38.

22 Q Okay. Thank you, Mr. Hayet. Thank you,
23 Mr. Baron.

24 So the page I showed you is -- the title of the
25 page is: Data from NERC 2020 to 2021 Winter Reliability

1 Assessment. Do you see the three columns marked ERCOT, SPP,
2 which is Southwest Power Pool -- of course, ERCOT is
3 Electric Reliability Council of Texas, and MISO, which is
4 Mid-continent Independent System Operator.

5 A (Witness Baron) Yes.

6 Q Okay. Now, this report shows that the
7 anticipated reserve margins for ERCOT, SPP, and MISO are
8 49.8 percent, 59.1 percent, and 48.4 percent,
9 respectively; correct?

10 A (Witness Baron) Yes.

11 Q And these anticipated reserve margins are
12 substantially higher than what you're reporting on the
13 Table 9, correct, which are 12 percent for SPP and MISO at
14 20.7 percent?

15 A (Witness Baron) Yes. And I'd have to actually
16 go through and look at the source -- all of the source data
17 for our table versus this report. The -- I can tell you,
18 for example, that in the most recent auction for MISO there
19 have been -- they're expecting extreme shortages of capacity
20 in all but the southern -- the Entergy portion basically of
21 MISO. So it's not consistent with the 48 percent reserve
22 margin, but -- so I would have to look at it.

23 I don't -- Mr. Hayet, do you have any -- he may
24 have a --

25 Q Okay.

1 A (Witness Baron) -- different view or something
2 to add on that.

3 Q Phil, you may be on mute. Phil, are you
4 trying to talk?

5 A (Witness Hayet) I don't have anything to add to
6 that. I think that this is showing, you know, 48 to
7 59 percent, which is significantly higher than the reserve
8 margin targets.

9 Q And I think Mr. Baron actually jumped ahead
10 to a question I was going to have later, which is: Even
11 with these reserve margins at this level, as reported in
12 this report, we're hearing the same thing you are,
13 Mr. Baron, that they're -- they're concerned about
14 shortages coming up, as well, even at these reserve
15 margins.

16 A (Witness Baron) In the -- in the non-Entergy
17 portion -- the non-Entergy zones. I think there are two
18 zones in MISO that are Entergy. But the rest of MISO is
19 expecting shortages, the -- and the market capacity prices
20 went from one year, \$5, up to 200 and something the
21 following year.

22 Q Yeah.

23 A (Witness Baron) Or current year, I guess I
24 should say.

25 Q Yeah.

1 A (Witness Hayet) And -- and this is for the 2021
2 time frame. It is expected to change. And we just saw that
3 the summer reliability assessment that came out from NERC is
4 much tighter and concerns for this particular summer season,
5 so...

6 Q And I think we both can agree that, you know,
7 even at these levels, MISO and SPP in Texas both -- both
8 struggled through the winter storm in February 2021;
9 correct?

10 A (Witness Hayet) They struggled, but I don't
11 know that you can make the connection of the reserve margin
12 target as the reason for the struggling and having added
13 more capacity would have changed the outcome.

14 There was a lot of -- the issue that came --
15 that came out was the impact on -- the impact on gas
16 infrastructure. And so having more gas resources, for
17 example, doesn't necessarily address the problems that
18 occurred in the February 2021 time period.

19 Q Mr. Hayet, you would agree with me it is
20 because -- the reason we plan for reserve margin is
21 because there's a combination of factors that can impact
22 that day where you don't want the lights to go out, but
23 the lights go out; correct?

24 A (Witness Hayet) That's correct. I would agree
25 with that.

1 Q Now, you've also listed PJM on Table 9, as
2 well, as having a 14.7 percent winter reserve margin. Let
3 me show you what I'll ask be marked as GPC Exhibit No. 5.

4 (The document referred to was marked for
5 identification as GPC Exhibit 5.)

6 MR. MARZO: Madam Chair, can Mr. Hewitson
7 approach?

8 MADAM CHAIR PRIDEMORE: Yes.

9 BY MR. MARZO:

10 Q What I'm going to have Mr. Hewitson hand out
11 is the 2021 PJM Reserve Requirement Study dated
12 October 12th, 2021. And, once again, I realize this is a
13 big study. You or Mr. Hayet may be familiar with it
14 there.

15 I'm going to ask you about page 44 of this
16 document to confirm some statements made by PJM.

17 A (Witness Newsome) All right.

18 MR. WALSH: Madam Chair, before the questions
19 get asked, I would ask -- he said they may be
20 familiar. I would ask the witness panel to -- if
21 they are familiar. And if they are familiar, then I
22 don't have any objection for future questions.

23 If they're not familiar with it and they are
24 just being asked to read off a page that they have
25 not seen before and are not familiar, I would have an

1 objection to the question and to the exhibit at that
2 point.

3 MADAM CHAIR PRIDEMORE: Sustained.

4 Mr. Marzo, you want to ask them a question?

5 MR. MARZO: I do want to ask them a question
6 about the document. Again, I'm not asking them to
7 confirm anything, other than this is -- this is an
8 official PJM document. It's not an article or a
9 newspaper or anything different from a source. This
10 comes from PJM.

11 The only thing I'm asking them to do is to
12 confirm the accuracy of the winter reserve targets
13 that they have listed within their document, which is
14 their business document. I'm not asking them to
15 confirm anything other than what is written in their
16 document.

17 MR. WALSH: And I think that would be properly
18 done through a panel that is familiar with the
19 document. And if they are -- if this witness panel
20 is, then I have no objection. If not, then I think
21 it should be asked of another panel or Georgia Power
22 Company --

23 MADAM CHAIR PRIDEMORE: I'm just going to go
24 ahead and ask the panel: Are you familiar with this
25 document?

1 WITNESS BARON: Madam Chair, I have not seen
2 this document. I am familiar with PJM and some of
3 their planning methodologies, but I haven't seen this
4 document.

5 MADAM CHAIR PRIDEMORE: Mr. Hayet is itching to
6 answer.

7 Yes?

8 MR. HAYET: I believe I'm familiar with the
9 document, but I'm not -- I don't have it in front of
10 me right now. But I believe I have a copy if it's
11 what I'm thinking the document -- what is the name of
12 the document?

13 BY MR. MARZO:

14 Q Mr. Hayet, it is the 2021 PJM Reserve
15 Requirement Study.

16 A (Witness Hayet) Yeah. I -- I'd have to have
17 it -- see it in front of me. I'm sorry.

18 Is it one of the DR responses?

19 Q It was not listed in the JKA-DR I cited you
20 to.

21 MR. MARZO: But, Madam Chair, can I ask some
22 questions without asking directly the question
23 Mr. Walsh is worried about it?

24 MADAM CHAIR PRIDEMORE: I think -- I think that
25 what Mr. Walsh would like you to do is just ask

1 questions related to your handout and then he can
2 apply his legal knowledge to each of those questions.

3 MR. MARZO: I will do so, Madam Chair.

4 BY MR. MARZO:

5 Q First of all, let me just ask. It sounds
6 like the panel -- let me ask the question. Is the panel
7 aware that PJM does -- has done a reserve requirement
8 study?

9 A (Witness Newsome) I'm not.

10 Q Okay. Mr. Hayet, I think you nodded yes.

11 A (Witness Hayet) Yes.

12 Q And they did one in 2021 and they produced
13 winter target reserves for 2021 based on that analysis.
14 Is that -- are you familiar with that, Mr. Hayet?

15 A (Witness Hayet) Yes, I am.

16 Q Okay. And would it surprise you, Mr. Hayet,
17 in your review of that study previously that the numbers
18 in that study are markedly higher than what's in Table 9?

19 A (Witness Hayet) The actual exceeds the target
20 reserve margin is what you're saying. No, it would not
21 surprise me that, you know, as -- it would not surprise me
22 the actual reserves and the actual reserve margin is higher
23 than the target. But over time it tightens if new resources
24 are not added. But it doesn't surprise me, no.

25 A (Witness Baron) I just -- one thing I think

1 needs to be understood. PJM is a substantially
2 summer-peaking system. The planning of the reliability
3 pricing model, which is the predominant method for
4 determining reliability on the system, uses the -- is
5 designed to meet requirement -- requirements for the summer
6 peak.

7 Notwithstanding that, in very extreme cold
8 weather situations there have been significant problems in
9 PJM during the winter. And what I think this is referring
10 to is that the -- the target reserve -- that the reserve
11 margins for winter, which for most utility and PJM are very
12 high because their capacity is designed to meet the summer
13 peak, this sets a minimum requirement for the winter to make
14 sure that in extreme cold weather, there wouldn't be a
15 problem.

16 For example -- but utilities might put units on
17 plan maintenance or something like that. So this -- this
18 isn't disputing what the document says, but I think it's
19 important to understand the context for PJM. It's different
20 than in the case of the Southern system where planning is
21 actually based now on both meeting summer reliability and
22 winter reliability. And that's how capacity is added to the
23 system.

24 Q Well, Mr. Baron, I think you may be making my
25 point, which is that when a table like this is produced,

1 not understanding the context behind these numbers can
2 lead to very misleading assumptions, which I think were
3 being asked to you on cross-examination by a number of
4 parties.

5 I mean, for example, would you agree with me if
6 I look at SERC -- I mean, you know, Southern Company's
7 company -- operating companies are in Southern Company SERC.
8 You've got listed there 15 percent winter and what we know
9 for sure is Alabama has got a 26 percent approved reserve
10 margin. Georgia Power has been planning to 26 percent.

11 But if I read this sheet, I would think that it
12 was 15 percent.

13 MR. WALSH: Madam Chair, I'm sorry. He's been
14 testifying for a little while here without some -- a
15 question. If he's going to start saying what reserve
16 margins -- different ones have that are not already
17 stated -- and I'm not sure how much was on this
18 exhibit or not. But I just want to know what is
19 being asked of the panel versus --

20 MR. MARZO: Well, sure.

21 BY MR. MARZO:

22 Q So -- and Mr. Hayet, you may be aware of
23 this.

24 COMMISSONER MCDONALD: Mr. Marzo, talk into
25 that mic for me, please.

1 MR. MARZO: Sure.

2 BY MR. MARZO:

3 Q The Florida utilities -- you've got FP&L
4 here. The Florida utilities, you have them planning to, I
5 believe, a 20 percent. And are you aware that in
6 Florida's 10-year plan they are addressing winter
7 planning, as well, and are planning to something higher
8 than what is being represented here?

9 A (Witness Baron) I have not -- if that's the
10 most recent, I -- I have not -- I could look at, if you want
11 to show me a document. I'm aware of the general load
12 characteristics in Florida, particularly Florida Power &
13 Light.

14 It's a summer-peaking system, but the winter
15 has very sharp spikes. And depending on the weather,
16 it can spike up. And, obviously, the system
17 requirement is to satisfy load.

18 Q And, Mr. Baron, to my earlier question -- and
19 I will frame it as a question. You have SERC listed here,
20 but isn't it true that the Southern Companies are all
21 planning to 26 percent?

22 A (Witness Baron) That's correct.

23 Q Okay. But if I looked at this --

24 A (Witness Baron) Certainly based on what the
25 company -- the company's analysis. I think the Georgia

1 Public Service Commission, as you know, did not approve a 26
2 percent reserve margin in the 2019 IRP, but that certainly
3 was a systems calculation.

4 Q Yeah.

5 A (Witness Hayet) Let -- let me, if I could, add
6 the mention of SERC here. These are NERC's -- when NERC
7 does an assessment of the reliability of different regions
8 around the country, they indicated that with a -- their
9 target reserve margin is 15 percent. That's why that's
10 indicated.

11 This isn't -- this isn't intent -- this isn't
12 indicated -- intended to be -- sorry. The reserve margin
13 targets that the utilities within SERC are actually planning
14 for and have approved by their commissions, this isn't --
15 these lines are the NERC's evaluation of reliability. And
16 they -- they assumed a 15 percent reserve margin target.
17 That's what that is.

18 Q All right. Thank you, Mr. Hayet. And I
19 appreciate that clarity because I was getting to my --
20 you've eliminated some more questions. I was getting to
21 my point, is that the 15 percent is essentially a
22 placeholder; is that fair?

23 A (Witness Hayet) I'm not sure what you mean by a
24 placeholder. What I mean by it is they've assumed that a
25 reasonable one-day-in-ten-year reliability criteria is

1 15 percent. That's what the -- they determined.

2 Q Let me rephrase that. But as you stated, the
3 underlying utilities may plan something very different; is
4 that fair?

5 A (Witness Hayet) That's fair.

6 Q Okay. So let's -- let's move on from the
7 chart. I have some questions for you related to hydro.
8 And I imagine those go to either Mr. Hayet or Mr. Newsome
9 or both.

10 A (Witness Newsome) Page number, please?

11 Q Well, the questions first I don't think
12 require a page number that I'm going to ask you.

13 A (Witness Newsome) Well, we need to get over
14 there.

15 Q Okay. Well, let me ask the question first
16 and you tell me if you need a page number.

17 A (Witness Newsome) Well, that's why I asked you
18 for a -- okay.

19 Q In the 2019 IRP, the Commission approved the
20 modernization of five hydroelectric facilities; correct?

21 A (Witness Newsome) Correct.

22 Q Okay. And that's Plant Terrora, Plant
23 Tugalo, Plant Bartletts Ferry, Plant Nacoochee, and Plant
24 Oliver; correct?

25 A (Witness Hayet) Yes.

1 Q And the company's completed the modernization
2 of Plant Terrera already; correct?

3 A (Witness Newsome) Correct.

4 Q And, in addition, as part of the stipulation
5 of the 2019 IRP, the company is reporting semiannually to
6 the Commission regarding the status of the hydro
7 modernization program; is that correct?

8 A (Witness Newsome) Correct.

9 Q Okay. And in this case, the company has
10 proposed to add Plant Burton, Plant North Highlands, and
11 Plant Sinclair to the program?

12 A (Witness Newsome) Correct.

13 Q Okay. Now, you were here when Mr. Grubb
14 testified during the company's direct testimony hearing,
15 were you not?

16 A (Witness Newsome) I mean, I -- go ahead and ask
17 your question.

18 Q Go ahead. Yeah. You reviewed his testimony?

19 A (Witness Newsome) I reviewed it. I don't
20 remember initially what it was in it, so let's --

21 Q Well, were you here when Mr. Grubb discussed
22 Plant Burton, Plant North Highlands, and Plant Sinclair
23 where he brought forward in this case -- that these plants
24 were being brought forward in this case by the company
25 because these three plants have the most pressing needs of

1 investment to avoid extended outages in the near future?

2 A (Witness Newsome) And that's why we want you to
3 do economic analysis, because it makes sense to spend the
4 dollar or you just let the water just keep flowing past.

5 Q And did you also hear him explain that the
6 investment in hydro fleet will mean these flexible,
7 dispatchable, and zero carbon resources would be available
8 to operate for at least the next four years?

9 A (Witness Newsome) I agree with that statement,
10 but they have not provided economic analysis to justify the
11 capital expenditures. That's what we're asking for. You
12 refuse to do it.

13 Q And you were --

14 A (Witness Newsome) Hang on. You didn't provide
15 the IRP filing. We asked you in the DR. You still didn't
16 provide it.

17 Q Okay. And you understand we did respond to
18 the question. And you understand that the company feels
19 that it's not practical to do that particular analysis;
20 correct?

21 A (Witness Newsome) Mr. Marzo, you -- Southern --
22 Georgia Power is capable of doing economic analysis on
23 something as simple as a hydro. You do it for all these --
24 this whole IRP, we had all this -- all these resources on
25 the entire Southern system, but then you can't do it for

1 three hydro plants. That's -- that's kind of a tough --
2 tough sell there.

3 Q Well, you understand the company's position
4 is taking down the dams and terminating the license is --
5 is not, one, something that has been determined what the
6 cost would be, nor is that an appropriate approach?

7 A (Witness Newsome) No. What you're asking for
8 is modernization of the turbines and the generators and all
9 the balance of plant. That's the modernization part.

10 The dams -- we're not contesting the dams.
11 It's whether you upgrade the water turbine, the generator,
12 balance of plant. Same analysis you do for all your other
13 fossil plants and any kind of generation. And you refuse to
14 do it. And I think the reason you refuse to do was it
15 because it's not economic.

16 Q Well, do you understand, Mr. Hayet [sic],
17 one, that if the plants aren't operating, that's a
18 requirement of the license; that the plants actually
19 operate?

20 A (Witness Newsome) But you haven't provided
21 that. You haven't said the plant is not going to operate
22 entirely. You're telling -- you can still operate the dam
23 without operating the plant. You've got sluice gates up
24 there to lower the water level.

25 Q Well, does -- does the dam generate

1 electricity or does the turbine in the plant generate
2 electricity?

3 Because the FERC license is attached to the
4 generation of that electricity and the requirements to keep
5 that plant operational. Do you understand that?

6 A (Witness Newsome) I understand your
7 representation of that, but that doesn't necessarily mean
8 you have to replace the -- fix the plant -- that doesn't
9 mean you necessarily have to upgrade the turbines and the
10 generator to maintain the plant. I'm not accepting that
11 from you.

12 Q And you understand that unlike the generation
13 that you have talked about, such as, like, a fossil
14 generator or a solar plant or some other generation where
15 you can do an economic analysis, there are components here
16 in this analysis that the company is telling you are not
17 practical for them to do, which are retirement of the dam,
18 taking down the electric generator, losing the FERC
19 license?

20 A (Witness Newsome) We're not going -- that's
21 not -- that's your position. Our understanding of the
22 modernization program was the dam stays. Whatever money you
23 need to spend to keep that rolling, you need to roll it.

24 The question is: Do you do the generator and
25 the water turbine and the balance of plant? Your claim is

1 it's a package deal. I don't know. I don't believe that to
2 be the case. You know, we'll leave it at that.

3 A (Witness Hayet) Let me -- let me state I think
4 you can lay out a number of scenarios. And one scenario is
5 the entire retirement of the hydro plant. Another scenario
6 you could lay out is continue to operate, have higher forced
7 outages, don't do any upgrades. Or the third analysis could
8 be: Continue to operate, do the upgrades, and you would
9 have fewer forced outages.

10 And the company hasn't done any analysis of any
11 of those three cases. It seems like you keep going to the
12 -- to the case that would be done is you have to take down
13 the whole plant.

14 And I think that what Mr. Newsome is saying we
15 would like to know what the difference is if you continue to
16 have higher forced outages and you continue to operate the
17 plant. You could do an economic analysis of that.

18 Q Well, let me ask this question, Mr. Hayet. I
19 mean, in terms of modernization -- we use that term.
20 There's a couple of ways you could approach this.

21 One would be to simply address issues as they
22 occur, which could actually be more costly, or to address it
23 as an aggregate of issues and modernize, as we're using the
24 term, as it pertains to hydro.

25 Is that your understanding of what we're

1 talking about here or are we talking two different things?

2 A (Witness Hayet) Would you -- please repeat
3 that.

4 Q Yeah. I was trying to understand your point
5 earlier about, you know, there's -- you could address
6 various things regarding the units individually. And that
7 is true. But do you understand the modernization approach
8 is, in part, to be the most efficient way of addressing
9 issues at the units to keep them operable, essentially?

10 A (Witness Hayet) Yeah. I understand it's the
11 company's position that the modernization is the most
12 efficient. But if it's, in fact, the most efficient, it has
13 to have an economic value.

14 And we want to have a demonstration that it is
15 the most efficient and it does have an economic value. And
16 the company hasn't provided that. It's -- it's: Trust us.
17 Believe us. You know, we believe this.

18 But all we're saying is: Provide that. It has
19 been a pretty standard position that staff has always taken
20 that in order to, you know, support -- agree with the
21 company's position on this, provide us with an economic
22 analysis so that we can determine if we agree.

23 Q Okay. And just to be clear, we -- you do
24 agree at least that the company has provided you scoping
25 details of the actual projects; is that correct?

1 A (Witness Newsome) That's --

2 A (Witness Hayet) The budgets, yes.

3 A (Witness Newsome) That is half the information.

4 You need to prove those budgets are economic. Spending the
5 money is economic. You haven't done that.

6 Q I understand that you don't think that is
7 enough information. I just want to make sure for the
8 record that we're clear, in terms of information that has
9 been provided.

10 A (Witness Hayet) That information has been --

11 A (Witness Newsome) You haven't provided -- you
12 haven't provided analysis to justify the expenditures.

13 You're just telling us you want to spend the money. You
14 don't provide any justification for spending the money.

15 Q Now, Mr. Newsome and Mr. Hayet, we had a
16 similar conversation, as you probably recall, back in
17 2019; correct?

18 A (Witness Newsome) Correct.

19 Q Okay. Same sort of request that you get some
20 analysis beyond what you've already been provided and --
21 we had this conversation in front of the Commissioners.
22 And I want to show you something related to that, if you
23 give me one second.

24 MR. WALSH: Madam Chair, I just want to be
25 clear, for the record, when he said that the request

1 is to provide analysis beyond what they've already
2 been provided, I believe the panel's testimony has
3 been that they have not been provided the analysis.
4 I just don't want this --

5 MR. MARZO: Well, for -- to counsel's question,
6 for the record, the reason I ask about the scoping
7 documents is because I wanted to be clear there have
8 been financial data points provided. It's not what
9 staff has wanted, but there has been financial data
10 provided. So that was the point of me asking the
11 scoping document question.

12 MADAM CHAIR PRIDEMORE: Mr. Marzo, do your
13 handouts pertain to the witnesses' prefiled testimony
14 or testimony that they have given so far?

15 MR. MARZO: It pertains to the testimony --

16 MADAM CHAIR PRIDEMORE: That's a yes or no.

17 MR. MARZO: It's the 2019 testimony, Madam
18 Chair.

19 MADAM CHAIR PRIDEMORE: So it pertains to their
20 2019 testimony, not their 2022 testimony?

21 MR. MARZO: No. It's the testimony we had on
22 this issue in the last -- last IRP.

23 MADAM CHAIR PRIDEMORE: That they gave?

24 MR. MARZO: That they gave. These two
25 witnesses gave.

1 MADAM CHAIR PRIDEMORE: I will allow this with
2 caution. This is the 2022 IRP.

3 MR. MARZO: Yeah. And I just want to ask one
4 clarification question, Madam Chair, and save me a
5 couple of questions to ask.

6 MADAM CHAIR PRIDEMORE: Okay. You may
7 approach.

8 MR. HEWITSON: Thank you.

9 MADAM CHAIR PRIDEMORE: For the purposes of
10 housekeeping, I just want to see -- kind of give me a
11 general time estimate.

12 MR. MARZO: I'm almost finished, Madam Chair.

13 MADAM CHAIR PRIDEMORE: You're almost finished?

14 MR. MARZO: I only have about maybe 10
15 minutes -- 10 or 15 minutes more.

16 MADAM CHAIR PRIDEMORE: Trying to keep the
17 trains running on time.

18 MR. MARZO: Absolutely.

19 BY MR. MARZO:

20 Q Now, Mr. Newsome, I handed you the transcript
21 from --

22 A (Witness Newsome) Hang on. I need to get
23 there.

24 Q Yeah. If I can identify it.

25 A (Witness Newsome) Go ahead.

1 Q I handed you a transcript from the 2020 --
2 2019 -- or 2019 IRP. This is the cross-examination that
3 we did back in that case with, I believe, you and
4 Mr. Hayet on this -- this same issue. I just have one or
5 two questions on this issue here.

6 A (Witness Newsome) All right.

7 Yeah. Okay.

8 Q Are you ready, Mr. Newsome?

9 A (Witness Newsome) Yes.

10 Q And I apologize, Mr. Hayet, for not being
11 able to give that to you in person.

12 A (Witness Hayet) I understand.

13 MADAM CHAIR PRIDEMORE: Commissioner Johnson
14 made a recommendation if Commissioner -- if Mr. Hayet
15 needs to see something, could it be photographed and
16 then just texted to him, if that helps him?

17 I'm trying to help you here, Mr. Hayet.

18 WITNESS HAYET: Thank you. I think that was
19 actually done on that PJM document. I received that
20 from Mr. Trokey.

21 MR. MARZO: Madam Chair, do you want me to wait
22 for Mr. Hayet to receive that document?

23 MADAM CHAIR PRIDEMORE: Please.

24 WITNESS HAYET: Okay. I have received it. I
25 will take a quick look at it.

1 Okay. I read it.

2 MR. MARZO: Madam Chair, can I just mark this
3 as Georgia Power Exhibit 6?

4 MADAM CHAIR PRIDEMORE: So marked.

5 (The document referred to was marked for
6 identification as GPC Exhibit 6.)

7 BY MR. MARZO:

8 Q Okay. And just one question really for you,
9 gentlemen. I'll cut down the line here.

10 My main question is: As I look at your
11 testimony, at the time Vice-Chair Echols was asking
12 questions about this being a policy decision. I think you
13 agreed within your testimony with him a hundred percent and
14 you also said you're not advocating to take down the hydro
15 facilities out of the portfolio.

16 And I just want to confirm that in this case
17 we're in the same place where you disagree with the
18 information you received, but you're not advocating to take
19 the hydro facilities out of the portfolio; correct?

20 A (Witness Newsome) We're not advocating taking
21 the dams down. What we're trying to figure out is whether
22 it makes sense to put them -- capital dollars in the
23 water -- in the water turbine, the generator, balance of
24 plant.

25 You're basically asserting that if you don't do

1 these upgrades to the generation equipment, that you're
2 going to lose your FERC license. If that's -- now, if you
3 provide that in a DR response, point that to me, and then we
4 can continue with this.

5 But we think the dam versus the generation
6 equipment are two separate issues. We're not arguing about
7 the dam. You need to maintain it. Just maintain it.

8 But the issue of the generation equipment we
9 think is separate. You haven't provided economic
10 justification for it.

11 Q And just so I understand, Mr. Hayet -- I
12 mean, Mr. Newsome, I think I understood from you a moment
13 ago that you thought there's an absence of information on
14 the law here as it pertains to the FERC license. And if
15 we provide that to you, that could give you more clarity;
16 is that -- is that fair?

17 A (Witness Newsome) I mean, I'm going to let the
18 attorneys look at it and interpret it, obviously.

19 Q All right. We would be happy to do that.

20 A (Witness Hayet) Let me -- let me jump in. I
21 think -- I think -- I think I should wait to see what you
22 might provide before I sort of speak. But I think what
23 you're going to is the law on the dam itself.

24 And, again, Mr. Newsome spoke about the
25 generation equipment, the hydro equipment, the -- you know,

1 what you -- the modernization. And the company's argument
2 for doing all these things is -- is to reduce forced
3 outages, extend the operation. And that -- that -- so
4 there's an economic question of whether or not it's worth
5 investing the money or suffering perhaps higher forced
6 outages.

7 Q And I understand that -- well, let me ask
8 this. Well, I won't -- let me leave this line of cross.
9 But I think I understand your position on the economic
10 analysis.

11 And just to finally confirm here, I believe
12 your position is still consistent with the last case and
13 that you're not advocating to remove the hydro units from
14 the portfolio?

15 A (Witness Newsome) Right. Advocating removing
16 the dams. We're open -- on the generation equipment, the
17 generation of power, we don't know because you won't provide
18 the analysis.

19 Q Have you done any analysis as to the impact
20 of just removing the electric equipment and operating a
21 dam that is no longer a hydroelectric facility?

22 A (Witness Newsome) I haven't done the full-blown
23 thing, but you just -- you just open the sluice gate and let
24 the water run out.

25 Q Have you done any analysis on it?

1 I mean, is there something that we --

2 A (Witness Newsome) I've used visionary common
3 sense. You've got a dam there. You have bypasses on the
4 thing. So you could use the bypasses to regulate the lake
5 level.

6 VICE-CHAIRMAN ECHOLS: Mr. Marzo, I want to ask
7 Mr. Newsome a question. Is it a matter of whether
8 it's producing at its nameplate capacity or nothing?

9 I mean, if the old equipment is running, it's
10 still producing something. Maybe not as efficient as
11 they would like, but it's not a matter of having to
12 replace it.

13 It can still be functioning at a reduced
14 capacity; is that right?

15 WITNESS NEWSOME: It could be, yes.

16 VICE-CHAIRMAN ECHOLS: And so it's not a matter
17 of just rerouting the water and not having it go
18 through?

19 I mean, just -- not having it turn the turbine?

20 WITNESS NEWSOME: Correct.

21 MR. MARZO: Madam Chair, that's all the
22 cross-examination I have. I appreciate the panel's
23 time.

24 Mr. Hayet, I hope you feel better soon.

25 WITNESS HAYET: Thank you.

1 MADAM CHAIR PRIDEMORE: Redirect, Mr. Walsh.
2 I will take a time estimate from you, too,
3 Mr. Walsh.

4 MR. WALSH: I'm hoping five minutes or less.

5 MADAM CHAIR PRIDEMORE: Oh, wow.

6 REDIRECT EXAMINATION

7 BY MR. WALSH:

8 Q I would like to begin the redirect on the
9 same exhibit that Mr. Marzo was just discussing, Georgia
10 Power Company Exhibit 6, which is the transcript from the
11 last IRP.

12 A (Witness Newsome) Okay.

13 Q And if you can turn with me to page 1332,
14 which is the second of the two pages that Georgia Power
15 Company has highlighted?

16 A (Witness Newsome) Okay. I'm there.

17 Q Okay. And this was where he was focusing on
18 that -- Mr. Hayet's testimony that staff was not
19 advocating taking the hydro facilities out of the
20 portfolio. Do you see that?

21 A (Witness Newsome) Correct.

22 Q And then after that Mr. Marzo says, beginning
23 on line 4 of page 1332: And just in summary, and I think
24 you have already said this, we can agree that we can
25 collaborate to get closer to the information you need to

1 provide you data to possibly have different units even
2 than you suggested in your testimony.

3 Have you received the additional information
4 that you would need to make a recommendation to this
5 Commission to approve what the company is proposing?

6 A (Witness Newsome) Not in this IRP docket, no.

7 Q Okay. Thank you.

8 Mr. Baron, I wanted to talk with you briefly
9 about some of the questions that you received on the reserve
10 margin.

11 A (Witness Baron) Yes.

12 Q Can you explain -- you mentioned the history
13 and how you factored that into in your analysis. And I
14 believe you mentioned 18 years of history.

15 Can you explain the significance of that?

16 A (Witness Baron) Yes. One of the -- the
17 model -- the SERVUM model, which is a very comprehensive
18 multi-input computer simulation model, uses information --
19 historic information on generator outages, 58 years worth of
20 weather experience in the Southern system and so forth, and
21 it -- one of the inputs also is the history of the -- the
22 forecast errors that the company makes.

23 Because the way the model works is it -- it
24 looks at 2025 and it uses the company's load and energy
25 forecast for the year 2025. It's weather normalized. And

1 one of the -- and then using some other -- using some of the
2 other models, the SERVVM model adjusts that for various
3 scenarios.

4 It adjusts it for -- under the assumption that
5 instead of having normal weather in 2025, we have, let's
6 say, 1962's weather or 1987's weather, and calculates how
7 that -- how the capacity needs compare to the load on the
8 system.

9 One of the other elements concerns load
10 forecast error because it's always true that no matter how
11 good someone's load forecast is they're going to be -- some
12 years it will be overforecasting, some years
13 underforecasting. And this is absent any weather effects
14 because that is handled separately.

15 In the Southern system what the company did,
16 which was an improvement, was to actually look at the
17 historic -- the history of how Southern Company's forecasts
18 compare to actual on what's called a weather normalized
19 basis. So you remove the effect of weather.

20 And what it showed is that for 18 years in a
21 row, the company's forecast, putting aside weather, always
22 overforecasted. And what that tells us is that if we --
23 from using all the available data, if we look at 2025, the
24 company did a forecast. What's the -- what would a
25 reasonable guess be as to whether that forecast is going to

1 be too high or too low?

2 If you had 18 years of history, one year, two
3 years, three years, that you always overforecast, the odds
4 are that forecast is -- in 2025 is not going to be an
5 underforecast. But what the company did was it took that
6 historic data and it changed it. It changed it so that
7 instead of showing an overforecast every year that the
8 forecast was too high relative to actual, it assumed that in
9 some years it was -- that data actually showed or pretended
10 to show an underforecast.

11 And the way the company did that is they
12 subtracted the median of that 18 years from the data. So,
13 basically, they took a distribution of overforecast errors.

14 In other words, if we look at the first year,
15 it had, let's say, a 4 percent overforecast. And four years
16 out and then the second load forecast is 6 percent, what
17 have you.

18 The company then changed that so that in some
19 of those years it really was an underforecast, that their
20 forecast really didn't account for the actual peak. And
21 that's simply not the history on the system.

22 That -- I hope that -- I know it is a long
23 explanation, but that's really what is going on. And the
24 effect of that in the reserve margin study is that they
25 will -- in the simulation that they will -- in the company's

1 analysis, that the actual forecast for 2025 was increased.

2 And when you increase a forecast, you're going
3 to create more scenarios where you fail to meet load. The
4 capacity at any reserve margin failed to meet load. And
5 that adjustment that the company made basically biased the
6 result. And our correction was to try to remove that bias.

7 Q You were asked about economic development
8 efforts and whether that should result in a -- that should
9 affect your analysis --

10 A (Witness Baron) Yes.

11 Q -- of the reserve margin. Is it -- is it
12 your position -- or what is your position, as far as
13 considering something like economic development efforts in
14 the context of a reserve margin?

15 A (Witness Baron) Well, the economic
16 development -- I think I was answering sort of the basic
17 question, which was: Can economic development cause
18 increases in load?

19 And certainly the answer is yes. That's one of
20 the attributes of doing that. But the history of the system
21 that we looked at, that the company calculated and used, but
22 then adjusted, reflects that.

23 And so it doesn't have any -- the economic
24 development is built into the actual historic results for
25 every year. Company has been doing economic development

1 for, you know, as long as anyone can remember. And
2 reasonably so. And it's -- it's reflected in the data.

3 Q You characterize your recommendation as
4 conservative; is that correct?

5 A (Witness Baron) Yes.

6 Q Okay. What does that practically mean?

7 Does that mean that a reserve margin could be
8 slightly less than what you're recommending and still be
9 within a range of reasonableness?

10 How would you define it?

11 A (Witness Baron) Yes. I think you summarized it
12 reasonably, that -- that the reserve margin that we
13 calculated is -- we believe is a reasonable estimate for
14 planning purposes. It's a reasonable value that the
15 Commission should adopt. But it certainly is not on the low
16 side based on the analysis that we did.

17 And so conservative means if it were adopted it
18 would not put the -- increase the risk of -- from a
19 reliability standpoint. And I should add, of course, we are
20 recommending a 24 and a half percent reserve margin. The
21 survey that we looked at showed 18 percent. We're not
22 recommending an 18 percent reserve margin.

23 MR. WALSH: Thank you very much.

24 Madam Chair, that completes my redirect
25 examination. I would ask that Staff Exhibits 9

1 through 16 be admitted into the record.

2 MADAM CHAIR PRIDEMORE: So moved.

3 (Staff Exhibits 9 through 16 were admitted into
4 evidence.)

5 MADAM CHAIR PRIDEMORE: Anybody else have to
6 admit anything else?

7 Mr. Marzo.

8 MR. MARZO: Madam Chair, we can move
9 individually or we can move at the end of the
10 proceedings. If I can, I can move my exhibits now.
11 I would like to ask --

12 MADAM CHAIR PRIDEMORE: So moved.

13 (GPC Exhibits 4-6 was admitted into evidence.)

14 MR. WALSH: Madam Chair, you ruled on the
15 motion. Staff objects to Georgia Power Company
16 Exhibit 5, which is the PJM Reserve Requirement
17 Study.

18 It's an entire report. We don't really know
19 what context there is for these particular numbers.
20 I believe that counsel for Georgia Power Company was
21 making that very same point with respect to a table
22 in staff's testimony, but staff has a panel of
23 witnesses that can defend that table and can answer
24 questions on it.

25 I believe that if Georgia Power Company, who

1 has the opportunity to present a rebuttal case, wants
2 to present this as an exhibit to one of their
3 witness's testimony that that would be more
4 appropriate than trying to get it through the staff's
5 witnesses.

6 MR. MARZO: So, Madam Chair, what I would say
7 to you is that oftentimes information is presented in
8 this context when there is a reference made to PJM
9 specifically in staff's testimony, a table that they
10 put together. This is information we thought would
11 have fed into that.

12 The fact that it did not I think is evidence
13 itself. But to the extent that Mr. Walsh is
14 concerned about his witnesses testifying to that
15 report, you can put weight on it. You can decide
16 what weight to give the report with this set of
17 witnesses.

18 I would suggest that if that's objectionable,
19 then there's going to be a lot of things
20 objectionable in this proceeding because that is --
21 materials like this are often used in
22 cross-examination. And the door open with their
23 reference to PJM on Table 9.

24 MR. WALSH: I would disagree that the door was
25 opened to anything. I think the door was opened

1 certainly for them to ask the witnesses their
2 familiarity. But, again, there was an entire report
3 that was focused on one page that there was not -- I
4 don't think context for the panel to testify to.

5 So I made my objection. I would object to
6 this.

7 MADAM CHAIR PRIDEMORE: We tend to be pretty
8 lenient.

9 MR. MARZO: I'm sorry, Madam Chair.

10 MADAM CHAIR PRIDEMORE: We tend to be pretty
11 lenient about what is allowed in handouts and in the
12 record. So for that, your objection is overruled.

13 MR. WALSH: Thank you. Thank you.

14 MADAM CHAIR PRIDEMORE: All right. Let's go to
15 lunch and let's make this short. So let's come back
16 at 20 minutes after 1:00.

17 (A recess was held from 12:43 p.m. until 1:20
18 p.m.)

19 MADAM CHAIR PRIDEMORE: Come to order.
20 Mr. Walsh, please swear in your witnesses.

21 MR. WALSH: Thank you. At this time, the staff
22 would like to call the panel of Robert Trokey and
23 Ralph Smith on behalf of the Commission Public
24 Interest Advocacy Staff. Gentlemen, if you could
25 both raise your right hands.

1 Thereupon,

2 ROBERT L. TROKEY,
3 RALPH C. SMITH,
4 having been duly sworn, testified as follows:

5 MR. WALSH: Thank you. You may be seated.

6 DIRECT EXAMINATION

7 BY MR. WALSH:

8 Q Mr. Smith, please state your full name for
9 the record and by whom you're employed.

10 A (Witness Smith) My name is Ralph C. Smith. I
11 am employed by Larkin & Associates, PLLC.

12 Q Mr. Trokey, could you please state your full
13 name for the record and by whom you are employed?

14 A (Witness Trokey) Yes. Robert Trokey, and
15 employed by the Georgia Public Service Commission.

16 Q Gentlemen -- I'll direct this to Mr. Trokey.

17 Mr. Trokey, on May 6, 2022, did you prefile or
18 cause to be prefiled 49 pages of direct testimony in
19 question-and-answer form?

20 A (Witness Trokey) Yes.

21 Q Are there any changes or corrections that you
22 would like to make to the prefiled direct testimony?

23 A (Witness Trokey) There are. There's a list of
24 corrections we've provided.

25 Q Thank you.

MR. WALSH: Madam Chair, staff would ask that

1 the Smith-Trokey direct testimony errata be marked
2 for identification as Staff Exhibit No. 17?

3 MADAM CHAIR PRIDEMORE: So marked.

4 (The document referred to was marked for
5 identification as Staff Exhibit 17.)

6 BY MR. WALSH:

7 Q Mr. Trokey, is it fair to say that these
8 changes are all just typographical errors or other nicks
9 that you've found in the testimony?

10 A (Witness Trokey) Yes, that's correct.

11 Q Noting those corrections in the errata, if I
12 were to ask you the same questions that are presented in
13 the prefiled testimony, would your answers be the same?

14 A (Witness Trokey) Yes.

15 MR. WALSH: Madam Chair, I would ask that the
16 prefiled direct testimony of the panel be copied into
17 the record as if read from the witness stand.

18 MADAM CHAIR PRIDEMORE: So moved.

19 (Whereupon, the prefiled direct testimonies
20 of Mr. Ralph C. Smith and Mr. Robert L. Trokey
21 follows:)

22

23

24

25

I. INTRODUCTION

Q. MR. SMITH, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit RCS-1. This exhibit summarizes my regulatory experience and qualifications.

Q. MR. TROKEY, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Robert L. Trokey, 244 Washington St. SW, Atlanta, Georgia 30334.

Q. WHAT IS YOUR OCCUPATION?

A. I am the Director of the Electric Section at the Georgia Public Service Commission ("Commission").

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit RLT-1. This exhibit summarizes my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. We are testifying on behalf of the Georgia Public Service Commission Public Interest

1 Advocacy Staff ("Staff").

2
3 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

4 A. The purpose of our testimony is to address certain accounting/ratemaking issues presented
5 by Georgia Power Company ("Georgia Power" or "Company") in this Integrated Resource
6 Plan ("IRP") proceeding.

7
8 We address generally the requests of Georgia Power for approval of specific costs. The
9 Company is requesting approval for several categories of costs, but not yet for the recovery
10 of such costs. An IRP proceeding is not the appropriate forum for addressing ratemaking
11 issues that should be addressed in a forum that considers the Company's earnings and risk.

12
13 In Section II, we address the Company's requests for accounting reclassifications related
14 to generating plants that are being retired. We agree with the Company's requests for
15 accounting reclassifications for decertified plant that is projected to be retired during the
16 2022-2025 IRP cycle. There is no need in the current IRP cycle for the Commission to
17 approve accounting reclassifications for generating units that are projected to be retired
18 after 2026. Accounting reclassifications for plant that is to be retired after 2026 can be
19 addressed in the Company's next IRP cycle which would cover 2026-2028. The Company
20 is also scheduled to have a rate case in 2022 in which depreciation rates and cost recovery
21 periods are expected to be reviewed and addressed.

22
23 In Section III, we address the Company's requests for accounting reclassifications related
24 to unusable materials and supplies at generating plants that are being retired.

25
26 In Section IV, we present information on Plant Held for Future Use ("PHFFU"). This
27 includes information concerning the cost of land being held by Georgia Power for future
28 use for projects that were included in prior IRPs but is not included in the Company's 2022

1 IRP because the projected use dates have been pushed out to 2040 or beyond, i.e., beyond
2 the Company's ten-year transmission planning period. The Company has a significant
3 amount of land which is not currently being used to provide utility service and for which
4 the projected use dates have been further extended into the 2040 and beyond period. This
5 includes a short discussion of Staff's continuing concerns with costs and amounts spent by
6 the Company for the future generating plant site land initially being held to preserve a new
7 nuclear option in Stewart County, Georgia. The Company has approximately \$22.9 million
8 in the PHFFU account for the related Stewart County land, which is being held as a site for
9 future generation.

10
11 In Section V, we discuss the approximate costs the Company has estimated for Asset
12 Retirement Obligations ("ARO") for Coal Combustion Residual ("CCR") rule compliance.
13 The Company has established a semi-annual reporting protocol to keep Staff updated with
14 its CCR spending and changes in its ash pond closures and ash pond and landfill
15 remediation activities. Overall, the Company projects spending approximately \$8.89
16 billion on CCR compliance, with spending projected to occur through 2075.¹ The
17 Company's projected CCR spending includes significant amounts for contingencies.
18 Recovery of costs related to CCR will be an issue in the Company's 2022 rate case.

19
20 In Section VI, we discuss the Additional Sum for capacity Purchased Power Agreements
21 (PPAs). Staff recommends that the Additional Sum for capacity PPAs continue to be set
22 at the \$2.30 /kW-year.

23
24 In Section VII, Staff addresses the costs associated with some of the Georgia Power
25 Company and Southern Company Services ("SCS") research projects, which are listed in
26 the IRP Main Document, Attachment H. The SCS research projects includes continued

¹ See, e.g., the response to STF-LA-4-5 Supplemental, a copy of which is included in Exhibit RS/RT-12.

1 research for a National Carbon Capture Center and spending to assess the feasibility of
2 CO2 storage in geologic formations in Kemper County², Mississippi near the site of the
3 lignite-fueled Kemper County IGCC plant that was cancelled by the affiliated utility,
4 Mississippi Power Company. Staff discusses its concerns with how the cost of some
5 research and development projects is being shared among Georgia Power and its Southern
6 Company affiliates.

7
8 In Section VIII and IX, respectively, we discuss the Company's request the approval of
9 costs for capital and operation and maintenance ("O&M") costs the Company will incur
10 for a Tall Wind demonstration project (but not yet the recovery of such costs) and for
11 approval of capital and O&M costs the Company will incur for an Integrated Hydrogen
12 Microgrid pilot project (but not yet the recovery of such costs), both of which are as set out
13 in the Selected Supporting Information section of Technical Appendix Volume I, which
14 we discuss in Sections I and IX. Staff has concerns about the need and benefit of such
15 projects and with how the cost of those research and demonstration projects, that would
16 not be funded by DOE grants, is being shared among Georgia Power and its Southern
17 Company affiliates.

18
19 In Section X, Staff addresses the Company's proposal for a Subsequent License Renewal
20 ("SLR") for the Plant Hatch nuclear units 1 and 2.

21
22 In Section XI, Staff addresses the Company's request for approval of its Environmental
23 Compliance Strategy ("ECS") and associated costs. The Company's ECS includes cost
24 recovery for Coal Combustion Residual ("CCR") Asset Retirement Obligations ("AROs").
25

26 Finally, in Section XII, Staff discusses concerns with the Company's proposal for

² See, e.g., page H-132 of Georgia Power Company's 2019 Integrated Resource Plan.

1 Beneficial Use of coal ash. Staff is concerned that the Company's beneficial use proposal
2 involves up-front investment, and projects future cost savings that might or might not
3 materialize, and thus could result in net overall cost increases to ratepayers. Staff
4 recommends that the Commission direct the Company to present additional information
5 prior to or in conjunction with its upcoming rate case so there can be confidence that the
6 Beneficial Use will more assuredly provide net cost savings, and not become an additional
7 cost burden on ratepayers, prior to approving the program. Once the Company evaluates
8 responses to the Beneficial Use RFP process, Staff recommends that the Commission direct
9 the Company to use that information to update its net present value cost benefit analysis,
10 and to present the updated NPV analysis for consideration in the Company's upcoming
11 rate case.

12
13 **Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?**

14 **A.** Yes. In addition to our qualifications, which are in Exhibit RCS-1 and RLT-1, respectively,
15 Staff has attached Exhibits RS/RT-2 through RS/RT-13 which contain responses to
16 discovery and other materials referenced in our testimony.

17
18 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-2?**

19 **A.** Exhibit RS/RT-2 contains responses to STF-LA-1-28, STF-LA-1-29, STF-LA-2-40, STF-
20 LA-2-42, STF-LA-2-44, STF-LA-2-46, STF-LA-2-48, and STF-LA-2-51 concerning
21 remaining net book value at December 31, 2021 for generating plant units for which the
22 Company has requested decertification.

23
24 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-3?**

25 **A.** Exhibit RS/RT-3 contains responses to STF-LA-2-35 through STF-LA-2-37 concerning
26 estimates of materials and supplies at plants for which the Company has requested
27 decertification and estimates by the Company of amounts that may become unusable.

1 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-4?**

2 A. Exhibit RS/RT-4 contains information on Plant Held for Future Use including pages from
3 the Company's 2021 FERC Form 1, Exhibit RS/RT-5 from Staff's testimony in Georgia
4 Power's 2019 IRP proceeding, and responses to STF-LA-1-44, STF-LA-1-45 (without
5 trade secret attachments), and STF-LA-1-46 through STF-LA-1-51.
6

7 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-5?**

8 A. Exhibit RS/RT-5 contains the response to STF-LA-1-21 concerning the dismantlement cost
9 and cost of removal.
10

11 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-6?**

12 A. Exhibit RS/RT-6 contains Georgia Power's discovery responses to STF-LA-3-1 through
13 STF-LA-3-6 and STF-LA-3-8 through 3-10 related to the Additional Sum on Capacity and
14 Energy Purchased Power Agreements ("PPAs").
15

16 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-7?**

17 A. Exhibit RS/RT-7 contains discovery responses to STF-LA-1-52 through STF-LA-1-65 on
18 research projects.
19

20 **Q. WHAT ARE SHOWN IN EXHIBITS RS/RT-8?**

21 A. Exhibit RS/RT-8 presents responses to STF-LA-2-21 (trade secret) and STF-LA-2-22 and
22 STF-LA-2-24 on the Tall Wind demonstration project.
23

24 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-9?**

25 A. Exhibits RS/RT-9 presents discovery responses to STF-LA-2-25, STF-LA-2-26, and STF-
26 LA-2-28 on the Integrated Hydrogen Microgrid Pilot Project.
27

28 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-10?**

1 A. Exhibit RS/RT-10 presents discovery responses to STF-LA-6-1 through STF-LA-6-5
2 related to the Plant Hatch Subsequent License Renewal. (STF-LA-6-2 and STF-LA-6-3
3 contain Trade Secret information).

4
5 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-11?**

6 A. Exhibit RS/RT-11 presents discovery responses to STF-LA-1-6, STF-LA-1-14, STF-LA-
7 4-12 and STF-LA-4-13 related to the Environmental Compliance Plan (includes trade
8 secret attachments).

9
10 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-12?**

11 A. Exhibit RS/RT-12 presents discovery responses to STF-LA-1-16, STF-LA-1-18, STF-LA-
12 4-4, and STF-LA-4-5 regarding Coal Combustion Residuals ("CCR") Asset Retirement
13 Obligation ("ARO") accounting, closure method selection and contingency amounts
14 (includes trade secret attachments).

15
16 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-13?**

17 A. Exhibit RS/RT-13 presents discovery responses to STF-LA-4-14 and STF-LA-4-15
18 concerning developing beneficial uses of CCR (includes trade secret information).

19
20 **Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS ON THESE
21 ISSUES?**

22 A. Staff's conclusions and recommendations are as follows:

23
24 **1. Cost Recovery Issues**

25 The Company's 2022 IRP has generally indicated that it is requesting approval of O&M
26 and capital costs (but not yet the recovery of such costs). Staff recommends that specific
27 requests for approval of costs, and the associated recovery for such costs, should properly

1 be addressed when the Company's earnings are considered, such as in the Company's
2 anticipated 2022 base rate case, as opposed to this resource planning case.

3
4 **2. Accounting Reclassifications and Ratemaking Issues**

5 An accounting reclassification basically involves moving costs or a gain from one account
6 into another. One of the reasons why an accounting reclassification can be done is to
7 provide for the deferral of costs or a gain from one period so it can subsequently be
8 addressed for ratemaking purposes. Concerning the accounting reclassifications requested
9 by the Company, Staff has the following recommendations:

10
11 **a. 2022 Retirements**

12 For 2022 retirements, Staff does not object to the accounting reclassifications of
13 unrecovered net book value (not including dismantlement/cost of removal) and the related
14 unusable materials and supplies at these decertified units into regulatory assets (or
15 liabilities) upon retirement on the condition that approval of an accounting reclassification
16 in the 2022 IRP proceeding is done only to facilitate review in a subsequent ratemaking
17 proceeding and is not an approval of the costs or cost recovery period.

18
19 Staff recommends that the Commission not authorize specific cost recovery amounts or
20 recovery periods at this time because current rates already include depreciation expense for
21 these generating plant assets that are being retired in 2022 and the Company will continue
22 to collect this depreciation expense after the units are retired until the Company's rates are
23 changed in the next base rate case scheduled for 2022. Staff recommends that authorization
24 of any amortization periods and amounts to be amortized in a given accounting period
25 should be addressed as part of the review by Staff of the Company's earnings in the 2022
26 base rate case, to be filed in June 2022.

b. 2023-2025 Retirements

Staff does not object to the accounting reclassifications of unrecovered net book value (not including dismantlement/cost of removal) and the related unusable materials and supplies at decertified generating plant units that are projected to be retired in the 2023-2025 time frame into regulatory assets upon retirement of those units. Staff notes that the Company's 2022 IRP does not contain decertification requests for Company-owned generating plant units that are scheduled to be retired in the 2023-2026 time frame. The Company's proposed retirement dates for Plant Bowen Units 1-2, Plant Gaston Units 1-4 and Unit A and Plant Scherer are all beyond 2026.

c. Company-Owned Generating Plant Retirements Projected to Occur Beyond 2026

Staff does not believe that it is necessary for the Commission to approve in the current IRP proceeding the Company's requested accounting reclassifications of unrecovered net book value (not including dismantlement/cost of removal) and the related unusable materials and supplies at the decertified units that are projected to be retired in years beyond 2026. The Company's proposed retirement dates for Plant Bowen Units 1-2, Plant Gaston Units 1-4 and Unit A and Plant Scherer are all beyond 2026. Staff recommends that accounting reclassifications for generating units to be retired in years beyond 2026 not be approved at this time. Rather, the Company's requests for accounting reclassifications for costs related to generating units that are to be retired in 2027 and 2028 can be addressed in the Company's next rate case.

b. Company Dismantlement Cost Estimates and Cost of Removal Balances

Staff has additional concerns regarding the Company's estimates of the cost of removal/dismantlement for some of the generating units, including concerns about the Company's projected costs for CCR compliance. Due to these concerns, Staff recommends that no transfers of cost of removal or dismantlement cost estimates into a regulatory asset account be approved at this time. Instead, Staff recommends that the Commission reserve

1 such determinations until after the Company's dismantlement/cost of removal estimates
2 can be reviewed in conjunction with Staff's review in the Company's 2022 rate case which
3 will include an updated dismantlement study.
4

5 **3. Plant Held For Future Use with "Use" Dates of 2040 or Beyond**

6 Of the approximately \$106.61 million of Electric Plant Held for Future Use in account 105
7 as of December 31, 2021, Staff has identified approximately \$75.178 million of plant
8 (property) held for future use for projects for which the projected in-use dates have been
9 revised to be beyond 2040. Among The December 31, 2021 PHFFU is \$22.9 million for
10 the cost of land acquired in Stewart County, Georgia for a new generating plant site with a
11 projected use date of 1/1/2031, although the Company does not appear to have firm plans
12 at this time to construct a new generating plant on that site. Staff recommends that the
13 Company continue with its quarterly evaluations and updates of usage plans concerning
14 whether PHFFU that is being held is believed to continue to be needed to provide electric
15 utility service, and that the Commission direct the Company to maintain documentation for
16 such reviews that can be reviewed by Staff upon request.
17

18 **4. Additional Sum for Purchased Power Agreements**

19 Staff recommends that the Additional Sum amounts for Capacity and Energy Purchased
20 Power Agreements ("PPAs") be continued at the current level of \$2.30/kW-year for the
21 new PPAs, instead of the levelized \$7.50/kW-year proposed by the Company.
22

23 **5. Research Projects**

24 Although the Company does not appear to request authorization to continue its current
25 research, Staff recommends the Commission explicitly order that the inclusion of the
26 research and development ("R&D") projects of Southern Company and Georgia Power in
27 the 2022 IRP does not convey approval of those costs, or allocated costs, into jurisdictional
28 expenses that become the responsibility of ratepayers.

1
2 The Company has requested approval of O&M and capital costs for a Tall Wind
3 demonstration project and for an Integrated Hydrogen Microgrid pilot project (but not yet
4 the recovery of such costs). Concerning the Tall Wind demonstration project and the
5 Integrated Hydrogen Microgrid pilot project, other Staff witnesses have recommendations
6 concerning conditions to be placed upon approval of proceeding with those projects.
7

8 It appears that both the Tall Wind demonstration project and the Integrated Hydrogen
9 Microgrid pilot project could have benefits to the other Southern Company operating
10 utilities, not only to Georgia Power, so the costs of those projects should be shared among
11 the system companies, and not borne exclusively by Georgia Power Company and its
12 ratepayers.
13

14 We also identify a beneficial provision in the federal income tax law, Internal Revenue
15 Code section 174, applicable to research and experimentation expenditures, that expired in
16 2021, and which is currently before Congress for renewal/extension for years beyond 2021,
17 but which is currently embedded in a larger piece of legislation (the so-called "Build Back
18 Better" bill) that has stalled. Having tax benefits available related to research and
19 experimentation expenditures, such as the ability to write-off the costs in the year incurred,
20 rather than capitalizing and amortizing them over a longer period for federal income tax
21 purposes, could help with the economics of the demonstration projects.
22

23 **6. Approval of the Company's Environmental Compliance Plan and Cost**

24 An IRP proceeding is the appropriate forum for the Commission to consider approval of
25 the Company's ECS. However, an IRP proceeding is not the appropriate forum to approve
26 costs associated with the ECS. The reasonableness of the cost is dependent on many
27 factors, including the Commission's resource decisions in this docket and, ultimately, the

1 Company's execution of its ECS. An assessment of the Company's execution is properly
2 made after the ECS has been implemented and the costs have been incurred.
3

4 **7. Plant Hatch Units 1-2 Subsequent License Renewal**

5 Staff notes that a number of other U.S. nuclear generating plants have either already
6 received or in the process of applying (or are expected to apply for) similar subsequent
7 license extensions to the one that Georgia Power is proposing to request for Plant Hatch.
8 Staff does not object to the Company's request for approval (but not yet the recovery) of
9 capital and O&M costs that the Company proposes to incur to pursue a Subsequent
10 License Renewal for Plant Hatch nuclear units 1 and 2, subject to the Company agreeing
11 to semi-annual reporting on cost and any developments, including but not limited to
12 changes in Nuclear Regulatory Commission ("NRC") rules and procedures relating to
13 license renewals, which could significantly impact the cost of continuing to operate the
14 Hatch nuclear units for an additional 20 years.
15
16

1 **II. RECLASSIFICATION OF THE REMAINING NET BOOK VALUE OF PLANT**
2 **BOWEN UNITS 1-2, PLANT WANSLEY UNITS 1-2, PLANT WANSLEY UNIT 5A,**
3 **PLANT SCHERER UNIT 3, AND PLANT BOULEVARD UNIT 1 AS OF THEIR**
4 **RESPECTIVE RETIREMENT DATES TO REGULATORY ASSET ACCOUNTS**
5 **AND THE AMORTIZATION OF SUCH REGULATORY ASSET ACCOUNTS**
6 **RATABLY OVER A PERIOD TO BE DETERMINED BY THE COMMISSION IN**
7 **THE COMPANY'S FUTURE BASE RATE CASES**
8

9 **Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNTING**
10 **RECLASSIFICATION OF THE REMAINING NET BOOK VALUE FOR**
11 **GENERATING PLANT UNITS THAT IT PROPOSES TO RETIRE?**

12 A. At page 1-13 of the IRP Main Document in paragraph 13, the Company requests
13 Commission approval for:

14 Reclassification of the remaining net book value of Plant Bowen Units 1-2, Plant
15 Wansley Units 1-2, Plant Wansley Unit 5A, Plant Scherer Unit 3, and Plant Boulevard
16 Unit 1 as of their respective retirement dates to regulatory asset accounts and the
17 amortization of such regulatory asset accounts ratably over a period to be determined
18 by the Commission in the Company's future base rate cases.
19

20 **Q. WHAT RETIREMENT DATES FOR THOSE UNITS IS THE COMPANY**
21 **CURRENTLY USING FOR BOOK DEPRECIATION PURPOSES?**

22 A. The Company's response to STF-LA-1-28³ lists the following projected retirement dates
23 for each unit that are being used for book depreciation purposes, based on the depreciation
24 rates that were approved by the Commission in Docket No. 42516, the Company's 2019
25 base rate case:

³ A copy of this response is included in Exhibit RS/RT-2 attached to our direct testimony.

<u>Coal-Fired Generating Units</u>	<u>Life Span</u>	<u>Depreciation Study</u>
	<u>(Note 1)</u>	<u>Retirement Date</u>
		<u>(Note 1)</u>
<u>Plant Bowen</u>		
Unit 1	59	2030
Unit 2	58	2030
Unit 3	60	2034
Unit 4	60	2035
<u>Plant Scherer</u>		
Unit 1	60	2042
Unit 2	60	2044
Unit 3	60	2047
<u>Plant Wansley</u>		
Unit 1	54	2030
Unit 2	52	2030

Note 1 - As approved by the Commission in Docket No. 42516

Q. WHAT GENERATING UNITS DOES THE COMPANY PROPOSE TO RETIRE IN 2022?

A. As summarized on page 1-5 of the IRP Main Document, the Company proposes to retire Plant Wansley Units 1-2 and Unit 5A and Plant Boulevard by August 31, 2022.

Q. WHAT DOES STAFF RECOMMEND CONCERNING THE ACCOUNTING RECLASSIFICATION OF REMAINING NET BOOK VALUE OF THOSE UNITS AS OF THE DATE OF RETIREMENT INTO A REGULATORY ASSET (OR LIABILITY) ACCOUNT?

A. For 2022 retirements, Staff does not object to the accounting reclassifications of unrecovered net book value, excluding dismantlement/cost of removal, and the related

1 unusable materials and supplies at these decertified units into regulatory assets upon
2 retirement on the condition that approval of an accounting reclassification in the 2022 IRP
3 proceeding is done only to facilitate review in a subsequent ratemaking proceeding and is
4 not an approval of the costs or cost recovery period.

5
6 Staff also recommends that the Commission not authorize specific cost recovery periods at
7 this time. Current rates already include depreciation expense for these assets and the
8 Company will continue to collect this depreciation expense after the units are retired until
9 the Company's rates are changed in the next base rate case scheduled for 2022. Staff
10 recommends that authorization of any amortization periods and amounts to be amortized
11 in a given accounting period should be addressed as part of the review by Staff of the
12 Company's earnings in the 2022 base rate case, to be filed in June 2022.

13
14 **Q. PLEASE EXPLAIN THE REASON FOR NOT INCLUDING APPROVAL OF**
15 **DISMANTLEMENT COSTS OR COST OF REMOVAL IN AN IRP**
16 **PROCEEDING.**

17 A. As indicated in the Company's response to STF-LA-1-21⁴ the Company's last
18 dismantlement study was conducted in 2018 and completed in 2019 was used in the
19 Company's 2019 rate case. Dismantlement costs and cost of removal are thus
20 appropriately reviewed and addressed in a base rate case, rather than an IRP proceeding.
21 The Company has not yet provided an updated dismantlement cost study, but would be
22 expected to have one for use in its 2022 base rate case.

23
24 **Q. DOES THE COMPANY PROJECT HAVING GENERATING PLANT**
25 **RETIREMENTS IN THE 2023-2025 TIME FRAME?**

26 A. Staff notes that the Company's proposed retirement dates for Plant Bowen Units 1-2, Plant

⁴ A copy of that response is included in Exhibit RS/RT-5.

Gaston Units 1-4 and Unit A and Plant Scherer are all beyond 2026.

Q. DOES THE COMPANY PROJECT HAVING GENERATING PLANT RETIREMENTS FOR DECERTIFIED UNITS BEYOND 2026?

A. Yes. The Company projects the following generating plant retirements beyond 2026:

- Plant Bowen Units 1-2 by December 31, 2027
- Plant Gaston Units 1-4 and Unit A by December 31, 2028
- Plant Scherer Unit 3 by December 31, 2028

Q. IS IT NECESSARY TO APPROVE ACCOUNTING RECLASSIFICATIONS IN THE CURRENT IRP PROCEEDING FOR GENERATING PLANT UNITS THAT ARE PROJECTED TO BE RETIRED BEYOND 2026?

A. No. It is unnecessary for the Commission to approve in this proceeding the Company's requested accounting reclassifications of unrecovered net book value (not including dismantlement/cost of removal) and the related unusable materials and supplies at the decertified units that are projected to be retired in 2026 or beyond. Staff recommends that accounting reclassifications for generating units to be retired beyond 2026 not be approved at this time. Rather, the Company's requests for accounting reclassifications for generating units to be retired in 2027 and 2028 can be addressed in the Company's next IRP case, which would be filed in 2025, and in the Company's 2025 rate case.

Q. HAS THE COMPANY IDENTIFIED REMAINING NET BOOK VALUE FOR THE GENERATING UNITS IT IS PROPOSING TO HAVE DECERTIFIED?

A. Yes. Generally, the Company has been able to identify the remaining net book value as of December 31, 2021, but not as of the projected dates proposed for retirement. For

1 example, the Company's response to STF-LA-1-29⁵ identifies a remaining net book value
2 (excluding land, asset retirement obligations, plant acquisition adjustment and cost of
3 removal costs) for plants Bowen, Scherer and Wansley at December 31, 2021 of
4 approximately \$3.14 billion.

5
6 The Company's responses to STF-LA-2-40, STF-LA-2-42, STF-LA-2-44 and STF-LA-2-
7 46⁶ include remaining net book value amounts for the Plant Gaston units as of December
8 31, 2021.

9
10 The Company's response to STF-LA-2-48⁷ shows the remaining net book value for Plant
11 Wansley Unit 5A at December 31, 2021.

12
13 Finally, the Company's response to STF-LA-2-41⁸ shows the remaining net book value for
14 Plant Boulevard at December 31, 2021. The remaining net book value ("NBV") for Plant
15 Boulevard listed there is a credit (i.e., negative) amount indicating that the amount of
16 depreciation that has been accumulated in account 108 has exceeded the original cost of
17 the plant recorded in account 101. The negative amount of remaining NBV for Plant
18 Boulevard at December 31, 2021 will need to be transferred into a regulatory liability
19 account if the remaining NBV continues to be negative as of the retirement date for that
20 unit. As noted above, Georgia Power projects to retire Plant Boulevard Unit 1 by August
21 31, 2022.
22

⁵ A copy of that response is included in Exhibit RS/RT-2.

⁶ Copies of those responses are included in Exhibit RS/RT-2. Amounts listed in those responses represent 100% of the SEGCO units. Georgia Power and Alabama Power each have 50% shares in SEGCO which operates the Plant Gaston generating units.

⁷ A copy of that response is also included in Exhibit RS/RT-2.

⁸ A copy of that response is also included in Exhibit RS/RT-2.

III. RECLASSIFICATION OF ANY UNSUABLE MATERIAL AND SUPPLIES INVENTORY BALANCE REMAINING AT THE UNIT RETIREMENT DATES TO A REGULATORY ASSET FOR RECOVERY OVER A PERIOD TO BE DETERMINED BY THE COMMISSION IN THE COMPANY'S FUTURE BASE RATE CASES, CONSISTENT WITH TREATMENT OF SUCH BALANCE IN THE 2019 ORDER

Q. WHAT HAS THE COMPANY PROPOSED FOR UNUSABLE MATERIALS AND SUPPLY BALANCES FOR THE GENERATING PLANT UNITS THAT IT PROJECTS TO RETIRE?

A. In paragraph 14 at page 1-13 of the IRP Main Document, the Company requests Commission approval for:

Reclassification of any unusable material and supplies inventory balance remaining at the unit retirement dates to a regulatory asset for recovery over a period to be determined by the Commission in the Company's future base rate cases, consistent with treatment of such balance in the 2019 IRP Order.

Q. HAS THE COMPANY IDENTIFIED AMOUNTS OF MATERIALS AND SUPPLIES AT THOSE PLANTS AS OF DECEMBER 31, 2021?

A. Yes. The Company's response to STF-LA-2-35 identifies materials and supplies ("M&S") balances for Plant Wansley and Plant Boulevard as of December 31, 2020 and 2021, respectively. The Company's response to STF-LA-2-36 indicates that the Company has not yet determined a projected amount of M&S that would become unusable at other Company locations after August 31, 2022. The Company's response to STF-LA-3-37 describes efforts being undertaken by the Company to minimize the amount of unusable M&S at Plants Wansley and Plant Boulevard Unit 1.⁹

Q. WHAT IS STAFF'S RECOMMENDATION CONCERNING THE COMPANY'S REQUEST TO TRANSFER UNUSABLE M&S INTO A REGULATORY ASSET ACCOUNT?

⁹ Copies of the Company's responses to these DRs are included in Exhibit RS/RT-3.

1 A. Staff is supportive of the concept of allowing unusable amounts of M&S at the plants that
2 are slated for retirements by August 2022 to be transferred into regulatory asset accounts;
3 however, since the Company will be filing a 2022 rate case prior to August 2022, Staff
4 recommends that the unused M&S amounts be reviewed in the Company's rate case and
5 that the Commission reserve judgment on approving M&S transfer amounts for the rate
6 case. As noted above with respect to remaining net book value for generating plants
7 scheduled to be retired, approval of an accounting reclassification in the 2022 IRP
8 proceeding would be done only to facilitate review in a subsequent ratemaking proceeding
9 and is not an approval of the costs or cost recovery period. Since the Company is filing a
10 2022 rate case prior to the August 2022 planned retirement dates for the Plant Wansley and
11 Boulevard units, pre-approval in this IRP of an accounting transfer for unused M&S does
12 not appear to be necessary. Rather, this is an item that should be subject to review in the
13 Company's 2022 rate case.

14
15 **IV. PLANT HELD FOR FUTURE USE**

16
17 **Q. HOW MUCH PLANT HELD FOR FUTURE USE DID THE COMPANY HAVE AS**
18 **OF DECEMBER 31, 2021?**

19 A. Based on the Company's FERC Form 1 for 2021¹⁰ and the Company's response to STF-
20 LA-1-44 which shows similar information, at December 31, 2021 the Company had
21 approximately \$106.61 million of PHFFU.

22
23 **Q. HAVE THE PROJECTED "IN-SERVICE" DATES FOR SEVERAL OF THE**
24 **PHFFU ITEMS BEEN PUSHED OUT INTO 2040?**

25 A. Yes. In comparison with the listing of PHFFU from Staff's testimony in the Company's

¹⁰ A copy of the 2021 FERC Form 1 pages for PHFFU and the Company's response to STF-LA1-44 are included in Exhibit RS/RT-4.

1 2019 IRP¹¹, which had a “date expected to be used in utility service” of 2030, several
2 PHFFU projects listed in the 2021 FERC Form 1 now have a date of 12/31/2040 as the
3 expected use date. Staff has identified approximately \$75.178 million of PHFFU that now
4 as a projected use date of 2040 or beyond.

5
6 **Q. WHAT IS STAFF’S CONCERN ABOUT THE AMOUNTS BEING HELD IN THE**
7 **PHFFU ACCOUNT AND THE PUSHING OUT OF THE PROJECTED “DATE**
8 **EXPECTED TO BE USED IN UTILITY SERVICE” FOR SEVERAL ITEMS TO**
9 **2040 OR BEYOND?**

10 **A.** Staff’s concern is that while being held in the PHFFU account, the PHFFU has generally
11 been included in rate base, and the financing costs, property taxes and maintenance costs
12 have been included in the Company’s revenue requirement and charged to ratepayers. Yet
13 the expected dates for use in the provision of utility service have continued to get pushed
14 out further into the future for several of the PHFFU items.

15
16 **Q. WHAT IS THE DECEMBER 31, 2021 PHFFU AMOUNT FOR THE STEWART**
17 **COUNTY LAND THAT THE COMPANY ORIGINALLY PURCHASED FOR A**
18 **POSSIBLE FUTURE NUCLEAR PLANT GENERATING SITE?**

19 **A.** The December 31, 2021 balance for the Stewart County land is approximately \$22.9
20 million, per the FERC Form 1 information and the Company’s response to STF-LA-1-44.
21 When asked about the Company’s plans for using that Stewart County land to provide
22 electric utility service, the Company’s response to STF-LA-1-49 stated that: “The
23 Company continues to consider all available options, but had not determined the type of
24 generation facility nor the timing of when such generation would be added to the Stewart

¹¹ A copy of the one-page exhibit __ (RS/RT-5) from Staff’s testimony in the 2019 IRP is also included in Exhibit RS-RT-4 for ease of reference.

County site.”¹²

Q. AS OF DECEMBER 31, 2021 DID THE COMPANY HAVE ANY REMAINING AMOUNTS ON ITS BOOKS RELATING TO THE STEWARD COUNTY SITE INVESTIGATION?

A. No, as confirmed in the Company’s response to STF-LA-1-51.¹³

Q. DOES THE COMPANY HAVE APPRAISALS FOR SOME OF THE PHFFU?

A. Yes. Appraisals for some of the PHFFU, including the Stewart County site, were provided in trade secret attachments to the Company’s response to STF-LA-1-45.¹⁴

Q. HAS THE COMPANY IDENTIFIED THE PROPERTY TAXES ON THE PHFFU?

A. Yes. The Company’s response to STF-LA-1-46 identifies the actual property taxes on the PHFFU for 2020 and 2021 and the estimated property taxes for each year, 2022 through 2025.¹⁵

Q. DURING 2021, DID THE COMPANY TRANSFER ANY ITEMS OUT OF PHFFU AND INTO NON-UTILITY PROPERTY?

A. No, as indicated in the Company’s response to STF-LA-1-47.¹⁶

Q. DURING 2021, DID THE COMPANY SELL ANY ITEMS THAT HAD BEEN RECORDED IN PHFFU?

¹² A copy of that response is included in Exhibit RS/RT-4.

¹³ A copy of that response is included in Exhibit RS/RT-4.

¹⁴ A copy of the Company’s response to STF-LA-1-45 is included in Exhibit RS/RT-4 without the Trade Secret attachments.

¹⁵ A copy of that response is included in Exhibit RS/RT-4.

¹⁶ A copy of that response is included in Exhibit RS/RT-4.

1 A. No, as indicated in the Company's response to STF-LA-1-48.¹⁷

2
3 **Q. DURING 2021, DID THE COMPANY PLACE ANY OF THE PRIOR YEAR PHFFU**
4 **ITEMS INTO ELECTRIC SERVICE?**

5 A. Yes. As indicated in the Company's response to STF-LA-1-50, the Company put the Coal
6 Mountain 230KV Transmission Line and Coal Mountain Substation Site into electric
7 service in 2021.¹⁸

8
9 **Q. WHAT IS STAFF'S RECOMMENDATION FOR PHFFU?**

10 A. Staff recommends that the PHFFU be reviewed in the Company's upcoming rate case.
11 Staff recommends that the Company continue with its quarterly evaluations and updates of
12 usage plans concerning whether PHFFU that is being held is believed to continue to be
13 needed to provide electric utility service, and that the Commission direct the Company to
14 maintain documentation for such reviews that can be reviewed by Staff upon request.

15
16
17 **V. THE CAPITAL, O&M, AND CCR ARO COSTS (BUT NOT YET THE**
18 **RECOVERY OF SUCH COSTS) AND ASSOCIATED MEASURES TAKEN TO**
19 **COMPLY WITH GOVERNMENT-IMPOSED ENVIRONMENTAL MANDATES,**
20 **AS SET OUT IN THE ECS IN TECHNICAL APPENDIX VOLUME 2 AND THE**
21 **ECCR AND CCR ARO TABLES IN THE SELECTED SUPPORTING**
22 **INFORMATION SECTION OF TECHNICAL APPENDIX VOLUME 1**

23
24 **Q. WHAT HAS THE COMPANY PROPOSED FOR THE CAPITAL, O&M, AND CCR**
25 **ARO COSTS AND ASSOCIATED MEASURES TAKEN TO COMPLY WITH**
26 **GOVERNMENT-IMPOSED ENVIRONMENTAL MANDATES?**

27 A. In paragraph 15 at page 1-13 of the IRP Main Document, the Company presents the

¹⁷ A copy of that response is included in Exhibit RS/RT-4.

¹⁸ A copy of that response is included in Exhibit RS/RT-4.

1 following request for Commission approval of:

2 The capital, O&M, and CCR ARO costs (but not yet the recovery of such costs) and
3 associated measures taken to comply with government-imposed environmental
4 mandates, as set out in the ECS in Technical Appendix Volume 2 and the ECCR and
5 CCR ARO tables in the Selected Supporting Information section of Technical
6 Appendix Volume I.

7
8 **Q. HAS THE COMPANY PROVIDED DETAILS FOR ITS PROJECTED ECCR**
9 **COSTS?**

10 A. Yes. The Company's response to STF-LA-1-6 and its TS-STF-LA-1-6 Attachment
11 provide project to date costs through 2021 as well as projected costs for the years, 2022
12 through 2025, and the response to STF-LA-1-14 and the TS STF-LA-1-14 Attachment
13 includes summary level ECCR capital expenditure projections and plant in service amount
14 projections for the years 2016 through 2031, and projected O&M expenses for 2026.¹⁹ The
15 Company's response indicates that it would also be providing the updated ECCR in an
16 errata filing.

17 **Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE COMPANY'S PROJECTED**
18 **ECCR COSTS?**

19 A. The Company's projected ECCR costs include capital and O&M expenditures for
20 environmental control equipment such as scrubbers and Selective Catalytic Reduction
21 (SCR) equipment, baghouses, waste water treatment, ash management, landfills, and other
22 controls.

23 **Q. HAS THE COMPANY'S ECCR TARIFF BEEN SUBJECT TO TRUE-UP?**

24 A. No. As indicated in the response to STF-LA-4-12, the ECCR tariff approved by the
25 Commission in the Company's 2019 base rate case in Docket No. 42516 was not subject
26 to true-up.

27 **Q. HAS THE COMPANY MAINTAINED INFORMATION ON WHETHER IT HAS**

¹⁹ A copy of those responses are included in Exhibit RS/RT-11, not including voluminous TS detail.

OVER- OR UNDER-RECOVERED COSTS VIA ITS ECCR TARIFF?

A. No, as indicated in the response to STF-LA-4-12, because the ECCR was not subject to true-up, the Company has not maintained an under- or over-recovery balance related to the ECCR.

Q. ARE CONTINGENCY AMOUNTS PROJECTED BY THE COMPANY FOR THE ECCR?

A. Yes. As indicated in the response to STF-LA-4-13, the \$238.90 million of total ECCR capital expenditures projected for 2022-2025 include a collective contingency of approximately \$9.5 million for projects that are valued at more than one million.

Q. WHAT IS STAFF'S RECOMMENDATION IN THIS IRP CASES CONCERNING THE COMPANY'S PROJECTED ECCR COSTS?

A. Staff's recommendation is that the Commission approve the Company's ECCR plan as updated in the Company's response to STF-LA-1-6 and in the filed errata, but not approve specific costs or cost recovery at this time. Staff recommends that approval of specific costs and ECCR cost recovery be addressed in the Company's upcoming rate case.

VI. THE LEVELIZED ADDITIONAL SUM AMOUNTS DESCRIBED IN ATTACHMENT K BASED ON THE VALUE OF THE PPAS PROCURED IN THE 2022-2028 CAPACITY RFP AS COMPARED TO THE COMPANY-OWNED PROPOSAL**Q. WHAT HAS THE COMPANY PROPOSED FOR LEVELIZED ADDITIONAL SUM AMOUNTS FOR THE PPAS PROCURED IN THE 2022-2028 CAPACITY RFP?**

A. In paragraph 17 on page 1-14 of the IRP Main Document, the Company presents the following request:

The levelized additional sum amounts described in ATTACHMENT K based on the value of the PPAs procured in the 2022-2028 Capacity RFP as compared to the Company-owned proposal.

1
2 **Q. WHAT LEVELIZED ADDITIONAL SUM FOR THE CAPACITY PPAS DOES**
3 **THE COMPANY REQUEST?**

4 A. The Company is requesting \$7.50 / kW-year.
5

6 **Q. HOW DOES THE GEORGIA CODE PROVIDE FOR AN ADDITIONAL SUM?**

7 A. O.C.G.A. §46-3A-8, states that the Company is entitled to an additional sum, as determined
8 by the Commission, for purchased power resources. This Code section also describes
9 certain factors that shall be considered by the Commission, such as lost revenues, changed
10 risks and equitable sharing of benefits between the Company and ratepayers in determining
11 the appropriate additional sum required to encourage long-term power purchases.
12 However, while the Georgia Code sets forth certain factors that the Commission must
13 consider in setting the additional sum, neither the Act nor Commission Order set forth any
14 specific methodology or formula to calculate that additional sum.
15

16 **Q. WHAT ADDITIONAL SUM HAS THE COMPANY TYPICALLY RECEIVED**
17 **FOR RESOURCES PROCURED IN CAPACITY RFPS?**

18 A. The Company has typically received \$2.30/kW-year for capacity resources procured
19 through capacity RFPs.
20

21 **Q. HOW HAVE THE ADDITIONAL SUM AMOUNTS BEEN TREATED FOR**
22 **RATEMAKING AND ASR PURPOSES?**

23 A. For both rate case and ASR purposes, the Additional Sum amounts provide revenue to the
24 Company but there is no related expense recorded in the Company's general ledger.²⁰ The
25 Additional Sum amounts essentially provide additional revenue and pre-tax income to the

²⁰ See, e.g., the Company's responses to STF-LA-2-20 and STF-LA-3-4, which provide the Company's explanation. Both of those responses are included in Exhibit RS/RT-6.

1 Company and the amounts are removed in the ASRs so the earnings related to that
2 additional pre-tax income has not been subject to sharing or keeping erring above the
3 minimum threshold. In the ASRs, the Additional Sum amounts are reflected in a column
4 adjustment.

5
6 **Q. WHAT ARE THE ADDITIONAL SUM AMOUNTS IN 2020 AND 2021 FOR**
7 **EXISTING CAPACITY PPAS?**

8 A. Those amounts are shown in the attachment to the Company's response to STF-LA-3-1.²¹
9 Other than for the Mid-Georgia Cogen PPA, which is based on a formula of 20% of actual
10 savings, the other Additional Sums use \$2.30/kW-year as the basis. The \$2.30 /kW-year
11 amount is multiplied by the designated capacity MW to derive the Additional Sum amount
12 for each of those existing capacity PPAs.

13
14 Similar information for each year, 2022 through 2025, is shown in the Company's response
15 to STF-LA-3-2.²²

16
17 **Q. HAS THE COMPANY PROVIDED INFORMATION SHOWING THE**
18 **PROJECTED ANNUAL ADDITIONAL SUM AMOUNTS THAT IT IS**
19 **PROPOSING FOR EACH OF THE 2022-2028 CAPACITY RFP PPAS?**

20 A. Yes. That information is shown in in the Company's response to STF-LA-3-3.²³

21
22 **Q. DOES THE COMPANY INCLUDE THE ADDITIONAL SUMS IN ITS**
23 **ECONOMIC EVALUATION OF THE CAPACITY PPAS?**

²¹ A copy of that response is included in Exhibit RS/RT-6.

²² A copy of that response is included in Exhibit RS/RT-6.

²³ A copy of that response is included in Exhibit RS/RT-6.

1 A. No, as indicated in the response to STF-LA-3-5.²⁴

2
3 **Q. DOES THE COMPANY CONSIDER THE ADDITIONAL SUMS IN ITS**
4 **ECONOMIC DISPATCH DECISION MAKING PROCESS?**

5 A. No, as indicated in the response to STF-LA-3-6.²⁵

6
7
8 **Q. HAS THE COMPANY COMPUTED THE "NET EQUIVALENT COST" FOR THE**
9 **SIX CAPACITY AND ENERGY PPAS AND/OR FOR THE COMPANY-OWNED**
10 **PROPOSAL ("COP") AMOUNT THAT IT USED IN EVALUATING THE**
11 **BENEFITS OF EACH OF THOSE PPAS?**

12 A. Yes.

13
14 **Q. DID THE COMPANY PREPARE A "NET EQUIVALENT COST" ANALYSIS FOR**
15 **THE GENERATING UNITS IT IS PROPOSING FOR DECERTIFICATION ON A**
16 **NET PRESENT VALUE PER KW BASIS?**

17 A. No, the Company did not prepare that "net equivalent cost" analysis as indicated in the
18 response to STF-LA-3-7.²⁶

19
20 **Q. HAS THE COMPANY EXPLAINED THE \$2.30 /KW-YEAR THAT HAS**
21 **HISTORICALLY BEEN USED FOR THE ADDITIONAL SUMS FOR EXISTING**
22 **CAPACITY PPAS?**

23 A. Yes. The Company's response to STF-LA-3-8 provides an explanation.²⁷ The \$2.30 /kW-

²⁴ A copy of that response is included in Exhibit RS/RT-6.

²⁵ A copy of that response is included in Exhibit RS/RT-6.

²⁶ A copy of that response is included in Exhibit RS/RT-6.

²⁷ A copy of that response is included in Exhibit RS/RT-6.

year additional sum is a fixed, stipulated amount adopted by the Commission in its Order Adopting Stipulation in Docket No. 11086, which was filed on March 30, 2000. With the exception of the Mid-Georgia Cogen PPA, the \$2.30/kW-year has been used consistently since then as the basis for additional sum amounts for capacity PPAs.

Q. IS THERE A RELATIONSHIP BETWEEN THE EXPIRATION DATES OF SOME OF THE CURRENT CAPACITY PPAS AND THE NEW CAPACITY PPAS THAT THE COMPANY IS PROPOSING?

A. Yes. The Company's response to STF-LA-3-9 provides an explanation of the expiration dates of the existing and proposed PPAs for Monroe 1 and 2 and Dahlberg 2 and 6, and Dahlberg 8-10, noting that Dahlberg 9 is not currently contracted.²⁸ The existing capacity PPA with Monroe 1 and 2 expires May 31, 2024 and the new proposed Monroe 1 and 2 capacity PPA would start on December 1, 2024. The existing Dahlberg 2, 6, 8 and 10 capacity PPA expires on May 31, 2025 and the new Dahlberg 2 and 6 and Dahlberg 8-10 capacity PPAs would start on June 1, 2025.

Q. ARE THE FACILITIES PROVIDING THE CAPACITY AND ENERGY FOR THE PROPOSED PPAS PROJECTED TO CONTINUE TO OPERATE BEYOND THE PPA END DATES?

A. The Company's response to STF-LA-3-10²⁹ which contains trade secret information is responsive to that question.³⁰

Q. WHAT DOES STAFF RECOMMEND FOR THE ADDITIONAL SUM FOR THE NEW CAPACITY PPAS?

²⁸ A copy of that response is included in Exhibit RS/RT-6.

²⁹ A copy of that response is included in Exhibit RS/RT-6.

³⁰ A copy of that response is included in Exhibit RS/RT-6.

1 A. Staff recommends that the current \$2.30 /kW-year level be continued for the new capacity
2 PPAs. Under traditional ratemaking the Company makes capital investments in order to
3 provide reliable service. The Commission allows the Company to earn a return on capital
4 investment in order to compensate investors for the capital they have provide to the
5 Company. In contrast, the Company makes no capital investment when procuring capacity
6 through capacity PPAs but is being allowed a return or profit through the additional sum.
7 The Additional Sum amounts, once approved by the Commission, effectively function as
8 additional revenue to the Company which produces pre-tax profits to shareholders. The
9 Additional Sum amounts for PPAs have traditionally been at \$2.30/kW-year for most of
10 the PPAs and the revenues related to those Additional Sums have historically been
11 excluded from consideration in the reviews of the Company's earnings and earnings
12 sharing that have occurred in conjunction with the reviews by Staff of the Company's
13 Annual Surveillance Reports.

14
15 **Q. WHAT CRITICISMS DO YOU HAVE OF THE COMPANY'S PROPOSAL?**

16 A. The Company's proposed levelized \$7.50/kW-year is based on comparisons with a
17 Company-Owned proposal that was not economic and was not selected. By increasing the
18 additional sum for the new capacity PPAs, the Company is diverting a larger portion of the
19 PPAs' benefit from ratepayers to its shareholders when its shareholders have put up no
20 capital or undertaken any risk. Staff finds that attempting to compare PPAs with an
21 uneconomic Company-Owned proposal should not be the basis for resetting or
22 substantially increasing the Additional Sum for the capacity PPAs. Under the Company's
23 proposed logic, the more uncompetitive its Company-Owned proposals are, the higher the
24 additional sum would be, since it would be based on a comparison of the capacity PPA
25 with the projected cost of the uneconomical COP. The Company wants a higher reward
26 (i.e., higher capacity PPA Additional Sums) for its COP being more costly, uneconomic
27 and uncompetitive. This is economically irrational and not in the public interest. There is
28 no compelling reason for increasing the PPA Additional Sum beyond the current level of

1 \$2.30/kW-year for the new capacity PPAs as the Company continues as in the past to make
2 no capital investment when procuring capacity under PPAs. Staff recommends that the
3 Company's proposals to increase the capacity PPA Additional Sum amounts to a new
4 levelized amount of \$7.50/kW-year in the current IRP proceeding be rejected. Staff
5 recommends that the Commission continue with the current \$2.30/kW-year as the basis for
6 the Additional Sums for the new capacity PPAs.

7
8 **Q. DOES STAFF INTEND TO REVIEW IN THE UPCOMING RATE CASE**
9 **WHETHER THE ADDITIONAL SUM AMOUNTS SHOULD CONTINUE TO BE**
10 **EXCLUDED PROSPECTIVELY FROM EARNINGS REVIEWS?**

11 **A.** Yes. In the upcoming rate case, Staff intends to re-examine the issue of including the
12 additional sums in the earnings reviews on a going forward basis. If the additional sum is
13 increased, that would only increase the need to include it in earnings reviews.

14
15 **VII. RESEARCH AND DEVELOPMENT**

16 **Q. HOW HAVE YOU ORGANIZED THE DISCUSSION OF THE COMPANY'S**
17 **RESEARCH AND DEVELOPMENT EXPENDITURES?**

18 **A.** First, we discuss generally the Company's research and development from the IRP Main
19 Document, Attachment I, Research Activities. This includes some discussion of Staff's
20 follow through on some research activities that were in prior IRPs. We then discuss in
21 Section VIII and IX, the Company's proposals for approval of a Tall Wind demonstration
22 project and an Integrated Hydrogen Microgrid Pilot Project, respectively.

23
24 **Q. HAS STAFF REVIEWED THE FOUR STRATEGIC ASPIRATIONS FOR**
25 **RESEARCH ACTIVITIES THAT ARE PRESENTED IN ATTACHMENT I TO**
26 **THE IRP MAIN DOCUMENT?**

27 **A.** Yes. Staff has reviewed and is generally supportive of those four strategic aspirations that
28 the Company has presented in Attachment I to the IRP Main Document.

1
2 **Q. WHAT CONCERNS DOES STAFF HAVE ABOUT THE COMPANY'S**
3 **RESEARCH PROJECTS?**

4 A. Staff has concerns about whether costs for research that are allocated and charged to
5 Georgia Power are actually beneficial to its customers. Staff also is concerned whether
6 research that is conducted and funded by Georgia Power provides wider benefits to the
7 Southern Company system without other system companies sharing in the costs.
8

9 **Q. HAS GEORGIA POWER INCURRED EXPENSE FOR THE NATIONAL**
10 **CARBON CAPTURE CENTER?**

11 A. Yes. The Company's response to STF-LA-1-52³¹ indicates that the Company incurred
12 expense of \$2.54 million and \$2.37 million in 2020 and 2021, respectively, that it recorded
13 in account 506.
14

15 **Q. HAS GEORGIA POWER INCURRED EXPENSE FOR THE KEMPER COUNTY**
16 **MISSISSIPPI CARBON STORAGE ASSURANCE FACILITY ENERTPRISE**
17 **(CARBONSAFE)?**

18 A. Yes. The Company's responses to STF-LA-1-53 and 1-54 indicates the amounts of
19 expense in 2020 and 2021 that the Company incurred for CarbonSAFE, which is located
20 in Kemper County, Mississippi.
21

22 **Q. HAVE GEORGIA POWER GENERATING UNITS STORED CO₂ AT THE**
23 **KEMPER COUNTY, MISSISSIPPI FACILITY OR ANYWHERE ELSE?**

24 A. No. The Company's responses to STF-LA-1-55, 1-56, 1-58, and 1-59 indicate that the
25 Company has not stored any CO₂ at that facility and that the Company does not currently

³¹ A copy of that response and the other responses being referenced in this section of our testimony, including the responses to STF-LA-1-52 through STF-LA-1-65 are included in Exhibit RS/RT-7.

1 have any generating units storing CO₂ and that none have been stored at that facility in
2 either 2020 or 2021 and that no Georgia Power generating units are currently anticipating
3 to store CO₂ at the Kemper facility.
4

5 **Q. WHAT IS THE TOTAL ANTICIPATED COST OF THE KEMPER FACILITY**
6 **AND HOW IS IT BEING ALLOCATED AMONG SYSTEM COMPANIES?**

7 A. The Company's response to STF-LA-1-57 indicates that the total anticipated cost for
8 phases 2 and 3 is approximately \$27 million of which Southern Company's share is
9 approximately \$3.975 million. The Company's response to STF-LA-1-57 also lists the
10 amounts booked to-date through Southern Company R&D as a research project which are
11 allocated based on Carbon Emissions to the Operating Companies, SEGCO and Southern
12 Power, with Georgia Power's allocation being approximately \$30,000.
13

14 **Q. DOES THAT RESPONSE ILLUSTRATE HOW THE COST OF SOUTHERN**
15 **COMPANY RESEARCH PROJECTS THAT COULD BENEFIT VARIOUS**
16 **AFFILIATES CAN BE ALLOCATED?**

17 A. Yes. This response provides one illustration of how cost of Southern Company research
18 projects are being allocated. Georgia Power is not using the facility to store Carbon and
19 has not anticipated that it would store Carbon at that facility, but is nevertheless being
20 allocated a portion of the research cost.
21

22 **Q. THE COMPANY'S 2019 IRP IDENTIFIED SOME RESEARCH PROJECTS FOR**
23 **DEVELOPING ELECTRIC VEHICLE ("EV") CHARGING. HAS STAFF**
24 **FOLLOWED-UP AND INQUIRED ABOUT THOSE PROJECTS?**

25 A. Yes. Staff discovery requests STF-LA-1-61 and 1-62 inquired about those EV charging
26 projects. From the response to STF-LA-1-61, other than a technology assessment, the
27 Company did not proceed with the EV Charging Network Interoperability project, from
28 page H-135 of the Company's 2019 IRP.

1
2 The Company's response to STF-LA-1-62 provides information on the cost, location and
3 revenues produced by the Company's EV charging stations, including the Company's
4 network of EV charging stations that are available to members of the general public. In
5 2021, the Company received approximately \$294,000 in revenue related to community
6 EV charging facilities. The Company's capital investment in EV charging facilities that
7 can be used by the general public is about \$7.161 million as of December 31, 2021, as
8 indicated in the response to STF-LA-1-62.
9

10 **Q. PAGE H-140 OF THE COMPANY'S 2019 IRP HAD A SMALL-SCALE BATTERY**
11 **STORAGE DEVELOPMENT WITH SOLAR PV PROJECT. PAGE H-141 OF**
12 **THE COMPANY'S 2019 IRP HAD A COMMERCIAL SCALE BATTERY**
13 **STORAGE DEMONSTRATION PROJECT. WHAT IS THE STATUS OF THOSE**
14 **PROJECTS?**

15 A. As indicated in the Company's responses to STF-LA-1-63 and STF-LA-1-64, those
16 combined projects was completed in 2018 at a combined cost of \$275,000. No amounts
17 were recorded in either 2020 or 2021 and no amounts will be recorded in future years.
18

19 **Q. HOW WERE THE COSTS OF THOSE RESEARCH PROJECTS ALLOCATED**
20 **TO GEORGIA POWER?**

21 A. The costs were allocated to Georgia Power on the basis of a load factor across all Operating
22 Companies and Southern Power.
23

24 **Q. PAGE H-142 OF THE COMPANY'S 2019 IRP DISCUSSED THE DEVELOPMENT**
25 **OF A LANDFILL GAS DEMONSTRATION OF BLOOM ENERGY FUEL CELL**
26 **TECHNOLOGY. WHAT IS THE STATUS OF THAT PROJECT?**

27 A. As described in the Company's response to STF-LA-1-65, that project is located in
28 Pensacola, Florida. Southern Company's share of the cost is approximately \$445,000, and

those costs are allocated among Georgia Power, Alabama Power, Mississippi Power and Southern Power based on a load factor. No amounts were recorded related to that project by Georgia Power in 2021 and no costs are expected to be recorded in 2022 through 2025.

Q. FROM THE REVIEW OF THE ABOVE-DESCRIBED RESEARCH PROJECTS FROM THE COMPANY'S 2019 IRP, DOES IT APPEAR TO BE APPROPRIATE TO ALLOCATE COSTS FOR RESEARCH THAT COULD BENEFIT THE OTHER OPERATING COMPANIES AND/OR SOUTHERN POWER TO THOSE COMPANIES SO THEY BEAR A PORTION OF THE RESEARCH COST, IN ADDITION TO GEORGIA POWER?

A. Yes.

VIII. THE CAPITAL AND O&M COSTS THE COMPANY WILL INCUR FOR THE TALL WIND DEMONSTRATION PROJECT (BUT NOT YET THE RECOVERY OF SUCH COSTS), AS SET OUT IN THE SELECTED SUPPORTING INFORMATION SECTION OF TECHNICAL APPENDIX VOLUME 1

Q. WHAT HAS THE COMPANY REQUESTED FOR COMMISSION APPROVAL FOR A TALL WIND DEMONSTRATION PROJECT?

A. In paragraph 27 on page 1-15 of the IRP Main Document, the Company presents the following request for Commission approval of:

The capital and O&M costs the Company will incur for the Tall Wind demonstration project (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 1.

Q. HAS THE COMPANY PROVIDED ESTIMATES OF THE ANNUAL CAPITAL AND O&M COSTS IT ANTICIPATES WOULD BE INCURRED FOR THE TALL WIND DEMONSTRATION PROJECT?

A. Yes. The Company's response to STF-LA-2-21 provides the Company's cost estimates in

trade secret portions of that response.³²

Q. HOW DOES THE COMPANY PROPOSE TO FUND THE TALL WIND DEMONSTATION PROJECT?

A. Except for a DOE grant, the Company has indicated that the demonstration project will be nearly fully funded by Georgia Power since the majority of the costs will be for a capital asset owned and operated by Georgia Power. The Company has indicated that there will be some smaller contributions from the SCS R&D department for due diligence and although those amounts have not been fully identified they could be for geotechnical drilling, surveying and environmental due diligence.

Q. DOES THE COMPANY HAVE PROJECTIONS OF ENERGY (MWH) THAT ARE ANTICIPATED TO BE GENERATED BY THE TALL WIND DEMONSTRATION PROJECT?

A. No, as indicated in the Company's response to STF-LA-2-22 a site has not yet been selected and the Company therefore cannot yet model the anticipated monthly energy (MWh) production.³³

Q. HAS THE COMPANY IDENTIFIED ANY SPECIAL STATE OR FEDERAL INCOME TAX BENEFITS, SUCH AS PRODUCTION TAX CREDITS OR OTHER BENEFITS, THAT IT COULD AVAIL ITSELF OF FOR THE TALL WIND DEMONSTRATION PROJECT?

A. No. The Company's response to STF-LA-2-24 indicates that it is not assuming any tax benefits for the Tall Wind demonstration project and notes that the production tax credit

³² A copy of that response is included in Exhibit RS/RT-8.

³³ A copy of that response is included in Exhibit RS/RT-8.

1 expired on December 31, 2021.³⁴ The response indicates that the Company will continue
2 to monitor legislation and pursue appropriate tax incentives that become available.
3

4 **Q. DOES IT APPEAR THAT THE TALL WIND DEMONSTRATION PROJECT**
5 **COULD HAVE BENEFIT NOT ONLY TO GEORGIA POWER BUT ALSO TO**
6 **THE OTHER SYSTEM OPERATING COMPANIES?**

7 **A.** Yes. A review of NREL wind maps suggests that portions of the service territories of
8 Georgia Power, Alabama Power and Mississippi Power have similar wind conditions at
9 various elevations. If Tall Wind proves to be workable in Georgia at the locations that are
10 yet to be selected for the demonstration project, it could also work where wind conditions
11 at similar altitudes prevail in the service territories of the other system operating
12 companies. Consequently, it would seem reasonable to allocate the costs of the project
13 among the companies, rather than having them borne only by Georgia Power.
14

15 **Q. ARE OTHER STAFF PANELS ADDRESSING ASPECTS OF THE COMPANY'S**
16 **PROPOSED TALL WIND DEMONSTRATION PROJECT?**

17 **A.** Yes. The Barber-Cook-Bower panel has recommended that the Company's proposed Tall
18 Wind demonstration project be approved subject to the conditions identified in their
19 testimony.
20

21 **IX. THE CAPITAL AND O&M COST THE COMPANY WILL INCUR FOR THE**
22 **INTEGRATED HYDROGEN MICROGRID PILOT PROJECT (BUT NOT YET**
23 **THE RECOVERY OF SUCH COSTS), AS SET OUT IN THE SELECTED**
24 **SUPPORTING INFORMATION SECTION OF TECHNICAL APPENDIX**
25 **VOLUME 1**
26

27 **Q. WHAT HAS THE COMPANY PROPOSED FOR THE CAPITAL AND O&M**

³⁴ A copy of that response is included in Exhibit RS/RT-8.

**COSTS THAT THE COMPANY WILL INCUR FOR THE INTEGRATED
HYDROGEN MICROGRID PILOT PROJECT?**

A. In paragraph 28 on page 1-15 of the IRP Main Document, the Company presents the following request for Commission approval of:

The capital and O&M costs the Company will incur for the Integrated Hydrogen Microgrid pilot project (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 1.

**Q. HAS THE COMPANY PROVIDED ITS ESTIMATED O&M AND CAPITAL
COSTS FOR THE PROPOSED INTEGRATED HYDROGEN MICROGRID
PILOT PROJECT?**

A. Yes. The Company's response to STF-LA-2-25 lists estimated O&M and capital costs expected to be allocated to Georgia Power for the pilot project in total and by year for 2022-2026.

**Q. DOES THE COMPANY HAVE PROJECTIONS OF ENERGY (MWH) THAT ARE
ANTICIPATED TO BE GENERATED BY THE PILOT PROJECT?**

A. Yes. The Company's response to STF-LA-2-26 provided a preliminary estimate that the hydrogen produced will support up to 1 MW of stationary power that will be utilized by the facility and to supply fast vehicle chargers, as well as supply the three proposed hydrogen fuel cell utility vehicles.³⁵

**Q. HAS THE COMPANY IDENTIFIED ANY SPECIAL STATE OR FEDERAL
INCOME TAX BENEFITS, SUCH AS PRODUCTION TAX CREDITS OR OTHER
BENEFITS, THAT IT COULD AVAIL ITSELF OF FOR THIS PILOT PROJECT?**

A. No. The Company's response to STF-LA-2-28 indicates that special tax benefits are not

³⁵ A copy of that response is included in Exhibit RS/RT-9.

1 anticipated.³⁶ Provisions for federal production and investment tax credits associated with
2 clean hydrogen production have been proposed in Congress as part of the “Build Back
3 Better Act” but have not been enacted into law. The response indicates that the Company
4 is expecting federal funding support for the project from the U.S. Department of Energy.
5

6 **Q. DOES IT APPEAR THAT THE INTEGRATED HYDROGEN MICROGRID**
7 **PILOT PROJECT COULD HAVE BENEFIT NOT ONLY TO GEORGIA POWER**
8 **BUT ALSO TO THE OTHER SYSTEM OPERATING COMPANIES?**

9 **A.** Yes. Consequently, if the project were to be approved, Staff recommends that the project
10 costs not being covered by governmental sources such as the DOE be allocated among the
11 system operating companies who could potentially benefit from the knowledge gained
12 from the project.
13

14 **Q. IS STAFF'S RECOMMENDATION CONCERNING THE INTEGRATED**
15 **HYDROGEN MICROGRID PILOT PROJECT BEING ADDRESSED BY**
16 **ANOTHER STAFF TESTIMONY PANEL?**

17 **A.** Yes. The Newsome-Hayet-Baron-Wellborn panel have also addressed this hydrogen
18 microgrid pilot. They recommend the Commission approve only a Georgia Power ratio
19 share of the net costs after the DOE portion of the costs have been accounted for and that
20 Southern Company Services retain the ownership of the assets at the completion of the
21 pilot.
22
23

24 **X. THE CAPITAL AND O&M COSTS THE COMPANY WILL INCUR FOR THE**
25 **SLR FOR PLANT HATCH UNITS 1-2 (BUT NOT YET THE RECOVERY OF**
26 **SUCH COSTS), AS SET OUT IN ATTACHMENT D**
27

³⁶ A copy of that response is included in Exhibit RS/RT-9.

1 Q. WHAT HAS THE COMPANY PROPOSED FOR THE CAPITAL AND O&M
2 COSTS THAT THE COMPANY WILL INCUR FOR THE SUBSEQUENT
3 LICENSE RENEWAL FOR PLANT HATCH UNITS 1-2?

4 A. In paragraph 18 on page 1-14 of the IRP Main Document, the Company requests
5 Commission approval of:

6 The capital and O&M costs the Company will incur for the SLR for Plant Hatch Units
7 1-2 (but not yet the recovery of such costs), as set out in ATTACHMENT D.
8

9 Q. HAS STAFF REVIEWED THE COMPANY'S PROPOSAL FOR PURSUING A
10 PLANT HATCH UNITS 1-2 SUBSEQUENT LICENSE RENEWAL?

11 A. Yes. Staff reviewed the Company's proposal to incur capital and O&M costs related to
12 pursuing a 20-year Subsequent License Renewal for the Plant Hatch nuclear generating
13 units 1-2 that was set forth in Attachment D to the Company's IRP, as well as the
14 Company's responses to discovery requests concerning this matter.
15

16 Q. DID THE COMPANY PROVIDE A BREAKOUT OF ITS PROPOSED \$28
17 MILLION OF PLANT HATCH SLR RELATED SPENDING BY YEAR?

18 A. Yes. The Company's Trade Secret response to STF-LA-6-3³⁷ identified anticipated
19 spending amounts for the Plant Hatch SLR, based on the Georgia Power ownership share,
20 by year for 2023 through 2028. The Company is requesting Commission approval of the
21 \$28 million even though the majority of that spending is projected to be incurred beyond
22 the 2023-2025 three-year period. The Company's response to STF-LA-6-3(d)³⁸ explains
23 that Southern Nuclear Company ("SNC") is required to communicate 24-26 months in
24 advance of an application review to allow the NRC to add resources for the application
25 review. Obtaining a SLR involves two steps: (1) developing the SLR application and (2)

³⁷ A copy of that response is included in Exhibit RS/RT-10.

³⁸ A copy of that response is included in Exhibit RS/RT-10.

1 supporting that SLR. Because those two steps are inherently linked, the Company is
2 requesting approval for the \$28 million spending in this IRP, including spending projected
3 to be incurred beyond the 2023-2025 three-year period.

4
5 **Q. HAVE OTHER U.S. NUCLEAR PLANTS RECEIVED SUBSEQUENT LICENSE**
6 **RENEWALS?**

7 A. Yes. A number of other U.S. nuclear generating plants have either already received or in
8 the process of applying (or are expected to apply for) similar subsequent license extensions.
9 The Company's response to STF-LA-6-1³⁹ provides a link to the NRC website which
10 provides up-to-date information on nuclear license extensions and lists a number of SLR
11 applications that have been submitted and are currently under review by the NRC and well
12 as identifying some anticipated future submittals of SLR applications.

13
14 **Q. DID THE COMPANY CONDUCT A FEASIBILITY STUDY WHICH**
15 **CONCLUDED THAT PLANT HATCH CAN OPERATE RELIABILITY BEYOND**
16 **60 YEARS WITHOUT INCURRING UNEXPECTED OR UNUSUALLY LARGE**
17 **CAPITAL EXPENDITURES?**

18 A. Yes. Company's IRP Main Document, page D-153, indicated that the Company had
19 conducted such a study. A copy of the study was provided in the Company's Trade Secret
20 attachment to its response to STF-LA-6-2.⁴⁰ Selected pages from that study are included
21 in Exhibit RS/RT-10. The Company's response to STF-LA-6-2⁴¹ in the Trade Secret
22 information provided estimated O&M and capital expenditures at Plant Hatch for years
23 2022-2025 in total and also showing Georgia Power's share. The Company's response to
24 STF-LA-6-2(c) explained that, per the SLR feasibility study, there is no specific dollar

³⁹ A copy of that response is included in Exhibit RS/RT-10.

⁴⁰ A copy of that response is included in Exhibit RS/RT-10.

⁴¹ A copy of that response is included in Exhibit RS/RT-10.

1 threshold used by the Company to determine "unusually large capital expenditures." SNC
2 referenced portions of the Electric Power Research Institute ("EPRI") Integrated Life Cycle
3 Management document and philosophy. SNC also referenced a list of high impact
4 equipment and concluded that those items were already in SNC's capital budgeting
5 processes for refurbishment and/or replacement, or, for those not already covered by the
6 capital budgeting process, SNC evaluated their potential impact and concluded there would
7 be no impact.

8
9 **Q. HAS THE COMPANY INDICATED WHETHER EXTENDING THE PLANT**
10 **HATCH UNITS 1-2 OPERATING LICENSE FOR AN ADDITIONAL 20 YEARS IS**
11 **EXPECTED TO RESULT IN SIGNIFICANTLY INCREASED COSTS?**

12 A. The Company's response to STF-LA-6-5⁴² indicated that extending the Plant Hatch Units
13 1-2 operating license for an additional 20 years is not expected to "result in any need for
14 additional expenditures that would be considered 'unusually large' or that could not be
15 'managed within the plant's normal capital and O&M budgets'."

16
17 **Q. HAS STAFF ASKED THE COMPANY ABOUT POTENTIAL IMPACTS ON THE**
18 **HATCH SLR FROM NATIONAL ENVIRONMENTAL POLICY ACT ("NEPA")**
19 **REVIEWS?**

20 A. Yes. A potential concern about delays and/or increasing costs of SLRs was raised in an
21 E&E News article entitled "Feds walk back plans for nuclear reactors to run 80 years"
22 which suggested that additional environmental impact reviews are being required and those
23 requirements will be applied to pending and future SLRAs. The Company's response to
24 STF-LA-6-4⁴³ addresses the Company's awareness of those NEPA reviews and indicated
25 that the Company was aware of that when it made its \$28 million estimate. The Company's

⁴² A copy of that response is included in Exhibit RS/RT-10.

⁴³ A copy of that response is included in Exhibit RS/RT-10.

1 response to STF-LA-6-4(c) indicates, among other things, that: "The NRC's action should
2 not affect the decision of whether to seek SLR for Plant Hatch, but rather may impact how
3 SNC prepares its ER [Environmental Impact Statement] as part of the application." The
4 Company's response to STF-LA-6-5⁴⁴ states that: "The Company does not expect the
5 NEPA process associated with SLR to result in any need for additional capital expenditures
6 that would be considered 'unusually large' or that could not be 'managed within the plant's
7 normal capital and operation and maintenance (O&M) budgets."
8

9 **Q. WHAT IS STAFF'S RECOMMENDATION CONCERNING THE PLANT HATCH**
10 **SLR?**

11 A. Staff does not object to the Company's request for approval (but not yet the recovery) of
12 capital and O&M costs that the Company proposes to incur to pursue a Subsequent License
13 Renewal for Plant Hatch nuclear units 1 and 2, subject to the Company agreeing to semi-
14 annual reporting on costs being expended and updates to the budgeted/projected amounts
15 and reporting on any developments which could significantly increase the cost related to
16 the SLRA and of continuing to operate the Hatch nuclear units for an additional 20 years.
17

18 **XI. INITIATE EXECUTION OF THE ECS, AS APPROVED BY THE COMMISSION,**
19 **TO COMPLY WITH GOVERNMENT-IMPOSED ENVIRONMENTAL**
20 **REQUIREMENTS**

21
22 **Q. HOW DID THE COMPANY INITIATE EXECUTION OF THE ECS TO COMPLY**
23 **WITH GOVERNMENT-IMPOSED ENVIRONMENTAL REQUIREMENTS?**

24 A. At paragraph 18 on page 3-19 of the IRP Main Document, the Company is requesting
25 Commission approval for the following:

26 Commenced execution of the approved ECS to comply with government imposed
27 environmental mandates, including plans to address CCR at the Company's ash ponds
28 and landfills as well as ELG at several plants. The Company completed the

⁴⁴ A copy of that response is included in Exhibit RS/RT-10.

1 construction and installation of equipment necessary for dry ash conversions and
2 wastewater treatment facilities to allow for all ash ponds to cease receipt of CCR and
3 non-CCR waste streams as part of compliance with federal and state rules and permits
4 including the Clean Water Act and Resource Conservation and Recovery Act. The
5 Company submitted CCR project progress and cost updates semi-annually to the
6 Commission through Docket No. 42310.

7
8 **Q. WHAT IS THE REMAINING AMOUNT AT DECEMBER 31, 2021 THAT THE**
9 **COMPANY SHOWS FOR CCR COMPLIANCE?**

10 A. As of December 31, 2021, the Company shows \$8.041 billion remaining as the CCR Asset
11 Retirement Obligation (ARO) cost.⁴⁵

12
13 **Q. HAS THE COMPANY IDENTIFIED THE AMOUNT OF CONTINGENCY IN ITS**
14 **CCR ARO PROJECTIONS FOR THE YEARS 2022-2075?**

15 A. Yes. The Company's TS response to STF-LA-4-5(c) identifies the approximate amount
16 of forecast contingency.⁴⁶

17
18 **Q. HAS THE COMPANY PROVIDED ITS ACCOUNTING ENTRIES FOR 2021**
19 **RELATED TO THE CCR ARO LIABILITY?**

20 A. Yes. The Company's response to STF-LA-1-16 provided its accounting journal entries for
21 the CCR ARO for 2021.⁴⁷

22
23 **Q. IS THE COMPANY EVALUATING THE CLOSURE METHODS FOR EACH OF**
24 **ITS 29 ASH PONDS?**

25 A. Yes. The evaluation of the method for ash pond closure and remediation to comply with

⁴⁵ See, e.g., the Company's response to STF-LA-1-18, which is included in Exhibit RS/RT-12. Total amount is not TS, but details by facility are.

⁴⁶ A copy of that response is included in Exhibit RS/RT-12. The estimated contingency amount is not being mentioned in the testimony because it has been designated as being TS, but can be found in the TS version of Exhibit RS/RT-12.

⁴⁷ A copy of that response is included in Exhibit RS/RT-12.

1 federal and state CCR rules focuses on the ability to meet regulatory performance standards
2 for the following two allowable closure options set forth in the federal and state CCR Rules:
3 (1) Closure-in-Place (CIP), which involves closing the CCR unit in the existing location
4 and dewatering, backfilling, and capping the impoundment; or (2) Closure-by-Removal
5 (CBR), which involves dewatering the surface impoundment, excavating the CCR, and
6 transporting and placing the ash material in an approved landfill or combining the ash with
7 onsite ash ponds to be closed in place.

8 For each ash pond, Staff inquired with the Company to explain in detail how the
9 Company determined which method to use, show the cost of that chosen method, and
10 show in detail how the Company evaluated the alternatives and determined that its
11 chosen method had the lowest cost. As described in the Company's response to STF-LA-
12 4-4, since the EPA published the CCR rule in 2015, the Company has developed and
13 implemented closure plans for its 29 ash ponds. The Company has continued to update
14 and report closure cost estimates with the Company's CCR Semi-Annual Status Reports.

15
16 **Q. ARE THE COMPANY'S CLOSURE PLANS FINAL?**

17 **A.** No. The Company has indicated it will continue to refine and optimize its closure plans.⁴⁸

18
19 **Q. IS GEORGIA POWER REVIEWING BENEFICIAL USE PROPOSALS AS A WAY**
20 **TO REDUCE CCR ARO CLOSURE COSTS?**

21 **A.** Yes. The Company has estimated that, a savings of approximately \$300 million can be
22 saved as a result of beneficial use being implemented at two sites.⁴⁹

23
24 **Q. DOES GEORGIA POWER MAINTAIN THAT CLOSURE IN PLACE WITH ASH**
25 **IN CONTACT WITH GROUNDWATER IS EQUALLY PROTECTIVE AS**
26 **CLOSURE BY REMOVAL?**

⁴⁸ Transcript Volume II P. 812, lines 23-25

⁴⁹ Transcript Volume II P. 826, lines 6-9

1 A. The Company's witness, Mr. Mitchell, testified that EPA determined both methods are
2 equally protective if one complies with the rules.⁵⁰

3
4 **Q. DOES STAFF HAVE REASON TO BELIEVE THE COMPANY'S CLOSURE**
5 **PLANS MAY NOT COMPLY WITH US EPA REGULATIONS?**

6 A. Yes. Georgia Power plans to close in place five impoundments with ash in contact with
7 groundwater. There are unresolved disputes concerning what constitutes compliance.

8
9 **Q. HAS EPA INDICATED HOW IT VIEWS COMPLIANCE?**

10 A. Yes. EPA issued a News Release on January 11, 2022 titled, "EPA Takes Key Steps to
11 **Protect Groundwater from Coal Ash Contamination**" in which it restated, through
12 proposed determinations, its:

13 ...consistently held position that surface impoundments or landfills
14 cannot be closed with coal ash in contact with groundwater. Limiting
15 the contact between coal ash and groundwater after closure is critical to
16 minimizing releases of contaminants into the environment and will help
17 ensure communities near these facilities have access to safe water for
18 drinking and recreation.⁵¹ (Emphasis Added).

19
20 **Q. PLEASE PROVIDE AN EXAMPLE OF AN EPA PROPOSED DETERMINATION**
21 **AND EXPLAIN HOW EPA RESTATED ITS CONSISTENTLY HELD POSITION**
22 **THAT SURFACE IMPOUNDMENTS OR LANDFILLS CANNOT BE CLOSED**
23 **WITH AS IN CONTACT WITH GROUNDWATER.**

24 A. One example is EPA's "Proposed Denial of Alternative Closure Deadline for General

⁵⁰ Transcript Volume II P. 851, lines 12-23

⁵¹ https://www.epa.gov/newsreleases/search/press_office/headquarters-226129

1 James M. Gavin Plant.”⁵² In its proposed decisions, EPA concludes that, if ash is in contact
2 with groundwater, an impoundments closure plan, “... would need to have discussed the
3 engineering measures taken to ensure that the groundwater had been removed from the unit
4 prior to the start of installing the final cover system, as required by 40 C.F.R. §
5 257.102(d)(2)(i).”⁵³ In other words, prior to closure in place, groundwater must be
6 removed.

7
8 **Q. ONCE AN ASH POND (OR LANDFILL) HAS BEEN CLOSED IN PLACE, HOW**
9 **DOES EPA ADDRESS GROUNDWATER THAT SUBSEQUENTLY**
10 **INFILTRATES THE IMPOUNDMENT?**

11 A. In the same determination, EPA found that Gavin Power, LLC’s closure plan document
12 did not sufficiently address how the closure of its Fly Ash Reservoir would “control,
13 minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids
14 into the waste and releases of CCR, leachate, or contaminated run-off to the ground or
15 surface waters or to the atmosphere” in accordance with 40 C.F.R. § 257.102(d)(1).⁵⁴ EPA
16 further clarifies that it views the word “infiltration” to include, “... any liquid passing into
17 or through the CCR unit by filtering or permeating from any direction, including the top,
18 sides, and bottom of the unit.”

19
20 **Q. HAVE INTERESTED PARTIES COMMENTED ON EPA’S PROPOSED**
21 **DETERMINATIONS?**

22 A. Yes. For example, 508 comments were filed in response to EPA’s solicitation of comments
23 for the “Proposed Denial of Alternative Closure Deadline for General James M. Gavin

⁵² <https://www.regulations.gov/document/EPA-HQ-OLEM-2021-0590-0002>

⁵³ Ibid, p. 46

⁵⁴ Ibid, p. 47

1 Plant.”⁵⁵ Staff notes, specifically, the Utility Solid Waste Activities Group, on behalf of its
2 members, filed comments opposing EPA’s proposed decision.⁵⁶ The Southern
3 Environment Law Center, on behalf of itself and a host of other organizations, filed
4 comments in support of EPA’s proposed decision.⁵⁷

5
6 **Q. HAS EPA ISSUED A FINAL DECISION REGARDING THE JAMES M. GAVIN**
7 **PLANT, OR THE RELATED DETERMINATIONS?**

8 A. Staff is not aware of a final decision. The decision is likely to be issued in the near future.

9
10 **Q. DOES EPA ALSO INTEND TO FINALIZE A FEDERAL PERMITTING PROGRAM**
11 **FOR THE DISPOSAL OF COAL ASH AND ESTABLISH REGULATIONS FOR**
12 **LEGACY COAL ASH SURFACE IMPOUNDMENTS?**

13 A. Yes, this is Staff’s understanding. EPA will review state level CCR program applications
14 to ensure they are as protective as federal regulations.⁵⁸

15
16 **Q. HAS THE COMPANY PROVIDED INFORMATION THROUGH 2021**
17 **CONCERNING ITS CCR ARO COMPLIANCE EXPENDITURES AND**
18 **RECOVERY?**

19 A. Yes. The Company provided information for 2020 and 2021 in its response to STF-LA-4-
20 5 and the TS STF-LA-4-5 Attachment.⁵⁹

21
22 **Q. IS THE REVIEW OF COMPANY COSTS PROPOSED FOR CCR ARO’S AN**

⁵⁵ <https://www.regulations.gov/document/EPA-HQ-OLEM-2021-0590-0001>

⁵⁶ <https://www.regulations.gov/comment/EPA-HQ-OLEM-2021-0590-0054>

⁵⁷ <https://www.regulations.gov/comment/EPA-HQ-OLEM-2021-0590-0063>

⁵⁸ https://www.epa.gov/newsreleases/search/press_office/headquarters-226129

⁵⁹ A copy of that response is included in Exhibit RS/RT-12.

1 **ISSUE THAT SHOULD BE APPROPRIATELY CONSIDERED IN THE**
2 **COMPANY'S UPCOMING RATE CASE?**

3 A. Yes.

4
5 **XII. BENEFICAL USE OF COAL ASH**

6 **Q. THROUGH DECEMBER 31, 2021 HAS THE COMPANY MADE ANY CAPITAL**
7 **INVESTMENT TO ENABLE COAL ASH BENEFICAL USE APPLICATIONS?**

8 A. No, as stated in the Company's response to STF-LA-4-14(a).⁶⁰

9
10 **Q. HOW MUCH DOES THE COMPANY PROPOSE TO SPEND ON ASH**
11 **PROCESSING INFRASTRUTURE TO ENABLE BENEFICAL USE**
12 **APPLICATIONS OF COAL ASH?**

13 A. The Company's TS responses to STF-LA-4-14(b) and STF-4-15(1) provide a range of
14 estimated infrastructure investment.⁶¹ Those appear to be preliminary estimates and have
15 not yet been finalized, as the Company is in the process of reviewing various Benefit Use
16 RFP proposals.

17
18 **Q. DOES STAFF HAVE CONCERNS ABOUT THE COMPANY'S BENEFICIAL USE**
19 **PROPOSALS?**

20 A. Yes. . Staff is concerned that the Company's beneficial use proposal could result in net
21 overall cost increases to ratepayers. While Staff recognizes that the Company has estimated
22 savings of approximately \$300 million as a result of beneficial use being implemented at
23 two sites,⁶² Staff has concerns about the Company's proposal to make capital investments
24 in ash processing infrastructure up-front, the cost of which could then be included in rate

⁶⁰ A copy of that response is included in Exhibit RS/RT-13.

⁶¹ A copy of those responses are included in Exhibit RS/RT-13. The TS estimate is not mentioned in our testimony but is shown in the TS version of that response.

⁶² Transcript Volume II P. 826, lines 6-9

base and financed by ratepayers. Staff also has concerns about whether the Company's estimated savings are realistic and will materialize sufficiently to produce net cost savings.

Q. YOU HAVE NOTED ABOVE THAT THE REVIEW OF COMPANY COSTS PROPOSED FOR CCR WILL BE AN ISSUE IN THE COMPANY'S UPCOMING RATE CASE. DOES STAFF HAVE A RECOMMENDATION ON THE COMPANY'S BENEFICIAL USE PROPOSALS AT THIS TIME?

A. Yes. Staff is concerned that the Company's beneficial use proposal involves up-front investment could result in net overall cost increases to ratepayers. Staff recommends that the Commission direct the Company to present additional information prior to or in conjunction with its upcoming rate case so there can be confidence that the Beneficial Use will more assuredly provide net cost savings, and not become an additional cost burden on ratepayers, prior to approving the program. Once the Company evaluates responses to the Beneficial Use RFP process, Staff recommends the Commission direct the Company to use that information to update its net present value cost benefit analysis, and to present the updated NPV analysis for consideration in the Company's upcoming rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

1 BY MR. WALSH:

2 Q Mr. Trokey, along with your direct testimony,
3 did you prefile or cause to be prefiled 14 public
4 disclosure exhibits marked RCS-1, RLT-1, and RS/RT-2
5 through 13?

6 A (Witness Trokey) Yes.

7 Q Do you have any changes or corrections to
8 make to any of those exhibits?

9 A (Witness Trokey) We do not.

10 MR. WALSH: Okay. Madam Chair, I ask that
11 Exhibit RCS-1 be marked for identification as Staff
12 Exhibit 18, that RLT-1 be marked for identification
13 as Staff Exhibit 19, and that Staff Exhibits RS/RT-2
14 through 13 be marked for identification as Staff
15 Exhibits 20 through 31.

16 MADAM CHAIR PRIDEMORE: So marked.

17 (The document referred to was marked for
18 identification as Staff Exhibit 18.)

19 (The document referred to was marked for
20 identification as Staff Exhibit 19.)

21 (The documents referred to were marked for
22 identification as Staff Exhibits 20-31.)

23 BY MR. WALSH:

24 Q Mr. Trokey, did you also prefile or cause to
25 be prefiled trade secret versions of Exhibits RS/RT-6, 8,

1 10, 11, 12, and 13?

2 A (Witness Trokey) That is correct.

3 Q Okay. Do you have any changes to make to any
4 of the trade secret exhibits?

5 A (Witness Trokey) We do not.

6 MR. WALSH: Madam Chair, I'd ask that the trade
7 secret exhibits to staff's testimony be marked
8 collectively as Staff Trade Secret Exhibit No. 32?

9 MADAM CHAIR PRIDEMORE: So marked.

10 (The documents referred to were marked for
11 identification as Staff Exhibit 32.)

12 BY MR. WALSH:

13 Q Has the panel prepared a summary of its
14 testimony?

15 A (Witness Trokey) Yes, we have.

16 MR. WALSH: Madam Chair, may the panel deliver
17 its summary at this time?

18 MADAM CHAIR PRIDEMORE: Please go ahead.

19 WITNESS TROKEY: Thank you, Madam Chair,
20 Commissioners.

21 The purpose of our testimony is to address the
22 accounting and rate-making issues presented by
23 Georgia Power Company in this IRP.

24 Our conclusions and recommendations are also
25 summarized on pages 7 through 12 of our testimony.

1 For cost recovery issues, the company is requesting
2 approval of several categories of costs, but not yet
3 the recovery of such costs.

4 Staff generally recommends request for cost
5 approval and cost recovery be addressed when the
6 company's earnings and risks are considered, such as
7 in the company's upcoming rate case, not in this IRP.

8 Concerning the accounting reclassifications
9 requested by the company, staff has the following
10 recommendations: First, for units decertified and
11 retired through 2025, staff recommends approval of
12 accounting reclassifications to regulatory assets.
13 This includes reclassification upon retirement of the
14 unrecovered net book value and the related unusable
15 materials and supplies.

16 Staff does not at this time recommend approval
17 of dismantlement or cost of removal related to the
18 decertified plant. Staff recommends that these be
19 addressed in the upcoming rate case.

20 Staff's recommendation for approval of
21 accounting reclassifications is done only to
22 facilitate review in a subsequent rate-making
23 proceeding. It is not intended for an approval of
24 the cost or the cost recovery period.

25 We also note that depreciation rates and cost

1 recovery periods are expected to be reviewed and
2 addressed in the rate case.

3 And second, for units projected to retire after
4 2026, the Commission does not need to approve the
5 accounting reclassifications at this time. For units
6 that retire in 2026 and thereafter, staff recommends
7 that accounting reclassifications be addressed in the
8 2025 IRP and rate case cycle.

9 Our testimony also describes concerns with
10 plant held for future use and in-service use dates
11 that have now been extended to 2040 and beyond.

12 The plant held for future use discussion
13 includes information concerning the cost of land and
14 land rights that were included in prior IRPs.

15 These are not in the company's 2022 IRP because
16 the projected use dates have been pushed out to 2040
17 or beyond.

18 The land and land rights are not being used to
19 provide utility service, and projected use dates have
20 been extended well into the future.

21 Our plant held for future use testimony also
22 reiterates concerns with costs incurred for the
23 Stewart County site. The site was intended to be
24 used for construction of new nuclear power
25 generation. The company has approximately

1 22.9 million in plant held for future use for the
2 Stewart County land. That land is now being held for
3 some unspecified future generation.

4 Staff recommends that the cost to ratepayers
5 and rate base inclusion of plant held for future use
6 be addressed in the company's upcoming rate case.

7 Concerning research projects, staff recommends
8 that the Commission order in this proceeding
9 explicitly state that the inclusion of research and
10 development projects of Southern Company in the '22
11 IRP and cost allocations to Georgia Power Company
12 does not convey approval of those costs into
13 jurisdictional expenses that then become the
14 responsibility of ratepayers.

15 In Sections 9 -- 8 and 9 of our testimony, we
16 discuss the company's request for approval of costs
17 of capital and operating and maintenance costs that
18 the company will incur for, first, the Tall Wind
19 demonstration project, and second, an integrated
20 hydrogen microgrid pilot project.

21 Staff has concerns about how the costs of those
22 research and demonstration projects is being shared
23 among Georgia Power and its Southern Company
24 affiliates.

25 The Tall Wind demonstration project and the

1 integrated hydrogen microgrid pilot project, if
2 pursued, would potentially benefit not only Georgia
3 Power but also the other system operating companies.

4 If the Commission authorizes the company to
5 proceed with those two research and demonstration
6 projects, staff recommends that the cost of those
7 projects be required to be allocated among the system
8 operating companies.

9 Other staff witness panels also address those
10 projects.

11 Concerning approval of the company's
12 environmental compliance plan and costs, we testified
13 that an IRP is the appropriate forum for the
14 Commission to consider approval of the company's
15 environmental compliance plan. And an IRP is not the
16 appropriate venue for approval of the costs
17 associated with implementation.

18 The reasonableness of environmental cost is
19 dependent on many factors, including the Commission's
20 resource decisions in this docket and ultimately on
21 the company's execution of its plan.

22 The time for the Commission to assess the
23 execution of the plan is after it's been implemented
24 and after costs have been incurred.

25 We also note that design and engineering have

1 not been completed for all of the projects included
2 in the company's plan.

3 There's still uncertainties related to certain
4 EPA rules. The company has stated it expects to
5 periodically update its estimates as well. And the
6 company recognizes this uncertainty in the costs by
7 including various levels of contingency in its
8 estimates.

9 As a more detailed analysis is performed, the
10 company could find alternative methods to meet
11 environmental regulations that may not
12 require incurring the level of expenditures that the
13 company has estimated in this filing.

14 For these reasons, staff recommends the
15 Commission defer approval of environmental compliance
16 costs until the assets and expenses are reflected in
17 either an annual surveillance report filing or in the
18 base rate case when the company's rates will be reset
19 to include the cost of environmental compliance.

20 Concerning the additional sum amounts for
21 capacity purchase power agreements, staff recommends
22 the additional sum amounts for capacity PPAs be set
23 at \$2.30 per kilowatt year.

24 Concerning the company's proposal for a
25 subsequent license renewal for Plant Hatch Nuclear

1 Units 1 and 2, staff recommends approval but not yet
2 the recovery of \$28 million of capital and O&M costs
3 that the company proposes to incur.

4 In conjunction with this item, staff recommends
5 semi-annual reporting requirements that would include
6 but would not be limited to costs being expended for
7 the renewal, updates to budgets and projected costs,
8 new developments which could significantly increase
9 the cost related to the renewal and also potentially
10 significant increases in the projected cost of
11 continuing to operate the Hatch nuclear units for an
12 additional 20 years.

13 Concerning asset retirement obligations for
14 coal combustion residual compliance, we discuss the
15 company's semi-annual reporting protocol which
16 updates the Commission and staff on spending, on ash
17 pond closures, and landfill remediation activities.

18 Overall, the company projects spending
19 approximately 8.89 billion on CCR compliance through
20 2075. This projection includes significant amounts
21 for contingencies and recovery of costs related to
22 CCR will be an issue in the company's 2022 rate case
23 and future cases.

24 Our testimony at pages 45 through 47 also
25 discusses an environmental protection agency news

1 release from January 2022 that indicates that surface
2 impoundments or landfills cannot be closed with coal
3 ash in contact with groundwater.

4 Georgia Power plans to close as many as five
5 impoundments with coal ash in contact with
6 groundwater. As a result, there are unresolved
7 issues concerning what constitutes compliance and
8 uncertainty about the ultimate cost of compliance.

9 Finally, we address the company's proposal for
10 beneficial use of coal ash. This proposal involves
11 upfront investments and also projects future cost
12 savings that may or may not materialize and thus
13 could result in cost increases to ratepayers.

14 Staff recommends that the Commission direct the
15 company to present additional information prior to or
16 in conjunction with its upcoming rate case. This is
17 so there can be confidence that the beneficial use
18 will provide net cost savings and also that there
19 will not be an additional cost burden on ratepayers.

20 Once the company evaluates responses to the
21 beneficial use RFP process, staff recommends the
22 Commission direct the company to use that information
23 to update its net present value cost benefit analysis
24 and to present the updated net present value analysis
25 for consideration in the company's upcoming rate

1 case.

2 This concludes our summary.

3 MR. WALSH: Thank you.

4 Madam Chair, the panel is available for
5 cross-examination and questions from the
6 commissioners.

7 MADAM CHAIR PRIDEMORE: Questions from the
8 commissioners first.

9 COMMISSIONER MCDONALD: Mr. Trokey, you
10 mentioned dealing with the coal ash some cost savings
11 possible. Was that reflecting on costs that have
12 been established in the past or is that on new costs
13 that we will see forthcoming?

14 WITNESS TROKEY: Potential savings could relate
15 to both beneficial use that the company is
16 considering. It could also be related to changes
17 that may occur to their closure plan. So that would
18 be perspective.

19 COMMISSIONER MCDONALD: We'll probably get more
20 into that during this entire segment, most likely.

21 WITNESS TROKEY: I believe that's likely.

22 COMMISSIONER MCDONALD: Thank you.

23 MADAM CHAIR PRIDEMORE: Questions from
24 commissioners?

25 (No response.)

1 MADAM CHAIR PRIDEMORE: Okay. Americans for
2 Affordable Clean Energy?

3 MR. GALLOWAY: No questions, Madam Chair.

4 MADAM CHAIR PRIDEMORE: Commercial Group?

5 MR. JENKINS: No questions.

6 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
7 for Georgia?

8 MR. PRENOVITZ: Madam Chairman, a housekeeping
9 question. Can I -- do you need me to come in person
10 to do my testimony, or can I do it on Zoom since
11 Mr. Hayet did it? I'll do whatever you want, but I
12 just thought I'd ask.

13 MADAM CHAIR PRIDEMORE: We're giving a special
14 consideration to Mr. Hayet under extreme
15 circumstances, so we'd like for you to come,
16 Mr. Prenovitz.

17 MR. PRENOVITZ: That's fine.

18 One thing, my compliments for having the panels
19 have nameplates in front of them. This is very
20 helpful.

21 MADAM CHAIR PRIDEMORE: Great.

22 MR. PRENOVITZ: Thank you.

23 MADAM CHAIR PRIDEMORE: Got it, Mr. Prenovitz.
24 Cypress Creek Renewables?

25 MR. STAIR: No questions.

1 MADAM CHAIR PRIDEMORE: Georgia Association of
2 Manufacturers?

3 MR. CHARLES JONES: No questions.

4 MADAM CHAIR PRIDEMORE: Georgia Center for
5 Energy Solutions?

6 MR. HUBBARD: No questions.

7 MADAM CHAIR PRIDEMORE: Georgia Coalition of
8 Local Governments?

9 MS. BROWN: No questions. Thank you.

10 MADAM CHAIR PRIDEMORE: Georgia Interfaith
11 Power & Light and Partnership for Southern Equity?

12 MS. KYSOR: No questions.

13 MADAM CHAIR PRIDEMORE: Georgia Large Scale
14 Solar Association and Advanced Power Alliance?

15 MR. CARVER: No questions.

16 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
17 Industries and Solar Energy and Vote Solar?

18 MR. THOMASSON: No questions.

19 MADAM CHAIR PRIDEMORE: Georgia Watch? Here we
20 go. She's ready. Good to see you, Ms. Coyle.

21 MS. COYLE: Good afternoon, Chairman Pridemore,
22 Panel, Commissioners. I have just a couple of
23 questions.

24 CROSS-EXAMINATION

25 BY MS. COYLE:

1 Q Related to your testimony for plants held for
2 future use, the discussion on page 10, lines 5 through 16.

3 Do I remember correctly that in the 2016 IRP,
4 this Commission approved a request by the company to recover
5 \$95 million from ratepayers to explore the feasibility of
6 new nuclear units on that site?

7 A (Witness Trokey) Yes. At the Stewart County
8 site.

9 A (Witness Smith) That's correct.

10 Q And after less than two years of review, did
11 they determine that the need for new units was outside the
12 planning horizon at that time?

13 A (Witness Trokey) Yeah, that's my
14 understanding.

15 Q And the value of that land is now at just
16 under \$23 million. So has the company invested already,
17 you know, quite a bit over \$100 million in that particular
18 site?

19 A (Witness Trokey) My recollection is that the
20 company did not spend the full amount of the 95 to
21 \$99 million that were approved for preliminary surveys and
22 investigations. But for the land, you have 23 million and
23 then you have an additional amount, which I -- I believe
24 may have been --

25 COMMISSIONER MCDONALD: 48 million?

1 WITNESS TROKEY: May have been closer to
2 50 million, yes. Yes, sir.

3 BY MS. COYLE:

4 Q And do ratepayers pay -- does the revenue
5 requirement for the land that's being held and for that 48
6 to 50 million that was spent, is there -- does the company
7 collect their profit on that? Is that part of the revenue
8 requirement?

9 A (Witness Smith) For the land, they would -- if
10 that's included in the rate base, there would be a rate
11 return on the land, so the future nuclear investigation cost
12 has been already amortized, so there is none of that
13 remaining at the end of 2021.

14 COMMISSIONER MCDONALD: Talk into that
15 microphone, please, sir.

16 BY MS. COYLE:

17 Q Mr. Smith, I just want a point of
18 clarification. Are you saying that for the land that
19 they're holding for possible future use possibly in 2031,
20 but no plans yet, are ratepayers -- and not just on
21 Stewart County.

22 On all the properties that the company is
23 holding for possible future use, do ratepayers pay a profit?
24 I know ratepayers pay property taxes on that. But are they
25 also paying a profit for that land that's being held?

1 A (Witness Smith) To the extent the property
2 held for future use is included in rate base, yes, that
3 would be subject to having a rate return applied, which
4 would include a return for common equity shareholders or a
5 profit, so, yes.

6 Q So for land that is not currently in use to
7 provide electricity and land that is not currently in the
8 planning horizon for building units of any type, not just
9 nuclear, ratepayers are paying for land to sit vacant?

10 MR. MARZO: I'd just object to the question,
11 because she asked a question without foundation.
12 There's no foundation that this land's not going to
13 be used.

14 BY MS. COYLE:

15 Q While the land is not being used and while
16 there's not a plan for the land to be used, are ratepayers
17 paying the company a profit to hold onto that land?

18 A (Witness Trokey) They're paying a return.
19 I -- I would acknowledge that often you need to acquire the
20 land, the land rights, in advance. So the contemplation is
21 that it will be used at some point in the future, but it is
22 not currently in service plant.

23 A (Witness Smith) Originally it has been
24 included in a rate base, so, yes, there is a profit on that.

25 Q Thank you.

1 And then just going back to page 9 in your
2 testimony, you're making the recommendation to the
3 Commission that they hold off on approving retirements that
4 will occur after the next IRP and rate case; is that
5 correct?

6 A (Witness Trokey) Yes.

7 Q And what would be the impact to rates if the
8 Commission were to not follow your recommendation but go
9 ahead and approve retirement of units that will be retired
10 per the company's proposal after the next IRP and rate
11 case?

12 A (Witness Smith) Let me just clarify. I think
13 what we've tried to distinguish is this section of our
14 testimony discusses a transfer into a regulatory asset
15 account of remaining book value and remaining materials and
16 supplies that are not useable.

17 So we agree that the Commission should approve
18 that accounting transfer for units that are scheduled to be
19 retired in 2022, and there are a couple of those.

20 And then we also would agree conceptually with
21 the Commission approving that accounting for units that were
22 going to be retired in this current IRP and rate case period
23 of 2023, '24, '25.

24 But there are some of them that are not going
25 to be retired until after 2026, and we don't think that

1 accounting approval is needed at this point in time.

2 Q Right. I understand. I'm just trying to
3 understand, what would -- if the commissioners do not
4 follow your recommendation, what would be the impact on
5 ratepayers and rates were they to approve those accounting
6 reclassifications now instead of after the next IRP and
7 rate case?

8 A (Witness Trokey) I believe with the timing of
9 the retirements, there wouldn't be a significant difference
10 because of -- the units are retiring after the next rate
11 case cycle and those are considered in that cycle. You
12 would essentially be approving that reclassification at that
13 time in 2025.

14 A (Witness Smith) And it may -- the depreciation
15 of the company's nuclear units as well as -- or generating
16 units as well as other plant is typically one of the issues
17 that's addressed in the context of the rate cases. So we're
18 anticipating that the company will file a depreciation study
19 in the context of this rate case and then parties can
20 debate, you know, should depreciation rates be adjusted to
21 reflect the new retirement dates, especially if the
22 retirements have been approved by the Commission, or do they
23 want to continue on with the current depreciation rates in
24 order to mitigate rate impacts.

25 So that that type of debate as to what

1 depreciation rates to use, what retirement dates to use in
2 the setting, new depreciation rates, that will probably be
3 held in the context of the company's rate case.

4 Q So if the company is allowed -- it gets
5 approval to reclassify those units that will be retired
6 later in their proposal, would they then in this year's --
7 in the rate case that's filed later this year, potentially
8 include the reclassification of those units in this rate
9 case?

10 A (Witness Smith) I would think they would
11 include the reclassification of units that have been retired
12 in 2022. Or if there were any that were projected to be
13 retired in '23 through '25, those would be included.

14 The units that are continuing to operate during
15 the rate case cycle, it would be my expectation that those
16 would continue to be treated as plant in service and they
17 would continue to have depreciation applied. And there
18 might be a debate about, you know, what should the proper
19 depreciation be for those units since a new quicker
20 retirement date for some of those units will be known at
21 that point in time.

22 MS. COYLE: Thank you.

23 No further questions.

24 MADAM CHAIR PRIDEMORE: Interstate Gas Supply?

25 MR. CARVER: No questions, Madam Chair.

1 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
2 Coalition?

3 MR. STEVEN JONES: Madam Chair, no questions.

4 MADAM CHAIR PRIDEMORE: Sierra Club?

5 MR. FABISH: No questions.

6 MADAM CHAIR PRIDEMORE: Southern Alliance for
7 Clean Energy?

8 CROSS-EXAMINATION

9 BY MR. BAKER:

10 Q Good afternoon, panel. Robert Baker for
11 Southface Energy Institute and the Southern Alliance for
12 Clean Energy. A few questions for you.

13 In order to accurately and fairly determine the
14 true economic value of a capacity PPA, shouldn't the amount
15 of the additional sum be included in the economic
16 evaluation?

17 A (Witness Smith) It's our understanding that
18 the panel that just left the stand did include a \$2.30
19 per kW year value for that additional sum in their economic
20 analysis. It's our understanding that the company's
21 analysis did not include anything for the additional sum.

22 Q So do you agree with your colleagues in the
23 first panel?

24 A (Witness Trokey) Yes, we do.

25 A (Witness Smith) We do, yes.

1 Q And the reason for including -- why is it
2 fair and equitable to include that additional sum in the
3 evaluation as opposed to leaving it out of the evaluation
4 process?

5 A (Witness Trokey) It represents more accurately
6 the overall cost of those PPAs.

7 A (Witness Smith) To ratepayers.

8 Q To -- that are recovered from ratepayers?

9 A (Witness Smith) That are recovered from
10 ratepayers; correct.

11 Q And should the company consider the amount of
12 the additional sum in its economic dispatch
13 decision-making process?

14 A (Witness Smith) We asked the company that in
15 the discovery request, and they said, no, they don't do that
16 because they consider that to be a fixed cost, and
17 typically, dispatch is based on an analysis of variable
18 costs.

19 Q What do you think?

20 A (Witness Smith) I think I agree with that,
21 that once the additional sum is set, it becomes a fixed
22 cost. It is not like a fuel cost that can vary.

23 MR. BAKER: All right. Thank you, gentlemen.

24 I appreciate it.

25 MADAM CHAIR PRIDEMORE: Southern Renewable

1 Energy Association?

2 MR. MAHAN: No questions, ma'am.

3 MADAM CHAIR PRIDEMORE: Georgia Power Company?

4 MR. MARZO: Thank you, Madam Chair.

5 CROSS-EXAMINATION

6 BY MR. MARZO:

7 Q Good afternoon, gentlemen.

8 A (Witness Trokey) Good afternoon.

9 Q Mr. Smith, Mr. Trokey, good to see you again.
10 We've got to keep -- stop meeting like this.

11 Let me start off with just a couple
12 clarification questions. Now, staff recommends, and I think
13 you mentioned in your summary, Mr. Trokey, that you
14 recommend that the -- there not be specific approval of
15 costs in this case, but can we both agree that costs are
16 reviewed as part of this case, and decisions are made based
17 on forecasts and assumptions on related costs?

18 A (Witness Trokey) Yes, we can agree.

19 Q And to be clear, it's not your recommendation
20 in this case that the company shouldn't recover costs;
21 correct?

22 A (Witness Trokey) The company should recover
23 prudently incurred costs.

24 Q And you got me on my next question, which is,
25 you're not making any improvements determinations in this

1 case; right?

2 A (Witness Trokey) Not at this point.

3 Q Okay. And would you agree with me
4 information regarding costs, you know, is routinely
5 included in the case by virtue of the rules, the
6 Commission rules requirements to do that; correct?

7 A (Witness Trokey) Yes, that is correct.

8 Q And finally on this point, is it also true
9 that the Commission has approved costs in prior IRP cases?

10 A (Witness Trokey) I believe that's the case,
11 yes.

12 Q Okay. Now, you were asked some questions, I
13 think, a moment ago about reclassification, and I just
14 want to get some clarity on this, and we're primarily
15 talking about the reclassification of the retiring units,
16 the net book value related to retiring units to a
17 regulatory asset. Is that -- is that the right
18 terminology, gentlemen?

19 A (Witness Smith) Into a regulatory asset. I
20 think the company is requesting the net book value and some
21 unusable materials and supplies.

22 Q Okay. And when we talk about
23 reclassifications, essentially, we're preserving that
24 issue to allow for the Commission to make a future
25 rate-making determination as to recovery of that cost. Is

1 that a fair statement of what we're doing?

2 A (Witness Smith) That would be our main reason
3 for transferring amounts into a regulatory asset account so
4 they can be considered in some future proceeding.

5 Q And that's just by recognition -- correct me
6 if I'm wrong -- that's just by recognition of the fact
7 that the company is a regulated utility and a cost-based
8 regulated utility, and by virtue of that, there are times
9 when costs are incurred in one period but then recovered
10 later in another period. Is that fair?

11 A (Witness Smith) That's fair, yeah.

12 Q Yeah.

13 A (Witness Smith) The Commission can review the
14 amounts in the regulatory asset and the period over which
15 it's recovered or amortized and can calibrate that based on
16 various considerations.

17 Q Now, I think in this case the company and the
18 staff agree that there are units that are retiring in 2022
19 and to the extent that those units are retiring -- we're
20 talking about Wansley 1 and 2 primarily -- those are going
21 to be carried over into a regulatory asset as we've
22 traditionally done in this case; is that correct?

23 A (Witness Smith) I think Wansley 1 and 2 and
24 Boulevard -- I think there might have been one other smaller
25 one -- are projected for retiring in August of 2022. So for

1 purposes of considering those costs in the rate case,
2 transfer of those amounts into a regulatory asset would be
3 appropriate --

4 Q Okay.

5 A (Witness Smith) -- to the timing.

6 Q I am sorry, Mr. Smith. Finish. Please
7 finish.

8 A (Witness Smith) In terms of the timing of --
9 as of the end of August of 2022, if those plants are retired
10 on schedule, that would be the time when the costs would
11 then be identified and shifted over into the regulatory
12 asset.

13 Q Okay. And I appreciate you adding Boulevard.
14 I should have included that as well.

15 Now, there are other units that are not
16 retiring in 2022, but if the requests for decertification is
17 approved in this case, those plants will retire in the
18 2027-2028 time frame? Is that your understanding?

19 A (Witness Smith) That's correct. Yeah. There
20 are some that the company has requested decertification for
21 that have retirement dates in 2027 and 2028. And for those
22 in terms of the next rate case, we would expect those not to
23 be treated as regulatory assets because they're still
24 operating.

25 We would expect those to continue to be treated

1 as plant in service, at least up until their retirement
2 dates, because the retirement dates are beyond the next rate
3 case cycle. We don't think there is a need at this point to
4 have those costs transferred into a regulatory asset
5 account. At least not in the context of the next rate case
6 cycle.

7 Q Okay. And so I think you've kind of hit on,
8 I think, the main point, and maybe the point of
9 disagreement between the company and staff, or at lease
10 point that needs clarity. So staff feels that it's
11 unnecessary today to establish the regulatory
12 classification to net book value for the retiring plants
13 that are past 2022 because your belief is that can be done
14 in a future rate proceeding. Is that right?

15 A (Witness Smith) Well, our concern is mainly
16 about the ones that are projected to be retired in 2027 and
17 '28. And we're trying to think about the treatment that
18 needs to be addressed in the company's next rate case,
19 which, presumably, will ask for 2023, '24, and '25.

20 So during that entire rate case cycle period,
21 the other plants, I mean, Bowen, will be continuing to
22 operate. So in the rate case, they will treat it as plant
23 in service. They will have depreciation applied during all
24 three of those years that are being considered in
25 determining the rate case, rate plan revenue requirement.

1 So the proper treatment for those units in the
2 next rate case is -- since they're continuing to operate and
3 to generate electricity is to continue to treat them as
4 plant in service. Now, presumably, in 2025 or some point in
5 that general time frame, the company will have another IRP
6 case, and then at that point the company can say, look, in
7 the next three-year horizon, these plants are scheduled for
8 retirement; and in fact, the retirements were approved by
9 the Commission, to the extent that they are approved.

10 So during the next rate case cycle, would it be
11 appropriate for when those plants are actually retired to
12 then move the remaining net book value and any unusable
13 material and supplies into a regulatory asset account at
14 that point.

15 Q And, Mr. Smith, I think there's two things
16 that we're talking about, so if you let me kind of ask the
17 question this way: So I believe we both agree that the --
18 whatever remains, if there's anything remaining at the end
19 of the -- let's take net book value is what we are talking
20 about now for retiring units.

21 If there's anything remaining at the end of the
22 life, the retirement year, that is exactly when that would
23 transfer to a regulatory asset. We both agree on that; is
24 that correct?

25 A (Witness Smith) While the plant is operating,

1 yes, it would continue to receive depreciation, and once
2 it's retired at that point, if there's a remaining net book
3 value, that would be the point in time at which an
4 accounting transfer of remaining costs would be appropriate.

5 Q And I think the point of -- perhaps the point
6 of disagreement between the company and staff on this
7 issue is not the point of transfer to regulatory asset but
8 when that declaration has to be made. And is it your
9 position that it's -- are you aware that it's the
10 company's position that it's necessary to make the
11 determination that a regulatory asset will be established
12 at the point in time that retirement is decided upon by
13 this Commission?

14 A (Witness Smith) It just seems like that's
15 premature in this current proceeding, because, I mean, the
16 company's depreciation rates are going to be reviewed in the
17 rate case. So I mean, one way of dealing with it is just to
18 say we know the plant's going to retire at the end of 2027,
19 so let's depreciate it through the end of 2027. If that
20 approach were to be applied, there may not be any remaining
21 net book value.

22 Q And I guess in that regard, if a
23 determination is necessary in this case in order to
24 preserve the issue for exactly what you're talking about,
25 the next rate case or a rate case in the future, to make

1 that determination, is staff opposed to making that
2 reclassification now just to preserve the issue as it's
3 done in prior IRPs?

4 A (Witness Smith) It's not needed to preserve
5 the issue in the current rate case cycle. You will have
6 another IRP proceeding, presumably in 2025, and there will
7 be another rate case cycle, presumably, that will address
8 years '26, '27, to '28.

9 So I think the company's request in that regard
10 is a bit premature. There is no need to make that
11 accounting approval at this point in time for something
12 that's going to occur out at the end of '27 and '28.

13 Q So you disagree that when the retirement
14 dates are set in this proceeding that the company must
15 consider projected balance at that point in time in
16 retirement? They've got to do it today? You disagree
17 with that?

18 A (Witness Smith) Once the retirement dates are
19 set, then there's various ways of dealing with that, and
20 you'll have basically two rate cases to address it, the one
21 that you're going to file at the end of June, which
22 presumably will cover '23, '24, and '25.

23 During that cycle, these plants will continue
24 to operate and generate electricity so they will receive a
25 plant in service depreciation-type accounting. In the

1 subsequent rate case cycle, you'll have another opportunity,
2 and they might fall within that three-year period.

3 So at that point, which is not in this current
4 IRP case, you'll have another opportunity to address the
5 accounting reclassification and the timing of it.

6 Q And so just so I have the record clear, so
7 it's your accounting understanding then that at the point
8 in time this Commission makes a determination for a
9 retirement, that the company then does not have to have
10 some certainty of how that will be handled in the future
11 period in order to carry that cost forward? There doesn't
12 need to be an immediate action taken? There's a risk of
13 immediate action being taken?

14 A (Witness Smith) Not when you have an upcoming
15 rate case in which depreciation rates are going to be
16 reexamined.

17 Q Well, I believe your recommendation was, one,
18 to look at it in the 2025 IRP or 2025 rate case; isn't
19 that correct? So that's not the upcoming rate case;
20 correct?

21 A (Witness Smith) The upcoming rate case, the
22 company's depreciation rates will be evaluated.

23 Q Yeah.

24 A (Witness Smith) So it can be - it will be --
25 depreciation rates will be looked at in the company's rate

1 case that's going to filed at the end of June.

2 Then there will be another opportunity to look
3 at depreciation rates again in the IRP that the company
4 would file in 2025 and look at depreciation rates in the
5 company's 2025 rate case cycle case.

6 COMMISSIONER MCDONALD: Mr. Smith, are all of
7 your assumptions that you talk about in the
8 depreciation schedule of those units that might
9 retire after '25, are all your assumptions in the
10 rate case based on that there will only be -- there
11 will be a rate case three years from now rather than
12 one next year or the next year?

13 WITNESS SMITH: That's a little bit more
14 uncertain. I mean, we know that the company's
15 announced that they're going to file a rate case at
16 the end of June.

17 I guess the next rate case we're not totally
18 certain, but they've had a fairly reliable pattern of
19 every three years.

20 COMMISSIONER MCDONALD: But, I mean, when you
21 take into consideration where we are today and
22 what -- what's on the platter of the company and its
23 partners and other venues of generation, are your
24 assumptions made on the fact that we'll have
25 something like another accounting order for three

1 years or something to that -- is that what you're
2 basing your assumptions on?

3 WITNESS SMITH: No. My basic knowledge rather
4 than assumption is that the company is coming in for
5 a rate case and its depreciation rates will be
6 reviewed in the rate case.

7 And the retirement dates for these units that
8 we're talking about are beyond the three-year period
9 that's going to be addressed in the rate case.

10 COMMISSIONER MCDONALD: Okay.

11 BY MR. MARZO:

12 Q So maybe I can wrap this line up. From your
13 testimony it's clear that both the company and staff agree
14 that the intent of what we do here is neither to decide
15 the cost recovery but it's also to allow for those
16 decisions to be made in a future period; is that correct?

17 A (Witness Smith) Yes.

18 Q Okay. And to the extent that it's necessary
19 to make some determination in this case in order to
20 preserve that issue and ensure that we can hear it in a
21 separate -- in a future period, I'm assuming we can work
22 with staff to come to some resolution of that issue. Is
23 that -- is that fair?

24 A (Witness Smith) Well, I think you have the
25 staff recommendation about which accounting transfers we're

1 recommending be approved in this IRP case --

2 Q And I guess --

3 A (Witness Smith) -- and which ones we think the
4 decision can be deferred on.

5 Q And, I guess, Mr. Smith, my concern is
6 there's a fundamental disagreement between the company and
7 staff as to whether or not the issue can be preserved
8 absent the Commission making the accounting determination.

9 So I think our -- I think our main purpose is
10 the same, and the question I believe that remains is how do
11 we accomplish that. I understand your position is you don't
12 have to do anything. The company's position is you do need
13 to preserve the issue through a classification in this case.

14 But ultimately our goals seem to be the same;
15 is that correct? Our goals to hear this issue and preserve
16 it for discussion in a future rate proceeding; right?

17 A (Witness Smith) Yes. We're not opposed to
18 accounting classifications when they're needed, at the point
19 in time that they're needed.

20 Q Okay. And I appreciate that.

21 You were asked -- well, let me ask this
22 question. You had mentioned during your summary,
23 Mr. Trokey, regarding the environmental compliance strategy.

24 And staff agrees that it is appropriate to
25 appropriate -- appropriate for the Commission to consider

1 approval of the company's ECS in the IRP; is that correct?

2 A (Witness Trokey) Yes, that's correct.

3 Q And indeed in the 2019 IRP, the Commission
4 approved the stipulation provided for that approval to
5 address the -- both the ECS and specifically the CCR plan
6 of the company; is that correct?

7 A (Witness Trokey) Yes. That was reviewed in
8 '19.

9 Q And it is clear from your testimony in this
10 case that staff did an extensive review of the costs for
11 environmental compliance as part of your review of the ECS
12 in this case; is that correct?

13 A (Witness Trokey) That's accurate.

14 Q Okay. And this includes the three-year
15 projected budgets for ECCR; correct?

16 A (Witness Trokey) It does. And those budgets
17 change.

18 Q And staff's recommending approval of the ECS
19 and that ECCR budget in this case -- correct? -- but not
20 the cost -- not yet the approval of the actual cost
21 recovery, but approval of the plan that supports those
22 budgets?

23 A (Witness Trokey) Yes. I would say that with
24 the caveat of certain unknowns related to the ash pond
25 closures, staff does believe that approval of the compliance

1 strategy, the plan itself, not the costs, are subject for
2 approval in this case.

3 Q And we can generally agree that the company
4 should recover prudently incurred costs for its
5 environmental compliance; correct?

6 A (Witness Trokey) That's correct.

7 Q And you understand that procedural scheduling
8 order for the 2022 rate case provides that the rate case
9 would be filed before the order would be issued in this
10 case; is that right?

11 A (Witness Trokey) Yes.

12 Q Okay. So to the extent there are schedules
13 filed in this case that report on, for example, the ECCR
14 costs, you wouldn't be surprised or you might even expect
15 that those schedules would look very similar to what you
16 reviewed in this case; correct?

17 A (Witness Trokey) Correct. I wouldn't be
18 surprised. I would also expect there would be additional
19 information available to the parties during the rate case.

20 Q Now, can we agree that the federal and
21 Georgia CCR rule authorized both closure in place and
22 closure by removals options for compliance?

23 A (Witness Trokey) Yes, that's my understanding.

24 Q And you discuss on page 45 and 46 some
25 concerns regarding the recent statements by EPA, and I

1 think you discuss those also in your summary?

2 A (Witness Trokey) Yes.

3 Q And specifically on page 45, you discuss
4 EPA's news release and refer to the statement in the
5 release that states that "EPA has consistently held the
6 position regarding service impoundments are being closed
7 in place"?

8 A (Witness Trokey) Yes, I see that.

9 Q Okay. Now, were you here when Mr. Mitchell
10 and Dr. Berry testified regarding EPA's new position?

11 A (Witness Trokey) I was.

12 Q Okay. And did you hear Mr. Mitchell's
13 testimony that the company's environmental compliance
14 plans are based on long-standing rule interpretations held
15 by both the industry and environmental regulators that
16 employ industry and agency-accepted engineering practices?

17 A (Witness Trokey) I may have heard that. I
18 don't remember the exact words.

19 Q Now, you -- I'm sorry. Go ahead, Mr. Trokey.

20 A (Witness Trokey) That's all. Yes, I believe
21 they said something to that effect.

22 Q And then you're aware that Georgia EPD
23 implements the federal and Georgia CCR rule through its
24 EPA approved program?

25 A (Witness Trokey) Yes. It has an approved

1 permit program.

2 Q Let me show you an exhibit, if I could.

3 MR. MARZO: And, Madam Chair, can I have
4 Mr. Hewitson approach the witness?

5 MADAM CHAIR PRIDEMORE: Yes, you may.

6 MR. MARZO: For the record, Madam Chair, this
7 is the e-mail from Richard Dunn, director of EPD, to
8 Carolyn Hoskinson, director of the Office of Resource
9 Conservation and Recovery, U.S. EPA, and several
10 individuals from EPA copied, including Region 4
11 administrator, Daniel Blackman.

12 BY MR. MARZO:

13 Q And you take a minute to look at that,
14 Mr. Trokey, and I'm going to ask you a question about it.

15 MR. MARZO: I'd like to have this marked, by
16 the way, Madam Chair, as GPC Exhibit, I believe, 7.

17 MADAM CHAIR PRIDEMORE: So marked.

18 (The document referred to was marked for
19 identification as GPC Exhibit 7.)

20 MR. WALSH: Madam Chair, I know I've made
21 similar statements earlier today, and I'll just say I
22 don't know what the question is going to be, but
23 obviously, it doesn't appear that any -- either
24 member of the panel was on the e-mail or -- I don't
25 know if anybody from the Public Service Commission

1 was on this e-mail, so I'm not sure if they're going
2 to be able to speak or not.

3 I'll wait for the question, I guess, but I do
4 have some concern that they're being presented an
5 e-mail between other people and being asked to speak
6 to it.

7 MR. MARZO: I'm sorry, Mr. Walsh.

8 MR. WALSH: That's all right.

9 MR. MARZO: Madam Chair, in the staff's
10 testimony, they reference a press release from EPA,
11 which also is a document which EPA is not attesting
12 to here but is a press release from EPA. This is a
13 letter from EPD that contradicts the idea that the
14 position that EPA is saying it's not new but
15 consistently hails the fact of the new position.

16 And that's the purpose of the e-mail is to
17 respond to a point that they were making to their
18 testimony.

19 MR. WALSH: I'm not saying that they can -- I
20 mean, obviously, if the staff sees something in their
21 review and their preparation of the testimony, they
22 can put something in their testimony that they didn't
23 themselves prepare.

24 I'm just saying, to answer questions on an
25 e-mail that they haven't seen and weren't copied on

1 and didn't prepare, I'm not sure -- I mean, the
2 e-mail exists, certainly, I guess, but they
3 haven't -- I don't know what they can do to respond
4 to questions about an e-mail that they were not on
5 and weren't a part of and didn't see previously.

6 MADAM CHAIR PRIDEMORE: Again, we're lenient
7 with handouts and so bring more handouts tomorrow is
8 all I can say. All right.

9 MR. MARZO: And I'll be efficient, Madam Chair.
10 I'll make this quick.

11 MADAM CHAIR PRIDEMORE: Overruled. Ask your
12 question.

13 BY MR. MARZO:

14 Q Mr. Trokey, would you read the highlighted
15 section, and I will ask you a question about it?

16 A (Witness Trokey) Sure. It says "I want to be
17 short placed on the agenda sometime for a discussion of the
18 rationale for EPA's new interpretation of the performance
19 standards for waste closed in place.

20 "As you indicated in your letter, EPA has long
21 been aware of how EPD reads the language in 40 CFR Part 257,
22 subpart D.

23 "Up until this week, it has been our
24 understanding that EPA shared similar views, particularly
25 given the meaning of the relevant terms in geology,

1 hydrology, and other solid waste regulations."

2 "Unfortunately, the brief time set aside for
3 last Monday's call did not allow us to discuss these issues
4 in any depth."

5 Q Thank you, Mr. Trokey.

6 And so as I mentioned in my explanation to the
7 Chair, I mean, do you agree, I mean, this confirms that the
8 regulator who oversees the closures here in Georgia believes
9 the EPA's position is a new position?

10 MR. WALSH: I'm going to object again. I don't
11 believe that the panel can testify as to what
12 somebody else believes. I mean, the --

13 MR. MARZO: I can rephrase.

14 MR. WALSH: The language speaks for itself on
15 the e-mail. I believe it's hearsay, but --

16 MR. MARZO: I can rephrase.

17 MADAM CHAIR PRIDEMORE: Sustained, Mr. Walsh.
18 Give you another shot at it.

19 BY MR. MARZO:

20 Q Mr. Trokey, you hadn't seen this e-mail
21 before you presented your -- put together your testimony;
22 correct?

23 A (Witness Trokey) Correct. I have not seen it
24 previously.

25 Q Thank you.

1 Now, are you aware that several utilities in
2 states have filed actions against EPA challenging EPA's
3 determination on the basis that EPA has issued new
4 regulations and requirements without notice and comment?

5 A (Witness Trokey) Can you repeat that? I
6 believe I heard something about --

7 Q For example --

8 A (Witness Trokey) -- an action, yes.

9 Q -- are you aware that several utilities and a
10 state have filed actions against EPA and challenging EPA's
11 determinations on the basis the EPA has issued new
12 regulations and requirements without notice and comment?

13 A (Witness Smith) In general or with respect to
14 this January 11, 2022 --

15 Q With respect to January 11, 2022, new
16 position they announced on closures.

17 A (Witness Smith) It's our understanding that a
18 lot of parties found this to be rather surprising, but it
19 does create uncertainty.

20 Q Now, you reference on page 45 and 46 in your
21 testimony the proposed denial of alternative closure
22 deadline for General James M. Gavin Plant?

23 A (Witness Trokey) Yes.

24 Q Okay. And you have reviewed that; correct?

25 A (Witness Trokey) I have read it.

1 Q Okay. And would you agree with me that Plant
2 Gavin is not a Georgia Power facility?

3 A (Witness Trokey) I would agree with you.

4 Q And would you agree with me that Gavin
5 closure plan upon which determination is based is not a
6 plan developed by Georgia Power?

7 A (Witness Trokey) I believe that is correct.

8 Q And as it pertains to closure in place plans
9 that have been developed by Georgia Power, what we know
10 today is that one closure in place permit has already been
11 approved by EPD, the Bowen Ash Pond 1 and another, Hammond
12 AP-3, has been issued in draft form?

13 A (Witness Trokey) That's correct. One permit
14 has been issued and one in draft form.

15 Q And would you agree that these actions by EPD
16 are consistent with the fact that the company's
17 environmental compliance plans are based on long-standing
18 rule interpretations, both held by the industry and the
19 regulator -- environmental regulators?

20 A (Witness Trokey) I'm not sure I would agree,
21 just with respect to what has been filed with EPD. I --
22 I -- it's voluminous. I've not reviewed all of that
23 material.

24 That said, you know, essentially the
25 uncertainty comes from the EPA's language that it has

1 expressed both in, you know, the press release and in the
2 decisions on those other units in other states.

3 I -- my understanding is Georgia Power has
4 plans and has perhaps filed for approval of permits at ponds
5 where ash is in the groundwater. And so to the extent that
6 that has not been determined and that there is clear
7 indication from EPA that that's not permissible, according
8 to the rules that have been in place for many years, that
9 provides the uncertainty as to whether -- whether in fact
10 Georgia's permit program or Georgia Power's understanding of
11 that rule is sufficiently addressing compliance with respect
12 to the rule.

13 Q And I understand, Mr. Trokey, your testimony
14 in terms of the visual and monitor, I think the company
15 has said that in its direct, that he agrees with that
16 position.

17 But I guess I'm trying, to understand with what
18 you just said, are you saying that you're taking the
19 position as to whether or not the issuance of those
20 particular permits that has either indicated compliance or
21 not indicated compliance? I couldn't unwrap what you said
22 on that.

23 A (Witness Trokey) So my understanding is EPA
24 has said that it has asked EPD to review those permits that
25 have been issued, so I -- it would be inappropriate for me

1 to say that they were approved as in compliance or not. It
2 would ultimately be up to EPD and EPA to make that
3 determination.

4 Q And the review you're referring to is the
5 review that was requested since January of 2022; correct?

6 A (Witness Trokey) Yes, that's correct.

7 Q Okay. And once again, I close out this line,
8 I think the company and staff are saying the same thing,
9 it's let's monitor what's going on, but the staff is not
10 proposing that the company alter its environmental
11 strategies pertaining to CCR currently; correct?

12 A (Witness Trokey) Correct. Yes. It's -- it's
13 not the Commission's role to determine, you know, what EPA
14 or EPD will do with that respect. But at the same time, it
15 would be premature to approve the costs associated with a
16 plan that may change in the near future. And we will have
17 more information about that as well.

18 Q And I don't -- I think we are saying the same
19 thing again, Mr. Trokey, which is we're not talking about
20 costs, but you're not proposing an alternative strategy
21 either; correct?

22 A (Witness Trokey) Staff has not proposed an
23 alternative strategy.

24 Q So just real quickly, the staff is proposing
25 to maintain the additional sum for the certificate of EPA;

1 is that correct?

2 A (Witness Trokey) Yes.

3 Q And that's the 2.30 kW a year?

4 A (Witness Trokey) That is correct.

5 Q And I think one of the statements that you
6 make in your testimony is that there's not a compelling
7 reason to change it? I can cite you to it if --

8 A (Witness Trokey) That's correct, yes. I would
9 say that.

10 Q Now, are you aware that a 2.30 kW year
11 additional sum was first established in 2000?

12 A (Witness Trokey) Yes.

13 A (Witness Smith) Yes.

14 Q Thereabout?

15 And so the level of additional sum hasn't
16 changed in 22 years; is that correct?

17 A (Witness Trokey) That is correct.

18 Q Now, you're familiar with the statute --
19 correct? -- for additional sum; is that right?

20 A (Witness Trokey) Yes.

21 Q Okay. And would you agree with me that the
22 additional sum is meant to be an incentive for the utility
23 to enter into purchase power contracts in lieu of
24 self-build generators?

25 A (Witness Trokey) Yes, it is an incentive.

1 Q Okay. And so it's fair to say that the
2 purpose of the additional sum is to provide the company
3 adequate incentive to forego the opportunity to earn a
4 return on the self-build resource; is that correct?

5 A (Witness Trokey) This is true. That's what's
6 in the statute. You know, at the same time, it would make
7 sense economically for ratepayers to pursue projects and
8 power purchase agreements with independent power producers
9 if they're more economic.

10 Q Now, are you aware that --

11 A (Witness Trokey) I believe the company would
12 do that with or without an additional sum.

13 Q I didn't mean to cut you off, Mr. Trokey.

14 A (Witness Trokey) I'm sorry. I was just adding
15 that, if it makes sense economically to pursue the power
16 purchase agreements, I think the additional sum itself will
17 not be a final determinant as to whether or not the company
18 would enter into those contracts, the Commission would do
19 that.

20 Q Yeah. But ultimately the staff's use
21 intended -- intends it being an incentive, and that was my
22 question.

23 A (Witness Trokey) Yes.

24 Q Correct?

25 A (Witness Trokey) It is an incentive.

1 Q And you're aware that the origin of the
2 2.30 kW year additional sum was based upon shared savings
3 analysis?

4 A (Witness Trokey) Yes. That's my
5 understanding.

6 Q And you would agree with me that the
7 Commission setting additional sums shall consider the
8 factors of lost revenues, changed risks, and equitable
9 share and benefits?

10 A (Witness Trokey) Correct.

11 Q And would you agree with me that in this
12 case -- I know you disagree with the methodology, but in
13 this case, the company has essentially done a shared
14 savings analogy taking into account its self-build
15 resource; correct?

16 A (Witness Trokey) Yes, it has.

17 Q Okay. One last question to you on -- related
18 to beneficial reuse -- or a couple questions on beneficial
19 reuse.

20 Now, you discuss in your testimony the
21 company's plan for beneficial reuse of coal ash; correct?

22 A (Witness Trokey) Yes, that's right.

23 Q And is it fair to say staff is supportive of
24 beneficial reuse of coal?

25 A (Witness Trokey) Yes. Staff supports that.

1 Q And in your testimony, you reference some
2 concerns regarding the company's plans to invest in
3 infrastructure to facilitate beneficial reuse and the
4 expected savings; is that -- is that fair?

5 A (Witness Trokey) Yes. I think that is
6 essentially to support staff's position to not approve the
7 costs at this point in time in the IRP because that will be
8 reviewed in the rate case. The amount of capital investment
9 upfront is not certain at this time and subject to change.

10 Q And I know that the company has met with
11 staff since filing your testimony to try to address some
12 of those concerns.

13 Is it fair to say that one of the primary ways
14 the company intends to both mitigate risks of cost increases
15 for infrastructure needed to process ash as well as reduce
16 the risk with marketing ash is through the contractual
17 arrangements that it intends to enter into with winning
18 proposals?

19 A (Witness Trokey) That's correct.

20 Q Okay. And I'm -- we explained that to you,
21 so I realize you haven't seen a contract yet. That was --

22 A (Witness Trokey) Correct, staff hasn't
23 reviewed the contract. But to the extent that over an
24 extended period of time, if ratepayers are better off
25 economically, then it makes sense to invest that upfront.

1 Q Okay.

2 MR. MARZO: That you, Mr. Trokey. Thank you,
3 Mr. Smith.

4 Madam Chair, I have no further questions.

5 MADAM CHAIR PRIDEMORE: Okay. Redirect?

6 MR. WALSH: Thank you, Madam Chair. Just a few
7 questions on redirect.

8 REDIRECT EXAMINATION

9 BY MR. WALSH:

10 Q Mr. Trokey, you were asked a few moments ago
11 about the additional sum?

12 A (Witness Trokey) Yes.

13 Q And you were asked about the statute that
14 lists certain factors for the Commission to consider in
15 the determination of an additional sum.

16 Do you recall those questions?

17 A (Witness Trokey) I do.

18 Q Does the statute, to your knowledge, specify
19 what weight the Commission should give each of those
20 factors and what the additional sum -- any minimum for
21 what the additional sum has to be?

22 A (Witness Trokey) It does not specify.

23 Q You were asked, I believe, whether the
24 statute sets up the additional sum as an incentive for the
25 company.

1 Do you recall those questions?

2 A (Witness Trokey) Yes.

3 Q Do you believe that the additional sum that's
4 been in place in -- the current additional sum, most
5 recent proceedings, serves as an adequate incentive for
6 the company to enter into purchase power agreements?

7 A (Witness Trokey) I do. The purchase power
8 agreements the company has entered into have been effective
9 and beneficial to customers.

10 Q So do you have reason to believe that that
11 additional sum would not serve as an adequate incentive
12 moving forward for the company to enter into cost
13 effective power purchase agreements?

14 A (Witness Trokey) No, we don't have any reason
15 to believe that.

16 MR. WALSH: Madam Chair, that's all the
17 redirect that I have. I would ask that Staff
18 Exhibits, I believe, 17 through 32 be admitted into
19 the record.

20 MADAM CHAIR PRIDEMORE: So moved.

21 (Staff Exhibits 17-32 was admitted into
22 evidence.)

23 MR. WALSH: Thank you.

24 MR. MARZO: Just ask Georgia Power Exhibit 7 be
25 admitted into the record.

1 MADAM CHAIR PRIDEMORE: So moved.

2 (GPC Exhibit 7 was admitted into evidence.)

3 MR. WALSH: I will just state -- I understand.

4 I'd just state for the record the staff's objection.

5 MR. MARZO: He's going to do that to me every
6 time.

7 MADAM CHAIR PRIDEMORE: It's on the record.

8 All right. Mr. Walsh, you can excuse your witnesses.

9 MR. WALSH: You may be excused.

10 MADAM CHAIR PRIDEMORE: Okay. We're going to
11 allow just a minute to allow the court reporter to
12 reset.

13 Go ahead, Mr. Thomas.

14 MR. THOMAS: Thank you.

15 Preston Thomas here on behalf of Public
16 Interest Advocacy Staff.

17 Madam Chair, at this time I would like to call
18 the panel of Jamie Barber, Timothy Cook, and Jeffrey
19 d. Bower to the stand.

20 Would y'all please raise your right hand.

21 Thereupon,

22 JAMIE BARBER,
23 TIMOTHY COOK,
24 JEFFREY D. BOWER,

25 having been duly sworn, testified as follows:

DIRECT EXAMINATION

1 BY MR. THOMAS:

2 Q And, Miss Barber, can you please state your
3 full name, by whom you are employed, and your
4 responsibilities, for the record.

5 A (Witness Barber) Jamie Barber, the Georgia
6 Public Service Commission. I am the director of the Energy
7 Efficiency and Renewable Energy Unit.

8 Q Mr. Cook, same question.

9 A (Witness Cook) I am Timothy Shayne Cook. I am
10 a -- I work for the Georgia Public Service Commission, and I
11 am a utilities engineer.

12 Q Thank you.

13 Mr. Bower.

14 A (Witness Bower) I'm Jeffrey Bower, managing
15 consultant with Daymark Energy Advisors.

16 Q And on May 6 of this year, did you file or
17 cause to be prefiled 75 pages of testimony in
18 question-and-answer format, along with 22 exhibits marked
19 as BCB 1 through BCB 22?

20 A (Witness Barber) Yes.

21 Q Do you have any corrections you need to make
22 to either your prefiled testimony or exhibits at this
23 time?

24 A (Witness Barber) We don't.

25 Q And if I were to ask you the same questions

1 today under oath, would your answers be the same?

2 A (Witness Barber) Yes, they would.

3 MR. THOMAS: Madam Chair, the court reporter
4 has been provided a copy of the prefiled testimony,
5 and I would ask that the direct testimony be copied
6 into the record as if given from the stand orally,
7 and I would ask that Exhibits BCB-1 through BCB-22 be
8 marked for identification purposes as Staff Exhibits
9 33 through 54.

10 MADAM CHAIR PRIDEMORE: So moved and so marked.

11 The documents referred to were marked for
12 identification as Staff Exhibits 33-54.)

13 (Whereupon, the prefiled direct testimonies
14 of Ms. Jamie Barber, Mr. Timothy Cook and Mr. Jeffrey
15 D. Bower follows:)

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1 **I. QUALIFICATIONS AND SUMMARY**

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

3 A. My name is Jamie Barber, and I am the Director of the Energy Efficiency and Renewable
4 Energy Unit for the Georgia Public Service Commission ("Commission"). My business
5 address is 244 Washington Street SW, Atlanta, GA 30334.

6 **Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK
7 EXPERIENCE.**

8 A. My educational background and work experience are provided in my resume, which is
9 attached as Staff Exhibit_BCB-1.

10 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?**

11 A. Yes. I testified in each of the 1998 through 2009 United Cities Gas Company (now known
12 as Atmos Energy Corporation) Gas Supply Plan Proceedings. I have also testified in
13 Docket No. 10270, GPSC Determination of Lack of Market Constraints on Atlanta Gas
14 Light Company's Commodity Sales; Docket No. 11114, Rule Nisi Against United Gas
15 Management of Georgia, Inc.; Docket No. 14311, Earnings Review to Establish Just and
16 Reasonable Rates for Atlanta Gas Light Company; Docket No. 15296 Service Quality
17 Standards for Certified Marketers and Regulated Provider; Docket No. 18638-Atlanta Gas
18 Light Company's 2004/2005 Rate Case; Docket No. 20298 Atmos Energy Corporation's
19 2005 Rate Case; Docket No. 27163 Atmos Energy Corporation's 2008 Rate Case; Docket

1 No. 30442 Atmos Energy's 2010 Rate Case; Docket No. 36498 Georgia Power Company's
2 2013 Integrated Resource Plan ("IRP") Filing; Docket No. 36499 Georgia Power
3 Company's 2013 Demand Side Program Certification; Docket No. 37854, Georgia Power
4 Company's Application for the Certification of the Power Purchase Agreements for Wind
5 Resources from the Blue Canyon II and Blue Canyon VI Wind Farms; Docket No. 38877,
6 Georgia Power Company's Application for the Certification of the 2015 and 2016
7 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of
8 the 2015 Advanced Solar Initiative Power Purchase Agreements, Docket No. 36989
9 Georgia Power Company's 2013 Rate Case, Docket No. 40161 Georgia Power Company's
10 2016 IRP Filing, 40162 Georgia Power Company's 2016 Demand Side Program
11 Certification, Docket No. 41596, Georgia Power Company's Application for the
12 Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale
13 Power Purchase Agreements, Docket No. 41734, Georgia Power Company's Application
14 for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility
15 Scale Power Purchase Agreements for the Commercial and Industrial Program, Docket No.
16 43210 Georgia Power's 2019 IRP Filing, Docket No. 43211 Georgia Power Company's
17 2019 Application for the Certification, Decertification, and Amended Demand-Side
18 Management Plan, and Docket No. 42516 Georgia Power Company's 2019 Rate Case.

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

20 **A.** My name is Timothy Cook, and I am a Public Utilities Engineer for the Commission. My
21 business address is 244 Washington Street SW, Atlanta, GA 30334.

1 **Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
2 **EXPERIENCE.**

3 A. My educational background and work experience are provided in my resume, which is
4 attached as Staff Exhibit_BCB-2.

5 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?**

6 A. Yes, I have testified in Docket No. 42625, Georgia Power Company's Application for the
7 Certification of the 2020/2021 Renewable Energy Development Initiative Utility Scale
8 Power Purchase Agreements; and Docket Nos. 4822, 16573 and 19279 Georgia Power
9 Company's PURPA Avoided Cost Dockets, and Docket No. 43814 Georgia Power
10 Company's Application for the Certification of the 2022/2023 Utility Scale Renewable
11 Power Purchase Agreements.

12 **Q. MR. BOWER, PLEASE STATE YOUR NAME, TITLE, AND BUSINESS**
13 **ADDRESS.**

14 A. My name is Jeffrey D. Bower. I am a Managing Consultant at Daymark Energy Advisors
15 ("Daymark"), which provides energy planning, market analysis, and regulatory policy
16 consulting and advisory services to support decision making within the electricity and
17 natural gas industries. We serve a broad range of clients in North America, including
18 private and public utilities, energy producers and traders, energy consumers and consumer
19 advocates, regulatory agencies, and public policy and energy research organizations, and
20 other industry stakeholders. Our technical skills include power market forecasting models
21 and methods, economics, management, planning, rates and pricing, and energy

1 procurement, and contracting. Our experience includes detailed analyses of energy and
2 environmental performance of the electric systems, economic planning for transmission,
3 and market analytics. My business address is 370 Main Street, Suite 325, Worcester, MA
4 01608.

5 **Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
6 **EXPERIENCE.**

7 A. My educational background and work experience are provided in my resume, which is
8 attached as Staff Exhibit_BCB-3.

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

11 A. Yes. I testified in Dockets Nos. 4822, 16573, and 19279 regarding the application of
12 Georgia Power Company's Renewable Cost Benefit Framework ("RCB Framework") to
13 Public Utility Regulatory Policies Act of 1978 ("PURPA") qualifying facilities ("QFs").
14 In addition, I have testified before regulatory commissions in other states. In addition, I
15 have supported Commission Staff's evaluation of Georgia Power Company's RCB
16 Framework since 2016.

17 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

18 A. We are presenting testimony on behalf of the Commission Public Interest Advocacy Staff
19 ("Staff").

1 **Q. PLEASE PROVIDE THE RECOMMENDATIONS THAT STAFF IS MAKING**
2 **FOR THE COMMISSION TO CONSIDER.**

3 A. Based on our review of Georgia Power Company's ("Georgia Power" or "Company")
4 filing, testimony, data request responses, and other pertinent information for this case, we
5 have the following recommendations for the Commission's consideration:

6 1. Staff recommends that the Company remove the Generation Remix component of the RCB
7 Framework and modify the Deferred Generation Capacity Cost component to use the
8 economic carrying costs ("ECC") of a combined cycle unit instead of a combustion turbine
9 unit.

10 2. Staff recommends that a renewable energy credit ("REC") component be included in the
11 RCB Framework.

12 3. Staff recommends that Staff and the Company meet after the 2022 IRP concludes to
13 determine how to appropriately value the REC component and then bring the method to
14 the Commission for approval.

15 4. Staff recommends that the Company use the effective load carrying capability ("ELCC")
16 method in place of the Incremental Capacity Equivalence ("ICE") / Capacity Worth Factor
17 Table ("CWFT") method going forward. As with the CWFT/ICE studies, the ELCC study
18 should be updated annually.

19 5. Staff does not recommend approval of the Company's request to replace Support Capacity
20 with the Integration Cost component in the RCB Framework. Staff recommends that the
21 Company reconduct the Renewable Integration Study to address the issues identified by
22 Staff and provide a benchmark study comparing the results to actual incurred system costs.

1 The Company should then bring the revised Renewable Integration Cost to the
2 Commission for approval.

3 6. Staff recommends that the Commission approve the McGrau Ford battery project, subject
4 to certain conditions, but withhold approval of any additional battery storage projects until
5 the next IRP, or until the Company provides additional support to the Commission and
6 stakeholders. Furthermore, Staff recommends that the Company be required to provide its
7 final McGrau Ford Engineering, Procurement, and Construction (“EPC”) Agreement to the
8 Commission prior to undertaking construction and procurement for the project. The
9 Company should be required to file quarterly construction monitoring reports through the
10 commercial operation of the battery facility. Finally, Staff and the Company should agree
11 to a deemed certified amount for the McGrau Ford project based on the budget for this
12 project filed in the 2022 IRP.

13 7. Staff recommends approval of the Company’s request to procure 2,300 megawatts (“MW”)
14 of additional renewable resources. In the event that the Company seeks to procure
15 additional renewable resources, beyond the amount approved in this IRP, it should be
16 required to seek separate Commission approval, unless the MW are rolled over from a prior
17 Commission-approved procurement.

18 8. With the understanding that key details will be determined as part of the Commission-
19 approved RFP, Staff recommends approval of the Company’s request to move to a “best-
20 cost” approach for future renewable procurements.

21 9. Staff recommends approval of the Company’s request to increase both the minimum Utility
22 Scale project size and maximum Distributed Generation (“DG”) project size to 6 MW.

- 1 10. Staff recommends approval of the Company's request to offer the 2,100 MW of Utility
2 Scale procurement for Commercial and Industrial ("C&I") subscription through the
3 proposed Clean and Renewable Energy Subscription ("CARES") Program. In the event
4 that, in this IRP, the Commission approves the procurement of more than 2,100 MW of
5 Utility Scale resources, Staff recommends that the additional MW should be procured on
6 behalf of all retail customers.
- 7 11. Staff recommends that the Utility Scale Request for Proposals ("RFP") not be limited to
8 projects sited in north Georgia. The Company should instead be required to quantify the
9 cost of transmission upgrades required to meet the resilience need with renewable
10 resources from south Georgia projects and apply that cost as a benefit to bids for projects
11 located in north Georgia.
- 12 12. Staff recommends that the Company allow all renewable projects that bid into future RFPs,
13 both with and without storage devices, to be operated on Automatic Generation Control
14 ("AGC"), and to consider new use cases that flexibly utilize the coupled energy storage
15 devices with AGC control.
- 16 13. Staff recommends that the Company modify its Locational Value study methodology to
17 include an assessment of economic congestion on its system.
- 18 14. Staff recommends approval of the hosting capacity tool with several modifications. First,
19 the hosting capacity tool should be made publicly available, without requiring participation
20 in one of the Company's current DG programs. Second, the tool should be updated at least
21 twice per year to maintain accuracy. Third, the hosting capacity analysis should reflect the
22 available capacity based on Minimum Daytime Loading or Coincident Peak limitations at
23 the sub-station, as described by the Transmission Evaluation scenarios. Finally, the

1 Company must maintain a robust process for validating the hosting capacity analysis and
2 the data provided by the tool.

3 15. Staff recommends that Staff and the Company initiate a review of Georgia Power's DG
4 interconnection process in order to establish a distribution interconnection cost matrix prior
5 to the next DG RFP, and to consider modifications that would reduce barriers to the
6 interconnection of projects.

7 16. Staff recommends that the Commission not approve the Company's request to modify the
8 current methodology for determining the additional sum for renewable procurements.

9 17. Staff recommends approval of the proposed capacity allocations for the CARES program.

10 18. Staff recommends that individual CARES carveout program specifics be finalized after
11 the 2022 IRP through the respective tariff negotiations and design.

12 19. Staff recommends approval of the Existing Resource Retail REC Retirement ("R3")
13 Program. Staff further recommends that the Company be required to file quarterly reports
14 that provide the amount of MW and the number of customers that have subscribed to the
15 R3 program.

16 20. Staff recommends approval of the Company's request to include a commercial option for
17 the commercial class as part of its Community Solar program. Staff also recommends
18 approval of the Company's proposed Income-Qualified Community Solar Pilot. However,
19 Staff does not recommend approval of the proposed increased rates, as the rates for this
20 program will be considered during the Company's upcoming rate case. Finally, Staff
21 recommends that the Company be required to file quarterly reports that provide the number
22 of customers and blocks that have subscribed for each portion of the Community Solar
23 program.

1 21. Staff recommends approval of additional Community Solar facilities once the existing
2 program is 75% subscribed; however, such resources should be reviewed by Staff and
3 approved by the Commission.

4 22. Staff recommends approval of the Company's proposal to modify the Simple Solar
5 Program to replace the current Simple Solar Large Volume offering with the Flex REC
6 program. However, Staff does not recommend revising the rates for this program as they
7 will be considered during the Company's upcoming rate case, which is scheduled to be
8 filed in June of this year. Staff further recommends that for the Economic Development
9 Flex REC option that the Company be required to file each negotiated contract.

10 23. Staff recommends Commission approval of the Company's request to pursue the Tall Wind
11 Demonstration project and the Company's proposed capital and operations and
12 maintenance ("O&M") costs for the Tall Wind demonstration project (but not yet the
13 recovery of such costs), as set out in the Selected Supporting Information section of
14 Technical Appendix Volume 1. However, these costs should be shared with the other
15 Southern Company Operating Companies, and the Commission should approve only a
16 Georgia Power ratio share of the net costs after the DOE funding has been accounted for.
17 Staff also recommends that if the Company anticipates that it will exceed the budgeted
18 amount for the Tall Wind Demonstration project found in the Selected Supporting
19 Information of the 2022 IRP, the Company should be required to request Commission
20 approval before exceeding that budget.

1 **II. MODIFICATIONS TO THE RCB FRAMEWORK**

2 **Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED MODIFICATIONS**
3 **RELATED TO THE RCB FRAMEWORK.**

4 A. The Company has proposed to "streamline and simplify" the RCB Framework (IRP Main
5 Panel Direct Testimony, pg. 50). The proposed changes to their existing RCB Framework
6 involve removing and replacing certain components. These include removing the
7 Generation Remix component and replacing Support Capacity with a new "Integration
8 Cost" component. According to the Company, the new Integration Cost component is
9 designed to account for the additional operating reserves needed to mitigate the impacts of
10 solar intermittency and uncertainty (IRP Main Panel Direct Testimony, pg. 50). This
11 modification will be discussed in Section IV below.

12 The Company is also proposing to eliminate several placeholder components that have not
13 been assigned values in prior applications of the RCB Framework. In addition to the
14 changes to RCB Framework components, the Company has also revised and significantly
15 shortened the RCB Framework document.

16 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSALS TO MODIFY THE**
17 **RCB FRAMEWORK?**

18 A. Yes. Staff recommends approval of the Company's proposal to remove the placeholder
19 components. However, Staff does not fully agree with the Company's proposal to remove
20 the Generation Remix component.

1 Regarding the Company's proposal to replace Support Capacity with the Integration Cost
2 component, Staff is generally supportive of the Company replacing the Support Capacity
3 Component with a new methodology given the issues Staff has raised with multiple aspects
4 of the Support Capacity component in prior proceedings. However, Staff has several
5 concerns with the proposed Integration Cost component due to issues with the Renewable
6 Integration Study upon which the Integration Cost component is based. These concerns are
7 discussed in more detail later in our testimony.

8 **Q. PLEASE EXPLAIN WHY STAFF DOES NOT FULLY AGREE WITH THE**
9 **COMPANY'S PROPOSAL TO REMOVE THE GENERATION REMIX**
10 **COMPONENT.**

11 A. The Generation Remix component was designed to quantify the costs and benefits of the
12 impact of renewable resources on the Company's long-term resource expansion plan and
13 the related changes to system production costs due to the changes in capacity. As an
14 example, if the Company was testing the addition of an incremental 1,000 MW of solar,
15 the Generation Remix component would quantify two impacts of that addition.
16 First, it would test how adding the solar would change the optimal capacity expansion
17 buildout, specifically assessing whether adding the resource would change the timing of
18 capacity additions or the type (combustion turbines or combined cycle units). The change
19 in type and timing of capacity additions impacts the capital costs of the Company's
20 resource expansion plan. The impact of the change in capital costs has typically been a
21 benefit of adding solar, reducing the need for more costly combined cycle units. This is the
22 capacity cost portion of the Generation Remix component.

1 After assessing the impact on change in capacity buildout, the Company then conducted a
2 long-term production cost analysis to test whether the addition of solar capacity and the
3 modified capacity expansion portfolio would result in a change in total system production
4 costs. This is the production cost portion of the Generation Remix component.

5 In this IRP, the Company has proposed removing the Generation Remix component,
6 explaining that:

7 *This component was appropriate in the past since incremental renewable resources*
8 *were not included in previous IRP Resource Mix Studies. The 2022 IRP Resource*
9 *Mix Study includes incremental renewable resources, which results in the bulk*
10 *impacts of future renewable resources being fairly represented in the IRP cases. As*
11 *such, it is appropriate to evaluate renewable resources consistent with other*
12 *resource types and remove the Generation Remix category*

13 (Company Response to STF-DEA-2-37; Staff Exhibit_BCB-4).

14 Staff agrees with part of the Company's explanation. Now that the Resource Mix Study
15 includes the addition of renewable resources, the production cost portion of Generation
16 Remix is no longer needed. However, we do not agree that the capital cost portion is
17 addressed with the new Resource Mix approach.

18 To the extent that adding solar resources to the Company's portfolio lowers future capital
19 costs of capacity additions, that customer benefit would not be quantified in the RCB
20 Framework analysis if the Generation Remix component is removed.

21 **Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE GENERATION**
22 **REMIX COMPONENT?**

1 A. The capacity portion of the Generation Remix component is an important element of the
2 evaluation of benefits of renewable resources. The Company's prior method of estimating
3 this benefit by comparing capacity expansion analyses with and without solar additions
4 was a reasonable approach. However, it was a time-intensive process to calculate due to
5 the modeling requirements, and Staff supports the Company's overall priority of
6 simplifying and streamlining the RCB Framework. As an alternative to continuing the
7 traditional Generation Remix modeling process, Staff recommends that the Company
8 instead modify the Deferred Generation Capacity Cost component to use the ECC of a
9 combined cycle unit instead of a combustion turbine unit. This approach acknowledges the
10 fact that as a primarily energy-focused resource, solar resources are more closely a
11 replacement for combined cycle units rather than combustion turbines, which are mainly
12 used for capacity needs.

13 **Q. DOES STAFF HAVE ANY RECOMMENDED CHANGES TO THE RCB**
14 **FRAMEWORK OUTSIDE OF THOSE PROPOSED BY THE COMPANY?**

15 A. Yes. The RCB Framework does not currently include a REC component. Staff
16 recommends that a REC component should be included in the RCB Framework.

17 **Q. WHAT ARE RECS?**

18 A. RECs are credits generated by a renewable resource that represents the rights to the
19 environmental attributes associated with energy generated from renewable resources. One
20 REC represents these attributes for one megawatt hour ("MWh") of renewable energy
21 generation.

1 **Q. DID THE COMPANY PROVIDE JUSTIFICATION FOR OMITTING RECS IN**
2 **THE RCB FRAMEWORK IN PREVIOUS IRPS?**

3 A. In the 2016 IRP proceeding, the Company asserted that RECs have no value because
4 Georgia does not have a Renewable Portfolio Standard (Company Response to STF-7-40
5 in 2016 IRP proceeding; Staff Exhibit_BCB-5).

6 **Q. DOES THE COMPANY ACKNOWLEDGE THAT RECS HAVE VALUE IN THIS**
7 **IRP?**

8 A. Yes. Several of the Company's renewable customer programs detailed in Section 14.4 of
9 the IRP Main Document place a value on RECs, such as the R3 Program, the Simple Solar
10 program, and the Flex REC program. These renewable customer programs are discussed
11 in greater detail in Section XI of our testimony.

12 **Q. WHY DOES STAFF RECOMMEND THAT THE COMPANY INCLUDE A REC**
13 **COMPONENT IN THE RCB FRAMEWORK?**

14 A. Staff recommends that the Company include a REC component in the RCB Framework
15 because it is a quantifiable benefit that renewable resources provide. When the Company
16 purchases renewable energy from a resource, it receives the RECs, but does not provide
17 any additional compensation for the credit. Georgia Power also does not include any value
18 for RECs in the determination of avoided costs through the use of the RCB Framework.
19 Just as the energy and capacity value provided by renewable resources are included in the
20 RCB Framework, the value of RECs generated by renewable resources should be included.

1 This is particularly true now that the Company is designing its customer programs around
2 the premise that RECs have value.

3 **Q. DOES STAFF HAVE A RECOMMENDATION REGARDING WHAT VALUE**
4 **RECS SHOULD RECEIVE IN THE RCB FRAMEWORK?**

5 A. No. Not at this time, but the value attributed to RECs in the RCB Framework should reflect
6 the value that the Company can or will receive from utilizing those RECs. Staff
7 recommends that Staff and the Company meet after the 2022 IRP concludes to determine
8 how to appropriately value the REC component and then bring the method to the
9 Commission for approval.

10 **III. ELCC ANALYSIS**

11 **Q. WHY HAS THE COMPANY CONDUCTED THE ELCC STUDY INCLUDED IN**
12 **THE IRP?**

13 A. As a result of the Commission's examination of PURPA avoided costs in Docket No. 4822,
14 the Company and Staff entered into a stipulation that was ultimately approved by the
15 Commission. The fifth item in the stipulation states, "the Company shall conduct an
16 analysis of the capacity value of different renewable technologies using the effective load
17 carrying capability ('ELCC') method" and include the results in its 2022 IRP (Docket No.
18 4822, 16573, and 19279; Stipulation between GPC and PIA Staff: Feb. 23, 2021).

As ordered, the Company provided an ELCC study in this proceeding, evaluating Utility Scale solar, DG solar, wind and battery storage. They also included in their ELCC study a comparison to their existing ICE/CWFT method.

Q. HOW DO THE RESULTS OF THE ELCC STUDY COMPARE TO THE COMPANY'S ICE/CWFT ANALYSIS?

A. The results from the ELCC study and ICE/CWFT analysis for solar and wind resources are presented in Table 1 below:

Table 1. Comparison of ELCC and ICE/CWFT results

Season	Winter				Non-Winter			
Methodology	ELCC			ICE/CWFT	ELCC			ICE/CWFT
Penetration Level	500 MW	1000 MW	3000 MW		500 MW	1000 MW	3000 MW	
Wind	50%	50%	50%	50%	40%	40%	40%	20%
Solar Fixed (DG or US)	0%	0%	0%	5%	20%	20%	15%	25%
Solar Tracking (DG or US)	10%	5%	5%	10%	35%	30%	25%	35%

The Company explains that the ICE factors are most comparable to the ELCC values at the 500 MW penetration level for solar resources due to the CWFT's inability to capture the capacity value impact at increasing penetration levels (IRP Volume 1, Section 2, pg. 10). A review of the results demonstrates that the ICE/CWFT and ELCC methods are identical for tracking solar, but the ICE/CWFT method produces a different value for fixed solar in both the winter and non-winter seasons with an estimate five percentage points above the ELCC value. The Company has also identified that due to the difference in the nature of

the wind profiles used for the ELCC study versus the ICE/CWFT, there is limited ability to directly compare the two results (IRP Volume 1, Section 2, pg. 10).

Table 2 and Table 3 below show the results for different levels of batteries from both the ELCC study and the ICE/CWFT analysis below. The Company explains that the ICE/CWFT results for batteries were developed prior to improvements in battery storage software and techniques and therefore, prevent the ability to directly compare them to the ELCC study results (IRP Volume 1, Section 2, pg. 11).

Table 2. ELCC results for battery storage

Season	Winter			Non-Winter		
Penetration Level	500 MW	1000 MW	3000 MW	500 MW	1000 MW	3000 MW
Battery – 1 hr	90%	90%	50%	100%	100%	40%
Battery – 4 hr	90%	90%	95%	100%	100%	70%
Battery – 6 hr	90%	90%	95%	100%	100%	95%
Battery – 8 hr	90%	90%	95%	100%	100%	100%

Table 3. ICE/CWFT results for battery storage

Season	Winter	Non-Winter
Battery – 4 hr	70%	90%
Battery – 5 hr	80%	90%
Battery – 6 hr	90%	95%
Battery – 7 hr	90%	95%
Battery – 8 hr	95%	95%

Q. DOES THE COMPANY PLAN TO USE THE ELCC METHOD GOING FORWARD?

A. The Company has not specified its long-term plan. It has noted that:

Currently, the Company is using the CWFT/ICE method for RCB calculations. The Company will consider the results of the ELCC Study, any advantages and

1 *disadvantages of both methodologies, and the impact on the planning process and*
2 *other related activities, to make the best decision concerning capacity equivalence*
3 *in future Integrated Resource Planning and resource procurement activities*
4 (Company Response to STF-DEA-2-39; Staff Exhibit_BCB-6).

5 **Q. DOES STAFF RECOMMEND THAT THE COMPANY USE THE ELCC**
6 **METHOD TO DETERMINE THE CAPACITY VALUE OF RENEWABLE**
7 **RESOURCES?**

8 **A.** Yes. The ELCC method is the industry-standard method for determining renewable
9 resource capacity contribution. It provides a consistent method that applies to all generators
10 within a project type, and appropriately evaluates the contribution of renewable resources
11 to the reliability of the system. Staff recommends that the Company use the ELCC method
12 in place of the CWFT/ICE method going forward. As with the CWFT/ICE studies, the
13 ELCC study should be updated annually.

14 **IV. EVALUATION OF RENEWABLE INTEGRATION STUDY – INTEGRATION**
15 **COST**

16 **Q. WHAT IS THE COMPANY'S OBJECTIVE IN THE DEVELOPMENT OF THE**
17 **RENEWABLE INTEGRATION STUDY?**

18 **A.** The stated objective of the study is “to determine the integration costs associated with a
19 range of solar penetration scenarios on the Southern Company system, including scenarios
20 representing the existing and committed solar resources on the system” (IRP Volume 2,

1 Section 3, pg. 2). The Company modeled various scenarios and resource portfolios to
2 attempt to quantify the incremental operating reserve costs caused by the addition of solar
3 resources.

4 **Q. HOW DID THE COMPANY USE THE RENEWABLE INTEGRATION STUDY**
5 **RESULTS IN THE IRP?**

6 A. The IRP uses the results of the Renewable Integration Study in two main ways. First, the
7 integration study is the analytical basis for the proposed Integration Cost component of the
8 RCB Framework. And second, the Company relies on the Renewable Integration Study to
9 support its proposal to construct and own 1,000 MW of battery storage.

10 **Q. PLEASE EXPLAIN HOW THE RENEWABLE INTEGRATION STUDY IS USED**
11 **TO DEVELOP THE INTEGRATION COST COMPONENT OF THE RCB**
12 **FRAMEWORK.**

13 A. The Renewable Integration Study attempts to quantify the additional system production
14 cost related to operating reserves needed to integrate additional renewable resources,
15 specifically solar capacity. The analysis tests multiple scenarios with different amounts of
16 solar capacity, and results in a cost per MWh to integrate solar capacity.

17 The study simulates system operations, matching load to generation on a 5-minute basis.
18 Intervals in which generation is not able to adjust output quickly enough to match load are
19 considered "flexibility violations." The general study methodology is to determine the
20 baseline level of flexibility violations in a system without solar, and then determine the
21 level of additional operating reserves required to meet that baseline level of flexibility

1 violations for scenarios with increasing levels of solar capacity. As the system carries
2 additional operating reserves, there is an increase in total system production cost. That
3 additional production cost is translated into the Integration Cost metric.¹

4 **Q. DOES STAFF HAVE ANY CONCERNS WITH THIS METHODOLOGY?**

5 **A.** Yes. Staff has multiple concerns with the methodology of the study and its conclusions.

6 First, the Company has not provided any data or evidence that there has been an actual
7 increase in operating reserve costs due to the increase in solar penetration. The
8 methodology relies on simulation modeling to estimate costs without consideration of the
9 Company's actual experience managing its operating reserves and the related cost data.
10 This results in cost estimates based on model results that may not reflect actual system
11 conditions. Second, the study focuses on the modeled cost of avoiding "flexibility
12 violations" which are not circumstances that necessarily impose a system cost to the
13 Company in actual system operations. Third, the study is only conducted on one test year,
14 but the results could be applied to solar projects with contracts of twenty years or more,
15 including future years when the Company's generation fleet is expected to include more
16 flexible generation and less baseload, inflexible coal generating capacity. Fourth, the
17 Company did not select the correct model scenario results for inclusion in the RCB
18 Framework. Fifth, as an RCB Framework component, this metric should be updated more
19 frequently than every three years. Sixth, the study calculates an average Integration Cost
20 for all solar resources (including those already online), instead of an incremental cost for

¹ The Renewable Integration Study refers to this cost as "Mitigation Cost," but it is the same metric as the Integration Cost component in the RCB Framework.

1 new resources, which would be more consistent with the objectives of the RCB
2 Framework. Each of these concerns will be addressed in more detail below.

3 **Q. REGARDING YOUR FIRST CONCERN WITH THE METHODOLOGY, PLEASE**
4 **ELABORATE ON HOW THE INTEGRATION COST IS NOT BASED ON**
5 **ACTUAL COST DATA.**

6 **A.** The objective of the Renewable Integration Study is to quantify the incremental operational
7 cost of integrating solar capacity. Staff's primary concern is that the Company has relied
8 solely on the results of SERVVM model simulations to calculate this value. The Company
9 has provided no information regarding costs the system has actually incurred to integrate
10 solar. Georgia Power has several years of experience integrating increasing amounts of
11 solar resources. It has reliably operated its system, and if the Company has had to change
12 its operating reserve processes, presumably it would have actual operational data which
13 could be used to quantify if there are additional customer costs driven by those reserves.
14 However, the Company has not offered any data as the basis for its Integration Cost
15 component, nor has it benchmarked the results of the SERVVM model simulation results
16 against actual data in order to ensure that the model is producing realistic results (Company
17 Response to STF-DEA-2-66; Staff Exhibit_BCB-7).

18 **Q. REGARDING YOUR SECOND CONCERN WITH THE METHODOLOGY,**
19 **PLEASE EXPLAIN HOW THE RENEWABLE INTEGRATION STUDY IS**
20 **QUANTIFYING A SYSTEM IMPACT THAT DOES NOT HAVE A DEFINED**
21 **COST CONSEQUENCE.**

1 A. The Renewable Integration Study methodology is structured to track the number of days
2 in which there is a “flexibility violation” in the study year for a certain scenario. A
3 flexibility violation is defined in the study as a 5-minute interval in which generation
4 cannot match load. Based on the information provided by the Company, this metric does
5 not appear to be a critical metric that results in a defined cost for customers.

6 First of all, occurrences of “flexibility violation” events are not a metric that the Company
7 tracks (Company Response to STF-DEA-2-56; Staff Exhibit_BCB-8), which indicates that
8 it is not a critical consideration in reliability assessment. Second, the Company
9 acknowledges that even in the Base Case in the Renewable Integration Study (with no solar
10 resources) there are flexibility violations; the study notes that “because of the frequency
11 bias and response of the interconnect, a flexibility violation event does not likely represent
12 an actual loss of load” and that “the flexibility violation metric should not be interpreted as
13 actual outage conditions” (IRP Volume 1, Section 3, pg. 17). Even though the “response
14 of the interconnect” is a mitigating factor that supports reliable system operation, the
15 Company chose to model Southern Company as an islanded system (IRP Volume 1,
16 Section 3, pg. 13).

17 The Company has developed the methodology to approximate the potential system impacts
18 of adding solar resources but acknowledges that several elements of the method diverge
19 from actual system conditions and rely on a “philosophical approach” rather than on actual
20 cost data. The result is a methodology that produces an Integration Cost with no direct link
21 to incremental costs, if any, that the system actually incurs as more solar is added to the
22 system.

1 Q. ARE THERE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
2 ("NERC") RELIABILITY RULES REGARDING THESE FIVE-MINUTE
3 "FLEXIBILITY VIOLATIONS"?

4 A. No. The Company testified that the analysis uses a five-minute period even though NERC
5 reliability rules require keeping frequency within certain bounds over a thirty-minute
6 period, stating that flexibility violations on a five-minute interval "indicates that there's
7 pressure on the ability of the system to meet those requirements for the BAL standard.
8 Doesn't indicate that there's going to be a violation, but there's pressure on the real time
9 balancing..." (Transcript (Tr.) at 524-525). The analysis was conducted using a more
10 stringent standard than NERC rules require, and therefore the study likely overestimates
11 the impact of "flexibility violations."

12 Q. ARE THERE OTHER WAYS IN WHICH THE MODELED SYSTEM DIVERGES
13 FROM THE ACTUAL SOUTHERN COMPANY SYSTEM?

14 A. Yes. Part of the study method included calibrating the base case and each scenario to meet
15 the same reliability standard as a starting point. This standard is a loss of load expectation
16 ("LOLE") of 0.1 days per year. In the base case simulation (with all solar resources
17 removed), the system exceeded that standard, so 290 MW of additional load was added to
18 the system (IRP Volume 1, Section 3, pg. 14). In the seven solar scenarios, increasing
19 amounts of load were added to counteract the increased system reliability provided by the
20 solar (IRP Volume 1, Section 3, pg. 15).

21 Essentially, the study methodology adds this incremental load in order to make the system
22 less reliable in order to meet a defined reliability criterion. This likely increases the

1 prevalence of “flexibility violations” in the analysis. However, in the actual system, solar
2 is being added before the system has a capacity need, and so the overall system reliability
3 exceeds the reliability criterion of 0.1 days per year. This is another way in which the
4 Integration Cost is being calculated using a system simulation that does not reflect actual
5 conditions.

6 The objective of the RCB Framework is to quantify the multiple components of actual costs
7 and benefits of renewable resources, but the method used to calculate the Integration Cost
8 component, as currently proposed, is not meeting that objective.

9 **Q. REGARDING YOUR THIRD CONCERN WITH THE METHODOLOGY,**
10 **PLEASE EXPLAIN WHY IT IS PROBLEMATIC THAT THE STUDY IS ONLY**
11 **CONDUCTED ON ONE STUDY YEAR.**

12 **A.** The other RCB Framework components are generally calculated based on a long-term
13 forecast of avoided cost values in order to develop a long-term levelized value to match
14 the term of the contract for the renewable resource. The Renewable Integration Study
15 calculates the Integration Cost component based on only one simulation year (2025) and
16 proposes to hold the value constant (IRP Volume 1, Section 3, pg. 14). This will provide a
17 value that is produced using a methodology that is inconsistent with the other RCB
18 components. In addition, the Company’s IRP has demonstrated that it expects significant
19 changes in the Company’s resource portfolio over time, in particular with the retirement of
20 multiple inflexible resources. Using a single-year snapshot does not adequately reflect the
21 changing system in a way that will allow the Integration Cost methodology to accurately
22 determine incremental operating costs over the life of a long-term resource.

1 **Q. REGARDING YOUR FOURTH CONCERN WITH THE METHODOLOGY, HOW**
2 **DID THE COMPANY SELECT THE INCORRECT MODEL SCENARIO FOR**
3 **USE IN THE RCB FRAMEWORK?**

4 A. The Company used the study results for Scenario B for the Integration Cost component
5 value provided with the IRP (Company Response to STF-DEA-2-46; Staff Exhibit_BCB-
6 9). This scenario includes all existing and planned resources. Since the RCB Framework is
7 intended to quantify the costs and benefits of incremental renewable resource additions,
8 the Company should have used the results for Scenario C which, as noted by Company
9 witnesses, is the scenario most closely aligned with the resource additions proposed in the
10 IRP (Tr. at 167-168).

11 **Q. REGARDING YOUR FIFTH CONCERN WITH THE METHODOLOGY, PLEASE**
12 **ELABORATE AS TO WHY THE RENEWABLE INTEGRATION STUDY SHOULD**
13 **BE UPDATED MORE FREQUENTLY.**

14 A. The Company intends to only update the study once every three years, during the IRP
15 process. Since the calculation of the Integration Cost is based on system production cost,
16 which is driven primarily by natural gas prices (Tr. at 191), it could change significantly
17 as fuel price forecasts change. Since this study will be used to calculate an RCB Framework
18 component, using the Company's approach means that the avoided cost of renewables will
19 not be based on current forecasts of market conditions in between study updates.

20 **Q. REGARDING YOUR SIXTH CONCERN WITH THE METHODOLOGY,**
21 **PLEASE EXPLAIN HOW THE CALCULATION SHOULD BE STRUCTURED TO**

1 **MEASURE THE INCREMENTAL INTEGRATION COST OF NEW SOLAR**
2 **ADDITIONS.**

3 A. The results of the Renewable Integration Study showed that the "Portfolio 1" Integration
4 Costs were \$2.88/MWh for Scenario B, which includes 5,000 MW of solar resources, and
5 reduces to \$2.50/MWh for Scenario C, which includes 8,000 MW of solar resources.
6 Since the average cost per MWh declines between Scenario B and Scenario C, the
7 incremental cost associated with the incremental 3,000 MW in Scenario C must be lower
8 than the \$2.50/MWh result. In fact, by using study results provided by the Company in
9 Table 24 of the Renewable Integration Study, Staff calculated that the incremental
10 Integration Cost for Scenario C, netting out the cost already incurred for the 5,000 MW in
11 Scenario B is \$1.93/MWh, rather than \$2.50/MWh. Based on the results of the study,
12 \$1.93/MWh is the Integration Cost that would be appropriate for the next tranche of solar
13 resources to be developed, but the Company is planning to use the \$2.88/MWh calculated
14 for Scenario B.

15 **Q. DOES STAFF RECOMMEND THAT THE RENEWABLE INTEGRATION COST**
16 **STUDY SHOULD BE USED TO DETERMINE THE INTEGRATION COST**
17 **COMPONENT OF THE RCB FRAMEWORK?**

18 A. No. Based on the information provided, Staff does not agree that the Company has
19 demonstrated that the Renewable Integration Cost study produces an accurate Integration
20 Cost that should be used in the RCB Framework. While Staff supports replacement of the
21 current Support Capacity component of the RCB Framework, we have outlined several
22 methodological concerns in the Company's proposed methodology. The Company should

1 conduct additional analysis which, at a minimum, simulates the expected system load and
2 resources without adding incremental proxy load, tests additional years beyond 2025
3 (incorporating resource portfolio changes), and selects the appropriate study scenario for
4 use in the RCB Framework.

5 Even more critical than the specific methodological concerns identified by Staff is that the
6 Company has not attempted to benchmark the results of the study to a quantification of
7 actual costs the Company has incurred to integrate the current set of existing solar
8 resources. This is a critical step needed to demonstrate that the new simulation
9 methodology developed by the Company and its consultant provides a realistic
10 approximation of actual system cost impacts.

11 If a new Renewable Integration Study is conducted after having addressed the issues
12 identified by Staff, and the Company provides a benchmark study comparing the results to
13 actual incurred system costs, Staff may be able to support the use of Integration Cost in a
14 future filing. However, Staff does not recommend approval of replacing the RCB
15 Framework's Support Capacity Cost with the Renewable Integration Cost. Staff
16 recommends that the Company reconduct the Renewable Integration Study to address the
17 issues identified by Staff and provide a benchmark study comparing the results to actual
18 incurred system costs. The Company should then bring the revised Renewable Integration
19 Cost to the Commission for approval.

1 **V. EVALUATION OF RENEWABLE INTEGRATION STUDY – BATTERY**
2 **STORAGE ANALYSIS**

3 **Q. IN THE PRIOR SECTION, YOU NOTED THAT THE RENEWABLE**
4 **INTEGRATION STUDY WAS ALSO USED TO SUPPORT THE COMPANY'S**
5 **REQUEST FOR 1,000 MW OF BATTERY STORAGE. PLEASE ELABORATE.**

6 A. The Company's IRP and testimony claimed that its request to own and operate 1,000 MW
7 of battery storage by 2030 is supported by the analysis provided in the Renewable
8 Integration Study. One of the Company's requests of the Commission is for "[a]pproval of
9 Company's use of the Renewable Integration Study for planning purposes and the
10 Company's long-term plan to own and operate 1,000 MW of ESS by 2030" (IRP Main
11 Doc., pg. 1-14). The IRP also states that "Support for adding [1,000 MW] of storage
12 capacity is provided by the Company's Renewable Integration Study, which demonstrates
13 that this level of storage significantly improves the reliable integration of large renewables
14 resource additions" (IRP Main Doc., pg. 13-91).

15 As discussed in the prior section, the Renewable Integration Study modeled the need for
16 operating reserves to avoid "flexibility violations" resulting from the addition of solar
17 resources. The study calculated the Integration Cost using only its existing portfolio of
18 operating reserve resources, and also tested two sensitivities. In one sensitivity, the
19 Company added battery storage resources equaling approximately 15% of the nameplate
20 capacity of the solar additions. These 2-hour batteries were available as additional
21 operating reserves to help avoid flexibility violations. The Company notes "the Renewable
22 Integration Study determined that flexible resources, such as battery energy storage

1 systems, can provide these essential grid services more efficiently by providing operating
2 reserves at a lower production cost” (IRP Main Panel Direct Testimony, pg. 14). As
3 previously mentioned, the Company noted that Scenario C of the study is the scenario most
4 closely aligned to the resources requested in this IRP. Scenario C includes 8,000 MW of
5 solar capacity and 1,150 MW of battery capacity. This is the connection between the
6 assumptions in the Renewable Integration Study and the Company’s specific request for
7 approval of 1,000 MW of battery storage resources.

8 **Q. DOES STAFF HAVE ANY CONCERNS WITH THE COMPANY’S CONCLUSION**
9 **THAT THE RENEWABLE INTEGRATION STUDY SUPPORTS ITS REQUEST**
10 **FOR 1,000 MW OF BATTERY STORAGE?**

11 A. Yes. Staff has one primary concern in addition to the methodological concerns that have
12 already been mentioned regarding Renewable Integration Study as it pertains to the
13 Company’s battery storage request. Staff’s primary concern is that the Company has not
14 provided evidence that 1,000 MW is the optimal amount of batteries to develop.

15 **Q. PLEASE EXPLAIN YOUR CONCERN REGARDING THE LACK OF ANALYSIS**
16 **ON THE OPTIMAL LEVEL OF BATTERY STORAGE DEVELOPMENT.**

17 A. The Company’s request for approval of its plan to develop 1,000 MW of storage resources
18 by 2030 is based on the conclusions of the Renewable Integration Study. However, as
19 previously noted, the study was not designed to determine what level of storage provides
20 the greatest benefits when compared to storage costs. This point was acknowledged by the
21 Company during the Direct Hearing (Tr. at 166). Since the Company’s study only analyzed

1 one storage amount for each scenario, it wasn't designed to determine how much benefit
2 different levels of storage would provide.

3 During the Direct Hearing, Company witnesses testified that the Renewable Integration
4 Study evaluated 1,150 MW of storage in the scenario with 8,000 MW of renewables, and
5 that the selection of 1,150 MW specifically was the result of "an iterative process when the
6 study was conducted" (Tr. at 169). However, Company witnesses acknowledged that the
7 Company did not test other amounts of storage and calculate alternative Integration Cost
8 values for that 8,000 MW scenario (Tr. at 170). The Company also did not consider the
9 capital cost of the batteries when determining the amount of capacity to add to each
10 scenario (Tr. at 171).

11 **Q. WHAT ARE STAFF'S CONCLUSIONS REGARDING THE COMPANY'S**
12 **REQUEST FOR APPROVAL TO PURSUE 1,000 MW OF BATTERY STORAGE**
13 **RESOURCES BASED ON THE RENEWABLE INTEGRATION STUDY?**

14 **A.** The Company's Renewable Integration Study, on its own, is not sufficiently robust to
15 support the Company's specific request for 1,000 MW of battery storage resources by
16 2030. The Company did not analyze alternative amounts, so there is no way to know from
17 the information provided whether alternative amounts would provide more benefits to
18 Georgia Power's customers. Therefore, in its current form it is not sufficient to be used for
19 planning purposes supporting specific resource requests.

**VI. COMPANY'S REQUEST FOR APPROVAL OF MCGRAU FORD AND 1,000 MW
OF TOTAL ADDITIONAL BATTERY STORAGE CAPACITY**

**Q. PLEASE SUMMARIZE THE COMPANY'S REQUESTS RELATED TO
BATTERY STORAGE PROJECTS.**

A. As discussed above, the Company has requested Commission approval for "the Company's long-term plan to own and operate 1,000 MW of ESS by 2030" (IRP Main Doc., pg. 1-14). In addition, the Company has requested "[t]he authority to develop, own, and operate the McGrau Ford Battery Facility as an initial part of the Company's long-term ESS plan to reliably support renewable integration" (IRP Main Doc., pg. 1-14). The Company has confirmed that the 265 MW McGrau Ford project is included in the 1,000 MW request (Tr. at 553).

**Q. WHAT IS THE COMPANY'S JUSTIFICATION FOR ITS REQUESTS RELATED
TO BATTERY STORAGE?**

A. The Company states three reasons for adding 1,000 MW of battery storage units. First, as discussed in the prior section, the primary justification by the Company is that adding batteries to be used as operating reserves will support the integration of additional renewable resources. Second, the Company claims that battery storage facilities will provide economic benefits to customers (IRP Volume 2, Section 4). Third, the Company has repeatedly emphasized that it is seeking to gain experience developing and operating battery projects to prepare for future developments:

1 *As battery and other storage technologies mature, the Company's near-term*
2 *investments and experience with operating this technology as an integral*
3 *component of the System will be critical to ensuring long-term reliability and*
4 *meeting customer needs*

5 (IRP Main Doc., pg. 13-89-13-90 and 13-91-13-92).

6 **Q. HAS THE COMPANY PROVIDED ANY ANALYSIS SUPPORTING THESE**
7 **REQUESTS?**

8 A. Yes. In addition to the Renewable Integration Study, the Company provided the Battery
9 Storage Cost-Benefit Analysis in Technical Appendix Volume 2. In this analysis, the
10 Company compares a forecast of costs and benefits of a 300 MW/ 600 MWh Battery
11 Energy Storage System ("BESS") as a proxy for the McGrau Ford project and concludes
12 that the analysis "demonstrate[s] that appropriately adding stand-alone battery storage
13 resources are in the best interest of customers" (IRP Volume 2, Section 4, pg. 2).

14 **Q. DOES STAFF HAVE ANY CONCERNS WITH THE BATTERY COST-BENEFIT**
15 **ANALYSIS AS PROVIDED BY THE COMPANY?**

16 A. Yes. Staff has a number of concerns regarding the battery cost-benefit analysis. Staff has
17 identified the following methodological issues:

- 18 • Multiple simultaneous uses. The Company's analysis quantifies three categories of
19 benefits: Flexibility Benefit (derived from the Renewable Integration Study),
20 Capacity Value (derived from avoiding other capacity additions after the year of
21 capacity need), and Production Cost Savings (from energy price arbitrage). It is
22 unclear whether battery resources would be able to simultaneously serve all three

1 functions, as the cost-benefit analysis appears to assume. If a battery resource is
2 being used for operating reserves to deliver the Flexibility Benefit, it is likely to be
3 charging and discharging throughout the daylight hours to manage variability in
4 load and solar output. It might not also be able to simultaneously deliver the energy
5 price arbitrage services (charging during low-cost hours and discharging during
6 high-cost hours). Indeed, the Company's analysis quantified the benefits of these
7 two services using different models, so it is likely that the benefits may not be
8 completely additive.

- 9 • Capacity credit. The Company assumed that the 2-hour battery received a capacity
10 credit of 90% of its nameplate size for the full 20 years of the study. However, in
11 the recent Capacity RFP, the Company did not allow 2-hour batteries to participate
12 (Docket No. 42641: Final Approved 2022-2028 Capacity RFP (Aug 31, 2020), pg.
13 12).
- 14 • Battery life assumption: The study assumes a 20-year life for the battery resource,
15 which is longer than most similar analyses.² As discussed above, the Company
16 appears to assume that the resource will be cycled frequently in order to be used for
17 energy price arbitrage as well as to manage volatility as an operating reserve.
18 Increased battery cycling reduces battery life.

² A recent NREL meta-analysis found that 20 years is the high-end of the range of assumed lifespans, with multiple studies using battery life assumptions of 10 years (or less). See: NREL. *Cost Projections for Utility-Scale Battery Storage: 2021 Update*. June 2021. Available at: <https://www.nrel.gov/docs/fy21osti/79236.pdf>

1 Due to these methodological concerns, the benefits estimated by the Company are likely
2 overstated, and the Company's conclusion that the battery project is net beneficial to
3 customers over its lifetime is unlikely to be true, solely based on these metrics.

4 **Q. DOES STAFF HAVE ANY OTHER CONCERNS WITH THE COMPANY'S**
5 **REQUEST RELATED TO BATTERY STORAGE?**

6 A. Yes. Staff does not agree that the Company has demonstrated the need for the Company to
7 own and operate all of the battery storage capacity it is seeking to add. The Company has
8 stated that "Power purchase agreements do not provide the same level of reliability and
9 control that comes with ownership of the resource" (Company Response to STF-DEA-2-
10 25; Staff Exhibit_BCB-10) and that the Company cannot currently anticipate all the
11 different uses that a battery will serve, so it wants to own the resources so it can ensure that
12 they are "maintained according to current system standards, whatever those are and
13 however those evolve over time" (Tr. at 202).

14 Aside from the Company's assertions, it has provided no analysis supporting the need to
15 own the resources. The Company has a long history of signing long-term contracts with
16 independent owners of generators, and these generators provide critical services that are
17 needed for system reliability and to meet the Company's energy and capacity needs.
18 Technology exists to support the Company's management and real-time control of battery
19 resources that are owned by third parties. In fact, there are many systems across the country,
20 such as the PJM Regional Transmission Organization, in which the system operator relies
21 on remote operation of batteries that it does not own.

1 Lastly, third-party ownership provides the possibility for competitive, lower-cost project
2 development and operation, which would result in lower costs to customers. The Company
3 acknowledged during the Direct Hearing that in its last Capacity RFP, it selected PPAs
4 instead of acquisitions because it was “more economic for customers” but they still get the
5 same “flexibility and the firm enough commitments necessary out of those PPAs to serve
6 reliability needs” (Tr. at 551). While this discussion was specifically related to the Capacity
7 RFP, the same principles apply to future procurement for battery storage resources.

8 **Q. WHAT DOES STAFF CONCLUDE REGARDING THE COMPANY’S REQUEST**
9 **FOR APPROVAL OF THE MCGRAU FORD PROJECT AND A TOTAL OF 1,000**
10 **MW OF BATTERY STORAGE TO BE OWNED AND OPERATED BY THE**
11 **COMPANY BY 2030?**

12 **A.** Staff’s conclusions regarding the Company’s request for 1,000 MW of battery storage are
13 summarized as follows:

- 14 • The storage cost-benefit analysis provided by the Company likely overstates the
15 economic benefits of the McGrau Ford storage resource, and it is possible that if
16 the Company made the modifications identified by Staff that the project would not
17 be net beneficial. The Company has not provided a cost-benefit analysis for the
18 remainder of the 1,000 MW of capacity requested.
- 19 • The Company has not adequately supported its claim that it needs to own the battery
20 storage resources.

- 1 • The Renewable Integration Study supports only the limited conclusion that
2 batteries help lower the cost of managing load volatility and generation
3 intermittency when compared to conventional resources.

4 Despite these concerns, Staff agrees with the Company that it is likely that battery storage
5 will provide valuable capabilities and flexibility in managing a grid with increasing
6 renewables. In fact, on a long-term basis, for Georgia to continue to be a leader in economic
7 renewable development, Staff believes it will be important that battery capacity be added
8 to the portfolio to manage a low-cost, low-carbon grid. However, there are many unknowns
9 at this point that prevent Staff from supporting the full request for 1,000 MW of Company-
10 owned resources. Delaying approval of the full 1,000 MW requested will give the
11 Company time to gain experience developing the McGrau Ford project and operating the
12 Mossy Branch project.

13 Information from the Company's experience integrating and operating with the McGrau
14 Ford and Mossy Branch facilities will help stakeholders and the Commission better
15 understand the different value streams of storage (operating reserves, capacity contribution,
16 energy price arbitrage), as well as gain a better understanding of whether there are
17 operational benefits to Company ownership. This additional information will allow the
18 Commission to make a more informed decision on the remainder of the Company's
19 request.

20 Given these conclusions, Staff recommends that the Commission approve the McGrau
21 Ford battery project, subject to certain conditions, but withhold approval of any additional

1 battery storage projects until the next IRP, or until the Company provides additional
2 support to the Commission and stakeholders.

3 **Q. WHAT ARE THE CONDITIONS THAT STAFF RECOMMENDS FOR**
4 **APPROVAL OF THE MCGRAU FORD PROPOSAL?**

5 A. Staff recommends that the Company be required to provide its final McGrau Ford EPC
6 Agreement to the Commission prior to undertaking construction and procurement for the
7 project. The Company should be required to file quarterly construction monitoring reports
8 through the commercial operation of the battery facility. Finally, Staff and the Company
9 should agree to a deemed certified amount for the McGrau Ford project based on the budget
10 for this project filed in the 2022 IRP. If Georgia Power exceeds this deemed certified
11 amount, the Company should have the burden to demonstrate the reasonableness and
12 prudence of recovery of costs in excess of the certified amount.

13 **VII. RENEWABLE ENERGY AND FUTURE PROCURMENTS**

14 **Q. IN THIS IRP, HOW MUCH RENEWABLE RESOURCES IS THE COMPANY**
15 **REQUESTING APPROVAL TO PROCURE?**

16 A. In the Company's 2022 IRP, Georgia Power is seeking approval to procure 2,100 MW of
17 Utility Scale renewable resources through two separate Utility Scale RFP, to be issued by
18 2025 and to be online by 2029. The Company is also requesting approval for an additional
19 200 MW of DG renewable resources to be procured through two 100 MW DG RFPs to be
20 issued by 2024 and to be online by 2025 (IRP Main Doc., pg. 1-14).

1 In its long-term renewable expansion plan, the Company identified an opportunity for up
2 to 6,000 MW of renewable resources to be economically added to its system by 2035. The
3 Company's long-term renewable expansion plan also shows that renewable procurements
4 up to 9,000 MW could be economically beneficial for customers depending on future
5 economic and market conditions (IRP Main Doc., pg. 11-78). However, Georgia Power is
6 only requesting approval for 2,300 MW of renewable resources in this IRP (Tr. at 213).

7 The Company's renewable procurement request would be in addition to the existing 3,070
8 MW of renewable resources online. An additional 2,330 MW of renewable resources are
9 under development on Georgia Power's system (Main IRP Doc., 14-95), including the
10 current 2023/2024 RFP For Utility Scale Renewable Generation which has a target
11 procurement of 1,030 MW. This will bring the total expected renewable resources online
12 to approximately 5,500 MW by 2025 (Main IRP Doc., pg. 14-96).

13 **Q. IN THIS FILING, IS THE COMPANY REQUESTING TO MODIFY ITS LONG-**
14 **TERM RENEWABLE PROCUREMENT STRATEGY?**

15 **A.** Yes. The Company requested to be able to modify the timing, cadence, and adaptability of
16 future RFPs to provide for the consideration and incorporation of best practices and lessons
17 learned. The Company proposes to incorporate modifications to the schedule and capacity
18 targets of successive individual solicitations. The Company also proposes to routinely issue
19 renewable Utility Scale and DG RFPs until it reaches the long-term plan of at least 6,000
20 MW of new renewable resources by 2035 (IRP Main Doc., pg. 14-100). As proposed, this
21 approach will provide ongoing opportunities for both small and large renewable projects.
22 Additionally, the Company stated that it may seek approval for additional renewable

1 procurements, for example to meet economic development demand, prior to the next IRP
2 in 2025 (IRP Main Doc., pg. 14-101, Company Response to STF-DEA-3-18; Staff
3 Exhibit_BCB-11).

4 **Q. DOES STAFF RECOMMEND APPROVAL OF GEORGIA POWER'S REQUEST**
5 **TO PROCURE 2,300 MW OF ADDITIONAL RENEWABLE RESOURCES AND TO**
6 **TRANSITION TO A LONG-TERM PROCUREMENT STRATEGY?**

7 A. Yes. Staff recommends approval of the Company's request to procure 2,300 MW of
8 additional renewable resources. Staff is generally supportive of the Company's request to
9 move to a long-term renewable procurement strategy although there are specific details of
10 this transition that have not been clearly defined by the Company in its filing. Staff expects
11 that those specific details will be discussed and agreed upon prior to the issuance of future
12 RFPs. In the event that the Company seeks to procure additional renewable resources,
13 beyond the amount approved in this IRP, it should be required to seek separate Commission
14 approval, unless the MW are rolled over from a prior Commission-approved procurement.

15 **Q. PLEASE DESCRIBE THE COMPANY'S REQUEST TO MOVE TO "BEST-**
16 **COST" RENEWABLE PROCUREMENTS.**

17 A. In this filing, the Company proposes to evaluate and select renewable resources based on
18 the best-cost provided to customers, evaluated using the RCB Framework, to ensure cost-
19 effective resources (IRP Main Doc., pg. 1-8). For past procurements, the Company only
20 selected renewable resources that offered projected energy savings to customers and put
21 downward pressure on rates in relation to the Company's moderate gas zero carbon

1 ("MG0") avoided cost as evaluated with the RCB Framework. That threshold would still
2 remain the critical evaluation metric in determining the value to customers of renewable
3 resource additions; however, adding new renewable resources above that threshold may be
4 deemed appropriate to help the Company meet certain system needs (Main IRP Doc., pg.
5 14-99).

6 This requested change also includes utilizing an enhanced portfolio analysis of winning
7 bids that balances the appropriate costs and benefits (IRP Main Doc., pg. 14-100), which
8 is similar to the approach used in prior Utility Scale RFPs, but it is a much different
9 approach than what has been used in prior DG RFPs.

10 **Q. HAS THE COMPANY FULLY DEFINED HOW THE "BEST-COST" APPROACH**
11 **WOULD OPERATE?**

12 **A.** No. In the IRP Filing and other supporting documents, the Company has provided limited
13 details regarding how the "best-cost" approach differs from the Company's current
14 evaluation approach. The Company stated that Georgia Power, along with the Commission
15 Staff and the Independent Evaluator ("IE"), will leverage the information gained through
16 the RFP process, such as actual bid prices (including the prices of Company-owned
17 proposals), projected in-service dates, updated interconnection costs, and other market
18 intelligence, to remain adaptable in procuring resources to meet the Company's renewable
19 energy need. The Company, working with the Commission Staff and the IE, will determine
20 the exact criteria and methods of evaluation, ranking, and selection as part of the
21 Commission-approved RFP process (Company Response to STF-DEA-2-7; Staff
22 Exhibit_BCB-12).

1 **Q. PLEASE DESCRIBE THE COMPANY'S CURRENT METHODOLOGY USED TO**
2 **EVALUATE BIDS FOR RENEWABLE RFPS.**

3 A. Currently, the Company, in parallel with Staff and the IE, evaluates renewable bids through
4 an evaluation model, which is agreed upon by Staff and the IE, and is "locked-down" prior
5 to bid evaluation. This spreadsheet model compares the bid price and any imputed
6 transmission upgrade costs for the bid to the bid's avoided energy/capacity benefits and
7 other RCB Framework costs and benefits. This calculation determines the net benefit value
8 for each bid. Bids are then ranked by net benefit. At this point, bids that individually do
9 not provide a net benefit are released. The remaining bids make up the initial Competitive
10 Tier and do not include system upgrade costs.

11 After the initial Competitive Tier is determined, the Company determines the transmission
12 and distribution impacts for each respective project since bidders are typically only
13 responsible for interconnection costs up to the point of interconnection. System
14 improvements and other interconnection costs beyond the point of interconnection are
15 calculated by Southern Company's Transmission Planning Group and are reviewed by the
16 IE and Staff. These costs and any benefits are then imputed into the economic value of the
17 bids and the net benefit of each project is recalculated. After a re-ranking of the updated
18 Competitive Tier which includes system improvement costs, the Company will identify
19 several portfolios, or groups of projects, which could each satisfy the procurement need.
20 The Company, then, performs additional transmission analysis for each portfolio to assess
21 cumulative transmission costs. The projects composing the portfolio with the greatest net
22 benefit are then selected as the Short List for the respective RFP.

1 **Q. HOW WOULD THE COMPANY'S PROPOSED "BEST-COST" APPROACH**
2 **DIFFER FROM ITS CURRENT METHODOLOGY OF ONLY SELECTING BIDS**
3 **THAT PROVIDE A NET BENEFIT?**

4 A. Based on the Company's transition to Aurora for its resource expansion plan modeling, the
5 Company has stated that it is now able to preselect renewable resources through its
6 modeling. Such modeling shows that renewable resources will provide economic benefits
7 to customers long-term (Tr. at 392). Georgia Power will continue to choose the resources
8 that provide the most value to customers, including their costs, their operational
9 characteristics, their interconnection costs, and the benefits they provide customers. The
10 primary change is that the Company will no longer propose to use the Company's MG0
11 Avoided Cost bogey as an eliminator of proposals (Tr. at 393). Transitioning to a "best-
12 cost" approach will likely be a significant change for DG procurements which have not
13 previously used a portfolio analysis. With this transition, along with the removal of the
14 requirement that an individual bid's net benefit must be below the Company's MG0
15 Avoided Cost, more DG projects may be considered for contracting,

16 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S REQUEST TO**
17 **MOVE TO A "BEST-COST" APPROACH?**

18 A. Yes. Staff is generally supportive of a transition to the "best-cost" approach for future
19 renewable procurements; however, there are key details of this transition that Staff still
20 needs since specific key criteria to be used during the evaluations was not proposed by the
21 Company in its filing. The Company stated that those details will be determined as part of
22 the Commission-approved RFP process for which Staff will be able to participate in, along

1 with the IE. With the understanding that key details will be determined as part of the
2 Commission-approved RFP, Staff recommends approval of the Company's request to
3 move to a "best-cost" approach for future renewable procurements.

4 **UTILITY SCALE RENEWABLE PROCUREMENTS**

5 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED UTILITY SCALE**
6 **PROCUREMENT PLAN.**

7 A. Georgia Power proposes to procure 2,100 MW of Utility Scale renewable resources greater
8 than 6 MW alternating current ("AC") in size. The Company proposes to issue one or more
9 geographically targeted RFPs. These targeted RFPs will convey to potential bidders
10 preferred geographic areas for new resources. As proposed, the next Utility Scale RFP will
11 solicit resources in north Georgia in support of the Company's North Georgia Reliability
12 and Resiliency Action Plan. Based on the results of the first Utility Scale RFP, the
13 Company will establish the guidelines and schedule for the second Utility Scale
14 procurement (Main IRP Doc., pg. 14-101). The Utility Scale resources procured from these
15 two RFPs will support the Company's proposed CARES Program (Main IRP Doc., pg. 14-
16 106).

17 **Q. IS THE COMPANY'S PROPOSAL FOR THE MINIMUM UTILITY SCALE**
18 **PROJECT SIZE OF 6 MW A CHANGE FROM PREVIOUS RFPs?**

19 A. Yes. Georgia Power proposes to increase the minimum size for Utility Scale projects from
20 3 MW to 6 MW. This request is accompanied by a request to increase a DG project's

1 maximum size from 3 MW to 6 MW. The Company has stated that this change will
2 accommodate the clear trend towards larger projects in Utility Scale RFPs, and greater
3 economies of scale in the DG RFPs (Company Response to STF-DEA-3-22; Staff
4 Exhibit_BCB-13).

5 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S PROPOSAL**
6 **TO INCREASE THE MINIMUM UTILITY SCALE PROJECT SIZE AND THE**
7 **MAXIMUM DG PROJECT SIZE TO 6 MW?**

8 **A.** Yes. Staff recommends approval of the Company's request to increase the minimum Utility
9 Scale project size and maximum DG project size to 6 MW.

10 **Q. HOW MUCH OF THE REQUESTED 2,100 MW OF UTILITY SCALE**
11 **RENEWABLE PROCUREMENT DOES THE COMPANY SEEK TO OFFER FOR**
12 **SUBSCRIPTION TO C&I CUSTOMERS?**

13 **A.** The Company has requested to make all of the Utility Scale renewable procurement
14 available for C&I Subscription through the CARES Program. The Company proposes to
15 procure the entire 2,100 MW, regardless of C&I participation, and any unsubscribed MW
16 will be used to serve all customers (IRP Main Doc., pg. 14-109).

17 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S REQUEST TO**
18 **OFFER ALL OF THE UTILITY SCALE PROCUREMENT FOR SUBSCRIPTION**
19 **TO C&I CUSTOMERS?**

1 A. Yes. Staff recommends approval of the Company's request to offer the 2,100 MW of
2 Utility Scale procurement for C&I subscription through CARES. In the event that, in this
3 IRP, the Commission approves the procurement of more than 2,100 MW of Utility Scale
4 resources, Staff recommends that the additional MW be procured on behalf of all retail
5 customers.

6 **Q. PLEASE DESCRIBE THE COMPANY'S REQUEST REGARDING LIMITING**
7 **THE PROCUREMENT OF UTILITY SCALE RENEWABLE RESOURCES TO**
8 **NORTH GEORGIA.**

9 A. The Company is proposing that the first phase of its Utility Scale renewable procurement
10 target renewable resources located in north Georgia (IRP Main Doc., pg. 12-88). Georgia
11 Power states that its evaluations have indicated significant transmission system challenges
12 associated with adding new renewable resources in south Georgia (Company Response to
13 STF-DEA-2-29; Staff Exhibit_BCB-14). In order to support the Company's north Georgia
14 resilience needs, Georgia Power proposes to issue the first Utility Scale RFP with a focus
15 on counties located north of Interstate 20 (IRP Main Doc, pg. 12-88).

16 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S REQUEST TO**
17 **ISSUE AN RFP TO TARGET RENEWABLE GENERATION SITED IN NORTH**
18 **GEORGIA?**

19 A. No. Staff recognizes that there are additional costs to serve load from north Georgia with
20 renewable resources located in south Georgia; however, Staff has concerns regarding the
21 viability and success of a north Georgia exclusive RFP. Staff is concerned that such an

1 RFP would ultimately be unsuccessful at procuring the targeted procurement amount of
2 1,050 MW due to availability and cost of suitable land and the production output
3 differences from solar insolation. Furthermore, Staff is concerned that renewable resources
4 procured in north Georgia may not represent the lowest cost option for meeting the
5 resilience needs of north Georgia. Staff does not recommend approval of the Company's
6 request to issue an RFP to only target generation sited in north Georgia. The Company
7 should instead be required to quantify the cost of transmission upgrades required to meet
8 the resilience need with renewable resources from south Georgia projects and apply that
9 cost as a benefit to bids for projects located in north Georgia.

10 **Q. HOW ARE ENERGY STORAGE RESOURCES ABLE TO PARTICIPATE IN**
11 **UTILITY SCALE RENEWABLE RFPS?**

12 **A.** Consistent with prior Utility Scale RFPs, energy storage resources, coupled with a
13 renewable energy source, have been eligible to participate (Tr. at 183). In the current
14 2023/2024 RFP for Utility Scale Renewable Generation, solar plus storage systems were
15 allowed to bid in one of three use cases: Smoothing, Firming and Smoothing, or Scheduled.
16 Bids with storage devices receive credit of some or all of the Support Capacity cost during
17 evaluation based on the RCB Framework.
18 Bids that provide a Smoothing storage device receive a credit that offsets a portion of the
19 RCB Support Capacity cost. Firming and Smoothing storage devices receive credit that
20 offsets the full RCB Support Capacity cost. Scheduled bids receive full credit to offset
21 RCB Support Capacity costs, and also receive additional avoided capacity and energy value
22 by allowing the Company to shift energy produced at low-demand hours to be released

1 during peak period hours.

2 **Q. PLEASE DESCRIBE AGC AND ITS ROLE IN THE RECENT 2023/2024 UTILITY**
3 **SCALE RFP AND FUTURE RENEWABLE PROCUREMENTS.**

4 A. AGC is a system by which Georgia Power can communicate directly with a generator's
5 control system to command its output level in real time. AGC allows the Company to both
6 rapidly and partially curtail a resource. In the current 2023/2024 Utility Scale RFP,
7 renewable resources controlled by AGC received an RCB credit during evaluation,
8 equivalent to the credit received of a project coupled with a Smoothing Storage device. As
9 part of the RFP, Georgia Power required all renewable bids that did not include an energy
10 storage device to include AGC to be eligible to participate. Bids that included an energy
11 storage device could not elect to include AGC. The Company has indicated that resources
12 controlled by AGC will be part of their future renewable procurement strategy (IRP Main
13 Doc., pg. 14-98).

14 **Q. DOES STAFF HAVE ANY CONCERNS REGARDING AGC, AS IT PERTAINS TO**
15 **FUTURE UTILITY SCALE RFPS?**

16 A. Yes. Staff recognizes great value in both energy storage and AGC; however, the current
17 implementation of these technologies may not be providing the optimal value for projects
18 located on the Company's system. Renewable generators with and without storage devices
19 can both be better utilized with the addition of AGC. The output of solar plus storage
20 projects can be controlled with AGC, and there is no reason to assume that the system
21 benefits of adding AGC are greater for standalone solar projects than the benefits of using

1 AGC for solar projects coupled with storage. Restricting the use of AGC in the Company's
2 most recent RFP handicapped solar plus storage bids; thereby, limiting the flexibility
3 inherent to the technology. Furthermore, these solar plus storage resources will be
4 restricted to operate in this limited fashion for up to thirty years regardless of future grid
5 needs.

6 **Q. DO THE CURRENT STORAGE USE CASES ADEQUATELY OPTIMIZE THE**
7 **CONTROL OF SOLAR PLUS STORAGE RESOURCES FOR THE GREATEST**
8 **SYSTEM BENEFIT?**

9 A. No. The Company's defined storage use cases are similarly limiting in the context of AGC
10 availability. As the Company thoroughly explores in its Battery Storage Cost Benefit
11 Analysis (IRP Technical Volume 2), energy storage systems may provide a variety of
12 services, even simultaneously. The storage use cases considered in the Company's Utility
13 Scale RFP evaluations only provide partial credits for regulating reserves and arbitrage.
14 The current storage use cases of Smoothing and Firming and Smoothing are operated based
15 on local metrics for generator output, rather than system needs.

16 While certainly beneficial, these storages use cases leave a large portion of energy storage
17 system value on the table. These storage use cases, with AGC capability, could operate the
18 storage devices based on system-wide needs for support capacity. They could also
19 responsively provide capacity during system peaks. In the Battery Storage Cost Benefit
20 Analysis, capacity value for an AGC controlled battery constituted a significant part of the
21 economic benefit of the storage device (IRP Technical Volume 2, Section 4, pg. 9).
22 Unfortunately, current solar plus storage projects on the Company's system designed for

1 Smoothing or Firming and Smoothing use cases will sit idle during system peaks and
2 emergencies, on both winter mornings and summer evenings. If any such projects are
3 selected in Georgia Power's current Utility Scale RFP, the resources will be unable to
4 provide the capacity that they are capable of delivering because of the current limitations
5 imposed by the Company's RFP requirements.

6 **Q. CAN AGC-ENABLED STORAGE COUPLED TO RENEWABLE RESOURCES**
7 **AVOID THE NEED FOR ADDITIONAL STANDALONE STORAGE?**

8 A. Yes. The Company has requested to build 1,000 MW of standalone energy storage by 2030,
9 specifically to provide regulating reserves to balance renewable generation. Solar plus
10 storage projects, in part, or in whole, will reduce the need for system regulating reserves to
11 compensate for the intermittency of the renewable resource. Requiring AGC to be installed
12 on solar plus storage projects will provide even greater regulating reserve value to such
13 projects, which in turn, should offset the need for standalone storage.

14 **Q. WHAT IS STAFF'S RECOMMENDATION REGARDING BATTERY STORAGE**
15 **AND THE USE OF AGC IN FUTURE UTILITY SCALE RFPS?**

16 A. Staff recommends that the Company allow all renewable projects that bid into future RFPs,
17 both with and without storage devices, to be operated on AGC, and to consider new use
18 cases that flexibly utilize the coupled energy storage devices with AGC control. To
19 facilitate Staff's recommendation, the Company will need to develop the methodology to
20 evaluate all renewable bids with AGC, including those with a storage device, in advance
21 of its next Utility Scale RFP.

DG PROCUREMENTS

Q. DOES THE COMPANY PLAN TO CONTINUE ANY DG CUSTOMER-SITED PROGRAMS?

A. Yes. The Company plans to continue the Customer Connected Solar Program ("CCSP"), which the Commission, on December 7, 2021, extended until the allocated 25 MW capacity is fulfilled. In its IRP filing, the Company did not request to allocate additional capacity to the program (Tr. at 63-64) or request to allocate any MW to a future DG customer-sited program.

Q. HAS THE RENEWABLE ENERGY DEVELOPMENT INITIATIVE ("REDI") CS II PROGRAM CONCLUDED AND IS THERE ANY REMAINING UNPROCURED CAPACITY?

A. The REDI CS II program application period concluded on January 29, 2021. As of April 18, 2022, the Commission has certified 3 REDI CS II resources, totaling 6.6 MW. Based on the submitted applications, REDI CS II will have unprocured capacity. Per the Commission's September 1, 2020 Order, this remaining capacity is directed to roll over to the 2020 DG RFP, which is also expected to have unprocured capacity.

Q. WHAT IS STAFF'S POSITION REGARDING THE CONTINUATION OF GEORGIA POWER'S DG CUSTOMER SITED PROGRAMS?

A. The Company has not requested to make any modifications or increase capacity for the CCSP. Staff is supportive of the continuation of the CCSP and will continue to monitor

1 both the CCSP and REDI CS II customer-sited programs as the programs move toward
2 completion.

3 VIII. LOCATIONAL VALUE STUDY PROPOSAL

4 Q. WHY HAS THE COMPANY PROPOSED THE LOCATIONAL VALUE STUDY 5 SUMMARIZED IN THE IRP MAIN DOCUMENT, ATTACHMENT H?

6 A. As with the ELCC study discussed previously, the locational value study proposal was a
7 requirement of the stipulation made by the Company and PIA Staff in Docket No. 4822.
8 The fourth item in the stipulation states, in part, “[t]he Company shall include in the 2022
9 IRP a proposal to study locational value aspects following the conclusion of the 2022 IRP”
10 (Docket No. 4822, 16573, and 19279: Stipulation between GPC and PIA Staff (Feb. 23,
11 2021)).

12 In Docket No. 4822, Staff and intervenors advocated for the Company to develop a
13 methodology to evaluate how renewable resources interconnected in different locations
14 could provide different benefits to customers and the grid. In Docket No. 4822, the focus
15 was on QF resources, but the same principles apply to all renewable resources. Staff’s
16 testimony in that proceeding explained the issue as follows:

17 *QF resources can provide differing values depending on their*
18 *interconnection location. This is due to differing avoided energy value resulting*
19 *from potential economic congestion on the transmission system. As a hypothetical*
20 *example, if a long-distance transmission line is operating near capacity in the*
21 *south-to-north direction and can’t deliver lower cost energy generated in the south*

1 to load in the north, there will be a marginal energy cost differential between the
2 southern and northern regions. That is, an additional MW of load in the north will
3 require the dispatch of a higher cost resource, in the northern region, than the
4 resource used to serve an additional MW of load in the south.

5 In this scenario, a new QF resource closer to the northern load would avoid
6 the generation of higher cost energy and would have more value to the grid. This
7 is one example of differing locational value of energy
8 (Docket Nos. 4822, 16573, and 19279: PIA Staff's Rebuttal Testimony, pg. 50).

9 **Q. DOES THE COMPANY'S PROPOSAL ACHIEVE THE OBJECTIVES THAT**
10 **WERE INTENDED IN THE STIPULATION FROM DOCKET NO. 4822?**

11 **A.** No. The Company's proposal does not fully address the objectives. The Company's
12 proposal is to conduct an analysis similar to how it calculates the Deferred Transmission
13 Investment component of the RCB Framework. It plans to evaluate how generation sited
14 in different locations in the state would impact the need for new transmission upgrades.
15 Staff agrees that this analysis is relevant to the question of locational value of renewables,
16 but it does not address other ways in which interconnection location impacts the benefits
17 of the renewable resource. As Staff testified in the recent QF avoided cost docket,
18 generation resources in different locations can have a different impact on marginal energy
19 prices whenever there is a constraint on a transmission line. New renewable capacity in a
20 constrained region that has higher cost generation has a higher avoided cost value than new
21 renewable capacity in areas with access to lower cost generation. The Company's
22 locational value study should provide insight into these differences, potentially as the basis

1 for developing region-specific avoided cost values that will send price signals to project
2 developers to site new generation in higher value locations.

3 **Q. HOW SHOULD THE COMPANY MODIFY ITS PROPOSAL TO ADDRESS**
4 **THESE ADDITIONAL AREAS AS NOTED BY STAFF?**

5 A. Staff recommends that the Company modify its Locational Value study methodology to
6 include an assessment of economic congestion on its system. In its production cost
7 modeling, which calculates marginal energy pricing, the Company typically models its
8 system without any transmission constraints between zones and there is no representation
9 of physical transmission limits and there are no pricing differences across the system. By
10 breaking its modeled system up into smaller zones connected by transmission links that
11 reflect actual system transfer limits, the study could forecast region-specific energy values.
12 The Aurora model that the Company already uses for production cost modeling has this
13 functionality built in and can perform the analysis described. This analysis is
14 complementary to the transmission investment-focused analysis described in the IRP Main
15 Document, Attachment H. Locational Value Study Proposal. With the two analyses, the
16 Company would have more information to assess the economic value delivered by
17 relieving transmission constraints.

18 **IX. DG INTERCONNECTION**

19 **Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE CURRENT DG**
20 **INTERCONNECTION PROCESS?**

1 A. Yes. The Company is proposing to improve interconnection guidance for DG projects by
2 offering a web-based hosting capacity tool. This tool will indicate where available capacity
3 exists on the distribution system in order to increase efficiency of project siting (Tr. at 58).

4 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED HOSTING CAPACITY**
5 **TOOL.**

6 A. The Company stated that the hosting capacity tool will be a Geographic Information
7 System ("GIS") based graphical interface providing a snapshot of distribution circuit
8 available capacity. This tool would be updated annually and is not meant as a replacement
9 for the Company's Interconnection Guidance program (Company Response to STF-DEA-
10 2-30; Staff Exhibit_BCB-15). The hosting capacity tool will be available free of charge to
11 registered generators participating in the Company's DG Programs (Company Response
12 to STF-DEA-4-6; Staff Exhibit_BCB-16).

13 The hosting capacity value will be based on the non-coincidental annual peak of the
14 individual feeder and will be calculated using the Eaton CYMDist software model. As
15 stated during the Direct Hearing, the Company envisions the hosting capacity to be
16 provided by a "red light, green light, maybe yellow light based on feeder location
17 throughout the state." For any additional information, the DG developer would need to
18 utilize the Company's current interconnection guidance process, which has fees for varying
19 levels of guidance (Tr. at 460-462).

20 The Company decided to not include transmission line or substation limitations in the
21 hosting capacity tool, and developers will need to utilize Tier 1 interconnection guidance

1 to understand if any transmission limits exist (Company Response to STF-DEA-4-17; Staff
2 Exhibit_BCB-17).

3 **Q. DOES STAFF RECOMMEND APPROVAL OF THE PROPOSED HOSTING**
4 **CAPACITY TOOL?**

5 A. Yes. Staff recommends approval of the hosting capacity tool with several modifications.
6 First, the hosting capacity tool should be made publicly available, without requiring
7 participation in one of the Company's current DG programs. This is common practice in
8 the industry and an appropriate policy to allow project developers to identify suitable sites
9 well in advance of competing in DG programs. Second, the analysis and information
10 provided by the tool should be updated at least twice per year to maintain accuracy. Third,
11 the hosting capacity analysis should reflect the available capacity based on Minimum
12 Daytime Loading or Coincident Peak limitations at the sub-station, as described by the
13 Transmission Evaluation scenarios. Such limitations are a significant factor in feeder
14 hosting capacity and should not require site-specific Interconnection Guidance to obtain
15 information. Finally, the Company must maintain a robust process for validating the
16 hosting capacity analysis and the data provided by the tool. The Company should share this
17 validation process with Staff and be required to provide the results of validation to Staff
18 when the hosting capacity analysis is updated.

19 **Q. DOES STAFF HAVE ANY ADDITIONAL CONCERNS REGARDING THE**
20 **CURRENT DG INTERCONNECTION PROCESS?**

1 A. Yes. During the current 2020 DG RFP, many bids were released due to interconnection
2 constraints or interconnection costs resulting in the projects not having a total net benefit
3 to customers. Historically, the bid prices of DG projects, on a per kW basis, have been
4 higher than the bids of Utility Scale projects; therefore, additional costs from
5 interconnection are more likely to cause a DG project to be above avoided costs. For this
6 reason, it is important that interconnection costs be calculated as fairly and accurately as
7 possible.

8 A distribution interconnection standard cost matrix for interconnection components would
9 be beneficial to this process by providing a common basis for the cost of interconnection.

10 A similar cost matrix is used for the Company's transmission interconnection evaluations
11 during the Utility Scale RFPs. Additionally, Staff has identified several concerns that affect
12 interconnection cost determination including planned component replacements, O&M
13 costs, Direct Transfer Trip ("DTT") requirements, and transmission constraints.

14 **Q. PLEASE DISCUSS STAFF'S CONCERNS REGARDING THE COMPANY'S**
15 **PLANNED COMPONENT REPLACEMENTS.**

16 A. Staff is concerned that costs to replace or upgrade equipment that was already planned for
17 replacement by the Company could inadvertently be included in the interconnection costs
18 for DG bids. For example, the Company confirmed that it began a program in 2019 to
19 replace all of its hydraulic reclosers with electronic reclosers (Company Response to STF-
20 DEA-4-15; Staff Exhibit_BCB-18). Staff believes that it would be inappropriate to assess
21 the entire cost of equipment upgrades to interconnecting DG projects if the Company
22 already has plans to replace such equipment. When a situation like this occurs for a

1 transmission interconnection, wherein a planned system upgrade is performed earlier due
2 to the interconnecting project, only the cost of project advancement is assessed to the
3 project's interconnection costs.

4 **Q. PLEASE DISCUSS STAFF'S CONCERNS REGARDING THE**
5 **DETERMINATION OF O&M COSTS CURRENTLY USED TO DETERMINE DG**
6 **INTERCONNECTION COSTS.**

7 A. Generally, the Company applies O&M expenses to DG projects as a flat rate proportional
8 to the capital costs of interconnection. This approach ignores that existing system
9 components have O&M expenses, or that some components have lower or higher O&M.
10 Projects that replace existing equipment do not necessarily increase O&M, and in fact, may
11 reduce this cost with newer equipment. The most expensive interconnection components
12 are often line reconductoring and DTT service. For example, line reconductoring is a
13 replacement of an existing line, which already has budgeted O&M assigned to it. The O&M
14 of the replacement line assigned to an interconnecting project should only be the
15 incremental O&M compared to the existing line.

16 **Q. PLEASE DISCUSS DTT AND STAFF'S CONCERNS REGARDING THE USE OF**
17 **DTT IN THE DG INTERCONNECTION PROCESS.**

18 A. DTT is a communications system between a generator and an upstream circuit breaker.
19 When the breaker is opened, it immediately sends a signal to the generator, which must
20 then disconnect to protect the circuit from being energized. This system has historically
21 used fiber optic cables for telecommunication between the two ends. However, wireless

1 DTT systems are now available with the potential to avoid much of the capital costs of
2 fiber optic DTT. The Company has not yet allowed DG interconnections to utilize wireless
3 DTT and has stated that it prefers fiber since radio communication is relatively slow, and
4 vulnerable to unauthorized access and harmful interference (Company Response to STF-
5 DEA-4-17; Staff Exhibit_BCB-17). However, the Company should consider wireless
6 DTT, where appropriate, which could help reduce PPA costs and provide the opportunity
7 for more projects to meet the requirement of providing a total net benefit.

8 **Q. WHAT ARE STAFF'S RECOMMENDATIONS FOR THE DG**
9 **INTERCONNECTION PROCESS?**

10 A. Staff recommends that Staff and the Company initiate a review of Georgia Power's DG
11 interconnection process in order to establish a distribution interconnection cost matrix prior
12 to the next DG RFP, and to consider modifications that would reduce barriers to the
13 interconnection of projects. Such a review should focus on the issues that Staff has
14 discussed above regarding component replacement costs, O&M costs, application of
15 wireless DTT and other limitations which disqualify bids for interconnection.

16 **X. ADDITIONAL SUM**

17 **Q. HAS THE COMPANY REQUESTED AN ADDITIONAL SUM FOR THE 2,300**
18 **MW REQUESTED IN THIS IRP?**

19 A. Yes. The Company requested a levelized additional sum amount of \$7.50/kilowatt ("kW")
20 alternating current ("AC") of the total capacity amount from which renewable energy is

1 procured from Utility Scale and DG resources, annually, for the term of each PPA (IRP
2 Main Doc., pg. 1-15).

3 **Q. WHAT IS THE CURRENTLY APPROVED METHODOLOGY THAT IS USED TO**
4 **DETERMINE THE ADDITIONAL SUM THAT THE COMPANY RECEIVES FOR**
5 **RENEWABLE RESOURCES?**

6 A. In the 2019 IRP Order, the Commission approved an additional sum for both Utility Scale
7 and DG RFP resources at 8.5% of the projected long-term net energy savings (July 16, 2019
8 Order in Docket No. 42310).

9 **Q. WHAT ADDITIONAL SUM HAS THE COMPANY TYPICALLY RECEIVED**
10 **FOR RESOURCES PROCURED IN CAPACITY RFPS?**

11 A. The Company has typically received \$2.30/kW-year for capacity resources procured
12 through capacity RFPs.

13 **Q. DOES THE GEORGIA CODE PROVIDE FOR AN ADDITIONAL SUM?**

14 A. Yes. O.C.G.A. §46-3A-8, states that the Company is entitled to an additional sum, as
15 determined by the Commission, for purchased power resources. This Code section also
16 describes certain factors that shall be considered by the Commission, such as lost revenues,
17 changed risks and equitable sharing of benefits between the Company and ratepayers in
18 determining the appropriate additional sum required to encourage long-term power
19 purchases. However, while the Georgia Code sets forth certain factors that the Commission

1 must consider in setting the additional sum, neither the Act nor Commission Order set forth
2 any specific methodology or formula to calculate that additional sum.

3 **Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S**
4 **REQUEST TO MODIFY THE ADDITIONAL SUM METHODOLOGY?**

5 A. Staff does not support a change to the Company's Additional Sum methodology. Staff
6 believes that the current Additional Sum methodology of 8.5% of projected long-term
7 energy savings provides adequate incentive to the Company for the procurement of
8 renewable resources. The Company has stated that solar project costs are projected to
9 continue to decline out into the future (Tr. at 242-243). It is appropriate for the Company
10 to realize an Additional Sum based on the projected long-term energy savings such low
11 priced solar resources will bring to the Company's customers. Staff recommends that the
12 Commission not approve the Company's request to modify the current methodology for
13 determining the additional sum for renewable procurements.

14 **XI. SOLAR CUSTOMER PROGRAMS AND TARIFFS**

15 **CARES PROGRAM**

16 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CARES PROGRAM.**

17 A. Similar to the Company's current Customer Renewable Supply Procurement ("CRSP")
18 program, the CARES Program will allow customers to subscribe to a portion of the energy

output and RECs from a portfolio of new renewable resources approved in this IRP. The Company proposes that the CARES program be allocated in the following manner:

CARES Programs	Load Minimum (MW)	Capacity Allotment (MW)
Existing Load	3	900
New Load	15	500
Municipalities, Universities, Schools, and Hospitals (MUSH)	1 up to 3	50
Carbon Free Energy - Around The Clock (CFE- ATC)	25	650
Economic Development (New Load Addition)	50	TBD

(IRP Main Doc., pp. 14- 104-105).

The CARES Existing Load and CARES New Load carveout are very similar to the previous CRSP Existing Load and CRSP New Load programs.

Q. PLEASE DESCRIBE THE PROPOSED MUSH CARVEOUT.

A. The CARES carve-out of 50 MW for MUSH customers is proposed for Municipalities, Universities, Schools, and Hospitals with aggregate annual peak demands of 1 to 3 MW. Such relatively small customers have expressed interest in renewable energy subscriptions.

1 If the level of interest exceeds the available MW for each solicitation, Georgia Power will
2 allocate MW on a pro-rata basis among participating customers who complete the notice
3 of intent ("NOI") process (Main IRP Doc., pg. 14-107).

4 **Q. PLEASE DESCRIBE THE PROPOSED CFE-ATC CARVEOUT.**

5 A. The CARES carve-out of 650 MW for CFE-ATC customers is proposed for eligible
6 customers with aggregate annual peak demands of at least 25 MW. This program is
7 designed for customers that have expressed interest in renewable energy subscriptions for
8 energy that is available around the clock (24 hours a day). To achieve 24-hour renewable
9 energy, GPC proposes to use an "appropriate sizing of BESS" with the 650 MW of
10 renewable resources proposed to offer a 100 MW block of 24-hour renewable energy for
11 subscription for the CARES CFE-ATC program. Customers will receive energy and
12 capacity credits based on their subscription level. As proposed, interested customers will
13 be able to subscribe up to 100% of their aggregated preceding year's total annual energy
14 consumption. If the level of interest exceeds the available MW for each solicitation,
15 Georgia Power will allocate MW on a pro-rata basis among participating customers who
16 complete the NOI process (Main IRP Doc., pp. 14- 107-108).

17 **Q. PLEASE DESCRIBE THE ECONOMIC DEVELOPMENT (NEW LOAD**
18 **ADDITION).**

19 A. The CARES for Economic Development customers is proposed for eligible customers
20 adding incremental, new load of 50 MW or greater, for subscription. This program is
21 designed to provide an opportunity for additional renewable solicitations to encourage

1 economic development in the state of Georgia. This program is proposed to meet customer
2 demands when/if the CARES New Load program is fully subscribed or does not meet the
3 needs of a qualified customer. The exact amount of MW to be allotted to the CARES
4 Economic Development program are not known at this time, but Georgia Power requests
5 that any such MW be in addition to the 2,100 of Utility Scale renewable resources requested
6 in the 2022 IRP (Main IRP Doc., pg. 14-108).

7 **Q. DOES STAFF RECOMMEND APPROVAL OF THE ALLOCATIONS OF**
8 **CAPACITY AS PROPOSED BY THE COMPANY?**

9 A. Yes. Staff recommends approval of the proposed capacity allocations for the CARES
10 program. The Company has indicated that each CARES program will be administrated
11 similarly to one another. The Company does not expect to have additional or different
12 program guidelines, timelines, or requirements, other than the customer type and aggregate
13 load requirements. Final approval for the specific requirements of each program is not
14 anticipated to occur until the program tariff and guidelines are filed with the Commission
15 following the 2022 IRP (Company Response to STF-DEA-2-32; Staff Exhibit_BCB-19).
16 Staff recommends that individual CARES carveout program specifics be finalized after the
17 2022 IRP through the respective tariff negotiations and design.

18 **R3 PROGRAM**

19 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED R3 PROGRAM.**

1 A. The proposed R3 program will provide participating customers the ability to claim
2 renewable benefits from existing renewable resources (2,000 MW) by subscriptions
3 through a reallocation of the RECs from resources that are already online or are in the
4 process of coming online. The RECs and environmental attributes that would otherwise be
5 retired on behalf of all customers will be made available for subscription by interested
6 customers. As part of the subscription, customers will pay a fixed cost per MWh for the
7 RECs that are generated from these portfolios. The monthly fee to participate in R3 will be
8 in addition to the customer's regular monthly electric service payments and will be based
9 on the value of the RECs at the time the customer agreement is executed. 1,000 MW from
10 the R3 program will be available for subscription by existing customers. Georgia Power
11 will offer up to 1,000 MW of renewable generation from the R3 program for subscription
12 by customers adding new load of 50 MW or greater (IRP Main Doc., pp. 14- 109-110).

13 **Q. PLEASE DESCRIBE WHICH EXISTING RENEWABLE RESOURCES THE**
14 **RECS FOR THE R3 PROGRAM WOULD BE SOURCED FROM.**

15 A. Participating customers will be able to subscribe to up to 1,000 MW of the current REDI I
16 and REDI II portfolios that were approved in the 2016 IRP and up to 1,000 MW of the
17 2022/2023 and 2023/2024 portfolios from the 2019 IRP once these resources come online
18 (IRP Main Doc., pg. 14-109).

19 **Q. DOES STAFF RECOMMEND APPROVAL OF THE R3 PROGRAM?**

20 A. Yes. Staff recommends approval of the R3 Program. The revenues received from the sale
21 of the RECs will go to the benefit of all customers. However, the Company will not be able

1 to count the 2,000 MW used for this program as renewable generation resources (in terms
2 of its generation mix) during the terms of the R3 customer agreements. Staff further
3 recommends that the Company be required to file quarterly reports that provide the amount
4 of MW and the number of customers that have subscribed to the R3 program.

5 **COMMUNITY SOLAR PROGRAM**

6 **Q. PLEASE DESCRIBE THE COMPANY'S COMMUNITY SOLAR PROGRAM.**

7 A. Georgia Power's Community Solar program was approved on June 7, 2017. Georgia
8 Power's Community Solar program provides customers the opportunity to support the
9 development of solar power in Georgia by subscribing to a portion of the output of local
10 solar resources. The program is designed to collect program costs from participating
11 customers (IRP Main Doc., pg. 1-112). Currently, the Community Solar program is only
12 available to customers receiving service through the residential service tariff. The original
13 Community Solar program was 3 MW, which was then expanded by an additional 5 MW
14 through the Company's 17th Vogtle Construction Monitoring proceeding in Docket No.
15 29849 for a total of 8 MW. As of January 1, 2022, customers have subscribed to 1,954
16 blocks out of a total 8,000 blocks available (Company Response to STF-DEA-2-20; Staff
17 Exhibit_BCB-20).

18 **Q. WHAT IS THE CURRENT PRICING FOR CUSTOMERS TO PARTICIPATE IN**
19 **THE COMMUNITY SOLAR PROGRAM?**

1 A. The current pricing for a 1 kW block is \$24.99 per month. The Company offsets the
2 customer's electric usage by the amount of energy produced at the Community Solar
3 facilities equivalent to the customer's subscription level (virtual net metering). If the solar
4 production from the customer's subscribed block(s) in the current month is greater than the
5 customer's current monthly electric usage, the customer receives a credit at the Company's
6 solar avoided cost rate. Based on the design of this program, Georgia Power anticipates
7 that the Community Solar block rate, on average, will exceed any bill credits received by
8 approximately \$5 each month (Tr. at 344).

9 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE**
10 **COMMUNITY SOLAR PROGRAM.**

11 A. Georgia Power is proposing to raise the residential community solar rate from
12 \$24.99/month to \$27.99/month and add a commercial option at \$29.99/month. The
13 Company is also proposing to open an Income-Qualified Community Solar Pilot for 5,000
14 of the remaining available blocks.

15 **Q. PLEASE DESCRIBE HOW THE INCOME-QUALIFIED COMMUNITY SOLAR**
16 **PILOT WOULD WORK.**

17 A. As proposed, a corporate sponsor would buy down the subscription fee for income-
18 qualified customers, and the RECs produced by those community solar blocks would be
19 retired on the sponsor's behalf. As proposed, the income qualified customers would pay
20 only \$6.99 per month for a single block (Main Doc., pg. 14-112).

1 **Q. WHAT APPROVAL(S) IS THE COMPANY REQUESTING REGARDING THE**
2 **COMMUNITY SOLAR PROGRAM IN THE 2022 IRP?**

3 A. The Company is seeking approval to update pricing for standard “R” rate residential
4 customers from \$24.99/month to \$27.99/month, add the commercial General Service rate
5 of \$29.99/month and a proposed 75% corporate buydown of the pricing for the Income
6 Qualified Community Solar Program. Proposed pricing for both customer classes is based
7 on December 2021 assumptions and the final pricing may be updated in the Rate Case
8 filing in June 2022. The Company will file an updated Community Solar Tariff for approval
9 subsequent to the outcome of the 2022 IRP (Company Response to STF-DEA-3-29; Staff
10 Exhibit_BCB-21).

11 Also, to maintain availability of subscription blocks for new customers, the Company is
12 requesting Commission approval to develop additional Community Solar facilities once
13 the available capacity is 75% subscribed. Once the subscribed capacity target is achieved,
14 Georgia Power will file with the Commission its plan to develop additional Community
15 Solar facilities (Main IRP Doc., pg. 14-113).

16 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY’S PROPOSED**
17 **MODIFICATIONS TO THE COMMUNITY SOLAR PROGRAM?**

18 A. Staff recommends approval of the Company’s request to include a commercial option for
19 the commercial class as part of its Community Solar program. Staff also recommends
20 approval of the Company’s proposed Income-Qualified Community Solar Pilot. However,
21 Staff does not recommend approval of the proposed increased rates, as the rates for this
22 program will be considered during the Company’s upcoming rate case. Finally, Staff

1 recommends that the Company be required to file quarterly reports that provide the number
2 of customers and blocks that have subscribed for each portion of the Community Solar
3 program.

4 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S REQUEST TO**
5 **DEVELOP ADDITIONAL COMMUNITY SOLAR FACILITIES ONCE THE**
6 **COMMUNITY SOLAR PROGRAM IS 75% SUBSCRIBED?**

7 **A.** Yes. Staff recommends approval of additional Community Solar facilities once the existing
8 program is 75% subscribed; however, such resources should be reviewed by Staff and
9 approved by the Commission. These resources should be developed below the Company's
10 MG0 Avoided Cost, similar to the previous Community Solar resources. Staff further
11 recommends that additional Community Solar resources should be in 5 MW or less
12 increments to allow the program subscription to grow into the capacity available and
13 moderate the amount of capacity that is not subscribed.

14 **SIMPLE SOLAR PROGRAM- LARGE VOLUME PURCHASE OPTION**

15 **Q. PLEASE DESCRIBE THE COMPANY'S SIMPLE SOLAR PROGRAM.**

16 **A.** As approved by the Commission on August 2, 2016 in Docket No. 40161 (Georgia Power's
17 2016 IRP), the Simple Solar program allows customers to participate by purchasing solar
18 RECs for either 100% or 50% of their monthly usage by paying a 1 cent per kWh charge.
19 This program also has Large Volume and Special Event purchase options.

1 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED FLEX REC PROGRAM.**

2 A. The Company proposes to replace the Simple Solar Large Volume program with the Flex
3 REC program. The current Simple Solar Large Volume program sources solar RECs for
4 large customers based on solar RECs in the voluntary REC market. The Flex REC program
5 will be supplied with RECs from a variety of sources, including solar, wind, and potentially
6 other renewable sources. Similar to the Simple Solar Large Volume Program, the Flex REC
7 program will provide pricing on a tiered basis, with the largest tier set to the market price
8 plus a 5% adder (IRP Main Doc., pg. 14-111).

9 **Q. WHAT OTHER CHANGES IS THE COMPANY PROPOSING FOR THE FLEX**
10 **REC PROGRAM?**

11 A. The Company is also proposing a new Economic Development Flex REC option. This
12 option will be available to customers that qualify for the large load exception of the Georgia
13 Territorial Electric Service Act and who purchase a minimum of 2,000,000 kWh monthly
14 through Flex REC, or 24,000,000 kWh annually for a fixed rate, quantity, and term. The
15 pricing is customer-specific and will be negotiated by Georgia Power and the customer on
16 a case-by-case basis for a defined contract period (up to three years), during which Georgia
17 Power will procure and retire RECs on behalf of the customer. To continue to provide
18 additional flexibility to customers, Georgia Power proposes to transition the Simple Solar
19 one-time purchase and Special Event purchase options to the Flex REC program (IRP Main
20 Doc., pp. 14-111-112).

1 **Q. WHAT SPECIFIC CHANGES IS THE COMPANY REQUESTING REGARDING**
2 **THE SIMPLE SOLAR PROGRAM?**

3 A. The Company is requesting approval to replace the current Simple Solar Large Volume
4 offering with the Flex REC program. This new program design includes new pricing,
5 adjustments to the tiered pricing structure, and the option to source program RECs from
6 resources beyond solar. Additionally, the Company is seeking approval to implement an
7 economic development option for use on a case-by-case basis where Georgia Power may
8 negotiate a REC agreement with potential large C&I customers that meets the filed criteria.
9 The Company intends to file for approval an updated Simple Solar and a new Flex REC
10 tariff subsequent to the IRP (Company Response to STF-DEA-3-35; Staff Exhibit_BCB-
11 22).

12 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S PROPOSED**
13 **MODIFICATIONS TO THE SIMPLE SOLAR PROGRAM?**

14 A. Staff recommends approval of the Company's proposal to modify the Simple Solar
15 Program to replace the current Simple Solar Large Volume offering with the Flex REC
16 program. However, Staff does not recommend revising the rates for this program as they
17 will be considered during the Company's upcoming rate case which is scheduled to be filed
18 in June of this year. Staff further recommends that for the Economic Development Flex
19 REC option that the Company be required to file each negotiated contract.

20 **RENEWABLE AND NON-RENEWABLE TARIFF (RNR TARIFF)**

1 **Q. PLEASE DESCRIBE THE COMPANY'S RNR TARIFF.**

2 A. The Company's RNR tariff is applicable to customers that sell energy from renewable
3 resources (e.g. solar and wind) such as rooftop solar and nonrenewable resources (e.g. fuel
4 cells). RNR-Instantaneous Netting is available to all eligible customers on a first come,
5 first served basis until the cumulative generating capacity of all renewable sources equals
6 to 0.2 percent (0.2%) of the Company's annual peak demand in the previous year. Under
7 RNR-Instantaneous Netting, all excess energy is credited at the Company's solar avoided
8 energy cost rate based on the Company's filing in Docket No. 16573.

9 In the Company's 2019 Rate Case, the Commission approved an RNR-Monthly Netting
10 pilot for 5,000 customers or an additional 32 MW, whichever occurs first. Under RNR-
11 Monthly Netting all excess energy is summed on a monthly basis and used to reduce the
12 customer's total monthly energy consumption. Excess energy that exceeds the customer's
13 total monthly usage is credited at the Company's solar avoided energy cost rate.

14 **Q. IN ITS FILING, HAS THE COMPANY REQUESTED TO INCREASE THE**
15 **NUMBER OF CUSTOMERS WHO CAN PARTICIPATE IN THE RNR-**
16 **MONTHLY NETTING PILOT?**

17 A. No. The Company does not support any expansion of monthly net metering. In its filing,
18 the Company stated that it will continue to work with the Commission and its Staff to
19 evaluate and report the impacts of the rapid growth in behind the meter ("BTM") renewable
20 generation and the RNR-Monthly Netting pilot (IRP Main Doc., pg. 14-155). Once the
21 program is full for at least one year, the Company has stated it will perform a preliminary
22 analysis on any cost shifting (Tr. at 356-357).

1 **Q. DOES THE COMMISSION TYPICALLY REVIEW RATE CHANGES AS PART**
2 **OF THE COMPANY'S RATE CASE?**

3 A. Yes. Company Witness Wilson Mallard agreed that such rate changes are traditionally
4 approved in a rate case or in a subsequent filing (Tr. at 240). Therefore, Staff does not
5 recommend approval of the Company's proposed rates and requested rate changes in this
6 docket.

7 **XII. PILOT REQUESTS**

8 **Q. DID THE COMPANY PROPOSE ANY PILOT PROJECTS AS PART OF ITS 2022**
9 **IRP?**

10 A. Yes. The Company has identified iron-air long-duration storage and tall wind technologies
11 as projects for study (IRP Main Doc., pg. 11-84).

12 **IRON-AIR BATTERY STORAGE**

13 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED PLAN TO STUDY IRON-**
14 **AIR BATTERY STORAGE.**

15 A. As the Company's resource mix continues to evolve, Georgia Power anticipates that
16 System needs could eventually shift towards long-duration or multi-day storage
17 applications. New technologies are emerging that may provide such services, but
18 commercial viability of these long-duration storage solutions requires additional testing,
19 monitoring, and demonstration. The Company is proposing to evaluate opportunities to

1 support, invest, and learn more about iron-air battery storage technology and possibly
2 deploy such technologies in the 5-15 MW range. The Company plans to request
3 Commission approval for an iron-air battery storage project once it has determined an
4 optimal application to demonstrate the technology. According to Georgia Power, this
5 technology can utilize relatively abundant materials, such as iron, for energy storage
6 applications that can be optimized to store energy for 100-hour durations. This multi-day
7 storage technology can also reduce the risk of thermal runaway and is considered easier to
8 recycle than other battery storage chemistries (IRP Main Doc., pp. 11- 84-85).

9 **Q. DOES STAFF AGREE THAT A LONG-TERM STORAGE PROJECT MIGHT BE**
10 **BENEFICIAL TO GEORGIA POWER'S RATEPAYERS?**

11 **A.** Yes. Staff agrees that research into iron-air battery storage technology might be beneficial
12 to Georgia Power's customers. Any projects that are developed on behalf of Georgia
13 Power's ratepayers should be reviewed by Staff and brought before the Commission for
14 approval.

15 **TALL WIND DEMONSTRATION**

16 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TALL WIND**
17 **DEMONSTRATION PILOT.**

18 **A.** The Company is proposing to develop a demonstration project of two wind turbines, up to
19 four MW each, with a hub height between 140–165 meters. The proposed towers will
20 utilize innovative spiral weld technology that employs on-site fabrication techniques.

1 Georgia Power states that this project is designed to demonstrate the economic and
2 technical feasibility of tall wind in Georgia as well as validating the in-field construction
3 techniques required for the spiral weld technology at higher hub heights. The Company
4 plans to team with a spiral weld technology company to leverage Department of Energy
5 ("DOE") funding awarded to the technology vendor for the further development and
6 demonstration of this innovative spiral weld tower technology.

7 **Q. DOES STAFF AGREE THAT SUCH A PROJECT WOULD BE BENEFICIAL TO**
8 **GEORGIA POWER'S RATEPAYERS?**

9 A. Yes. The Commission has previously approved wind research projects for Georgia Power
10 through the Small Wind Demonstration Pilot Project (evaluating small to medium wind
11 turbine technologies in Georgia Power's service territory) in the Company's 2013 IRP and
12 the High Wind Study (studying high wind potential in Georgia) in the Company's 2016
13 IRP. These, and other studies have found the potential for economic wind resources in the
14 Southeast (Main IRP Doc., pg. 14-103). Wind resources are complementary to solar
15 resources, as they produce energy during non-daylight hours, particularly during winter
16 morning system peak loads. The Tall Wind Demonstration should validate the potential for
17 wind energy resources in Georgia, enabled by the emerging spiral welding technology to
18 reach higher hub-heights.

19 The Company still has no Georgia based wind power generation on its system providing
20 power to Georgia Power's ratepayers (Main IRP Doc., pg. A-140). This project would be
21 the first Utility Scale wind resource in Georgia, to Staff's knowledge. Although the
22 Company stated that the Tall Wind Demonstration project will be constructed in areas of

1 significant wind potentials it is still unlikely to be economical for the system (Tr. at 241,
2 245). Staff supports demonstration projects that study future technology, although, when
3 research projects provide benefits to all Southern Company Operating Companies, the
4 costs should be shared across Southern Company's system and not to just Georgia Power's
5 customers.

6 **Q. DOES STAFF RECOMMEND APPROVAL OF THE TALL WIND**
7 **DEMONSTRATION PROJECT?**

8 A. Yes. Staff recommends Commission approval of the Company's request to pursue the Tall
9 Wind Demonstration project. Staff recommends approval of the Company's proposed
10 capital and O&M costs for the Tall Wind demonstration project (but not yet the recovery
11 of such costs), as set out in the Selected Supporting Information section of Technical
12 Appendix Volume 1. However, these costs should be shared with the other Southern
13 Company Operating Companies, and the Commission should only approve Georgia
14 Power's share of the net costs after the DOE funding has been accounted for. Staff also
15 recommends that if the Company anticipates that it will exceed the budgeted amount for
16 the Tall Wind Demonstration project found in the Selected Supporting Information of the
17 2022 IRP, the Company should be required to request Commission approval before
18 exceeding that budget.

19 **Q. DOES THIS CONCLUDE STAFF'S TESTIMONY?**

20 A. Yes.

1 MR. THOMAS: And with your permission, I would
2 like to ask that the panel give a summary.

3 MADAM CHAIR PRIDEMORE: Please go ahead.

4 WITNESS COOK: Good morning, Commissioners.
5 Public Interest Advocacy Staff's renewable resource
6 testimony addresses Georgia Power Company's proposed
7 integrated resource plan. A little bit closer.

8 The company has proposed the procurement of
9 additional renewable and storage resources, new
10 renewable customer programs, and changes to its
11 methodologies.

12 The staff is generally supportive of these
13 changes and has some recommendations to modify the
14 company's proposed resource plan.

15 The company proposes to modify the renewable
16 cost benefit or RCB framework by removing the
17 generation remix component, as well as a number of
18 placeholder components and to replace the support
19 capacity component with a new integration cost
20 component.

21 Staff agrees with the removal of the RCB
22 placeholder components but recommends that in the
23 absence of the generation remix component, the
24 deferred generation capacity cost component should
25 use the economic carrying cost of a combined cycle

1 unit instead of a combustion turbine unit.

2 Staff disagrees with the replacement of support
3 capacity with the proposed integration cost analysis
4 and recommends that the company revisit that study
5 with actual operational data and bring it back before
6 the Commission for approval at a later date.

7 Finally we recommend -- we also recommend
8 adding a renewable energy credit or REC component to
9 the RCB framework and utilizing the effective load
10 carrying capability method in place of the current
11 incremental capacity equipments.

12 The staff recommends approval of the company's
13 proposed McGrau Ford battery project, subject to
14 certain conditions, but withholds approval of any
15 additional battery storage projects until the next
16 IRP or until the company provides additional support.

17 Staff recommends approval of the proposed
18 procurement of 2,300 megawatts of renewable resources
19 as well, utilizing a best cost approach.

20 All of these renewable resources are proposed
21 to be made available to commercial and industrial
22 customers through the CARES program.

23 We recommend that if the Commission decides to
24 approve a procurement greater than 2,300 megawatts,
25 that any of the additional resources be procured on

1 behalf of all customers. For the utility scale
2 procurements, staff disagrees with the proposal's
3 limit the first RFP to projects sited only in North
4 Georgia. Instead, staff recommends that the RFP
5 remain open to projects from any location but
6 quantify the cost of transmission upgrades or delays
7 required to meet the resilience need with the
8 renewable resources from South Georgia and other
9 locations and apply that cost during an evaluation.

10 Staff also recommends that all resources
11 procured in future utility scale RFPs shall operate
12 on an automatic generation control.

13 For distributed generation, staff recommends
14 that the company and staff initiate a review of
15 Georgia Power's DG interconnection process in order
16 to establish a distribution and a correction cost
17 matrix prior to the next DG RFP and to consider
18 modifications that will reduce barriers to the
19 interconnection projects.

20 We also recommend approval of the company's
21 proposed hosting capacity tool with modifications to
22 make it publicly available and more useable to
23 developers.

24 Regarding the additional sums, staff recommends
25 maintaining the current methodology for determining

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1 the additional sum to the company's renewable
2 procurements.

3 Staff is supportive of the company's proposed
4 new and modified customer programs and the carve-out
5 amounts. We recommend for the programs the tariff
6 details should be designed in collaboration with C&I
7 customers.

8 Staff recommends approval of the CARES and
9 existing resource -- retail REC retirement programs.
10 Staff also supports the company's proposed changes to
11 the community solar and simple solar programs but
12 recommends that any changes to tariff rates be
13 addressed in the upcoming rate case.

14 Finally, staff supports the Tall Wind pilot
15 project and recommends approval of the limitations on
16 the budget for the project.

17 That concludes our summary.

18 MR. THOMAS: Madam Chair, the panel is
19 available for questions from Commissioners and
20 cross-examination.

21 MADAM CHAIR PRIDEMORE: Questions from
22 commissioners?

23 (No response.)

24 MADAM CHAIR PRIDEMORE: Okay. All right.
25 Americans for Affordable Clean Energy?

1 MR. GALLOWAY: No questions, Madam Chair.
2 MADAM CHAIR PRIDEMORE: Commercial Group?
3 MR. JENKINS: No questions.
4 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
5 for Georgia?
6 MR. PRENOVITZ: (No response.)
7 MADAM CHAIR PRIDEMORE: Cyprus Creek
8 Renewables?
9 MR. STAIR: No questions.
10 MADAM CHAIR PRIDEMORE: Georgia Association of
11 Manufacturers?
12 MR. CHARLES JONES: No questions.
13 MADAM CHAIR PRIDEMORE: Georgia Center for
14 Energy Solutions?
15 MR. HUBBARD: No questions.
16 MADAM CHAIR PRIDEMORE: Georgia Coalition for
17 Local Governments?
18 MS. BROWN: No questions.
19 MADAM CHAIR PRIDEMORE: Georgia Interfaith
20 Power and Light and Partnership for Southern Equity?
21 Can always count on Ms. Kysor.
22 MS. KYSOR: I passed on the last panel.
23 MADAM CHAIR PRIDEMORE: It's all right. You're
24 fine, Ms. Kysor. Go ahead.
25 MS. KYSOR: I'll keep it brief.

CROSS-EXAMINATION

BY MS. KYSOR:

Q Good afternoon.

A (Witness Barber) Good afternoon.

Q I'll just address my questions to the panel and let y'all decide who is best situated to answer.

Do you agree that it's a policy decision for this Commission whether they want to adopt monthly netting on a broader scale?

A (Witness Barber) Yes, it is.

Q And the Commission has the authority to make that policy decision in this IRP?

A (Witness Barber) They do.

Q And staff recommends approving several substantive changes to the community solar program but recommends holding the issue of whether or not the monthly fee should be increased until the rate case; correct?

A (Witness Barber) Yes, that's correct.

Q And is that because certain programmatic changes might make sense to address in the IRP, but cost-related questions might be more appropriate later?

A (Witness Barber) Yes, that's correct.

Q And on page 71 of your testimony, lines 4 through 6, you note that instantaneous netting is available until the capacity hits 0.2 percent of the

1 company's annual peak demand; correct?

2 A (Witness Barber) Yes, that's correct.

3 Q Would rooftop solar customers still be able
4 to sell excess energy after that 0.2 percent threshold is
5 hit?

6 A (Witness Barber) Well, our understanding would
7 be that this is a minimum amount from the legislation. The
8 Commission can vary from that in the tariff, like they did
9 on the size of the commercial customers. So -- so that
10 would -- that is currently in the tariff, that language. So
11 it would be up to that amount.

12 Q Do you know how close we are to that 0.2
13 percent threshold?

14 A (Witness Cook) I don't have that number on me.
15 It was in a data request.

16 A (Witness Barber) I don't have it with me. I
17 don't think we are close, but if you have it...

18 MS. KYSOR: Madam Chair, if the information has
19 not been provided in a data response already and you
20 have it, could I ask that that number be provided?

21 MADAM CHAIR PRIDEMORE: You can do it as a data
22 request.

23 MS. KYSOR: Thanks.

24 BY MS. KYSOR:

25 Q And then on page 71, lines 20 through 22,

1 other than the partial analysis that the company filed in
2 this docket with respect to its monthly netting program,
3 are you aware of any additional analysis that the company
4 has done?

5 A (Witness Barber) No. That data request asked
6 for all analysis and that was all that we have received to
7 date.

8 Q Thank you.

9 MS. KYSOR: I have no further questions.

10 MADAM CHAIR PRIDEMORE: Georgia Large Scale
11 Solar Association and Advanced Power Alliance?

12 MR. CARVER: No questions, Madam Chair.

13 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
14 Industries Association, Solar Energy Association, and
15 Vote Solar?

16 MR. THOMASSON: Thank you, Madam Chair.

17 I'm going to address the panel, but y'all can
18 answer however you want.

19 CROSS-EXAMINATION

20 BY MR. THOMASSON:

21 Q I'm going to start with distributed
22 procurement. Y'all mentioned in your testimony some of
23 the challenges that some of the recent DG procurement has
24 had, specifically with respect to interconnection issues;
25 is that correct?

1 A (Witness Cook) Yes.

2 Q And you mentioned some of the specific
3 examples of some of the cost issues that have come up,
4 reclosers and DTT and others; is that correct?

5 A (Witness Cook) Yes.

6 Q Were these issues only issues that staff has
7 identified or were they also brought up during the process
8 or in feedback from bidders and developers?

9 A (Witness Cook) Well, I'll say that -- I mean,
10 that RFP is still going on, but we -- I would say that it's
11 not only something that staff has identified, and also it's
12 something that we've heard from developers prior to this RFP
13 as well.

14 Q And specifically on some of the things you've
15 heard before that, you know, you mentioned hydraulic
16 reclosers as an example where the company has already had
17 plans to replace reclosers.

18 Have you heard of specific examples from market
19 participants about concerns that the company is trying to
20 recover, whether it's intentional or not, from those solar
21 projects?

22 A (Witness Cook) I would say that that's
23 specifically something that came up in this specific IRP,
24 that -- RFP. Sorry. That's something that came up in this
25 specific RFP that we identified.

1 Q Okay. One of the improvements that y'all are
2 recommending to the DG interconnection process is a
3 distribution interconnection cost matrix.

4 Could you describe what kind of information
5 would be in that and how it would be developed?

6 A (Witness Cook) So this is something that we
7 have on -- that we utilize on the transmission side already.
8 It's -- so a transmission interconnection cost matrix, which
9 is a basic list of costs for general -- the generic upgrades
10 to the system, so whether that be -- on the transmission
11 side, it's, you know, substation improvements and three-ring
12 buses and reconductoring of lines, that sort of thing.

13 And so our recommendation is that, you know, a
14 DG interconnection cost review of actual interconnection
15 costs from previous RFPs or -- and after this IRP -- after
16 this RFP is completed, these interconnection costs would
17 inform what these DG interconnection costs are on average.

18 Q And so presumably it's been staff's
19 experience that those cost matrixes have been helpful on
20 the utility scale side?

21 A (Witness Cook) Yes, because we otherwise don't
22 have a good basis on which to judge whether or not
23 interconnection costs are reasonable.

24 Q And that that's sort of where we are on DG
25 procurement right now?

1 A (Witness Cook) Yes.

2 Q Okay. You also recommend specifically with
3 regard to the interconnection cost matrix that the company
4 work with staff to develop that cost matrix and design the
5 kind of information that's included in it; correct?

6 A (Witness Cook) On the interconnect -- or on
7 the transmission side. We -- that's --

8 Q Oh, that was specific to --

9 A (Witness Cook) We don't have one -- we don't
10 have on the distribution side.

11 Q No. But one of the recommendations for
12 improvements to the DG interconnection process is for the
13 company to work with staff after the IRP process is
14 completed?

15 A (Witness Cook) Yes. Yes, we would work with
16 them.

17 Q Would staff be open to having some market
18 participants participate in that dialogue about how to
19 design that interconnection matrix?

20 A (Witness Barber) I'm not sure. I'll have to
21 think on that.

22 Q All right. But no immediate objections to
23 getting some feedback on what that matrix might look like?

24 A (Witness Barber) Yeah. I'm -- I'd still have
25 to think on that part.

1 Q All right. The company's also proposed a
2 hosting capacity tool as one of its improvements for the
3 procurement process; correct?

4 A (Witness Cook) Yes.

5 Q Has the company laid out in detail how that
6 hosting capacity tool is going to look and what kind of
7 information it's going to include?

8 A (Witness Cook) We received a couple of
9 responses to data requests that explained a little bit more
10 around it, and I believe the hearings for the direct company
11 testimony also did a little bit of explanation of the
12 description. But our understanding is that it's going to be
13 a GIS-based tool that's -- so it is online and would utilize
14 a specific -- a software that would actually do the
15 distribution system analysis that comes up with the hosting
16 capacity. So it's an off-the-shelf program that -- that
17 evaluates the hosting capacity.

18 Q But staff's also recommending some additional
19 modifications to what's been proposed; correct?

20 A (Witness Cook) Yes. Not necessarily on the
21 technical side of how it's being analyzed, but on the --
22 what's being provided specifically.

23 Q Could you just summarize real quick some of
24 the information or the modifications that you're
25 recommending?

1 A (Witness Cook) I believe our -- so our
2 testimony is that we recommend that it's publicly available.
3 We recommend that it would include the MDL or peak load
4 limits on the substation or the feeder as well as -- yeah.
5 Also more frequent updates. Sorry.

6 Q And are those -- those recommendations that
7 staff came up with or has that been a process from market
8 feedback?

9 A (Witness Cook) That's something that staff
10 came up with.

11 Q Okay. I'm going to move on to the best cost
12 approach that the company's proposing.

13 The best cost methodology, the approach would
14 apply to both utility scale and distributed generation;
15 correct?

16 A (Witness Cook) That's our understanding.

17 Q But in your testimony, you explained that it
18 would be specifically significant for -- or especially
19 significant for DG; correct?

20 A (Witness Cook) Yes.

21 Q Could you explain why?

22 A (Witness Cook) Mostly because on the -- on the
23 transmission side, we already have a portfolio analysis, so
24 I think the really big component is that you're changing the
25 way that you're analyzing the -- the winning projects.

1 Q And just a reminder, could you quickly
2 describe what a portfolio analysis looks like and why it
3 would relate?

4 A (Witness Cook) When you -- when you narrow
5 down what projects you're interested in taking, so you'll
6 have, say, 100 projects bid in, 75 of them are economic, you
7 then take only, you know, some fraction of those that you're
8 expecting are on your -- say your reserve list.

9 You then do an analysis of groupings of those
10 projects in order to find which of those projects work best
11 together for the lowest cost. And that already happens on
12 the transmission interconnected side, but we don't do that
13 on the distribution side.

14 Q So could you explain how that would relate to
15 the best cost approach and how the best cost would allow
16 more of that for DG?

17 A (Witness Cook) I think it's simply just
18 because the company is proposing to start using that
19 portfolio analysis for DG, so it's just a different way of
20 looking at the projects that are --

21 Q So they're almost two separate improvements
22 or proposals to improve the process?

23 A (Witness Cook) Sure. Yeah.

24 Q All right. Let me move on.

25 But the portfolio approach is different from

1 the discussion that y'all have in your testimony about
2 locational value; correct?

3 A (Witness Cook) Yes.

4 Q Could you talk about locational value and how
5 best costs might allow more possibility for locational
6 value for these types of procurements, also?

7 I'll let -- yeah, I'll let Jeff.

8 A (Witness Bower) So the -- the locational value
9 study that the company has proposed in the IRP, at this
10 point, there's no integration between that, per se, and the
11 best-cost approach. So the best-cost approach would be a
12 method for evaluating the results of RFPs.

13 At this point, the locational value study
14 approach is primarily trying to determine -- and as the
15 company has proposed it -- we have several recommendations
16 for modifications. But as the company has proposed it, it
17 is a -- something that's focused on PURPA projects and
18 determining whether there is an additional value for PURPA
19 projects being in different geographic locations in Georgia.

20 That -- obviously, because the best -- the
21 best-cost approach is something that is pertinent to RFPs
22 and RFP evaluations, so it wouldn't be relevant as it's
23 currently proposed.

24 As we noted, locational value is something that
25 goes beyond PURPA projects. If the company can devise a

1 method for determining whether there's a differentiated
2 value of renewable resource throughout the state, that would
3 be relevant to utility scale and DG RFPs as well. And I
4 think that could be a factor that is incorporated into
5 either the initial screening through -- through our projects
6 that have been to an RFP or through the portfolio component
7 of the best costs.

8 Q But isn't there an element of that principal
9 of locational value in staff's recommendation about
10 whether the company should limit a utility scale proposal
11 to -- or -- sorry -- procurement RFP to North Georgia only
12 or apply it to the whole state and then sort of make
13 adjustments for location?

14 A (Witness Cook) Yeah. And I think that's
15 moving to a different point.

16 Q Yes.

17 A (Witness Cook) Yeah. On the North Georgia
18 RFP, yes, there -- there certainly is some crossover between
19 the locational value idea and whether or not you should do
20 an RFP solely for North Georgia.

21 And I think our recommendation kind of reflects
22 that idea, that if there's a difference in locational value
23 between them, they can compete based on that locational
24 value.

25 Q And just as a broad principal, there may be

1 some similar analogue for distributed generation
2 procurement?

3 A (Witness Cook) Yes, clearly possible.

4 Q Has the company given much detail about how
5 it's going to apply the best-cost approach in future RFP
6 procurements?

7 A (Witness Barber) No, not really. And we state
8 that in our testimony, is that we are generally supportive,
9 but they didn't provide a lot of details but also staff in
10 the IE will have a part as the Commission approves the RFP
11 documents. So the Commission ultimately will have the final
12 say about how that approach will work.

13 Q And as part of that RFP process, are the
14 market participants' potential bidders going to be able to
15 provide feedback on that -- what that approach --

16 A (Witness Barber) Well, the RFP documents, yes.
17 Yes.

18 Q Because presumably the best-cost approach is
19 going to be laid out in the draft RFP documents; right?

20 A (Witness Trokey) It should. Usually the
21 evaluation criteria is an attachment on how the
22 evaluation -- to some degree -- I don't know per se what
23 exactly would be laid out, but market participants do get to
24 comment on the documents before they get approved and issued
25 through an RFP.

1 Q That's actually a good transition to my next
2 set of questions is about the RFP process.

3 Commission staff, you on the panel have been
4 part of the RFP process for both utility scale and DG
5 procurements; correct?

6 A (Witness Barber) Yes, that's correct.

7 Q And you personally participated in some of
8 these RFPs.

9 In addition to the specific recommendations,
10 the hosting capacity and some of the other things that we
11 just discussed, for DG, are there other improvements that
12 staff thinks might be worth considering for the solar
13 procurement process specifically with DG?

14 Are there, you know, broader -- broader
15 obstacles that you've seen? And I can build to that
16 question if I'm skipping --

17 A (Witness Cook) You might need -- you might to
18 build on that.

19 Q All right. All right. Let me -- let me step
20 back a second here.

21 The DG RFP process, let's start with that, it's
22 modeled after the same RFP process that's used for utility
23 scale; right?

24 A (Witness Barber) Yes, that's correct.

25 A (Witness Cook) Yes.

1 Q Do you know whether all the elements of that
2 process, whether it's for utility scale or specifically
3 for DG, including the communications protocols and whether
4 there's direct three-way communication between staff and
5 the company and -- and bidders, are all of those mandatory
6 for the company to apply to the DG process or is it just
7 sort of a cut and paste from utility scale?

8 A (Witness Barber) No. Assuming that an
9 affiliate doesn't bid in a DG RFP, there's not an
10 independent evaluator used, so the company proposes, and the
11 Commission has approved the use of an independent monitor.

12 That's not really required by Commission rules
13 but the company, you know, has -- wants to do that for fair
14 and transparency and that part used during the communication
15 protocols.

16 And so when we approve an RFP document or the
17 Commission approves it with an IM, that the protocols are in
18 place that, you know, stop the communication between the
19 parties, but it's not required by Commission rule.

20 Q And so if -- if the company doesn't have an
21 affiliate bidding on a project, you are saying they
22 could -- they might have the flexibility to --

23 A (Witness Barber) Well, on the DG side.

24 Q On the DG in particular?

25 A (Witness Barber) Yes.

1 Q That that full application of the independent
2 evaluator, independent monitor --

3 A (Witness Barber) Is voluntary. It's not
4 required.

5 Q Voluntary. On the company's part?

6 A (Witness Barber) Yes.

7 Q Okay. So the company would have some
8 flexibility, if it wanted to, to voluntarily modify that
9 piece of the process; correct?

10 A (Witness Barber) Correct.

11 Q And the Commission, if it wanted to, if it's
12 not sort of mandated under the rules, the Commission could
13 also consider changes to that piece of the process?

14 A (Witness Barber) Correct. Correct.

15 Q That's great.

16 Do you think that changes to the communication
17 in particular in the RFP process might reduce the number of
18 the frequency with which bidders have to come before the
19 Commission to sort of make complaints about the process or
20 protest specific elements of the process? If there were a
21 little more communication on the front end, would we see
22 fewer complaints here before the commissioners on the back
23 end?

24 A (Witness Barber) Potentially. Potentially so.

25 Q On the additional sum for renewable

1 procurement, the staff is recommending a smaller amount
2 than what the company is proposing; correct?

3 A (Witness Barber) Yes. We are -- we are
4 recommending maintaining the status quo, eight and-a-half
5 percent of long-term projected savings.

6 Q Do you believe the Commission has the ability
7 to consider adjustments to the additional sum based on its
8 evaluation of how the company has conducted the RFP
9 process, the procurements that were laid out in the IRP?
10 Basically, is the -- is the additional sum a policy
11 decision for the Commission, or is there -- is it a
12 mandatory thing once we have approved it in an IRP?

13 A (Witness Barber) Well, it is a policy
14 decision. I know that it is from the statutes. I don't
15 want to get into the legality of it. But, yeah, it is -- it
16 is definitely a policy decision by the Commission. I
17 have -- we have not recommended, you know, specifics, other
18 than eight-and-a-half percent of net savings. We haven't
19 said you had to procure 100 percent or you don't get any of
20 it. That was not part of our testimony.

21 COMMISSIONER MCDONALD: Ms. Barber, I think I
22 heard the question: Does the Commission have the
23 ability?

24 WITNESS BARBER: And I -- yes. Yes, it is a
25 policy, most definitely.

1 BY MR. THOMASSON:

2 Q I'll take it. In fact, that's all I have on
3 additional sum.

4 A couple more quick questions on RECs. You
5 mentioned staff is recommending that the company change the
6 RCB methodology to include a value for RECs; correct?

7 A (Witness Cook) Yes.

8 Q And staff is recommending that the company
9 meet with staff to figure out what that value should be;
10 right?

11 A (Witness Cook) Yes.

12 Q Is there any openness to that, including a
13 broader group of stakeholders or previous intervenors that
14 are weighed in on this?

15 A (Witness Barber) Yes, we are fine with that.

16 Q Okay.

17 A (Witness Barber) We are not getting into
18 confidential company information on this issue.

19 Q Yeah. I mean, if it's just sort of the
20 design element and not --

21 A (Witness Barber) Yes.

22 Q And then a couple quick questions on storage,
23 and I will be done.

24 Part of your testimony, you conclude that the
25 company has not demonstrated the need to own and operate

1 proposed battery storage resources; correct?

2 A (Witness Cook) Yes.

3 Q And you also conclude third-party ownership
4 provides at least an opportunity for lower costs and has
5 done so historically, and that same principle applies to
6 battery storage; correct?

7 A (Witness Cook) Yes.

8 Q If the Commission decides to approve the
9 1,000 megawatts or some other figure for the battery
10 storage proposed in the IRP, do you believe that all of
11 that capacity or that that full amount of battery storage
12 ought to go through the competitive procurement process?

13 A (Witness Cook) I believe that even if the
14 company owns it, it still gets competitively bid for pre BC
15 but your question being if we believe that it should be
16 competitively bid for third-party ownership as well.

17 Yeah, go ahead.

18 A (Witness Barber) Well, I mean, our
19 recommendation is for the company to be allowed to build
20 McGrau Ford, but if the Commission does approve the
21 remainder of the thousand, we do believe it should go out
22 for competitive bid, for third-party ownership.

23 Q Okay. And you have also recommended that
24 storage, combined with solar, solar plus storage, should
25 be included in the company's competitive RFPs; correct?

1 A (Witness Cook) Yes. That being a somewhat
2 different issue, yes.

3 Q Separate category.

4 MR. THOMASSON: That's all I have. Thanks.

5 MADAM CHAIR PRIDEMORE: Georgia Watch?

6 MS. COYLE: No questions.

7 MADAM CHAIR PRIDEMORE: Interstate Gas Supply?

8 MR. CARVER: No questions, Madam Chair.

9 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
10 Coalition?

11 MR. STEVEN JONES: No questions, Madam Chair.

12 MADAM CHAIR PRIDEMORE: Sierra Club?

13 MR. FABISH: No questions.

14 MADAM CHAIR PRIDEMORE: That side door is like
15 the Muppet show to me. It really is. No offense to
16 Steven and Liz. But it's like when that door swings
17 open, I expect Kermit to come out.

18 Southern Alliance for Clean Energy and
19 Southface Energy Institute? Kermit is a beloved
20 figure. There is nothing negative about that.

21 Mr. Baker, hello.

22 MR. BAKER: Hello.

23 CROSS-EXAMINATION

24 BY MR. BAKER:

25 Q Hello, panel. Robert Baker on behalf of

1 Southface Energy Institute and the Southern Alliance for
2 Clean Energy. Good afternoon.

3 A (Witness Barber) Good afternoon.

4 Q A few questions for you.

5 In your prefiled testimony, you discuss flaws
6 with the renewable integration study that Astrape performed
7 and you recommend against the use of the renewable
8 integration cost, at least for now.

9 But at page 27, you state, "Staff may be able
10 to support the use of integration costs in future filing."
11 And you go on to say, "The company should then bring the
12 revised renewable integration costs to the Commission for
13 approval."

14 When would that occur? When do you think that
15 should occur?

16 A (Witness Barber) Well, it would need to occur
17 before we would allow that change, because they currently
18 have integration costs as part of the support capacity cost
19 as part of the RCB framework. So we already have it.

20 So they -- for us to be able to replace it,
21 they would need to bring it as our recommendation back to
22 the Commission at some point, prior to an evaluation, an
23 RFP, where the RCB costs are determined.

24 Q Should it wait until the 2025 IRP?

25 A (Witness Barber) They don't have to.

1 Q Okay.

2 A (Witness Barber) Yes. We were very open-ended
3 with that. They can do it at any point. But until they do
4 that, we don't recommend that change.

5 Q But you do recommend the change before they
6 do the next RFP?

7 A (Witness Barber) No. We -- if the company
8 wants to do it, to change it, they have to bring it in and
9 get approved by the Commission before they could replace the
10 support capacity --

11 Q Right. Thank you.

12 And toward the end of your testimony, you
13 recommend approval of most of the proposed changes to the
14 community solar program. And at page 68, you state that
15 "Additional community solar resources should be at
16 5 megawatt or less increments."

17 Part of the reason the current program is
18 undersubscribed is that it's marketed as a premium product.
19 Won't restricting expansions to a maximum of 5 megawatts
20 limit the ability of this program to ever evolve beyond a
21 premium status?

22 A (Witness Cook) I don't believe the current
23 limitation is available capacity. And so I think if there
24 was a demonstrated need for additional capacity above and
25 beyond 5 megawatts, then that would be great. But as of

1 right now, the -- the limitation and the reason why it's,
2 you know, potentially undersubscribed is not because of a
3 lack of available capacity.

4 Q Well, isn't it because of the cost of it?

5 A (Witness Cook) I don't believe that the cost
6 of the -- the rate, the tariff rate on community solar is --
7 it is not cost-based. It's not based off of the project
8 cost. It is based off of a revenue, like in a revenue
9 erosion model.

10 A (Witness Barber) Yes, you are right.

11 Q All right. But it is -- cost does have an
12 impact on consumer demand, doesn't it?

13 A (Witness Cook) Certainly the -- the tariff
14 price certainly does, yes.

15 Q Right.

16 A (Witness Cook) Well, I think I -- what I'm
17 saying is that even reducing the cost of the community solar
18 projects themselves, the actual solar in the ground, isn't
19 what would bring down that cost of the community solar
20 tariff.

21 Q What would?

22 A (Witness Cook) Changing methodology on which
23 the community solar tariff is based.

24 Q And in order to get a lower cost, what would
25 have to happen in order to make that change?

1 A (Witness Barber) It would have to be a
2 different way of how that is calculated. Currently, it is
3 based on the company's lost revenues for that customer.

4 So it's not based on what the project costs the
5 company. So I think that's what staff is saying, is that I
6 agree with you, larger projects should have economies of
7 scale. And the reason we put that recommendation in there
8 is to kind of now see, depending on what happens with -- you
9 know, staff did not take a position -- we said we are not
10 going to address the increase in this case. We are going to
11 take it up in the rate case.

12 So depending on what happens in that, we don't
13 want a lot of extra capacity there. You know, we don't want
14 the company building 20-megawatt project and it not get
15 subscribed, because we definitely have an issue because it's
16 under 2 megawatts and it's been several years.

17 Q Well, following up on your statement, could
18 future community solar expansions instead be carved out of
19 other larger projects to allow community solar to benefit
20 from economies of scale?

21 A (Witness Cook) It certainly could. I think
22 the current idea is that it's self -- or it's utility-owned.
23 So it could be carved out of other utility-owned resources,
24 yes.

25 Q But, for example, let's say the utility is

1 developing a 50-megawatt project. I mean, can you
2 designate 3 megawatts of that for the community -- if you
3 had the demand for it, designate 3 megawatts of that
4 generation for community solar, but get the benefit of the
5 economies of scale by having the larger 50-megawatt
6 project and not have it dedicated, you know, that 3
7 megawatts? You know, just a standalone project for the
8 community solar?

9 A (Witness Cook) Yes, that's certainly -- yes,
10 that's certainly an option, yes.

11 MR. BAKER: Okay. Thank y'all very much.
12 Appreciate it.

13 MADAM CHAIR PRIDEMORE: Southern Renewable
14 Energy Association?

15 CROSS-EXAMINATION

16 BY MR. MAHAN:

17 Q Good afternoon, Commission. Good afternoon
18 panel. I am Simon Mahan.

19 A (Witness Barber) Good afternoon.

20 A (Witness Cook) Afternoon.

21 Q I'm Simon Mahan with the Southern Renewable
22 Energy Association.

23 Page 7, Recommendation 11, "Staff recommends
24 that the company should not issue a North Georgia RFP for
25 renewables but should instead require the cost of

1 transmission upgrades" -- "require to meet the resilience
2 for southern projects to be added to projects in the north."

3 Can you describe how you plan on that process
4 working?

5 A (Witness Cook) So I think to the point we were
6 making earlier about locational value, there is the
7 production cost difference between -- and as well as
8 necessary transmission upgrades to allow Southern Solar to
9 provide for the reliability ease of the load in the north.

10 So I think along those lines, you can quantify
11 the cost of those transmission assets or any other
12 constraints in order to apply an evaluation benefit to one
13 resources -- or one geographic location versus another.

14 Q Okay. And so what you just described, is it
15 possible that the South Georgia to North Georgia movement
16 of power is not just a single transmission line, it could
17 be multiple projects in order to resolve any constraints?

18 A (Witness Cook) Certainly.

19 Q And over time; right? It's not all going to
20 be done in one single year; right?

21 A (Witness Cook) Certainly. I would direct any
22 more detailed questions about transmission to the
23 transmission, you know -- our consultant that does
24 transmission.

25 Q Sure. And transmission projects can provide

1 multiple benefits, not just for solar developers. It can
2 provide for, you know, shifting frequency in voltage
3 around.

4 So it can provide multiple benefits; right?

5 A (Witness Cook) Certainly it provides -- yes,
6 it does more than just carry electrons for solar, yes.

7 Q And so this North Georgia reliability and
8 resilience plan that we're all kind of talking about, when
9 we come up with some transmission solutions out of there,
10 you're proposing that 100 percent of those costs be then
11 applied to any North Georgia solar projects that bid into
12 the RFP?

13 A (Witness Barber) Repeat your question.

14 A (Witness Cook) Yeah, repeat your question.

15 Q So all of the projects that are going to go
16 into the North Georgia reliability transmission plan,
17 you're going to take all of those costs and then assume
18 all of those costs are caused because of the solar
19 developers in the south and then you're going to apply
20 those costs as a benefit to projects that may bid into the
21 north; is that right?

22 A (Witness Cook) Okay. You're talking about the
23 transmission projects required in the North Georgia
24 reliability plan?

25 Q Yes. Yes.

1 A (Witness Cook) I don't believe that we're --
2 we're not recommending that all of the costs associated with
3 the North Georgia reliability plan would be coalesced and
4 attributed to those southern resources. I think that would
5 require more of a -- a more specific study that looked more
6 directly at the costs of bringing those electrons from South
7 Georgia to North Georgia and -- yeah. And shoring up those
8 reliability constraints specifically, not necessarily --
9 because I believe a lot of the North Georgia reliability
10 plan also revolves around unit retirements as well that are
11 kind of beyond that scope.

12 Q And so it really -- you really have to go
13 transmission project by transmission project, line by line
14 to figure out what costs you would then want to attribute
15 to North Georgia renewable bids?

16 A (Witness Cook) That might be a little bit
17 beyond my expertise on that. I would probably try that with
18 John Chiles.

19 Q Okay. Yes, we can do that.

20 Have you all looked at the generation air
21 connection queue up in the northern part of Georgia within
22 the past six months?

23 A (Witness Cook) We did review it. It was part
24 of a data request. We did see that interconnection queue,
25 yes.

1 Q Okay. And do you recall approximately how
2 many renewable projects in northern Georgia might be able
3 to bid into a northern Georgia specific RFP?

4 A (Witness Cook) That number crossed our desk.
5 I certainly couldn't quote it for you. I know that the vast
6 majority of projects in development, including things in the
7 interconnection queue, are located in middle, south Georgia.
8 It's just kind of the reality of the situation.

9 Q Sure. But just to boil it down. I mean,
10 part of this recommendation that y'all are making is
11 because you're concerned that the North Georgia only RFP
12 will fail?

13 A (Witness Cook) Yes.

14 A (Witness Barber) Yes. And I think we put that
15 in our testimony as well.

16 Q Okay. Going back to this concept of applying
17 transmission benefit costs to northern Georgia projects,
18 presuming there are -- we're going to presume that there's
19 going to be a Northern Georgia renewable project that's
20 going to bid into an RFP at some point in the future.

21 Would a future battery project get that same
22 transmission benefit assigned to it?

23 A (Witness Cook) A battery project in North
24 Georgia?

25 Q Yeah.

1 A (Witness Barber) Well, it can't bid in.

2 A (Witness Cook) Well, yeah, it wouldn't be able
3 to bid into the renewable, but in theory if you -- in theory
4 if we -- you know, if we develop a locational value, as we
5 talk about in the locational value study section, then, yes,
6 that locational value could be applied to other resources
7 outside of the renewable RFPs.

8 Q Okay. So it could theoretically apply to
9 natural gas plants?

10 A (Witness Cook) Yes, in theory.

11 Q Okay. And I don't think you want to do this,
12 but why wouldn't you also assign that transmission benefit
13 to existing coal units?

14 A (Witness Cook) In theory it could, yes.

15 Q Okay. And if you did that, it could
16 potentially encourage those coal units to stay on for a
17 very long time?

18 A (Witness Cook) Depending on the level of
19 the -- the difference in cost, yes.

20 Q So let's go back to this hypothetical
21 situation where we've got a renewable project in North
22 Georgia that bids into an all Georgia RFP and you're
23 giving that project some sort of transmission adder,
24 benefit, you know, let's call it \$3 a megawatt hour, you
25 know, it doesn't matter what the price is; is that

1 renewable project actually avoiding any transmission
2 build-out in the southern part of the state, or is it just
3 a hypothetical?

4 A (Witness Cook) I mean, I guess it would depend
5 on how the analysis was done and how that -- that value
6 was -- was determined.

7 I could see that some evaluation methodologies
8 might be much more correlated with actual costs, but it also
9 certainly depends on the level of response from North
10 Georgia. And so it is sometimes hard to see a benefit from
11 one generator. But, you know, we -- when we do analyses --
12 when we do analysis, particularly, say, in Aurora, you know,
13 you look at 300-megawatt blocks, and so you're looking at
14 generators in aggregate.

15 And so if you have a block of respondents that
16 bid into the North Georgia -- or bid into the RFP from North
17 Georgia, you could see those benefits.

18 Q But in order to do that, you would have to
19 cancel transmission projects in the North Georgia
20 reliability plan then?

21 A (Witness Cook) Yeah. I would -- I would
22 probably kick that to John Chiles.

23 Q Okay. Speaking of Mr. Chiles, I presume
24 you've read his testimony?

25 A (Witness Cook) Yes.

1 Q Okay.

2 A (Witness Barber) Yes. And we -- and we
3 discussed our recommendation with him before it got put in
4 our testimony, so it is -- it was from his guidance.

5 Q Okay. Well, one of his recommendations is to
6 create a new collaborative transmission planning process.

7 And you are familiar with that recommendation
8 generally?

9 A (Witness Cook) Generally, yes.

10 Q Do you envision that collaborative
11 transmission process occurring before the 2023 renewable
12 RFP process?

13 A (Witness Barber) Not really sure. I'm not
14 sure of the timing of that recommendation.

15 Q Okay. So going back to this original
16 recommendation of if there are northern Georgia renewable
17 projects and you want to provide a transmission adder
18 benefit for them so they can get ranked and appropriately
19 evaluated, but the collaborative planning process isn't
20 completed yet, how do you expect to be able to assign some
21 sort of transmission benefit when you don't have the
22 number?

23 A (Witness Cook) That's not to say that a study
24 couldn't be done ahead of a collaborative group.

25 Q But that study would presumably be run solely

1 by Georgia Power without any collaboration involved in it?

2 A (Witness Cook) With staff involvement, but
3 potentially not industry involvement.

4 Q Sure. Which staff specifically would be
5 involved? Because the collaborative process that
6 Mr. Chiles outlines mentions that staff and consultants
7 will be involved in that process. Can you name like the
8 specific staff that would be involved in that process?

9 A (Witness Barber) I don't know specifically,
10 but it would probably be someone from electric. Blair Fink,
11 maybe, possibly somebody from our unit as well.

12 Q And do you have a sense of who the specific
13 consultants would be that would help in the collaborative
14 process?

15 A (Witness Barber) No, I sure don't.

16 Q Okay. Generally, do you believe that the
17 Commission staff have enough resources to evaluate these
18 transmission alternatives and optimization of transmission
19 of the system?

20 COMMISSIONER McDONALD: No?

21 A (Witness Barber) No. No.

22 MR. MAHAN: Thank you, Commissioner.

23 BY MR. MAHAN:

24 Q Mr. Chiles also recommends and discusses the
25 North Carolina transmission planning collaborative as an

1 example of what he'll eventually propose down here which
2 y'all are familiar with.

3 Have y'all participated in that planning
4 collaborative in North Carolina?

5 A (Witness Cook) No.

6 Q Have you spoken to anyone in North Carolina
7 that has participated in that collaborative?

8 A (Witness Cook) I haven't, no.

9 A (Witness Barber) No, we haven't.

10 Q Do you happen to know if that collaborative
11 is run by an independent entity or is it run by the
12 utilities?

13 A (Witness Barber) We're not sure.

14 Q Okay. Let's move on to staff
15 recommendation 13 regarding the locational value study
16 that came out of the Docket 4822. And on page 52 of your
17 testimony, you cited earlier testimony that y'all provided
18 in that docket that gave an example of solar resources
19 being built in the south providing a different value than
20 solar resources being provided in the north.

21 But that's just like a generic example, that's
22 not a specific example of the two regions that y'all
23 anticipate to evaluate; right?

24 A (Witness Bower) That's right. That's just a
25 sort of generic description of how locational -- a

1 locational energy value would work.

2 Q Okay. And so there's potentially many more
3 locations that a locational value study would or could
4 evaluate?

5 A (Witness Bower) That's right.

6 Q Do you have a sense of how many locations or
7 how you would divvy up those locations?

8 A (Witness Bower) No. I mean, I think that
9 would have to be -- that would really depend on -- and this
10 is what we're hoping the study would kind of, you know,
11 figure out is where there are transmission constraints,
12 where there are load pockets or generation behind
13 transmission constraints that may lead to differentiated
14 locational value of energy, and, therefore, you know,
15 differentiated value of renewables in those regions.

16 But the number, that would have to be the
17 output of the study, not something that we know --

18 Q Okay.

19 A (Witness Bower) -- at this point.

20 Q And do you happen to know if other utilities
21 or regions conduct a similar locational study or forecasts
22 like that?

23 A (Witness Bower) I don't know of any utilities
24 that do studies similar to those exactly like that. I know,
25 for example, I've reviewed the PacifiCorp IRP in the past,

1 and they have different regions where they are -- you know,
2 they have different -- when they're doing capacity
3 expansion, for example, they take into account transmission
4 constraints between regions and differing value both, you
5 know, capital cost value but also avoided energy in
6 different regions as part of the economic analysis.

7 Certainly every -- every market based region
8 locational value is baked into energy pricing and, you know,
9 to the extent there are different capacities on those
10 capacity pricing as well.

11 Q And when you say "market," what do you mean?

12 A (Witness Bower) I mean like an RTO or an ISO
13 market, an AM or MISO.

14 Q All regional transmission organizations
15 include this, and it's -- is it called locational marginal
16 pricing?

17 A (Witness Bower) Yes. LMP is generally what --
18 what that's referring to.

19 Q Okay. So just to be very clear, what the
20 staff is recommending is that the company conduct a
21 locational marginal pricing study.

22 A (Witness Bower) Not -- I wouldn't characterize
23 it that way. There are ways to evaluate locational value
24 without everything that goes into locational -- locational
25 marginal pricing that markets use.

1 So hourly LMP's by node is locational pricing.
2 Locational marginal pricing. You can look at regions with
3 general transmission constraints and general constraints
4 that prevent the free flow of lowest cost energy and
5 characterize that in a regional context rather than on a
6 nodal, you know, point-by-point context.

7 So, conceptually, it's similar, but I think
8 that you can do a lot to -- and what we are -- what we are,
9 you know, proposing here or suggesting is that there are
10 additional ways that you can do these studies. It is not a
11 full LMP-based analysis, but it's more than what the company
12 has proposed, which is only transmission capital cost
13 focused.

14 Q And so what you are proposing is a less
15 granular, less accurate version of a locational marginal
16 price?

17 A (Witness Bower) Probably a less -- a less --
18 certainly less granular.

19 Q And you anticipate the study to be released
20 on an annual basis or is it a once-in-a-three-year basis
21 or...

22 A (Witness Bower) Well, I think -- I think the
23 first step would be doing the study once, you know, to get a
24 sense of transmission constraints on Georgia Power system,
25 whether there is any -- any value in -- whether there is a

1 differentiated locational value. I think that that's not
2 necessarily a certainty until the study is complete.

3 Q So you only evaluate a single year then? Is
4 that what you are proposing?

5 A (Witness Bower) No. You can do a forecast.
6 You know, you can do multiple years. But, again, I think to
7 first -- the first order of business is just do the study to
8 determine whether those transmission constraints exist and
9 whether the prices of renewables in different regions would
10 have a different value.

11 You could do that with one-year or you could do
12 a multi-year forecast and gain different amounts of
13 information. But all of it would be useful in helping
14 determine whether this is something that's worth pursuing.

15 Q But could you -- I mean, if you could kind of
16 help me out here, because I think we all agree in the room
17 that there is a difference between Northern Georgia and
18 Southern Georgia, and that there are transmission
19 constraints. And so kind of the -- the answers you just
20 describe are things that we all agree on.

21 And so what -- what additional value is that
22 study going to provide if it's not going to do additional
23 granularity?

24 A (Witness Bower) Well, I think you can go more
25 granular than -- I think there is a granularity level

1 between is it north or is it south. And every single
2 substation on Georgia Power's system, which is what really
3 an LMP-type analysis would do.

4 Q But locational marginal pricing analysis from
5 the RTOs, this is something that they have been doing for
6 decades at this point; right?

7 A (Witness Bower) Yes.

8 Q And so your -- strike that.

9 Let's move on to page 53 here real quick,
10 line 5. You explain how the Aurora model currently used by
11 the company doesn't include transmission topology and then
12 you suggest that the model could be used to break into,
13 quote, "smaller zones connected by transmission links that
14 reflect actual system transfer limits."

15 Again, can you give a sense of how big of a
16 region or zone you are thinking of that the company needs to
17 evaluate?

18 A (Witness Bower) I really don't -- don't have
19 an example that I can give on, you know, physically how big
20 those regions are. You let the transmission topology sort
21 of determine that, rather than a, you know, square miles or
22 anything like that.

23 Q Regarding the model itself, who told you that
24 the model can do that?

25 A (Witness Cook) We have some experience in

1 Aurora. And both I and other members on staff have done
2 some work in Aurora, going through their models, and we've
3 demonstrated that, yes.

4 Q Okay. So you verified that the model can
5 potentially do what you're asking it to do?

6 A (Witness Cook) Yes. Aurora can differentiate
7 between zones, yes.

8 Q Okay. Wouldn't it also be helpful to do
9 locational marginal pricing across the Southern Company
10 territory, given that the southern pool operates as a
11 pool?

12 A (Witness Cook) Certainly. I think we really
13 operate in the context of Georgia Power here.

14 Q Sure. Well, but you're aware, also, that
15 Southern Company uses Aurora planning software in
16 Mississippi and Alabama, here in Georgia?

17 A (Witness Cook) Yes.

18 Q Would it be helpful to have that type of
19 analysis across SERC?

20 A (Witness Cook) Certainly.

21 Q Is it possible that there are transmission
22 solutions into Tennessee that would be better suited to
23 fix the northern Georgia problems?

24 A (Witness Cook) I -- Yeah, I can't speak to
25 that, but you might try John Chiles.

1 Q Okay. I did a search in the testimony
2 regarding the Southeastern Energy Exchange Market.

3 Are you familiar with what this is?

4 A (Witness Cook) Yes.

5 A (Witness Barber) Vaguely.

6 A (Witness Cook) Vaguely.

7 Q Vaguely?

8 A (Witness Cook) We've been -- we've been
9 watching it develop, yes.

10 Q Okay. The Southeastern Energy Exchange
11 Market, did that have any role to play in fulfilling this
12 request for your locational value study?

13 A (Witness Cook) I don't believe so.

14 Q Do you value -- do you see -- or let me --
15 let me rephrase.

16 The Southeastern Energy Exchange Market, do you
17 believe it will provide a benefit to Georgia?

18 A (Witness Cook) I think that's outside the scope
19 of our testimony.

20 Q Is there anyone that gave testimony regarding
21 the Southeastern Energy Exchange Market?

22 A (Witness Cook) I don't believe so, no.

23 Q Okay. So it's entirely outside of the scope
24 of the integrated resource plan.

25 Let's move on to page 33 of your testimony,

1 line 11. You mention in the most recent capacity RFP, the
2 company did not allow two-hour batteries to participate.

3 Did staff recommend that two-hour batteries be
4 allowed to bid into that RFP?

5 A (Witness Cook) Yes, I believe we did.

6 Q And you were overruled?

7 A (Witness Cook) Yes.

8 Q Okay. How do we resolve that deficiency in
9 the future?

10 A (Witness Cook) I think in future capacity RFPs,
11 we'll be continuing to advocate for two-hour batteries.

12 Q Okay. Line 38 -- or sorry. Page 38, line 8
13 of your testimony explains that there's about
14 2.3 gigawatts renewables currently under development; is
15 that correct?

16 A Yes.

17 Q And that's all from the 2019 IRP?

18 A (Witness Cook) It may not be all from the 2019
19 IRP but most of it, yes.

20 Q And the company is now requesting
21 2.3 gigawatts of new renewables --

22 A (Witness Cook) Yes.

23 Q -- in this IRP?

24 And also in this IRP, the company is requesting
25 2.3 gigawatts of gas power purchase agreements?

1 A (Witness Cook) Yes.

2 Q 2.3 gigawatts over and over and over. Is
3 that -- is that a coincidence?

4 A (Witness Cook) I can't speak to that.

5 A (Witness Barber) Yeah. Not really sure.

6 Q Okay. Appreciate it. Thank you.

7 MADAM CHAIR PRIDEMORE: Georgia Power?

8 MR. HEWITSON: Thank you, Madam Chair.

9 Hello, panel.

10 PANEL: Good afternoon.

11 BY MR. HEWITSON:

12 Q Steve Hewitson on behalf of Georgia Power
13 Company. I want to start with the RCB framework, and
14 before getting into any specific components, let me ask
15 you generally about modeling for a second.

16 Did staff provide any modeling results to
17 support its testimony in this IRP?

18 A (Witness Barber) Can you be specific which
19 testimony?

20 Q On the RCB framework.

21 A (Witness Bower) No.

22 Q Did you run any models in developing your
23 testimony?

24 A (Witness Bower) No.

25 Q So although you have questions and concerns

1 about the modeling prepared by the company, would it be
2 fair to say that the company's modeling is the only
3 modeling that we have available for the RCB framework?

4 A (Witness Bower) That's correct.

5 Q Is it a fair characterization of your
6 testimony to say that staff supports replacing the support
7 capacity component of the RCB framework with a new
8 methodology to determine integration costs, but once the
9 company revised the way the renewable integration study
10 considers some factors?

11 A (Witness Bower) Yes.

12 Q One of the issues you identify relates to
13 wanting to see data regarding increased operating reserve
14 costs due to solar penetration; is that correct?

15 A (Witness Bower) That's correct.

16 Q Do you recall meeting with the company on
17 August 30, 2021, to review data on actual increases in
18 solar ramping 10-minute variability in solar forecast
19 error?

20 A (Witness Bower) We met with the company and
21 reviewed some data related to those matters, none of which
22 included any cost data.

23 Q Okay. But those data points all lead to the
24 system to carry more operating reserves; right?

25 A (Witness Bower) Generally speaking, yes. With

1 the variability, I'd have to look back at the data -- the
2 data package which I don't have with me. But variability, I
3 know, was demonstrated in that data. I'm not sure about the
4 operating reserves. I'd have to check in order to determine
5 that.

6 Q For integration costs you calculated, I
7 believe, a value of \$1.93 per megawatt hour; right?

8 A (Witness Bower) The \$1.93 per megawatt hour
9 value is a calculation of -- based on Georgia Power's
10 results or Astrape's results in the renewable integration
11 study, and it's basically -- rather than taking the average
12 of all solar online, it is the incremental costs of the next
13 3,000 megawatts calculated.

14 Q Okay. And I believe I heard Mr. Hayet say
15 earlier that he would be comfortable using the \$1.93 value
16 for planning purposes. Did you hear that testimony, also?

17 A (Witness Bower) I remember him discussing
18 that. I don't recall him saying specifically that.

19 Q Okay. Well, let me ask it this way: Would
20 you, as staff, support using that value for procurements
21 that come out of this IRP while it gives time for the
22 company to refine and validate the renewable integration
23 study?

24 A (Witness Bower) I will say that on the basis
25 of the analysis that's been done, the \$1.93 is a more

1 appropriate number than the 2.88 or the 2.50, so just to be
2 a little more clear here. The company did multiple
3 scenarios of solar.

4 The scenario a was 3,000 megawatts of solar,
5 and that's what's currently -- or a proxy for what's
6 currently online -- or pre-2019 IRP solar resources.
7 Scenario b is 5,000 megawatts. That's scenario A, plus the
8 resources that were approved in the 2019 IRP.

9 And then scenario C is 8,000 megawatts of
10 solar, and so that's, from what I understand, generally a
11 proxy for what was approved through the 2019 IRP plus
12 approximately what's being requested here. So it's kind of
13 the next tranche.

14 The company indicated, I believe, in data
15 requests that they were intending to use the scenario B
16 cost, which was \$2.88 for -- as the value in the RCB
17 framework. When we recalculated things, the results, to
18 determine what's the next tranche, what's the cost of the
19 incremental costs of integration for the next tranche of
20 3,000 megawatts and calculated that through, it came to the
21 \$1.93 we're talking about.

22 So if you disregard all of our other
23 recommendations \$1.93 is better than the others, but I think
24 that there are other issues with the study that we would
25 like to see resolved before any integration cost number is

1 used. But I'll let staff kind of make the final word on
2 what gets used.

3 A (Witness Barber) We agree with Mr. Bower.

4 Q You agree to use it? Thanks.

5 A (Witness Barber) No. We agree with Mr. Bower.

6 Q I appreciate that. You're more comfortable
7 with \$1.93 than you were -- are with the other values. Is
8 that a fair statement?

9 A (Witness Bower) From the results of
10 the Astrape study, the \$1.93 is a more representative
11 result.

12 Q Okay. On page 13 of your testimony, you
13 recommend that a REC component be added to the RCB
14 framework, and you propose that a REC value be included
15 because it's a benefit of solar, not because it's a cost
16 that is avoided by purchasing solar electricity.

17 Is that a fair statement?

18 A (Witness Bower) Well, I think that it -- now
19 that the company is essentially selling RECs through some of
20 their renewable programs, it essentially is an avoided cost.
21 If the company has to get RECs in order to sell them to
22 two customers through their REC programs, then the RECs that
23 are generated by these resources are an avoided cost.

24 Q Okay. Is it staff's position that a REC
25 value should be included when the procurement includes

1 transfer of RECs to Georgia Power?

2 A (Witness Bower) Sorry. Can you repeat that?

3 Q Yes. I guess the question is: Would you
4 want to see the valuation of a REC be included only when
5 the REC is actually being transferred to Georgia Power in
6 a procurement?

7 In other words, if Georgia Power is purchasing
8 electricity, solar electricity doesn't get the RECs. The
9 REC value shouldn't be added to it, should it?

10 A (Witness Cook) No.

11 A (Witness Barber) No. That's correct. Yes.

12 Q All right. On page 18, lines 5 through 13,
13 you suggest that Georgia Power should use the ELCC, the
14 effective load carrying capability, to determine capacity
15 of value of renewable resources; right?

16 A (Witness Bower) That's correct.

17 Q Okay. You also suggest that the ELCC be
18 updated annually; right?

19 A (Witness Bower) That's correct.

20 Q Okay. What leads you to believe that the
21 ELCC would materially change between reserve margin
22 studies that are done by the company every three years?

23 A (Witness Bower) Well, I think that as
24 resources are brought online, as, you know, loads and load
25 forecasts change as additional, you know, weather years and

1 other additional input data is available, that that can
2 impact the ELCC results.

3 Q It could, but you're not -- I guess the
4 question is: There isn't a specific reason why you think
5 it needs to be updated annually; is that a fair statement?

6 A (Witness Bower) I think it's -- the
7 recommendation in part is to be consistent with industry
8 best practices which is generally annual updates to ELCC
9 studies.

10 Q Okay.

11 A (Witness Bower) In addition, I mean, we have
12 to be honest. The methodologies improve, you know, the
13 understanding of some of the models. There's always model
14 updates and that sort of thing. So analysis will improve
15 and be more accurate if it's updated more frequently.

16 Q I want to move a little bit later in your
17 testimony to procurements. You were generally supportive
18 of the utility scout procurements, but you did note on
19 pages 45 to 46 that you have concerns regarding the
20 viability and success of the RFP exclusive to
21 North Georgia.

22 Mr. Mahan asked you a number of questions on
23 that; right? So I want to direct your attention there. Do
24 you agree that geography can matter and that having
25 generation closer to load is beneficial?

1 A (Witness Cook) Yes. Absolutely. And I
2 would -- I would say that our position isn't against
3 north -- you know, northern-located solar, it's simply that
4 we would like it to compete against resources throughout the
5 state -- or throughout the region, really.

6 Q Do you agree that it's possible that if you
7 open the bidding to all locations in the state, you very
8 well may get only bids in south Georgia, which is -- or
9 the vast majority of the bids from south Georgia like
10 we've seen in a lot of our procurements?

11 A (Witness Cook) It's certainly a possibility,
12 yes.

13 Q And Mr. Mahan asked you a number of questions
14 about how you would actually in your proposal identify a
15 benefit that you would confer on south Georgia -- from
16 south Georgia bids onto north Georgia bids, and I'm not
17 really sure I fully understand exactly what you mean by
18 doing that. I mean transmission upgrades are unique to
19 each facility; right? Is that right?

20 A (Witness Cook) Yes. Specific transmission
21 upgrades for -- will be unique to each project that's
22 evaluated, yes. There -- given the probably limited number
23 of lines that connect north and south Georgia, there are
24 some commonalities. And specifically given the large number
25 of con- -- the large constraint between south and north,

1 there's certainly commonality between the needs of south
2 Georgia solar resources to supply load in the north.

3 Q I'm not sure I understood that last
4 statement.

5 What is the commonality of south Georgia
6 resources to supply north Georgia?

7 A (Witness Cook) There are certainly a limited
8 number of constraints between south and north Georgia. And
9 so if there's a lack of capacity to move power from south to
10 north Georgia, then there is a -- a limited number of
11 potential upgrades.

12 Q But you're talking about the major corridors
13 of south to north Georgia. But to determine costs for a
14 facility and how much it costs to interconnect to the
15 system and deliver power to the rest of the system, each
16 facility needs to be studied individually.

17 We've had quite a few discussions about that
18 over that last several months; right?

19 A (Witness Cook) Yes, certainly.

20 Q And so to identify any type of cost, you
21 would have to identify specific bids, you would have to
22 then verify or -- or study those costs, specifically those
23 bids, and then find a way to create some sort of benefit
24 that you just artificially confer, then, on north Georgia
25 bids.

1 Is that what staff's proposal is?

2 A (Witness Cook) That might be a better question
3 for John Chiles, but --

4 Q It was in your testimony. That's the only
5 reason I'm still asking you. Sorry.

6 A (Witness Cook) So I will state that we are --
7 like, staff is open to working with the company to develop
8 this -- you know, a plan for how to do this evaluation and
9 how to value specifically, but I think to the -- our general
10 point is that there should be a limited number of upgrades
11 needed that are commonly needed for south Georgia solar.

12 Q Okay.

13 A (Witness Cook) I'm sorry.

14 A (Witness Barber) No, I was just going to say
15 for us, you know, the -- it wasn't very clear in the
16 company's testimony exactly these issues. It surrounded
17 more around the retirements of the coal units in north
18 Georgia, which is not a 100 percent certain about what's
19 going to happen with that.

20 Plus, too, a lot of these projects are not
21 coming online until 2027. That's the proposal. And based
22 on just feedback we got from solar developers that north
23 Georgia's not really, I guess, made for a lot of these large
24 utility scale, we just don't really see it being very
25 successful.

1 And so, you know, will there be projects bid
2 in, I'm sure there are. We did look, and we can't remember
3 right off -- because I did get Tim to look to see an
4 interconnection queue projects that are there.

5 We just don't think we will get a
6 1,050-megawatts. So, in essence, you know, you could issue
7 it in north Georgia, would it be successful likely, in our
8 opinion, no.

9 Q Well, are you aware that Georgia Power
10 Company might not even be able to build the transmission
11 lines necessary to meet the required need dates for the
12 north Georgia RFP?

13 A (Witness Cook) I don't know that staff is
14 specifically aware of that. I don't believe that the
15 company's testimony was explicit about not being able to
16 hold another RFP without having significant delays.

17 Q All right. Let me ask it this way: If
18 Georgia Power was not able to build the infrastructure
19 necessary to support transmission coming from south
20 Georgia to north Georgia, that could delay the
21 procurements; right?

22 A (Witness Cook) Yes.

23 Q All right. Turning to page 49 of your
24 testimony, line 16 to 21, you recommend that all renewable
25 projects be operated with automated generation control, or

1 AGC, even renewable projects coupled with storage; right?

2 A (Witness Cook) Yes.

3 Q Okay. You also proposed that Georgia Power
4 develop additional use cases to evaluate renewable plus
5 storage; right?

6 A (Witness Cook) Yes.

7 Q Are you proposing a use case in which the
8 battery can be charged by power supplied by the grid or is
9 it limited to the solar facility? Being charged by the
10 solar facility? Sorry.

11 A (Witness Cook) If it were to be charged by the
12 grid, that would be a change to the way we do our
13 renewables, so that's not specifically what we're saying
14 here. It's more to provide AGC but still utilizing the
15 renewable energy.

16 Q And I think, Mr. Cook, that you would agree
17 that most solar-plus storage bids are constrained in the
18 flexibility of use if they're trying to get the benefit of
19 the ITC; right?

20 A (Witness Cook) Certainly, yes.

21 Q And stand-alone storage isn't constrained by
22 that ITC limitation, is it?

23 A (Witness Cook) No, it's not. But it also has
24 associated higher cost because it doesn't give the ITC at
25 all.

1 Q All right. Locational value. The locational
2 value study proposal is shared with staff prior to the
3 filing of the IRP; is that right?

4 A (Witness Barber) Yes, it was.

5 Q Okay. And staff provided feedback to the
6 company which was incorporated into the study proposal;
7 right?

8 A (Witness Barber) Yes.

9 Q You now recommend that study include an
10 assessment of economic congestion on the system; right?

11 A (Witness Bower) Yes.

12 Q Would you agree that there are two generally
13 ways to avoid constraints on the system? One is through
14 coordinated transmission planning like Georgia Power tends
15 to do, or, two, by sending price signals to have
16 developers build generation in a specific location?

17 A (Witness Bower) Yes, I -- generally I would
18 agree with that. Those are the two ways to avoid economic
19 constraints.

20 Q Is it staff's position that the locational
21 value study should be used to develop the price signals
22 for studying generation?

23 A (Witness Bower) Yes. I think that would be
24 one of the uses of the study.

25 Q Okay. And as Mr. Mahan pointed out, that

1 would be like a -- it would be similar to an LMP, a
2 locational marginal pricing, approach that the regional
3 transmission market should use; right?

4 A (Witness Bower) Yeah. As I -- as I tried to
5 clarify with him, it's in that same ballpark. Thematically
6 it's similar yes.

7 Q Do you agree, though, Mr. Bower, that
8 coordinated long-term transmission planning does a better
9 job of keeping costs down and the lights on?

10 A (Witness Bower) I don't think I would agree
11 with that, no.

12 Q Markets like @IRCA and the California ISO use
13 locational marginal pricing, don't they?

14 A (Witness Bower) All ISO and RTO markets do,
15 yes.

16 Q Do you agree that Georgia's system of
17 coordinated generation and transmission planning as
18 overseen by this Commission has served customers well in
19 terms of pricing and reliability?

20 A (Witness Cook) Yes.

21 Q All right. Hosting capacity tool, page 55 of
22 your testimony. You recommend approval of the hosting
23 capacity tool but with several modifications; right?

24 A (Witness Cook) Yes.

25 Q First, you want it to be publicly

1 available; is that right?

2 A (Witness Cook) Yes.

3 Q Okay. Why do you think it should be publicly
4 available?

5 A (Witness Cook) I -- I think we believe that
6 there are benefits particularly for product developers to be
7 able to utilize the information like before RFPs began.
8 There's value to that information outside of RFPs as well.

9 Q But you agree that the program is intended to
10 benefit distributed generation procurement programs by
11 providing that information to developers; right?

12 A (Witness Barber) Yes. I think it's more of a
13 timing is to give them access to the tool quicker and
14 sooner.

15 A (Witness Cook) Yes.

16 Q So it would still be limited to developers
17 planning to participate in procurement programs, not
18 necessarily just generally publicly available; is that a
19 fair statement?

20 A (Witness Cook) It would depend on how you're
21 going to define who is a developer who may some day
22 participate in a program.

23 Q And that's a good point, Mr. Cook. And one
24 of the problems with making it publicly available, isn't
25 it, that it puts Georgia Power a little bit at a

1 disadvantage in pursuing customer choice projects?

2 A (Witness Cook) I don't know that I can speak to
3 that. I -- I will say, however, that Georgia Power
4 certainly wouldn't be the only utility that had a publically
5 available hosting capacity map. I think it's very common
6 across the country for these hosting capacity maps to be
7 publically available.

8 Q But is it common in Georgia with the
9 competition that Georgia Power faces with the other
10 utility providers in the state of Georgia?

11 A (Witness Cook) I'm not aware of any other
12 utilities within Georgia that has a hosting capacity map.

13 Q And I guess just in a more broader sense,
14 should Georgia Power be required to publicly provide
15 information that would put it as a competitive
16 disadvantage in the market?

17 A (Witness Cook) I don't know that I can answer
18 that.

19 A (Witness Barber) Yeah. I'm not sure either on
20 that, you know. For us it's more, for this tool is a
21 distribution system, per se.

22 A (Witness Cook) Yeah.

23 A (Witness Barber) I didn't really know customer
24 choice loads were that small. So I think we're looking at
25 it from a perspective of really access to solar developers

1 quicker than programs, because if they're going to go out,
2 find a location, they need time to do that.

3 Q You want the information in the tool updated,
4 I think you said, twice a year?

5 A (Witness Cook) Yes.

6 Q And validated through what you called a
7 robust process, and you also suggest additional
8 information you would like included; right?

9 A (Witness Cook) Yes.

10 Q Okay. Have you done any analysis to know how
11 much those recommendations would cost to implement?

12 A (Witness Cook) No. I -- I would -- I would
13 expect that a robust validation process be in place
14 regardless. But on the other two points, I -- we have not
15 done any analysis, and the company hasn't provided any costs
16 that I know of.

17 A (Witness Barber) We just -- we know that -- for
18 example, Dominion updates their tool quarterly, and so, you
19 know, we were looking -- we just feel annually is not really
20 going to be a good guidance, so twice a year should be a
21 minimum, but that was what we recommended.

22 A (Witness Cook) It's, again, looking at other
23 examples across the country and their average times over
24 which they're updated, and it's very common for them to be
25 updated more often than one year.

1 Q You also recommend that Georgia Power develop
2 a distribution interconnection cost matrix prior to the
3 next IRP; right?

4 A (Witness Cook) Yes.

5 Q Are you suggesting that this standardized
6 cost matrix be used as a substitute for an interconnection
7 study?

8 A (Witness Cook) No. No. That would be in
9 conjunction with.

10 Q Okay. Because hosting capacity will help
11 identify good feeders for developers; right?

12 A (Witness Cook) Yes.

13 Q One of the concerns that you have seems to be
14 that a developer might be charged for an interconnection
15 cost that was already planned on the system; right?

16 A (Witness Cook) Yes. And we provided an example
17 of hydraulic reclosers, which we also issued a data request
18 about. Specifically, the company was currently replacing
19 hydraulic reclosers with electronic reclosers and had a plan
20 to replace all of their hydraulic reclosers within -- I
21 believe by 2028. And so we give that as a specific example.

22 Q Right. But did you give an example of a
23 situation where it incurred that Georgia Power was
24 charging for a cost for a distribution upgrade that it was
25 already planning to do, not the general sense of what the

1 data request was, but to a specific developer?

2 A (Witness Cook) I can speak to the fact that
3 there were replacement costs for hydraulic reclosers
4 attributed to specific developers in the RFPs and that there
5 was already a preexisting plan by the company to replace all
6 hydraulic reclosers within the next few years.

7 Q Are you aware that generally -- and would the
8 hydraulic reclosers -- I think, the plan was over several
9 years; right?

10 A (Witness Cook) Yes.

11 Q Okay.

12 A It might have been eight or ten years for the
13 plan.

14 Q (Witness Cook) So a little bit more long-term
15 planning; right?

16 A (Witness Cook) Agreed. I believe it was much
17 shorter than the expected lifetime of those components.

18 Q But are you aware that Georgia Power
19 specifically reviewed each interconnection within the
20 DG programs to make sure that it's not charging for an
21 upgrade that it's already planning to do in the near term?

22 A (Witness Cook) I'm not aware that those were
23 captured in that.

24 Q Are you aware that they do that analysis?

25 A (Witness Cook) I'm aware that they do.

1 A (Witness Barber) No. I think that is, hence,
2 our recommendation, is that we want to sit down with the
3 company and walk through how all of this is done prior to
4 the next RF. So no, we're not aware that they do that.

5 Q Couple of questions on Community Solar. You
6 support the Community Solar program but don't support the
7 proposed increased rate; is that right?

8 A (Witness Cook) Yes.

9 Q And you were aware that the program is priced
10 at a rate Georgia Power believes is necessary to prevent a
11 cost shift to nonparticipants; is that right?

12 A (Witness Cook) That's what my understanding
13 is.

14 A (Witness Barber) Yes.

15 Q Are you aware that the proposed price
16 increase is based on projection of cost impacts not
17 related to the base rates such as fuel and NCCR?

18 A (Witness Cook) That's my understanding. Yeah.
19 I did review the -- there's a provided data request that
20 provided that.

21 Q So if the company has designed the price
22 based on these projections with the goal of preventing
23 cost shifting, is there really a reason to wait until the
24 base rate case if the cost change is not reliant upon any
25 base rate increases?

1 A (Witness Barber) Well, staff asked the data
2 what -- request, and the company stated that these rates
3 could change in their upcoming rate case. So for us, from a
4 policy side, we didn't take a position on whether we want to
5 keep Community Solar priced this way because it hasn't been
6 successful, so we're, like, saying that the rate should be
7 addressed in the upcoming rate case.

8 Q Even though the cost factors that are driving
9 increase don't really relate to the base rate case?

10 A (Witness Barber) Yes. Because --

11 A (Witness Cook) It is a tariff.

12 A (Witness Barber) Well, it's a rate on a tariff
13 that we normally address in rate cases.

14 Q Staff hasn't undertaken -- has not undertaken
15 any analysis to disprove Georgia Power's belief that
16 there's a cost shift that occurs if a price increase is
17 not instituted, has it?

18 A (Witness Cook) No.

19 A (Witness Barber) No.

20 A (Witness Cook) No. We're not disputing that.

21 Q All right. The tall wind demonstration
22 project, you support it but believe costs should be
23 socialized among all the operating companies; right?

24 A (Witness Cook) Yes.

25 A (Witness Barber) Right.

1 A (Witness Cook) That's what we're --

2 Q Now, the tall wind project is to be built in
3 Georgia; right?

4 A (Witness Barber) Yes.

5 A (Witness Cook) Yes.

6 Q And the energy will serve Georgia Power
7 customers; right?

8 A (Witness Cook) Yes.

9 A (Witness Barber) Yes.

10 Q And the investment will benefit Georgia
11 through increased tax structure; right?

12 A (Witness Cook) Yes.

13 Q Does staff believe it's appropriate to charge
14 customers in Alabama or Mississippi to build generation in
15 Georgia?

16 A (Witness Barber) Well, it's our position it's
17 research that those companies all could benefit from, so
18 there should be a share of that research cost.

19 Q Would staff support a request that Georgia
20 Power customers pay for generation built in Alabama or
21 Mississippi along these same lines?

22 A (Witness Cook) I think the point here is that
23 it's a pilot project that is specifically above avoided
24 costs for the sake of research. So if the benefits accrue,
25 I can't speak to whether or not -- I don't know that our

1 specific panel would be the one that would recommend
2 approval of that -- of those costs or not.

3 A (Witness Barber) yeah. It may have been Ralph
4 Smith and Trokey, Rob Trokey's panel that was just up that
5 talks about the cost allocation part.

6 Q Well, you talk about the cost allocation part
7 for the tall wind project, too.

8 A (Witness Barber) Yes.

9 Q I'm asking --

10 A (Witness Barber) We do feel that it should be
11 shared. It's research.

12 Q And I understand. And if this was located in
13 the state of Alabama, would you also be opining that the
14 cost should be shared by your power customers?

15 A (Witness Barber) Well, if you brought it before
16 the Commission and we were going to get a benefit from it,
17 possibly.

18 A (Witness Cook) That research for us, yes.

19 MR. HEWITSON: Thank you. I appreciate your
20 time.

21 MADAM CHAIR PRIDEMORE: Redirect?

22 REDIRECT EXAMINATION

23 BY MR. THOMAS:

24 Q Panel, you were asked a few questions about
25 the additional sum. Am I correct that your recommendation

1 is just to keep the status quo in place?

2 A (Witness Barber) Yes. That's correct.

3 Q And can you please explain to the Commission
4 why you think the status quo is an adequate incentive?

5 A (Witness Barber) Because it shares the
6 projected long-term savings between the company and
7 customers instead of just a per kW basis.

8 Q And Mr. Hewitson asked you a few questions
9 around the RCB framework and pointed out that staff had
10 questions about the company's modeling but did not do
11 their own modeling.

12 Does staff believe that it is possible to have
13 valid concerns with the company's modeling even though they
14 have not done their own?

15 A (Witness Bower) Yes, sir.

16 Q Couple of the questions concerning utility
17 scale procurement from North Georgia. You've got
18 questions around why staff wanted to open up the RFP to
19 all regions and have as, I think you put it, the regions
20 compete. Staff conceded that a risk exists that all the
21 bids might come from south Georgia.

22 Can you explain to the Commission that, even
23 with that risk, why staff supports opening it up?

24 A (Witness Cook) I believe in that case where you
25 really don't get a response from North Georgia you were

1 likely to not get a good response from North Georgia. So
2 that would have been -- it would have resulted in a failed
3 RFP even in that case. And in that case, it also indicates
4 that South Georgia resources were, in fact, the most
5 economic.

6 A (Witness Barber) Yeah. And I just want to add
7 that the current projections is that the second part of the
8 utility scale RFP would not go out until 2025. So that is,
9 you know -- the original one's issued next year, and we
10 only -- and the company only got half or not even half.
11 That's two additional years they're going to have to wait
12 until additional renewables are procured.

13 Q And transmission upgrades necessitated by
14 solar facility in South Georgia serving customers in
15 North Georgia could also be used by other facilities in
16 South Georgia for the same purpose; right?

17 A (Witness Cook) Certainly. Yeah.

18 MR. THOMAS: That's all the redirect questions
19 I have. I would ask that the panel be excused and
20 that Staff Exhibits 33 through 54 be entered into the
21 record.

22 MADAM CHAIR PRIDEMORE: So moved. So marked.

23 (Staff Exhibits 33-54 were admitted into
24 evidence.)

25 MADAM CHAIR PRIDEMORE: Okay. We're going to

1 take a hard stop today at 4:45 to allow people who
2 have not voted and exercise their right to vote go
3 vote today. Polls are open until 7:00.

4 So while we let this witness panel exit, we can
5 go ahead and ask for Mr. Alvarez, and Mr. Stephens,
6 who is going to join us remotely. And we will see
7 how far we get today.

8 MADAM CHAIR PRIDEMORE: Okay, Mr. Thomas.

9 MR. THOMAS: Thank you. Okay. Madam Chair, at
10 this time I call Paul Alvarez and Dennis Stephens to
11 the stand.

12 Thereupon,

13 PAUL ALVAREZ,
14 DENNIS STEPHENS,
15 having been duly sworn, testified as follows:

16 DIRECT EXAMINATION

17 BY MR. THOMAS:

18 Q Mr. Alvarez, for the record, can you please
19 state your name, by whom you are employed, and your
20 responsibilities?

21 A (Witness Alvarez) Paul Alvarez. I work for the
22 Wired Group.

23 Q And what are your responsibilities?

24 A (Witness Alvarez) I lead the Wired Group, a
25 Small consulting firm that specializes in distribution
business optimization.

1 Q Mr. Stephens, same question.

2 A (Witness Stephens) My name is Dennis Stephens,
3 and I am an independent consultant with the Wired Group.

4 Q And on May 6 of this year, did you file or
5 cause to be prefiled 23 pages of testimony in
6 question-and-answer format along with eight exhibits
7 marked as Exhibit PJA 1 and PA/DS 1 through 7?

8 A (Witness Alvarez) We did.

9 Q And do you have any corrections you need to
10 make to your prefiled testimony or exhibits at this time?

11 A (Witness Alvarez) We do not.

12 Q And if I were to ask you the same questions
13 under oath today, would your answers be the same?

14 A (Witness Alvarez) They would.

15 A (Witness Stephens) Yes, they would.

16 MR. THOMAS: I'd like to mark these exhibits as
17 Staff Exhibits 54 [sic] through 63 [sic].

18 And Madam Chair, at this time the court
19 reporter has been provided with a copy of the
20 prefiled direct testimony, and I would ask that the
21 direct testimony be copied into the record as if
22 given here today orally.

23 MADAM CHAIR PRIDEMORE: So marked. So moved.

24 (The documents referred to were marked for
25 identification as Staff's Exhibits 55-62.)

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1 (Whereupon, the prefiled direct testimonies
2 of Mr. Alvarez and Mr. Stephens follows:)

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I. INTRODUCTIONS AND PREVIEW

Q. MR. ALVAREZ, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul J. Alvarez. My business address is Wired Group, P.O. Box 620756, Littleton, Colorado 80162.

Q. WHAT IS YOUR OCCUPATION?

A. I lead the Wired Group, a small consultancy specializing in distribution utility planning, investment, operations, and performance.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit PJA-1. This exhibit summarizes my regulatory experience and qualifications.

Q. MR. STEPHENS, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis Stephens. My business address is 1153 Bergen Parkway, Suite 130, Evergreen, CO 80439.

Q. WHAT IS YOUR OCCUPATION?

A. I am an independent consultant specializing in utility distribution planning, investment, operations, asset management, reliability, safety, and performance. I frequently work for the Wired Group in support of the firm's clients.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit DS-1. This exhibit summarizes my regulatory experience and qualifications.

1 **Q. ON WHOSE BEHALF ARE YOU APPEARING?**

2 A. We are testifying on behalf of the Georgia Public Service Commission ("PSC" or
3 "Commission") Public Interest Advocacy Staff ("Staff").
4

5 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

6 A. The purpose of our testimony is to address the portions of the Georgia Power Company
7 ("Georgia Power" or "Company") Integrated Resource Plan ("IRP") which have
8 implications for the Company's distribution business.
9

10 In Section II, we explain why the PSC should reject Georgia Power's proposals for two
11 new distributed energy resource (DER) customer programs.
12

13 In Section III, we explain why the PSC should reduce the number of locations for the
14 Company's proposed DER pilots from seven locations to two.
15

16 In Section IV, we describe our concerns regarding Georgia Power's substation capacity
17 upgrade practices, and recommend the Commission review capacity upgrade practices
18 from utilities in multiple states for comparison to the Company's practices.
19

20 In Section V, we describe our concerns regarding dramatic increases in Georgia Power
21 distribution grid investment in recent years.
22

23 We summarize our testimony and recommendations in each of these areas in Section VI.
24

25 **Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?**

26 A. Yes. In addition to our qualifications, which are in Exhibit PJA-1 and DS-1, respectively,
27 we have attached Exhibits PA/DS-2 through PA/DS-8 which contain responses to
28 discovery referenced in our testimony.

1
2 **II. THE PSC SHOULD REJECT GPC PROPOSALS FOR NEW DER CUSTOMER**
3 **PROGRAMS**
4

5 **Q. PLEASE SUMMARIZE GEORGIA POWER'S PROPOSED NEW DER**
6 **CUSTOMER PROGRAMS.**

7 A. Georgia Power is proposing two new DER customer programs as described in proposed
8 optional tariffs RAST-1 and DRC-1.¹ RAST-1, the "Resiliency Asset Service Tariff",
9 involves Georgia Power's ownership, as rate-based assets, of distributed energy resources
10 ("DER") located on commercial and industrial ("C&I") customers' premises, *behind those*
11 *customers' meters*.² DER could include solar panels, batteries, or fossil-fueled generators.
12 The DER are intended to provide power to participating customers in the event of grid
13 service interruptions. The Company proposes that participating customers pay the revenue
14 requirements on the DER assets installed on those customers' premises, plus ongoing asset
15 operations and maintenance expenses and any fuel costs.
16

17 Proposed tariff DRC-1, the "DER Demand Response Tariff", is optionally available to C&I
18 customers participating in the RAST-1 tariff. DRC-1 pays participating customers a credit
19 in exchange for allowing Georgia Power to employ the DER up to 200 hours per year
20 during times of tight energy supplies or high energy demand, for example, on cold weekday
21 winter mornings or hot weekday summer afternoons.
22

23 **Q. WHAT IS GEORGIA POWER'S RATIONALE FOR OFFERING THESE NEW**
24 **DER PROGRAMS?**

25 A. The Company claims its RAST-1 program/tariff will meet C&I customers' needs for

¹ Georgia Power Integrated Resource Plan, Section 9.2, "DER Customer Program". Page 9-61.

² Typically the meter represents the demarcation between Company and customer property and responsibility for certain events and cost. By placing assets on customers side of the meter may expose the Company to liability and / or cost that could be passed on to other ratepayers.

1 reliability during service interruptions, and that the DRC-1 program/tariff will benefit all
2 customers by reducing demand on the Company's system (demand response). The
3 Company also claims the DER Customer Programs will "provide the Company with
4 valuable knowledge and experience in the operations of behind-the-meter DER."³
5

6 **Q. DOESN'T GEORGIA POWER ALREADY OFFER DEMAND RESPONSE**
7 **PROGRAMS TO C&I CUSTOMERS?**

8 A. Yes. Optional tariff DPEC-4 is available to large C&I customers that can deliver 200kW
9 or more of demand reduction upon Georgia Power's request. The DPEC-4 tariff offers
10 participating customers a \$0.1175 per kWh credit for energy reductions during demand
11 response events, as well as a credit of \$1.75 per kW for demand a customer makes available
12 (regardless of whether or not any demand response events are called).
13

14 **Q. DOES TARIFF DPEC-4 SPECIFY HOW A PARTICIPATING CUSTOMER MUST**
15 **PROVIDE THE LEVEL OF DEMAND RESPONSE THE CUSTOMER HAS**
16 **COMMITTED TO DELIVERING TO GEORGIA POWER UPON REQUEST?**

17 A. No. Presumably, a customer participating in DPEC-4 could provide the demand response
18 by reducing its loads, or by operating its DER, or by some combination of the two.
19

20 **Q. DO SOME OF GEORGIA POWER'S C&I CUSTOMERS ALREADY OWN**
21 **DISTRIBUTED ENERGY RESOURCES?**

22 A. Yes.
23

24 **Q. HOW DID GEORGIA POWER C&I CUSTOMERS WITH DER INSTALL THE**
25 **DER?**

26 A. There is an entire industry of consultants, engineering firms, DER installers, DER
27 manufacturers, and other companies competing in an unregulated market to deliver DER

³ Ibid, Page 9-62.

1 assets, capabilities, services, and financing options to Georgia Power's C&I customers.
2 The Company's C&I customers interested in installing DER have many options from
3 which they can choose today.
4

5 **Q. WHAT ARE YOUR CONCERNS REGARDING GEORGIA POWER'S**
6 **PROPOSED DER CUSTOMER TARIFFS/PROGRAMS?**

7 A. We have two significant concerns, either of which should be enough to cause the
8 Commission to reject the DER Customer tariffs/programs. The first concern is that
9 allowing Georgia Power to own rate-based assets located on customer premises increases
10 risk and cost to non-participating customers. The second concern is that Georgia Power's
11 status as a large company authorized to operate as a monopoly confers unfair advantages
12 over competitors already operating in a thriving market. If the Commission were to
13 authorize these tariffs/programs, the competitors and the market could be harmed,
14 potentially reducing customer choice and ultimately resulting in higher prices to customers
15 considering DER installation over time. Thus, Georgia Power's proposed DER Customer
16 Tariffs/Programs are not in the public's interest nor the State of Georgia's interest.
17

18 **Q. PLEASE EXPLAIN HOW ALLOWING GEORGIA POWER TO OWN RATE-**
19 **BASED ASSETS LOCATED ON CUSTOMER PREMISES BEHIND THE METER**
20 **INCREASES RISK AND COST TO NON-PARTICIPATING CUSTOMERS.**

21 A. If Georgia Power were to own rate-based assets located on customer premises behind the
22 meter, non-participating customer risk and cost increase in at least three ways: bad debt
23 risk, program cost subsidization risk, and program cost-effectiveness risk.
24

25 **Q. PLEASE EXPLAIN HOW ALLOWING GEORGIA POWER TO OWN RATE-**
26 **BASED ASSETS LOCATED ON CUSTOMER PREMISES INCREASES BAD**
27 **DEBT RISK.**

28 A. When Georgia Power invests in new grid equipment, the investments generally benefit all

1 customers. Even in instances in which investments are made to accommodate a new
2 customer, or to accommodate significant growth in load from an existing customer, the
3 investments are designed to be paid off over time through energy sales. Even if such
4 customers were to become insolvent, or to leave Georgia Power's service area, a new
5 customer is likely to take the old customer's place, and to continue paying off any
6 investments made to accommodate the original customer's new operations.

7
8 The same cannot be said for 'behind the meter' ("BTM") assets. A new customer might
9 not want to continue making payments on BTM assets, and it could be difficult for Georgia
10 Power to force the new customer to do so. Further, as the DER equipment will consist of
11 fixed assets with twenty- to thirty-year depreciation periods, the abandonment by
12 participating customers is not a far-fetched concern, but is likely to be a fairly common
13 occurrence. Relatively few customers can be expected to remain in the same location for
14 twenty or thirty years, and it can be very costly if not impossible to relocate DER. In cases
15 in which a customer participating in the RAST-1 tariff becomes insolvent, or leaves
16 Georgia Power's service area, non-participating customers will be left to pay for the rate-
17 based DER equipment.

18
19 **Q. BUT THE DER ASSETS WILL REMAIN IN PLACE IN EVENT OF CUSTOMER**
20 **DEFAULT, CORRECT? GEORGIA POWER COULD STILL USE THE DER**
21 **ASSETS TO RELIEVE SUPPLY CONSTRAINTS?**

22 **A.** We imagine Georgia Power could still use the DER, but at what cost? Surely large peaking
23 plants common in the Company's generation portfolio could be employed to relieve supply
24 constraints at a much lower cost than multiple relatively small, customer-sited DER
25 scattered around the Company's service area. This brings us to our second concern:
26 Program Cost Subsidization risk.

27
28 Relatively small DER assets specific to particular customers are certain to be more costly

1 to operate and maintain than centralized, utility-scale peaking plants, and this is certainly
2 part of our Program Cost Subsidization risk concern. We are also concerned that the
3 Company could easily pull engineering and field resources away from the distribution
4 business from time to time to meet the needs of the DER Customer Program. Accounting
5 project codes on employee time sheets can help ensure appropriate cost assignment, but
6 such arrangements are not fool-proof. Thus, non-participating customers could end up
7 subsidizing customers participating in the DER customer program, even when customers
8 participating in RAST-1 fulfill all payment responsibilities over a twenty- or thirty-year
9 period. We also note that the large account management team that non-participating C&I
10 customers currently pay for in rates would likely be used to promote the RAST-1 tariff.
11 Thus, RAST-1/DRC-1 sales and marketing expense constitutes another likely source of
12 subsidization from non-participating customers to C&I customers participating in the
13 RAST-1/DRC tariffs.

14
15 **Q. DOES THIS CONSTITUTE YOUR OVERALL COST-EFFECTIVENESS**
16 **CONCERN?**

17 **A.** In part, but not completely. We noted earlier that Georgia Power already offers a demand
18 response tariff, DPEC-4. Presumably, the DPEC-4 tariff already represents a cost-effective
19 approach to securing C&I customer assistance in reducing demand when energy supplies
20 are tight. Presuming further, C&I customers participating in the DPEC-4 tariff are already
21 making the best decisions for their businesses regarding how best to respond to Georgia
22 Power's calls for demand reductions during times of tight energy supply. These C&I
23 customers can reduce demand upon Georgia Power's request as required by DPEC-4 by
24 either cutting back on their operations, or by installing and operating DER, or through some
25 combination of the two. Through the RAST-1 tariff, Georgia Power offers a program which
26 might be attractive to some C&I customers, but which comes at a greater cost to non-
27 participating customers than the existing DPEC-4 tariff due to the bad debt and
28 subsidization risks described above. We do not perceive that the RAST-1 tariff combined

1 with the DRC-1 tariff (combined, the "DER Customer Program") can be less costly for
2 non-participating customers than the existing DPEC-4 tariff, which accomplishes precisely
3 the same objectives as the DER Customer Program.
4

5 **Q. PLEASE EXPLAIN HOW GEORGIA POWER'S PROPOSED DER CUSTOMER**
6 **PROGRAM GRANTS UNFAIR ADVANTAGES OVER COMPETITORS**
7 **ALREADY OPERATING IN A THRIVING MARKET, THUS HARMING THAT**
8 **MARKET.**

9 A. Georgia Power's proposed offering of the proposed DER Customer Program as a regulated
10 service entails multiple advantages over competitors already operating in the DER market.
11 Over time, these advantages could drive existing competitors out of the DER market,
12 thereby reducing C&I customer DER choices, expanding Georgia Power's monopoly into
13 the DER business, and providing the Company with pricing and market power. This would
14 be detrimental to public interest and the State of Georgia's interests.
15

16 **Q. WHAT ARE THE ADVANTAGES GEORGIA POWER WOULD HAVE OVER**
17 **DER COMPETITORS IF THE COMMISSION WERE TO APPROVE THE**
18 **COMPANY'S PROPOSAL FOR THE DER CUSTOMER PROGRAMS?**

19 A. There are multiple financing, cost, and marketing advantages an incumbent monopoly such
20 as Georgia Power could wield over existing DER competitors. If the Commission were to
21 approve the DER Customer Program, including tariffs RAST-1 and DRC-1, as regulated
22 services, these advantages would threaten the viability of the existing market and suppliers,
23 and represent an unwarranted extension of Georgia Power's monopoly.
24

25 **Q. WHAT FINANCING ADVANTAGES WOULD GEORGIA POWER HAVE OVER**
26 **EXISTING DER COMPETITORS?**

27 A. The ability for Georgia Power to add the DER costs to C&I customer bills via the RAST-
28 1 tariff constitutes a significant advantage not available to other DER providers. Let us

1 examine the situation from the perspective of a C&I customer considering DER
2 installation. With Georgia Power's RAST-1 tariff, the C&I customer gets new DER
3 installed with no capital expenditure, and likely without any kind of internal capital
4 expenditure review (recall that Georgia Power proposes to own DER equipment as a rate-
5 based asset). The C&I customer would compare the RAST-1 alternative available from
6 Georgia Power to purchasing DER from an existing competitor. To purchase DER from an
7 existing DER competitor, the C&I customer would need to make a large financial
8 commitment, and would typically need to secure financing for the project. Thus, the effort
9 and risk a C&I customer would need to undertake to work with an existing DER competitor
10 to install DER would be significantly greater than the effort and risk required for the C&I
11 customer to accommodate a small increase in its operating budget in the form of a RAST-
12 1 tariff item on its monthly Georgia Power bill. It is difficult to over-estimate the advantage
13 of on-bill financing the RAST-1 tariff represents over existing DER competitors without
14 such an option.
15

16 **Q. WHAT COST ADVANTAGES WOULD GEORGIA POWER HAVE?**

17 A. Perhaps the most significant cost advantage is in the financing rate. While a C&I customer
18 would rely on its own debt interest rate or cost-of-capital hurdles when deciding to
19 purchase DER from an existing DER competitor, Georgia Power proposes to calculate
20 payments under the RAST-1 tariff using its existing revenue requirements.⁴ As Georgia
21 Power's cost of debt and equity capital, used to calculate DER revenue requirements to
22 participating customers, is most likely lower than almost every one of its C&I customers,
23 this provides Georgia Power and its RAST-1 tariff a significant cost advantage over DER
24 a C&I customer might otherwise purchase from an existing DER competitor.
25

26 **Q. ARE THERE OTHER COST ADVANTAGES GEORGIA POWER HAS THAT**
27 **WOULD BE UNFAIR RELATIVE TO EXISTING DER COMPETITORS?**

⁴ Direct Testimony of Francisco Valle, Andy Phillips, Jeff Smith, and Lee Evans. March 11, 2022. Page 24 at 23.

1 A. Yes. Primary among these is "economy of scale" in procurement. Georgia Power could
2 consolidate its DER purchases for multiple RAST-1 customers into orders to its existing
3 suppliers that provide equipment to the regulated business, from solar panels and batteries
4 to fossil-fueled generators, conductors, circuit breakers, and so forth. This is a significant
5 cost advantage Georgia Power would enjoy that is not available to existing DER
6 competitors.

7
8 In addition, the items identified above as risk and cost subsidies from non-participating
9 customers serve as cost reductions available to Georgia Power that are not available to
10 existing DER competitors. For example, the fact that Georgia Power proposes to own the
11 DER as a rate-based asset eliminates RAST-1-related bad debt expenses. If a C&I customer
12 becomes insolvent or moves operations out of Georgia Power's service area, non-
13 participating customers, not Georgia Power, will be exposed to the bad debt risk. Thus,
14 Georgia Power need not price bad debt expense into the bill increments it offers to C&I
15 customers under RAST-1. Such a cost advantage will not be available to existing DER
16 competitors, who must price bad debt risk into their bids to design, build, and maintain
17 DER for C&I businesses.

18
19 Another non-participating customer subsidy which constitutes an unfair cost advantage for
20 Georgia Power over existing DER competitors is the ability to pull existing engineering
21 and operations labor that already exists in Georgia Power's labor pool to work on RAST-
22 1 as needed. While such resources constitute a variable cost to Georgia Power's RAST-1
23 program, they constitute a fixed cost to existing DER competitors. Thus, while existing
24 DER competitors must employ these resources full-time in their businesses, at considerable
25 cost as existing DER competitors' business revenues rise and fall, Georgia Power has no
26 such concerns. When RAST-1 labor needs fall from time to time, Georgia Power has no
27 fixed costs to cover; the Company simply applies those resources to distribution grid
28 business needs. DER competitors have no such advantage. Further, this same advantage

1 applies to Georgia Power's RAST-1 sales efforts, in the form of the Company's large
2 account management team, whose costs are covered by the distribution business when not
3 developing RAST-1 opportunities. Unlike Georgia Power, DER competitors must cover
4 their own sales and marketing expenses as a fixed cost.

5
6 **Q. GEORGIA POWER'S LARGE ACCOUNT MANAGEMENT TEAM SERVES AS**
7 **A SALES AND MARKETING ADVANTAGE OVER EXISTING DER**
8 **COMPETITORS, CORRECT?**

9 A. Correct. Georgia Power's existing large account management team is employed by the
10 Company specifically to build strong relationships between the Company and its C&I
11 customers. That these C&I customer relationships exist as a spring-board for Georgia
12 Power's DER Customer Program, whereas existing DER competitors must build and pay
13 for C&I customer relationships through sales forces dedicated to the DER business,
14 constitutes yet another unfair advantage for Georgia Power's DER Customer Program.

15
16 **Q. WHAT ARE GEORGIA POWER'S POSITIONS REGARDING YOUR**
17 **CONCERNS?**

18 A. During the Company's Direct Hearings, Company Witness Evans disagreed that non-
19 participating customers would subsidize participating customers. He also disagreed that the
20 Company's proposed DER Customer Program offered Georgia Power any advantages over
21 existing DER providers. Mr. Evans stated that other utilities were offering different types
22 of resiliency programs to different types of customers. He also stated that because Georgia
23 Power would own and maintain the DER at customer locations, the DER are more likely
24 to be available when called upon under the DRC-1 tariff relative to the existing DPEC-4
25 tariff.⁵

26
27 **Q. WHAT IS YOUR RESPONSE TO GEORGIA POWER'S POSITIONS?**

⁵ Hearing testimony, Volume II, pages 621-634.

1 A. Per our testimony above, the potential for non-participating customers to subsidize
2 participating customers is significant. Furthermore, per our testimony above, the design of
3 the DER Customer Program combined with the Company's position as a large incumbent
4 monopoly do indeed confer significant advantages for Georgia Power over existing DER
5 competitors. We disagree with Mr. Evans on these points.

6
7 Regarding Mr. Evans's representation that other utilities offer resiliency programs to
8 different customer types, we are not aware of any such programs that allow regulated
9 utilities to own behind-the-meter DER equipment as rate-based assets. We believe the
10 absence of such programs is likely due to regulators' concerns regarding cost and risk
11 subsidization by non-participating customers, by concerns regarding unfair competitive
12 advantages conferred to incumbent monopolies in such situations, and by concerns
13 regarding unwarranted expansion of an incumbent's monopoly into competitive markets.

14
15 Regarding Mr. Evans's contention that DER assets owned and maintained by Georgia
16 Power are more likely to be available when called upon under proposed tariff DRC-1 than
17 existing tariff DPEC-4, we disagree. We note that the DPEC-4 tariff already includes
18 penalties charged to participating customers for failing to deliver agreed-upon reductions
19 in energy use when called upon. Presumably, these penalties are charged to DPEC-4
20 customers irrespective of a DPEC-4 customers' anticipated response method, be it to
21 reduce energy used in operations or to operate any DER the DPEC-4 customer might own,
22 or some combination. Thus, mechanisms to promote compliance with Georgia Power's
23 calls to reduce demand are already in place by way of the existing tariff. Furthermore, even
24 if Mr. Evans were correct on this issue, the difference in demand response compliance
25 between DPEC-4 and DRC-1 would have to be weighed against the significant non-
26 participant subsidization and market destruction issues presented by the DER Customer
27 Program (RAST-1 and DRC-1 tariffs). It is our opinion that any small demand response
28 compliance improvement would be far outweighed by these detrimental aspects of the DER

1 Customer Program Georgia Power has proposed.

2
3 **Q. GIVEN YOUR TESTIMONY, WHAT IS YOUR POSITION ON THE RAST-1 AND**
4 **DRC-1 TARIFFS GEORGIA POWER HAS PROPOSED, AND WHAT ARE YOUR**
5 **CORRESPONDING RECOMMENDATIONS TO THE COMMISSION?**

6 **A.** Given current technology and cost trends for DER, including PV solar and battery storage
7 as well as other types of back-up power supplies, we believe the options for electricity
8 customers in Georgia to pursue DER, for reasons of resilience or economics, will continue
9 to grow in the future. Our position is that it is in the public interest, and in the best interest
10 of the State of Georgia, that a competitive market for DER be preserved. We believe a
11 competitive market for DER will lead to the greatest breadth of customer DER choices and
12 the greatest development of Georgia's economy, both as to the further development of the
13 DER industry in Georgia as well as the improved competitiveness of Georgia businesses
14 and industries that choose to deploy DER.

15
16 Unfortunately, Georgia Power's proposed RAST-1 and DRC-1 tariffs are antithetical to
17 these outcomes. Not only does the resulting DER Customer Program provide substantial
18 risks to and subsidies from non-participating customers in favor of participating customers,
19 Commission approval will confer significant competitive advantages to Georgia Power
20 over existing DER service providers. These advantages will ultimately harm the DER
21 market in Georgia with corresponding impacts to customer choice and Georgia's economic
22 development. We also note that the proposed tariffs are unnecessary, as the existing DPEC-
23 4 tariffs provide customer incentives for demand response, customer flexibility as to how
24 that demand response is secured, and customer penalties for failing to deliver promised
25 demand response levels.

26
27 Finally, we note that the State authorizes monopolies only when it is in the public interest
28 to do so. As an example, because it would be more expensive to build more than one set of

1 electric wires to power every home in a state, customers are better off if just one system is
2 built and maintained, as long as the company that runs the system is prohibited by
3 regulators from using its monopoly power to drive up prices. This type of "natural
4 monopoly" simply does not apply to DER, and thus any advantages bestowed to an
5 incumbent monopoly related to this market likely constitutes a violation of State law.⁶
6

7 **Q. IF THE COMMISSION REJECTS GEORGIA POWER'S DER CUSTOMER**
8 **PROGRAM, WOULD THIS PREVENT GEORGIA BUSINESSES FROM**
9 **BENEFITTING FROM GEORGIA POWER'S EXPERTISE?**

10 Not necessarily. If Georgia Power has an interest in the DER market, it can always pursue
11 its interest through an unregulated subsidiary not subject to Commission jurisdiction. The
12 Commission should not advantage the regulated utility in what is otherwise a competitive
13 market, nor should it jump-start Georgia Power's ambitions in the DER market on the
14 backs of ratepayers. For all these reasons, we recommend the Commission reject Georgia
15 Power's proposals to introduce RAST-1 and DRC-1. It is in the State's interest, and the
16 public interest, for the Commission to reject these proposed tariffs.
17

18 **III. THE PSC SHOULD REDUCE THE NUMBER OF DER PILOT LOCATIONS**
19 **FROM SEVEN TO TWO**
20

21 **Q. PLEASE SUMMARIZE GEORGIA POWER'S DER PILOT PROPOSAL.**

22 **A.** The Company proposes to implement seven DER pilots in various locations around the
23 state at an estimated cost of \$33 million. The Company proposes to learn how DER might
24 be able to 1) avoid or defer the cost associated with increasing capacity to accommodate
25 growing loads (for example, the capacity of a substation or a circuit); 2) improve reliability

⁶ O.C.G.A. 10-1-394 (2010), subpart (a): "The administrator is authorized to adopt as substantive rules that prohibit specific acts or practices in violation of Code Section 10-1-393 those rules and regulations of the Federal Trade Commission interpreting Section 5(a)(1) of the Federal Trade Commission Act (15 U.S.C. Section 45(a)(1)), as from time to time amended."

1 in the event of a local service interruption (for example, operating DER to provide power
2 locally if service is interrupted); and 3) improve the ability to recover from a service
3 interruption (resilience).⁷ In addition, the Company's learning objectives include 1) To
4 gauge customer receptivity to the siting of DER; 2) to gain experience with DER operations
5 (in "islanded" mode, of the DER themselves, to develop best practices, and to identify
6 potential additional use cases); 3) to understand the impact of, or appropriate role for, PV
7 solar in such applications; and 4) to compare the cost of DER to the cost of capacity
8 increases that might otherwise be needed.⁸
9

10 **Q. What are your concerns regarding the Company's DER Pilot?**

11 A. First, we believe two locations will be sufficient to satisfy both the learning objectives the
12 Company describes in its IRP and the additional lessons the Company described in
13 discovery. The only additional lesson to be learned by a second pilot location is to compare
14 a pilot location with solar to a pilot location without solar. Second, at an average cost per
15 location of \$4.7 million, we do not believe any incremental experience the Company gains
16 through five additional pilot locations will be worth the incremental \$23.6 million cost.
17 Further, none of the seven locations Georgia Power is considering for DER pilots have any
18 apparent need for capacity increases.⁹ This means that none of the pilot locations offer any
19 potential for avoiding or deferring capital investments to increase capacity.
20

21 **Q. GIVEN YOUR TESTIMONY, WHAT IS YOUR POSITION ON THE COMPANY'S**
22 **PROPOSED DER PILOT, AND WHAT ARE YOUR CORRESPONDING**
23 **RECOMMENDATIONS TO THE COMMISSION?**

24 A. We agree that the Company could gain some valuable experience by conducting a DER
25 pilot. However, limiting DER pilot locations to two will provide almost as much experience

⁷ Georgia Power Integrated Resource Plan, Section 9.1, "Local Reliability and Constraints Pilot". Page 9-60.

⁸ Georgia Power response to STF-WG-2-1.

⁹ CONFIDENTIAL Georgia Power response to STF-WG-2-2 (a) and (b).

1 in the learning objectives the Company cites at a fraction of the cost of seven pilot
2 locations. Further, we note that none of the seven DER pilot locations offer any opportunity
3 to avoid or defer capital investments to increase capacity. As a result, we recommend the
4 Commission reduce the number of DER pilot locations from seven to two.

5
6 **IV. THE PSC SHOULD REVIEW TRANSMISSION AND DISTRIBUTION**
7 **CAPACITY UPGRADE PRACTICES FROM UTILITIES IN MULTIPLE**
8 **STATES FOR COMPARISON TO GEORGIA POWER'S PRACTICES**
9

10 **Q. WHAT DOES GEORGIA POWER'S INTEGRATED RESOURCE PLAN**
11 **PROPOSE REGARDING DISTRIBUTION SUBSTATION CAPACITY?**

12 A. Georgia Power proposes to upgrade the capacity of 21 distribution substations over the
13 next four years at a very significant cost.¹⁰
14

15 **Q. WHAT ARE YOUR CONCERNS REGARDING THE COMPANY'S PROPOSAL**
16 **TO INCREASE THE CAPCITY AT 21 DISTRIBUTION SUBSTATIONS?**

17 A. Upon review of information obtained in discovery, we find Georgia Power's capacity
18 increase practices to be too aggressive,¹¹ meaning that investments to increase capacity are
19 likely earlier than necessary on average. Further, we find very little evidence in Company
20 approved capital spending authorization packages that potentially less costly alternatives
21 (for example, adding distribution circuit capacity to allow for shifting circuits to banks with
22 capacity, or delaying capacity increases to observe more customer or developer behavior
23 before acting) have been adequately evaluated and/or exhausted.¹² Multiple "earlier than
24 necessary" capacity increase investments have a cumulative effect on rate base over time,
25 making it larger than necessary, and increasing customer rates earlier and to a greater

¹⁰ Georgia Power Integrated Resource Plan, Volume 3, Section F, "GPC Distribution Substation Projects & Forecast (Five-Year Loading Plan).

¹¹ CONFIDENTIAL Georgia Power responses to STF-WG-2-5 (b), (c), and (d), as provided in Attachments A1, A3, A4, C1, F1, H1, L1, N, P1, and S1.

¹² CONFIDENTIAL Georgia Power responses to STF-WG-2-5 (f), as provided in Attachments F1, J1, L1, N, and P1.

1 degree than necessary.

2
3 **Q. IN YOUR EXPERIENCE, WHAT TYPES OF DISTRIBUTION CAPACITY**
4 **UPGRADE PRACTICES HAVE YOU FOUND THAT RESTRAIN CAPITAL**
5 **EXPENDITURES WITHOUT UNDUE RISK THAT CAPACITY WILL BE**
6 **UNAVAILABLE WHEN NEEDED BY A CUSTOMER OR DEVELOPER?**

7 **A.** The first step should be to forecast load growth on each substation bank and compare the
8 forecast to each bank's rated capacity. We have found customer or developer assertions to
9 be less reliable than building permits when developing load forecasts. (Indeed, one of the
10 21 substation capacity increase projects included in the IRP has already been cancelled due
11 to a change in a customer's plans.)¹³ When a load forecast indicates a substation bank's
12 rated capacity will be exceeded in the next three years, the area planning engineer should
13 begin by considering alternatives to substation capacity additions, such as adding
14 distribution circuit capacity to allow for switching circuits to different banks with capacity,
15 or to allow more time to observe customer or developer behavior before determining that
16 a substation capacity addition is required. We note that a few utilities are even considering
17 substation-specific demand response programs. Only once all alternatives to investment
18 have been exhausted should planning begin on capacity increase step 3 -- engineering,
19 procurement, and construction -- such that the project can be completed within three years.

20
21 **Q. WOULD THE DISTRIBUTION CAPITAL EXPENDITURE CRITERIA LISTED**
22 **ABOVE PREVENT THE COMPANY FROM PROVIDING RELIABLE SERVICE?**

23 No. Though temporary exceedances of rated capacity are something to be avoided, it is not
24 appropriate to avoid such exceedances *at any cost*. Temporary exceedances of rated
25 capacity rarely result in service interruptions or equipment failures, as all substation
26 equipment is designed to accommodate significant load in excess of ratings for short
27 periods of time. These are called "Net Overload Limits" ("NOL"), and they are designed

¹³ Georgia Power response to STF-WG-2-5, Attachment E

specifically to extend the length of time required between substation capacity increase projects.

We find potential distribution capacity increase projects can be categorized as shown below. Only projects landing in the top right quadrant (tight capacity and moderate / high load growth) merit consideration for capacity increase. Even a substation at 95% of its rated capacity can carry on without a capacity upgrade for many years if load is falling, or flat, or growing very slowly.

		AVAILABLE CAPACITY	
		Plenty	Tight
LOAD GROWTH	Moderate to High		
	None to Low		

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S DISTRIBUTION SUBSTATION CAPACITY INCREASE PROPOSALS?

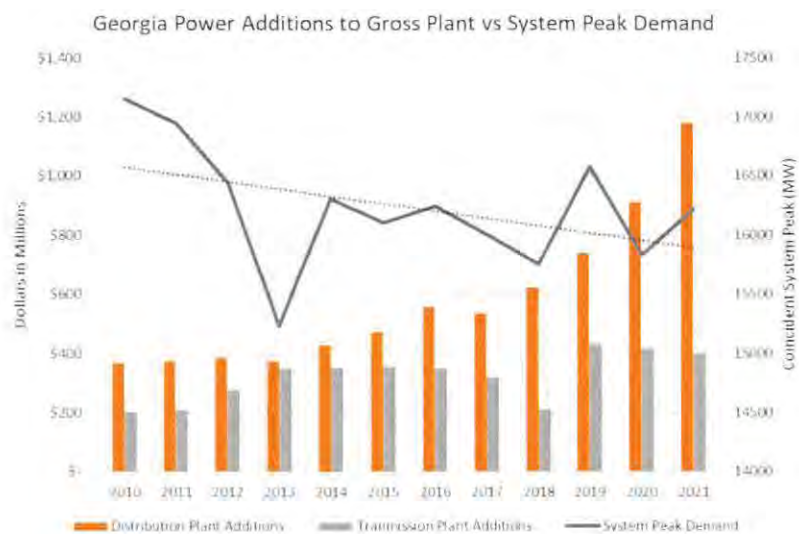
A. We do not presume to have sufficient understanding of the Company's grid, load forecasts, customer/developer plans, or capacity planning processes to recommend the Commission reject the Company's substation capacity increase proposals. Information asymmetry is a significant regulatory issue, and it cannot be resolved in the limited context of an IRP review. However, we have reviewed sufficient information for us to believe grid capacity planning may be too aggressive at Georgia Power, likely leading to earlier-than-necessary investments to increase grid capacity, and resulting in a larger-than-necessary rate base. To address this concern, we recommend the Commission review the capacity planning practices at multiple utilities, to include utilities without capital bias (co-operative and municipal utilities). In this manner, the Commission would be able to judge for itself the

degree to which capacity planning and investment practices at Georgia Power are appropriate.

V. THE PSC SHOULD BE CONCERNED ABOUT DRAMATIC INCREASES IN GEORGIA POWER'S DISTRIBUTION (AND TRANSMISSION) INVESTMENT LEVELS IN RECENT YEARS

Q. PLEASE DESCRIBE THE DRAMATIC INCREASE IN GEORGIA POWER'S DISTRIBUTION INVESTMENT LEVELS IN RECENT YEARS.

A. The figure below illustrates the dramatic increase in Georgia Power's distribution investment level in recent years.¹⁴ In 2021, Georgia Power's distribution investment was more than double the amount spent in 2017, and more than triple the amount spent as recently as 2013. Georgia Power's transmission investment in 2021 was almost double the amount spent as recently as 2018. If peak demand had been growing during this time, that would be one thing, but the figure below indicates this has not been the case.



¹⁴ Georgia Power's response to STF-WG-3-1(a).

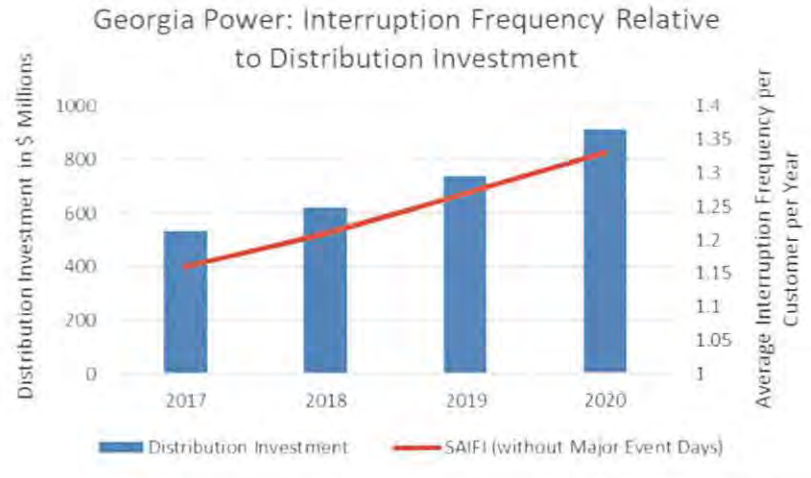
1
2 **Q. WHAT ARE YOUR CONCERNS REGARDING THESE DRAMATIC**
3 **INCREASES IN DISTRIBUTION AND TRANSMISSION INVESTMENT**
4 **LEVELS?**

5 A. Our overall concern is the rationale for such dramatic investment increases, and in
6 particular, what has changed to justify such increases. For example, has Georgia Power
7 service interruption frequency (once every 9 months per average customer in 2020) or
8 duration (142 minutes per interruption on average in 2020) suddenly become unacceptable?
9 (Energy Information Administration records indicate Georgia Power performance on both
10 measures is only slightly worse than the averages for U.S. for-profit utilities).¹⁵ Is there
11 some data which indicates that massive grid investments lead to reliability improvements?
12 FERC Form 1 data on both for-profit U.S. utilities as a group, and for Georgia Power
13 specifically, indicates that grid investment increases in recent years have not delivered
14 reliability improvements.¹⁶ Rather, Georgia Power service interruptions have increased
15 even as distribution investment has grown, as shown in the chart below. We note this
16 phenomenon has been observed nationwide by Lawrence Berkeley National Laboratory
17 research.¹⁷
18

¹⁵ All reliability data sourced from data submitted by investor-owned utilities to the U.S. Energy Information Administration on Form 861.

¹⁶ Distribution Investment data from response to STF-WG-3-1(a); SAIFI data submitted by Georgia Power to the U.S. Energy Administration Information on Form 861.

¹⁷ Larsen P et al. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Lawrence Berkeley National Laboratory. August, 2015. Page 37.



We also wonder how Georgia Power grid planning processes have changed to result in such investment increases, and how these process changes comport with traditional practices historically employed at Georgia Power and other utilities. To summarize, we are concerned that the customer benefits of such investment increases may be much less than the costs to customers.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING GEORGIA POWER'S MASSIVE GRID INVESTMENT INCREASES IN RECENT YEARS?

A. As with substation capacity increases, at this time we simply bring the issue to the Commission's attention for future consideration. Intervenors may be disappointed in the lack of results from dramatic investment increases in recent years, and the Commission should expect significant challenges to Georgia Power grid spending in the Company's next rate case.

1 VI. SUMMARY OF TESTIMONY AND RECOMMENDATIONS
2

3 Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS FOR
4 GEORGIA POWER'S DER CUSTOMER PROGRAM, INCLUDING PROPOSED
5 RAST-1 AND DRC-1 TARIFFS.

6 A. We find that allowing Georgia Power to own rate-based assets located on customer
7 premises increases risk and cost to non-participating customers. We further find that, due
8 to Georgia Power's status as a large company authorized to operate as a monopoly, the
9 approval of these tariffs will confer unfair advantages over competitors already operating
10 in a thriving DER market. If the Commission were to authorize these tariffs/programs, the
11 DER competitors and the market could be harmed, potentially reducing customer choice
12 and ultimately resulting in higher prices to customers contemplating DER installation over
13 time. Finally, we find that Georgia Power already offers a tariff, DPEC-4, that
14 accomplishes the same demand response as proposed DRC-1, for which customers may
15 already employ DER, and that already discourages lack of customer performance through
16 penalties. We also note that if Georgia Power wishes to enter the DER market, it can do so
17 via an unregulated subsidiary. As a result of all of these findings, we recommend the
18 Commission reject the proposed DER Customer Program and the associated RAST-1 and
19 DRC-1 tariffs as not in the public or State's interest.
20

21 Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS FOR
22 GEORGIA POWER'S PROPOSED DER PILOT.

23 A. We find that Georgia Power can secure the learning objectives established for the DER
24 pilot with as few as two DER pilot locations. We also find that the additional experience
25 gained through five additional pilot locations is not worth the incremental cost of five
26 additional locations, which we estimate at \$23.6 million. We also note that none of the
27 seven locations Georgia Power has selected appears capacity constrained, meaning that
28 none of the seven locations offers capacity increase cost avoidance or deferral benefits. As
29 a result of these findings, we recommend the Commission restrict the Company's proposed

1 DER pilot to two locations.

2
3 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS**
4 **REGARDING GEORGIA POWER'S PROPOSED DISTRIBUTION CAPACITY**
5 **INCREASES FOR 21 DISTRIBUTION SUBSTATIONS.**

6 A. We find indications that Georgia Power's distribution capacity increase policies are likely
7 more aggressive than necessary, resulting in earlier-than-necessary investments to increase
8 capacity, and a larger-than-necessary rate base. However, indications are not proof, and we
9 refrain from criticizing the proposed capacity increases at 21 distribution substations at this
10 time. Instead, we recommend the Commission review the capacity increase practices at a
11 variety of utilities, including co-operative and municipal utilities, for comparison to
12 Georgia Power practices.

13
14 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS**
15 **REGARDING GEORGIA POWER'S DRAMATIC INCREASE IN**
16 **DISTRIBUTION (AND TRANSMISSION) INVESTMENT IN RECENT YEARS.**

17 A. We find that Georgia Power has increased distribution (and transmission) investments in
18 recent years at a rate that is double or triple that of historical baselines. We further find, for
19 both Georgia Power and for investor-owned utilities across the U.S., that grid investment
20 increases have not delivered improved reliability in recent years. Thus, we are concerned
21 that these spending increases are not justified. However, as with substation capacity
22 investment, we refrain from critiquing these increases until more information can be
23 obtained and analyzed. Instead, we simply ask the Commission to be prepared to review
24 extensive stakeholder challenges to these spending increases in the Company's next rate
25 case.

26
27 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

28 A. Yes, it does.

1 BY MR. THOMAS:

2 Q And with your permission, I'd like to ask
3 that Mr. Alvarez give a summary of his prefiled testimony.

4 MADAM CHAIR PRIDEMORE: Please read your
5 summary.

6 A (Witness Alvarez) Thank you, Your Honor.
7 Again, my name is Paul Alvarez, and appearing with me
8 virtually today is my colleague Dennis Stephens. I lead the
9 Wired Group, a small consulting group firm specializing in
10 distribution utility business performance optimization.

11 Mr. Stephens is an independent consultant
12 specializing in electric distribution operations, planning,
13 asset management, and performance measurement.

14 Mr. Stephens and I have been working closely
15 together for several years now across dozen of states in
16 distribution utility proceedings generally on behalf of
17 consumer and business advocates.

18 We are testifying as a panel on behalf of
19 Public Interest Advocacy Staff of the Georgia Public Service
20 Commission. And the purpose of our testimony is to respond
21 to certain elements of Georgia Power Company's 2022
22 integrated resource plan.

23 Our testimony addresses four issues identified
24 in the company's IRP, including the company's proposal for
25 new distributed energy resource customer programs -- I'll be

1 referring to those as DER, or D-E-R programs. The company's
2 proposal to conduct a seven-location DER pilot. The
3 company's distributions substation capacity planning upgrade
4 practices and the dramatic increase in the company's
5 distribution and transmission capital investment levels in
6 recent years.

7 I'll summarize these in turn. First, I'll
8 discuss the company's proposal for a new DER customer
9 program. The company introduces the concept of two new
10 optional tariffs in its IRP for these programs.

11 The tariff RAST-1 allows larger commercial
12 industrial or C&I customers to pay the company overtime for
13 the cost of installing and maintaining company-owned DER,
14 such as solar panels, batteries, or fossil fuel generators
15 as examples, on participating customer premises behind the
16 customer's meters.

17 The company sees two primary benefits in the
18 program, including backup power for participating customers
19 in the event of a power outage, and a demand response to be
20 employed at the company's option by utilizing the customer's
21 sited DER for up to 200 hours per year when energy supplies
22 are tight.

23 In exchange for the option to operate the DER
24 up to 200 hours per year as a demand-response program, the
25 company introduces the concept of a second related optional

1 tariff, DRC-1. This tariff is limited to C&I customers
2 participating in the RAST-1 DER tariff and would pay
3 customers a credit when the DER is operated for demand
4 response purposes.

5 Mr. Stephens and I have two primary concerns
6 regarding these DER customer programs. The first concern is
7 that by allowing Georgia Power to own rate-based assets
8 located on a customer premises, a risk is created and cost
9 is maybe created for nonparticipating customers.

10 The second concern is that Georgia Power's
11 status as a large company authorized to operate as a
12 monopoly confers unfair advantages over competitors already
13 operating in the thriving market.

14 If the Commission were to authorize these
15 tariffs and programs, the competitors in the market could be
16 harmed, potentially reducing customer choice and ultimately
17 resulting in higher prices to customers considering DER
18 installation in the long term.

19 Further, we recognize that large C&I customers
20 may already participate in a demand response tariffs that
21 the company offers, DPEC-4, and that these C&I customers are
22 already able to use DER to facilitate their participation in
23 that tariff if they wish.

24 Finally, if Georgia Power wanted to pursue a
25 DER business, it could do so through an unregulated

1 subsidiary at no risk to nonparticipating customers and with
2 little to no advantage over existing DER market competitors.

3 In summary, the DER customer program as Georgia
4 Power introduces are not in the public's interest, nor in
5 the State of Georgia's interest, and we recommend the
6 Commission prohibit Georgia Power from offering RAST-1 and
7 DRC-1 as regulated tariffs.

8 Our next recommendation for the Commission
9 involves the company's proposal to complete a DER pilot in
10 seven locations in the service territory at a cost of
11 \$33 million.

12 The primary goal of the pilot is for the
13 company to learn how it might use local DER, for example, at
14 or near a substation, to avoid the cost of increasing
15 capacity in response to growing peak loads.

16 Other goals include understanding how the local
17 DER might improve local reliability during a service
18 interruption, and how the local DER might be able to help
19 the company recover more quickly from a service
20 interruption.

21 Our primary concern regarding the DER pilot is
22 its cost in general but also bang for buck more
23 specifically. We don't dispute that some value might be
24 created if Georgia Power were to gain experience from using
25 DER at or near substations as a potential alternative to

1 spending capital on capacity increases. However, at an
2 average cost of \$4.7 million per location, we ask what
3 incremental lessons that cannot be learned from one location
4 and require six additional locations.

5 So in discovery, the company replied that its
6 learning objectives included an interest in solar DER as
7 well as an interest outside of solar DER making for two
8 locations; so thus we recommend the Commission instruct the
9 company to reduce the locations of its DER pilot from 7 to
10 2.

11 Our third recommendation for the Commission's
12 considerations concerns the company's proposal to increase
13 the capacity of 21 distribution substations at a significant
14 cost. Ultimately our lack of understanding of the company's
15 grid, load forecasts, customer and developer plans, and
16 capacity planning practices present us -- prevent us from
17 recommending any reductions in this company proposal.

18 Further, the limited time frame for discovery
19 in an IRP is not conducive to securing such understanding.
20 However, in discovery, we did identify project specific and
21 process specific issues which cause us concern that the
22 company's distribution of substation capacity increased
23 spending is too aggressive, leading to rate base and rate
24 increases that could be considered premature.

25 In lieu of recommendations to curtail

1 distribution substation capacity increase plans or capital
2 spending, we instead encourage the Commission to review the
3 substation capacity increased practices and triggers
4 employed by multiple utilities, including those with
5 nonprofit utilities without capital bias, such as
6 municipally or cooperatively owned utilities.

7 With such reviews, the Commission could --
8 would build a base of experience against which Georgia Power
9 practices and triggers could be compared in the future.

10 The fourth and final issue we bring to the
11 Commission's attention involves the dramatic distribution
12 and transmission spending increases the company has incurred
13 in recent years. Using the company's most recent rate case
14 projections as a guide, we note the distribution capital
15 spending projected for 2021 is double the amount spent as
16 recently as 2017 and triple the amount spent as recently at
17 2013. Likewise, transmission capital spending projected for
18 2021 is double the amount spent in 2018.

19 Simultaneously we note that systemwide peak
20 demand is falling and systemwide reliable delayed
21 performance is deteriorating; we, therefore, wondered what
22 changes have occurred to justify these spending increases
23 and what benefits customers are securing from them.

24 We made no recommendations regarding the
25 company's recent and dramatic distribution and transmission

1 capital spending increases at this time, but simply alert
2 the Commission to our significant concerns.

3 We appreciate the opportunity Public Interest
4 Advocacy Staff has provided us to introduce ourselves and
5 our experience and our perspectives to the Commission in
6 this case, and we hope the Commission finds our
7 contributions to the record in this case valuable.

8 MR. THOMAS: Chair Pridemore, one correction.
9 I believe that I misstated the exhibits. If staff
10 exhibits could be marked as 55 through 63, so thank
11 you for that correction and --

12 MADAM CHAIR PRIDEMORE: So marked.

13 MR. THOMAS: Thank you.

14 And the panel is available for questions from
15 Commissioners and cross-examination.

16 MADAM CHAIR PRIDEMORE: Questions from
17 Commissioners?

18 (No response.)

19 Mr. Alvarez, I'm sorry, I missed, what state
20 are you from?

21 MR. ALVAREZ: Colorado.

22 MADAM CHAIR PRIDEMORE: Colorado.

23 Have you worked on a utility here in Georgia or
24 in a similar case maybe in a coop or someplace in
25 Georgia in the past?

1 MR. ALVAREZ: No, not in Georgia. No, Your
2 Honor.

3 MADAM CHAIR PRIDEMORE: Okay. So are you
4 familiar at all with Georgia's stature as the number
5 one state in the nation to do business?

6 MR. ALVAREZ: No, not aware, but I don't doubt
7 you.

8 MADAM CHAIR PRIDEMORE: Okay.

9 COMMISSIONER MCDONALD: You are now.

10 MADAM CHAIR PRIDEMORE: So, yes, we are the
11 number one state to do business and have been for, I
12 believe, eight years now, Commissioner McDonald?

13 COMMISSIONER MCDONALD: Eight years.

14 MADAM CHAIR PRIDEMORE: Eight years in a row.
15 And a hallmark of that is the flexibility of
16 utilities to be able to work in economic development
17 environments and to be able to assist companies that
18 want to relocate here.

19 So over the last couple of years, we've had an
20 onslaught of businesses, many from the West, who have
21 decided to relocate to Georgia. And they've done so
22 because they like our flexible options that are
23 available to serve their utility needs.

24 Companies like Rivian, companies like SK
25 Battery, most recently, last week, Governor Kemp

1 announced the largest economic development project in
2 the history of the state where Hyundai is coming in
3 and building new manufacturing facilities in
4 Southeast Georgia.

5 Do you see DER as a means to be able to assist
6 economic development especially for commercial
7 industrial customers?

8 MR. ALVAREZ: Yeah. I can imagine a company
9 wanting to relocate here who would be interested in
10 that -- in having their own DER in their location,
11 sure.

12 MADAM CHAIR PRIDEMORE: Okay. All right.
13 Good.

14 Any other questions from Commissioners? \

15 (No Response.)

16 Okay. Let's take the list. Americans for
17 Affordable Clean Energy?

18 MR. GALLOWAY: No questions.

19 MADAM CHAIR PRIDEMORE: Commercial Group?

20 MR. JENKINS: No, Madam Chair, you did a nice
21 enough job.

22 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
23 for Georgia?

24 (No response.)

25 MADAM CHAIR PRIDEMORE: Cypress Creek

1 Renewables?

2 MR. STAIR: No questions.

3 MADAM CHAIR PRIDEMORE: Georgia Association of

4 Manufacturers?

5 MR. JONES: No questions.

6 MADAM CHAIR PRIDEMORE: Georgia Center for

7 Energy Solutions?

8 MR. HUBBARD: No questions.

9 MADAM CHAIR PRIDEMORE: Georgia Coalition of

10 Local Governments?

11 MS. BROWN: No questions, Madam Chair.

12 MADAM CHAIR PRIDEMORE: Georgia Interfaith

13 Power & Light and Partnership for Southern Equity?

14 MS. KYSOR: No questions.

15 MADAM CHAIR PRIDEMORE: Georgia Large Scale

16 Solar and Advanced Power Alliance?

17 MR. CARVER: No questions, Madam Chair?

18 MADAM CHAIR PRIDEMORE: Georgia Solar Energy

19 Industries Association, Solar Energy Association, and

20 Vote Solar?

21 MR. THOMASSON: No questions.

22 MADAM CHAIR PRIDEMORE: Georgia Watch?

23 MS. COYLE: No questions.

24 MADAM CHAIR PRIDEMORE: Interstate Gas Supply?

25 MR. CARVER: No questions.

1 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
2 Coalition?

3 MR. JONES: No questions.

4 MADAM CHAIR PRIDEMORE: Sierra Club?

5 MR. FABISH: No questions.

6 MADAM CHAIR PRIDEMORE: Southern Alliance for
7 Clean Energy and Southface Energy Institute?

8 MR. BAKER: No questions.

9 MADAM CHAIR PRIDEMORE: Southern Renewable
10 Energy Association?

11 MR. MAHAN: No questions.

12 MADAM CHAIR PRIDEMORE: Georgia Power?

13 MR. HEWITSON: Questions.

14 CROSS-EXAMINATION

15 BY MR. HEWITSON:

16 Q Good afternoon, Mr. Alvarez.

17 A (Witness Alvarez) Good afternoon.

18 Q Steve Hewitson on behalf of Georgia Power
19 Company.

20 I don't know how -- I did not know that
21 Mr. Stephens was going to be remote, so I apologize
22 Mr. Stephens. I will have -- I may have a number of
23 exhibits throughout and --

24 MADAM CHAIR PRIDEMORE: We can take photographs
25 and send him.

1 MR. HEWITSON: Yeah, that's what we'll try and
2 do. And we're also trying to get them by e-mail and
3 maybe transfer that way. That might be a little bit
4 easier.

5 MADAM CHAIR PRIDEMORE: Thank you for your
6 patience, Mr. Hewitson. We've had a recent medical
7 issue that has...

8 MR. HEWITSON: No problem at all. I just
9 apologize that we didn't have them available
10 electronically.

11 BY MR. HEWITSON:

12 Q Okay. Mr. Alvarez, I want to start with your
13 testimony about -- and I really want to say D-E-R,
14 everyone keeps saying DER, so I'm just going to go ahead
15 and go with the flow.

16 The DER customer program, the RAST-1 and DRC
17 tariffs, now, neither you nor Mr. Stephens are lawyers; is
18 that correct?

19 A (Witness Alvarez) That's correct.

20 Q Okay. So on page 14, line 5 when you say
21 "Advantages bestowed to an incumbent monopoly likely
22 constitutes a violation of State law," you are not giving
23 a legal opinion, are you?

24 A (Witness Alvarez) I'm not.

25 Q Mr. Stephens?

1 A (Witness Stephens) I'm not either.

2 Q And would it be fair to say that neither of
3 you are qualified to provide a legal opinion in this
4 proceeding?

5 A (Witness Alvarez) That's correct.

6 A (Witness Stephens) That's correct.

7 Q You have two primary concerns regarding these
8 programs, the first -- well, is that right, you have two
9 primary concerns?

10 A (Witness Alvarez) Yes.

11 Q Okay. The first concern is that programs --
12 the programs risk increased costs to nonparticipants; is
13 that right?

14 A (Witness Alvarez) That's correct.

15 Q And one of those risks is bad debt risk;
16 right?

17 A (Witness Alvarez) That's correct.

18 Q On page 6, lines 12 to 13 of your testimony,
19 you state that abandonment by participating customers is
20 likely to be a fairly common occurrence.

21 Do you see that in your testimony?

22 A (Witness Alvarez) I recall that, yes.

23 Q Okay. What information or data is that
24 statement based on?

25 A (Witness Alvarez) Personal experiences.

1 Turnover of businesses in locations.

2 Q Do you know how often Georgia Power customers
3 1 megawatt or larger default on their accounts?

4 A (Witness Alvarez) I do not know that, no.

5 Q Do you know how often Georgia Power customers
6 1 megawatt or larger change locations?

7 A (Witness Alvarez) I do not know that, no.

8 Q Okay. Do you know how often Georgia Power
9 customers 1 megawatt or larger fail to honor the terms of
10 any long-term contract they sign with Georgia Power?

11 A I do not know that, no.

12 Q So if you don't know the answer to those
13 questions, you can't really say with any degree of
14 certainty regarding Georgia Power's programs that
15 abandonment is likely to be a fairly common occurrence,
16 can you?

17 A (Witness Alvarez) Well, that comment was based
18 on the long-term nature. I mean, it's a long time. If
19 you're going to pay for, you know, a multimillion dollar
20 installation, that's probably going to be, you know, a
21 20-year depreciation period. So you'd be looking at a
22 20-year kind of commitment, and that's a long time. So that
23 was the basis of the statement was that over that long time
24 period, business changes do happen.

25 Q So it was based on a general statement, not

1 based on any specific information regarding Georgia Power
2 or its customers?

3 A (Witness Alvarez) That's correct. Yeah.

4 Q You also say on page 6, line 14, it can be
5 very costly, if not impossible, to relocate DER.

6 What analysis have you performed on relocation
7 costs?

8 A (Witness Alvarez) Well, none. But I mean, a
9 solar array is not something that's easy to move. I mean,
10 it's fixed in place. A large, you know, gas-fired turbine
11 is a really significant piece of equipment.

12 Dennis, correct me when I'm wrong, but those
13 are -- those are going to be cost prohibitive to move, I
14 would think.

15 Dennis, would you care to add to that?

16 A (Witness Stephens) I guess based on our
17 experience and specifically on my experience, I have been
18 involved with the construction of solar systems on our Xcel
19 energy system while I worked there. I did not -- we were
20 never involved in relocation, but I do know the complexities
21 of installing a solar system. And from that complexity, I
22 know that it would be very costly to relocate.

23 Q Okay. Are you aware that Georgia Power's
24 program would be designed to recover the cost of
25 relocation from the participating customer?

1 A (Witness Alvarez) I don't recall that being in
2 any testimony or materials.

3 Q Do you agree that there are ways that Georgia
4 Power can protect itself contractually to reduce these
5 risks that you have identified in your testimony?

6 A (Witness Alvarez) I imagine that there are.

7 Q And if the risks come to fruition, the
8 customer can determine whether the program should be
9 continued; is that a fair statement?

10 A (Witness Alvarez) I'm sorry. Could you repeat
11 that?

12 Q Yeah. If the risks that you have identified
13 were to come to fruition after the DER program was in
14 place or if the DER program was in place, the Commission
15 would have the authority to discontinue the program if it
16 decided that the risks were too great?

17 A (Witness Alvarez) Sure. Sure. Certainly.

18 Q On page 8, lines 2 to 3, you compare the DER
19 customer program with DPEC, DPEC-4 tariff, and conclude
20 that DPEC accomplishes the same objectives as the DER
21 customer program. Is that your testimony?

22 A Yes, it is.

23 Q Okay. DPEC is a program where customers
24 receive credits in exchange for reducing demand when
25 necessary; right?

1 A (Witness Alvarez) That's correct.

2 Q That means the customers' operations are
3 interrupted or reduced; is that correct?

4 A (Witness Alvarez) Well, I would say there are
5 multiple ways a customer could reduce their load on the
6 system. I mean, they -- one way is to reduce operations.
7 Another way would be to use on-site DER resources to reduce
8 their load on the system.

9 Q But that's not the DPEC program. The DPEC
10 program is an interruptible program; right?

11 A (Witness Alvarez) Right. There are no
12 restrictions that I'm aware of as to how a customer
13 accomplishes those reductions; right?

14 Q I understand what you're saying.

15 With the DER customer program, though, the
16 customers' business is not interrupted in any way; right?

17 A (Witness Alvarez) I think that would be --
18 don't know about that. I mean, if the customer were to rely
19 on that DER for power, and then the company exercises option
20 to use that resource that behind the resource -- behind the
21 meter resource for demand response, then the customer would
22 no longer have access to that. So I think it's possible
23 that a customer might have to have an operational
24 interruption even with the RAST program.

25 Q Okay. Are you aware, though, that the plan

1 for Georgia Power or one of the benefits that Georgia
2 Power promotes with the DER program is that the customer
3 can maintain operations at 100 percent without
4 interruption?

5 A (Witness Alvarez) Again, I think that would
6 depend on how the customers structure their operations
7 around that DER.

8 Q The second primary concern you have regarding
9 the DER customer program is that you believe it could give
10 Georgia Power an unfair advantage and stifle competition.
11 Is that your concern?

12 A (Witness Alvarez) Yes, sir.

13 Q Do you believe the current DER market in
14 Georgia is competitive and operating as it should?

15 A To my knowledge, yes.

16 Q Are you aware that Georgia Power already has
17 an unregulated business offering DER to customers?

18 A (Witness Alvarez) I was not aware of that, no.

19 Q Are you aware that that business relies on
20 Georgia Power's cost capital and procurement methods, but
21 it doesn't seem to be hurting the market right now, does
22 it?

23 A (Witness Alvarez) I don't know the size of it
24 or any of the details of that program.

25 Q On page 9, lines 20 to 22, you state that

1 Georgia Power's cost of debt in equity capital is most
2 likely lower than almost everyone of its C&I customers.

3 Do you remember that testimony?

4 A (Witness Alvarez) I do.

5 Q What did you do to validate that statement?

6 A (Witness Alvarez) Simply compared the size of
7 the various companies.

8 Q Did you review the capital structure of
9 customers that may potentially sign on with the DER
10 program?

11 A (Witness Alvarez) No, I did not.

12 Q Are you aware that Georgia Power has a
13 regulated lighting service?

14 A (Witness Alvarez) Yes.

15 Q Okay. Are you aware that the market has
16 thrived since Georgia Power Company's regulated lighting
17 services were started in Georgia?

18 A (Witness Alvarez) I would have to know more
19 about your definition of "thriving."

20 Q Not been harmed?

21 A (Witness Alvarez) No. I mean, are there
22 multiple competitors? What did they -- you know, what are
23 their market shares? You know, that kind of market
24 information.

25 Q But you're aware there's a regulated lighting

1 program?

2 A (Witness Alvarez) Yes.

3 Q And you're not aware of any market
4 constriction because of it?

5 A (Witness Alvarez) I'm not familiar with that
6 market here.

7 Q You say on page 12, lines 8 and 9, that
8 you're not aware of any other programs that allow
9 regulated utilities to own time-metered DER equipment as
10 rate-based asset.

11 Is that your testimony?

12 A (Witness Alvarez) That was my testimony -- that
13 was our testimony at the time, yes.

14 Q Okay. Has that testimony changed?

15 A (Witness Alvarez) Well, we have become aware of
16 a program that Duke Energy has in North Carolina since the
17 testimony was filed.

18 Q Okay. When did that Duke Energy program get
19 instituted? I thought that program went into effect in
20 January of 2022?

21 A (Witness Alvarez) That may be true. I just was
22 not aware of it.

23 Q Oh, I see. You're not saying the program
24 started after your testimony was filed; you're saying --

25 A (Witness Alvarez) My awareness of it since the

1 testimony was filed, right.

2 Q Okay. All right.

3 And you both reside in Colorado; right?

4 A (Witness Alvarez) Yes.

5 Q Did you know that the Public Service Company
6 of Colorado has proposed a similar program as well?

7 A (Witness Alvarez) I was not aware of that.
8 Dennis?

9 A (Witness Stephens) No, I'm not aware of that.
10 MR. THOMAS: May Mr. Marzo approach?

11 MADAM CHAIR PRIDEMORE: Yes, you may.

12 BY MR. HEWITSON:

13 Q And I just received word that -- I believe
14 the information is being e-mailed -- the exhibits are
15 being e-mailed to Mr. Stephens. So I don't know by whom,
16 but we're getting them to staff to get them to you,
17 Mr. Stephens. And if they come by the time -- okay.

18 A (Witness Stephens) Could I ask a question?
19 Could we get some -- a little bit of clarification on
20 exactly what you're saying Public Service Company in
21 Colorado is doing?

22 Q Yeah. That's the tariff that I have now in
23 front of Mr. Alvarez that we've e-mailed to you,
24 Mr. Stephens.

25 A (Witness Stephens) Oh, okay. Great. Thank

1 you.

2 MR. THOMAS: And, also, I would just like to,
3 Chair Pridemore, you know, object in any way if
4 questions come from this once we've established
5 that -- if they're not familiar with it, and also
6 just make sure that we explain that this is not --

7 COMMISSIONER MCDONALD: Mr. Thomas, would you
8 get in front of the microphone, please, if you will.

9 MR. HEWITSON: Here. Join mine.

10 MR. THOMAS: Sure. Thank you.

11 Just explain as -- you know, first establish
12 whether the witnesses are familiar with this, and
13 then explain that this is actually a suspended
14 program, as we try to ask questions about this.

15 MR. HEWITSON: What do you mean by "suspended"?

16 MR. THOMAS: I thought you were the one who
17 said --

18 MR. HEWITSON: Do you know about it, or should
19 I talk about it?

20 MR. THOMAS: Well, I think you're -- you know,
21 that's the problem is that, you know, it's being
22 presented something that, I think they've already
23 said they're not familiar with the program in
24 Colorado. Do you --

25 MR. HEWITSON: Yes. And that's exactly the

1 point, is that there was a proposal by the Public
2 Service Company of Colorado for a program that is
3 almost exactly the same as Georgia Power's, and the
4 witnesses have said they're not aware of any program
5 that is like Georgia Power's offering.

6 This tariff was issued, and then it was
7 suspended, and it's under review right now. But it
8 was an offering that was made by the Public Service
9 Company of Colorado.

10 So rather than going -- and in the interest of
11 time, because I know you're going to stop me at a
12 certain point, Chair, let's do it this way:

13 I'll mark this as Georgia Power Exhibit 8.

14 (The document referred to was marked for
15 identification as GPC Exhibit 8.)

16 BY MR. HEWITSON:

17 Q Are either of you gentlemen aware of the
18 tariff that was issued by the Public Service Company of
19 Colorado regarding a DER customer behind-the-meter
20 program?

21 A (Witness Alvarez) Not until I was presented
22 with this document, no.

23 Q Okay.

24 A (Witness Alvarez) Dennis?

25 A (Witness Stephens) No, me either.

1 MR. THOMAS: Madam Chair, I understand our
2 policy for leeway, but I'm still going to, for the
3 record, object.

4 MADAM CHAIR PRIDEMORE: Understood, Mr. Thomas.
5 This is new today. Usually, we just let it fly. I
6 have a stack of things from Mr. Prenovitz in my
7 office over the years, and they are duplicate, but
8 that's okay.

9 MR. HEWITSON: May Mr. Marzo approach again?

10 Q And I'll try and be -- since we're just going
11 to look at the tariffs, I want to see -- we're handing
12 Mr. Alvarez Exhibits 9 and 10. Exhibit 9 is a tariff by
13 the Northern States Power Company in Wisconsin, and
14 Exhibit 10 is a Florida Power & Light tariff.

15 And each of these tariffs are regarding current
16 program offerings in Wisconsin and Florida. And so let me
17 do this way: Mr. Alvarez and Mr. Stephens, were you aware
18 that there were programs in Wisconsin and Florida that are
19 similar, if not exact, to the Georgia Power customer sited
20 behind-the-meter DER program?

21 A (Witness Alvarez) I was not.

22 A (Witness Stephens) I was not.

23 (The document referred to was marked for
24 identification as GPC Exhibit 9.)

25 (The document referred to was marked for

1 identification as GPC Exhibit 10.)

2 MR. HEWITSON: And while Mr. Marzo is still
3 standing, can I have him approach one more time?

4 MADAM CHAIR PRIDEMORE: Yes, you may.

5 MR. HEWISTON: And I believe this will be
6 Exhibit 11, and what you're being handed is a
7 proposed program. This is not yet in place. It's
8 under review in Minnesota that was filed by Xcel
9 Energy doing business as Northern States Power
10 Company on April 7, 2022.

11 Are you familiar with this proposal in
12 Minnesota, Mr. Alvarez, or Mr. Stephens?

13 A (Witness Alvarez) I am not.

14 A (Witness Stephens) I'm not.

15 (The document referred to was marked for
16 identification as GPC Exhibit 11.)

17 Q The Georgia Public Service Commission
18 regulates Georgia Power; right?

19 A (Witness Alvarez) Yes.

20 Q And as that regulatory authority, is it your
21 understanding that this Commission is mandated to ensure
22 Georgia Power provides safe, reliable, and affordable
23 electricity to Georgia Power's customers?

24 A (Witness Alvarez) That's my understanding.

25 Q And Georgia Power's DER customer program is

1 designed to provide customers participating in the RAST-1
2 tariff with an enhanced resiliency service that helps
3 maintain critical business operations that rely on
4 electric service; right?

5 A (Witness Alvarez) Correct.

6 Q And DRC-1 is designed to provide reliability
7 benefits to all customers by using DER to reduce system
8 load during system reliability events. Would you agree
9 with that?

10 A Yes.

11 Q So the program is designed not only to
12 provide customers with resiliency for critical operations
13 but to enhance system reliability, both of which are core
14 aspects of utility service, aren't they?

15 A (Witness Alvarez) Well, they are, but that's
16 not the question at issue here. The question at issue here
17 is, should the company offer those services as regulated
18 service? Those are two different things.

19 Q Sure. And if the DER customer program was a
20 regulated program, the Commission would be able to
21 supervise the DER customer program to ensure that the
22 rates charged remain just and reasonable, just as it has
23 with the company's lighting service; right?

24 A (Witness Alvarez) I would imagine that's
25 correct, yes.

1 Q Okay. Let me jump to the DER pilots. I
2 assume you're aware that this Commission has encouraged
3 Georgia Power to investigate and study DER alternatives to
4 traditional distribution solutions; is that right?

5 A (Witness Alvarez) Yes.

6 Q Would you agree that reducing the number of
7 pilot locations will reduce the amount of information that
8 Georgia Power will be able to learn from these efforts?

9 A (Witness Alvarez) I don't necessarily agree
10 with that, no.

11 A (Witness Stephens) I don't necessarily agree
12 with that either.

13 Q Okay. Georgia Power requested seven pilot
14 locations, but you believe it should be two; right?

15 A (Witness Alvarez) That's correct.

16 Q There are at least three use cases, though,
17 that that Georgia Power has identified, right, wire
18 capacity, reliability, and resiliency; is that right?

19 A (Witness Alvarez) Yes.

20 Q Okay. And regarding wire capacity, you
21 reviewed the company's feeder loading threshold
22 guidelines; is that right?

23 A (Witness Alvarez) That's correct.

24 Q Okay. Are you aware that some of the
25 distribution feeders for the identified pilot locations

1 are at or near those loading thresholds?

2 A (Witness Alvarez) My recollection of that data,
3 which I think was confidential data so I don't want to say
4 too much, but my recollection of that data was that very
5 few, if any, were at that threshold.

6 And also, they relied on some load growth,
7 expected, honestly, but load growth that had yet -- that was
8 forecasted but had not yet materialized.

9 Q In addition to the three use cases, do you
10 agree that there are other variables that would provide
11 additional useful information such as looking at different
12 topographies?

13 A (Witness Alvarez) Well, before we leave the
14 concept of three use cases, let's just say we -- there are
15 probably ways you could evaluate all three use cases in a
16 single location, first of all. But I would agree that
17 topography offers some additional benefit.

18 Q And different regions, such as coastal or
19 higher elevation, might reveal useful information as well.
20 Would you agree with that?

21 A (Witness Alvarez) I don't know.

22 Mr. Stephens, what do you think about that?

23 A (Witness Stephens) I would say all those are
24 marginal additional value.

25 Q Okay. But they do have additional value.

1 I'm sorry, you said it. They have marginal additional
2 value?

3 A (Witness Stephens) There are all kinds of
4 things that you can say could provide additional value, but
5 the question is can you get 99 or 95 percent of what you
6 need to know from two locations, and I think that's true.

7 There may be a little bit of marginal value by
8 doing 100 locations, each one having a little bit of
9 marginal value, but you really only need two to get most of
10 the value.

11 Q Okay. Well, at the end of the day, if we
12 can't agree on the number of pilots to run, should we be
13 able to expect this Commission to balance the cost and
14 benefits and tell us whether the number of pilot locations
15 is worth the additional cost?

16 A (Witness Alvarez) I can't speak to the
17 Commission's technical experience.

18 Q It wasn't really technical. It was, if we
19 can't agree, the Commission is going to tell us what to
20 do; right?

21 A (Witness Alvarez) Sure. That's accurate.

22 A (Witness Stephens) That's true.

23 Q All right. Let me skip to the distribution
24 grid capacity projects. This is on page 16 of your
25 testimony. It's in -- your testimony on lines 12 and 13

1 on that page state that: Georgia Power Company proposes
2 to upgrade the capacity of 21 distribution substations
3 over the next four years."

4 Do you remember that testimony?

5 A (Witness Alvarez) I do.

6 Q Your opinion is that Georgia Power's capacity
7 increase practices are too aggressive. Is that a correct
8 characterization of your testimony?

9 A (Witness Alvarez) It is.

10 Q On page 17, lines 11 to 16, it seems that
11 your opinion is that Georgia Power Company should look at
12 alternatives to capacity upgrades or take a little time to
13 wait, see if the capacity upgrade is necessary.

14 Is that a fair reading of your testimony?

15 A (Witness Alvarez) I think that's fair.

16 Dennis, do you have any color to add to that?

17 A (Witness Stephens) No, I don't.

18 Q Am I correct that the 21 substation projects
19 you identified are found in Technical Appendix Volume 3,
20 Section F?

21 A (Witness Alvarez) That sounds right.

22 Q Are you aware that of those 21 projects, 13
23 are still in working status, meaning that they're still
24 underdeveloped and yet to be approved?

25 A (Witness Alvarez) I seem to remember that

1 several of them were, that's correct.

2 Q Are you aware that of those 13 projects still
3 in working status, 8 have already been delayed while
4 waiting on load to develop?

5 A (Witness Alvarez) I was not aware of that, no.

6 Q By any chance, did you compare Section F in
7 the 2022 IRP with Section F in the 2019 IRP?

8 A (Witness Alvarez) I did not.

9 Q Okay. Did you realize, then, if you made
10 that comparison, you would find 8 projects on the 2022
11 list were also in Section F in 2019 but with earlier need
12 dates?

13 A (Witness Alvarez) I did not do the comparison,
14 so I don't know.

15 Q Well, if -- assuming that to be true,
16 assuming I compared the two Section Fs correctly, doesn't
17 that mean that Georgia Power does exactly what you say it
18 should, take the wait and see approach at times?

19 A (Witness Alvarez) I think that would be an
20 indication of that, yes.

21 Q Okay. And you also noted on page 17 that at
22 least one of the projects, and I think it's only one, has
23 been canceled since the IRP was filed; right?

24 A (Witness Alvarez) Correct.

25 Q And wouldn't you agree that that's the right

1 thing to do, if the project is no longer needed, you
2 cancel it rather than spending money on it?

3 A (Witness Alvarez) Absolutely.

4 Q A couple of clarifications real quick. On
5 page 18 of your testimony, you include a chart regarding
6 load growth and capacity and on --

7 A (Witness Alvarez) Yes.

8 Q And I think it's the -- I'm always bad at
9 this. The Y axis, load growth, it says "moderate" and
10 "high." What is your definition of moderate load growth?

11 A (Witness Alvarez) Well, I think it depends on
12 the situation. I mean if you're a substation at 90 percent
13 capacity, I think moderate growth is more concerning than it
14 would be at 80 percent capacity, so I think it's location
15 specific.

16 Dennis, do you have anything to add to that?

17 A (Witness Stephens) No. I just -- it's
18 obviously situational.

19 A (Witness Alvarez) Situational specific, yeah.

20 Q And it's because you've got them labeled
21 "none below, moderate to high," and then on available
22 capacity you have "plenty" and "tight."

23 And I'm not trying to be flippant here, but
24 those are not engineering terms; right?

25 A (Witness Alvarez) Well, it was conceptual. The

1 chart was meant to be conceptual and strategic, not
2 specific.

3 Q And your conclusion is that you believe
4 Georgia Power's grid capacity planning is too aggressive
5 leading to unnecessary investments and costs; right?

6 A (Witness Alvarez) Perhaps. We do not reach
7 that conclusion, we are concerned about it.

8 Q Okay. You didn't do any quantifications of
9 any costs or anything of that nature, did you?

10 A (Witness Alvarez) No.

11 MR. HEWITSON: Madam Chair, I know it's 4:45.
12 I might be able to finish up if I have another 10 to
13 15 minutes.

14 MADAM CHAIR PRIDEMORE: We're going to pick
15 this up tomorrow.

16 MR. HEWITSON: Sorry, gentlemen, I tried.
17 Thank you, Madam Chair.

18 MADAM CHAIR PRIDEMORE: We still have redirect,
19 so...

20 MR. HEWITSON: Okay.

21 MADAM CHAIR PRIDEMORE: Okay. All right. So
22 we're going to pick this up tomorrow at 9:30.

23 (Hearing adjourned at 4:45 p.m.)
24
25

C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.



Kelley Marie Nadotti, RPR
CCR-6256-8388-8026-4192



Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664



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