

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION
STATE OF GEORGIA

In Re:

Georgia Power Company's)
2022 Integrated Resource Plan) Docket No. 44160

Georgia Power Company's 2022)
Application for the Certification) Docket No. 44161
Decertification, and Amended)
Demand-Side Management Plan)
_____)

(VOLUME 1)

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Monday, April 4, 2022

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

PRESENT WERE:

TRICIA PRIDEMORE, Madam Chair
TIM ECHOLS, Vice-Chairman
FITZ JOHSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
JASON SHAW, Commissioner

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I N D E X

WITNESSES:	DIRECT	CROSS	REDIRECT	RECROSS
Jeffrey R. Grubb				
A. Wilson Mallard				
Michael B. Robinson				
Jeffrey B. Weathers				
By Mr. Hewitson	18	--	565	--
By Mr. Walsh	--	87	---	--
By Mr. Galloway	--	--	---	--
By Mr. Jenkins	--	--	---	--
By Mr. Prenovitz	--	--	---	--
By Mr. Charles Jones	--	283	---	--
By Mr. Hubbard	--	--	---	--
By Ms. Brown	--	320	---	--
By Ms. Kysor	--	351	---	--
By Mr. Carver	--	385	---	--
By Ms. Ottenweller	--	423	---	--
By Mr. Thomasson	--	452	---	--
By Ms. Coyle	--	478	---	--
By Mr. Carver	--	--	---	--
By Mr. Clarkson	--	--	---	--
By Mr. Steven Jones	--	493	---	--
By Mr. Fabish	--	510	---	--
By Mr. Baker	--	515/559	---	--
By Mr. Jacob	--	--	---	--
By Mr. Mahan	--	543	---	--

1 EXHIBITS FOR IDENTIFICATION IN EVIDENCE

2 Georgia Power Company:

3 1 - 2022 Amended IRP 19 20
4 Public Disclosure (PD) &
Trade Secret (TS) Version

5

6 STAFF:

7 1 - Response to STF-JKA-3-2 93 267

8 2 - Response STF-JKA-1-1 144 267

9 3 - Response STF-JKA-4-12 164 267
10 (TRADE SECRET)

11 4 - STF-LA-1-44 233 267

12 5 - STF-DEA-2-30 246 267

13 6 - IRP Filing Excerpt 262 267
(Trade Secret)

14 7 - Public Disclosure 262 267

15

16

17 GAM:

18 1 - Southern Company 2022 288 319
19 Long Term Target Reserve
Margin Study Metrics

20 2 - Unit Retirement Study 295 319
21 (Trade Secret)

22 3 - Proposed Retirement Dates 310 319
23 and Remaining Net Book
Value at 12/31/21

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1	EXHIBITS	FOR IDENTIFICATION	IN EVIDENCE
2	RCG:		
3	1 - Copy of GPC's Bi-Annual	505	571
4	Hydro Modernization Report		
	for period ending 12/31/21		
5	2 - Letter to Ms. Bose dated	507	571
6	9/23/21 from Ms. O'Mara		
7	and Attachment A: Application		
	for Non-Capacity Related		
	Amendment of License		
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9	GIPL:		
10	1 - GPC's Response to	351	385
11	Staff's Data Request		
	STF-DEA-3-37		
12	2 - GPC's Response to	365	385
13	Staff's Data Request		
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15	<u>GCSC:</u>		
16	1 - Data Response	435	477
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P R O C E E D I N G S

MADAM CHAIR PRIDEMORE: Okay. Good morning.
How is everybody doing on this fine, sunny Monday
morning? Okay.

All right. This is Docket No. 44160, Georgia
Power Company's 2022 application for approval of its
integrated resource plan.

Call for appearances.

MR. WALSH: Thank you, Madam Chair. On behalf
of the Public Interest Advocacy staff, I'm Daniel
Walsh. I'm with the Georgia Attorney General's
Office. And with me this morning, Preston Thomas
and Alex Davis with the Public Service Commission.
Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh.
Georgia Power Company.

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

MADAM CHAIR PRIDEMORE: Thank you,
Mr. Hewitson.
Americans for Affordable Clean Energy.

MR. GALLOWAY: Madam Chair, Newton Galloway and
Terri Lyndall on behalf of AACE. Thank you.

MADAM CHAIR PRIDEMORE: Okay. Newton Galloway

1 on behalf of AACE present.

2 Commercial Group.

3 MR. JENKINS: Thank you, Madam Chair. Alan

4 Jenkins for the Commercial Group. Good morning,

5 all.

6 MADAM CHAIR PRIDEMORE: Good morning. Thank

7 you, Mr. Jenkins.

8 Concerned Ratepayers of Georgia.

9 MR. PRENOVITZ: Good morning, Madam Chair.

10 Benjamin J. Stockton, Steven C. Prenovitz for

11 Concerned Ratepayers of Georgia.

12 MADAM CHAIR PRIDEMORE: Thank you,

13 Mr. Prenovitz. You can now mute your line. I will

14 let you know when to unmute. Thank you.

15 Cypress Creek Renewables, LLC.

16 MR. STAIR: Good morning, Madam Chair,

17 Commissioners. Jeff Stair on behalf of Cypress

18 Creek Renewables.

19 MADAM CHAIR PRIDEMORE: Okay. Georgia

20 Association of Manufacturers.

21 MR. JONES: Clay Jones for GAM, Madam Chair.

22 MADAM CHAIR PRIDEMORE: Thank you.

23 Georgia Center for Energy Solutions.

24 MR. HUBBARD: Good morning, Madam Chair. Peter

25 Hubbard for the Georgia Center for Energy Solutions.

1 MADAM CHAIR PRIDEMORE: Thank you, Mr. Hubbard.
2 Georgia Coalition of Local Governments.
3 MR. SEYDEL: John Seydel from the City of
4 Atlanta representing the coalition.
5 MS. BROWN: Alicia Brown from the City of
6 Savannah.
7 MR. NIFONG: David Nifong, City of Decatur.
8 MADAM CHAIR PRIDEMORE: Okay. Mr. Seydel, as
9 the signer of the application, now would probably be
10 a good time for you to give us the list of the local
11 governments that are intervening.
12 MR. SEYDEL: Yes. Absolutely. Do you want me
13 to come up?
14 MADAM CHAIR PRIDEMORE: Sure. That would be
15 great. That way everybody can hear you.
16 MR. SEYDEL: Oh, sure. Absolutely.
17 So the list right now, as we have it, just does
18 not include Fulton County. So it's DeKalb County,
19 the City of Atlanta, City of Decatur, Athens-Clarke
20 County, and City of Savannah.
21 MADAM CHAIR PRIDEMORE: Okay. So five?
22 MR. SEYDEL: That's right.
23 MADAM CHAIR PRIDEMORE: Thank you, Mr. Seydel.
24 MR. SEYDEL: Thank you.
25 Okay. Georgia Interfaith Power & Light and

1 Partnership for Southern Equity.

2 MS. KYSOR: Good morning, Commissioners. Jill
3 Kysor. And I'm also here with Nicha Rakpanichmanee
4 and Munashe Magarira. Thanks.

5 MADAM CHAIR PRIDEMORE: Thank you, Ms. Kysor.

6 Georgia Large Scale Solar Association and
7 Advanced Power Alliance.

8 MR. CARVER: Good morning, Madam Chair, fellow
9 Commissioners. Brad Carver from Hall, Booth, Smith
10 on behalf of Georgia Large Scale Solar Association
11 and Advanced Power Alliance.

12 MADAM CHAIR PRIDEMORE: Okay. Thank you,
13 Mr. Carver.

14 Georgia Solar Energy Industries Association,
15 Solar Energy Association, and Vote Solar.

16 MR. THOMASSON: Good morning, Madam Chair and
17 Commissioners. Scott Thomasson on behalf of Georgia
18 GSEIA and SEA. And I'm here with my co-counsel
19 Katie Ottenweller from Vote Solar.

20 MADAM CHAIR PRIDEMORE: Thank you,
21 Mr. Thomasson.

22 Georgia Solar Energy Association, otherwise
23 listed here as GA Solar.

24 (No response.)

25 MADAM CHAIR PRIDEMORE: Not present.

1 Georgia Watch.

2 MS. COYLE: Good morning, Commissioners. Liz

3 Coyle for Georgia Watch.

4 MADAM CHAIR PRIDEMORE: Thank you, Ms. Coyle.

5 Interstate Gas Supply.

6 MR. CARVER: Brad Carver and Adam Wise on

7 behalf of Interstate Gas Supply.

8 MADAM CHAIR PRIDEMORE: Mr. Wise is not listed

9 on my appearance list. So check in with the

10 executive secretary's office, please.

11 MR. CARVER: Thank you.

12 MADAM CHAIR PRIDEMORE: Thank you.

13 Resource Supply Management.

14 (No response.)

15 MADAM CHAIR PRIDEMORE: Not present.

16 Restore Chattooga Gorge Coalition.

17 MR. JONES: Madam Chair, Steven Jones on behalf

18 of the coalition which makes up Chattooga

19 Conservancy, Georgia Canoeing Association, Natural

20 Land Trust, and Upstate Forever.

21 MADAM CHAIR PRIDEMORE: Are those other

22 organizations listed on your application?

23 MR. JONES: Yes, ma'am.

24 MADAM CHAIR PRIDEMORE: Okay. Thank you,

25 Mr. Jones.

1 MR. JONES: Thank you.

2 MADAM CHAIR PRIDEMORE: Sierra Club.

3 MR. FABISH: Good morning, Madam Chair. Zach
4 Fabish and my co-counsel, Isabella Ariza on behalf
5 of the Sierra Club.

6 MADAM CHAIR PRIDEMORE: Okay. Southern
7 Alliance for Clean Energy and Southface Energy
8 Institute.

9 MR. BAKER: Madam Chairman, Robert Baker on
10 behalf of -- we have a slight change to the names.
11 We are All-American Southern Alliance for Clean
12 Energy and Triple A South -- Southface Energy
13 Institute. So could we get a change in the
14 appearance list for these change in the names?

15 MADAM CHAIR PRIDEMORE: I appreciate your
16 passion, Mr. Baker. And I certainly appreciate your
17 phonebook application to this process. But, no,
18 it's as filed. Mr. Baker, Mr. Jacob, and
19 Ms. Southworth, okay.

20 Southern Renewable Energy Association.

21 MR. MAHAN: Good morning. This is Simon Mahan
22 with the Southern Renewable Energy Association.

23 MADAM CHAIR PRIDEMORE: Okay.

24 All right. That should be everybody. Anybody
25 that has been missed speak now?

1 (No response.)

2 MADAM CHAIR PRIDEMORE: Okay. Good.

3 All right. Any housekeeping matters to come

4 before us before beginning?

5 COMMISSONER McDONALD: Madam Chair.

6 MADAM CHAIR PRIDEMORE: Yes, Commissioner.

7 COMMISSONER McDONALD: Old school folks, we've

8 got a lot of intervenors. If you hear the question

9 asked, don't ask it again. We're not going to just

10 keep repeating and repeating and repeating the same

11 question over and over. Got it?

12 MADAM CHAIR PRIDEMORE: To reiterate

13 Commissioner McDonald, I have a couple housekeeping

14 matters. And one of which is: If your question has

15 been asked, please don't ask it again.

16 We are in for a long day. We've got three days

17 of hearings, just to kick us off on this docket. So

18 I appreciate everybody being kind and considerate of

19 everybody else's time. Everybody is going to get

20 their moment in the sun, but please don't duplicate

21 questions.

22 All right. Today prepare for a long one. Not

23 only are we here doing this, but our friends across

24 the street are having sine die. So we'll have time

25 for lunch. We'll have some breaks.

1 I'll try to do it with consultation from across
2 the street so that we're not all hitting the
3 cafeteria at the same time. But please be mindful
4 of the fact that Capitol Hill is crowded today, but
5 we are in for a long one.

6 All public comments have been submitted, are
7 put in the record, and have been sent to
8 Commissioners. Thank you all for submitting public
9 comments at our public forum, as well as those who
10 have submitted electronically and via phone.

11 All right. With that, Mr. Hewitson, would you
12 like to swear in your witnesses.

13 MR. HEWITSON: Thank you, Madam Chair.

14 Again, Steve Hewitson on behalf of Georgia
15 Power Company. At this time I would like to call
16 Georgia Power's first panel of witnesses on direct,
17 Mr. Grubb, Mr. Mallard, Mr. Robinson, and
18 Mr. Weathers. I will note for the record that we
19 have filed the notice of publication as required by
20 the Commission's rules.

21 Gentlemen, please raise your right hands.

22 Thereupon,

23 Jeffrey R. Grubb,
24 A. Wilson Mallard,
25 Michael B. Robinson,
Jeffrey B. Weathers,

having been duly sworn, testified as follows:

1 //

2 DIRECT EXAMINATION

3 BY MR. HEWITSON:

4 Q Mr. Grubb, would you please start us off by
5 stating your full name, your employer, and your
6 responsibilities for the record.

7 A (Witness Grubb) Yes. My name is Jeffery R.
8 Grubb. I'm the director of resource policy and planning
9 at Georgia Power Company where I'm able to -- and
10 fortunate enough to lead the group that works on capacity
11 RFPs, PPA administration, and then also, importantly, the
12 development of integrated resource planning.

13 Q Mr. Mallard, would you do the same.

14 A (Witness Mallard) Hi. I'm Andrew Wilson
15 Mallard. I'm the director of renewable development at
16 Georgia Power. And I lead the group that's responsible
17 for all of Georgia Power's procurements and renewable
18 programs.

19 Q And, Mr. Robinson, would you do the same.

20 A (Witness Robinson) Good morning. Michael B.
21 Robinson. I'm vice-president of planning, operations,
22 and policy for our power delivery team. So my team that
23 I lead is a team that plans and operates the transmission
24 grid for the state of Georgia, as well as our
25 distribution facilities throughout the state.

1 Q And Mr. Weathers.

2 A (Witness Weathers) Good morning,
3 Commissioners. My name is Jeffrey Weathers. I'm the
4 resource planning manager for Southern Company Services.
5 In my role, I support Georgia Power and our other retail
6 operating companies and all of their integrated resource
7 planning activities.

8 Q Thank you, gentlemen.

9 Mr. Grubb, on January 31st of this year, did
10 Georgia Power file its integrated resource plan, also
11 known as the IRP?

12 A (Witness Grubb) Yes.

13 Q On April 1st, did you file or cause to be filed
14 an errata to Georgia Power Company's IRP filing?

15 A (Witness Grubb) Yes.

16 MR. HEWITSON: Chair Pridemore, for the record,
17 I would like to identify Georgia Power Company's
18 2022 Integrated Resource Plan, as amended, as
19 Exhibit GPC-1PD and GPC-1TS for the public
20 disclosure and trade secret versions.

21 MADAM CHAIR PRIDEMORE: So moved.

22 (The documents referred to were marked for
23 identification as Exhibit GPC-1/PD and TS.)

24 MR. HEWITSON: Commission, staff, and all
25 parties who have executed confidentiality agreements

1 have access to the trade secret versions.

2 And, Chair Pridemore, I would also move that
3 Georgia Power's Exhibits 1-PD and 1-TS be moved into
4 the record, subject to cross-examination, of course.

5 MADAM CHAIR PRIDEMORE: So moved.

6 (The documents referred to were marked
7 received into evidence.)

8 BY MR. HEWITSON:

9 Q Mr. Grubb, on March 11th of this year, did you
10 prefile or cause to be prefiled 59 pages of direct
11 testimony in question-and-answer format in this case?

12 A (Witness Grubb) Yes, I did.

13 Q Are there any corrections you need to make to
14 your prefiled testimony?

15 A (Witness Grubb) Yes, there is one. On page 26
16 of panel one's testimony on lines 13 to 14, the phrase
17 "to seek SLR approval" should be deleted.

18 Q Subject to that correction, if I were to ask
19 you the same questions today under oath, would your
20 answers be the same as are set forth in your prefiled
21 testimony?

22 A (Witness Grubb) Yes, they would.

23 MR. HEWITSON: Madam Chair, the court reporter
24 has been provided a copy of the prefiled direct
25 testimony, and I now ask that the direct testimony

1 of this panel be copied into the record as if given
2 here today with Mr. Grubb's correction.

3 MADAM CHAIR PRIDEMORE: So moved.

4 (Whereupon, the prefiled direct testimonies
5 of Mr. Robinson, Mr. Mallard, Mr. Grubb and Mr.
6 Weathers follows:)

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STATE OF GEORGIA

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

In Re:

**Georgia Power Company's
2022 Integrated Resource Plan**

)
)

Docket No. 44160

DIRECT TESTIMONY OF

JEFFREY R. GRUBB, A. WILSON MALLARD, MICHAEL B. ROBINSON,

AND JEFFREY B. WEATHERS

March 11, 2022

**DIRECT TESTIMONY OF
JEFFREY R. GRUBB, A. WILSON MALLARD, MICHAEL B. ROBINSON,
AND JEFFREY B. WEATHERS**

**IN SUPPORT OF GEORGIA POWER COMPANY'S
2022 INTEGRATED RESOURCE PLAN
GPSC DOCKET NO. 44160**

I. INTRODUCTION

1

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

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

6 A. My name is Andrew Wilson Mallard. I am the Director of Renewable Development
7 for Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E.,
8 Atlanta, Georgia 30308.

9 A. My name is Michael B. Robinson. I am the Vice President for Planning, Operations,
10 and Policy for Georgia Power. My business address is 241 Ralph McGill Boulevard
11 N.E., Atlanta, Georgia 30308.

12 A. My name is Jeffrey Bryan Weathers. I am the Manager of Resource Planning for
13 Southern Company Services, Inc. ("SCS"). My business address is 600 North 18th
14 Street, Birmingham, Alabama 35203.

15 **Q. MR. GRUBB, PLEASE SUMMARIZE YOUR EDUCATION AND**
16 **PROFESSIONAL EXPERIENCE.**

17 A. I began my career with Georgia Power in 1992 as a cooperative education student
18 in Commercial and Industrial Marketing. I graduated from the Georgia Institute of

1 Technology in 1996 with a Bachelor of Science degree in Mechanical Engineering.
2 After joining the Company as a full-time employee in 1997, I worked in various
3 roles within Marketing until 2001 at which time I participated in a Company
4 developmental program where I gained experience in a wide range of functional
5 areas. During this period, I earned a Master of Business Administration degree from
6 Auburn University in 2000.

7 In 2003, I joined the Resource Policy and Planning organization at Georgia Power
8 where I served as a Project Manager through 2006. From 2007 through 2016, I
9 worked for SCS in various planning roles including SCS Forecasting Team Leader
10 (2007), SCS Fuels Planning Manager (2007-2011), and SCS Resource Planning
11 Project Manager (2011-2016) where I managed the team that supports the
12 development of the Southern Company System ("System") Integrated Resource
13 Plan ("IRP"). In this role, I supported Georgia Power's 2013 IRP (Docket No.
14 36498) and 2016 IRP (Docket No. 40161). In 2016, I returned to Georgia Power as
15 Project Manager in Resource Policy and Planning where I worked on the
16 development of the 2019 IRP. Beginning in March 2018, I assumed my current
17 position of Director of Resource Policy and Planning for Georgia Power.

18 **Q. MR. GRUBB, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
19 **GEORGIA PUBLIC SERVICE COMMISSION?**

20 **A.** Yes. I testified in Docket Nos. 4822, 16573, and 19279, the Georgia Public Service
21 Commission's ("Commission") Review of Georgia Power's PURPA Avoided Cost
22 Methodology; Docket No. 42310, Georgia Power's 2019 IRP; Docket No. 42625,
23 Georgia Power's Application for the Certification of the 2020/2021 Renewable
24 Energy Development Initiative ("REDI") Utility Scale Power Purchase
25 Agreements ("PPAs"); Docket No. 41596, Georgia Power's Application for the
26 Certification of the 2018/2019 REDI Utility Scale PPAs; and in Docket No. 41734,
27 Georgia Power's Application for the Certification of the 2018/2019 REDI Utility
28 Scale PPAs for the Commercial and Industrial ("C&I") Program.

1 **Q. MR. MALLARD, PLEASE SUMMARIZE YOUR EDUCATION AND**
2 **PROFESSIONAL EXPERIENCE.**

3 A. I have a Bachelor of Arts degree in Geography from the University of Georgia and
4 a Master's in Business Administration degree from Mercer University. I began my
5 career with Georgia Power in 1997 and have held various positions in Retail Sales
6 and Service, Pricing and Rates, Energy Efficiency, Renewable Development, and
7 Marketing. I served as the first manager of the Company's Green Energy Program,
8 and I helped create the Renewable Development organization in 2013. From 2013
9 until 2016, I was the Renewable Energy Planning Manager with primary
10 responsibility for renewable energy strategy and program development for both
11 Georgia Power's renewable energy procurement plans and customer solar
12 programs. I managed and oversaw the team responsible for all aspects of analysis,
13 compliance, reporting, and communication related to the Company's renewable
14 energy initiatives. Immediately prior to my current role, I served as Assistant to the
15 Senior Vice President of Marketing for Georgia Power, where I provided oversight
16 and assistance for all of Georgia Power's marketing, energy efficiency, energy
17 services, sales, pricing and planning activities.

18 Currently, I serve as the Director of Renewable Development for Georgia Power.
19 In this role, I lead the Customer Engagement, Distributed Generation, Utility Scale
20 Procurement, Self-Build Project Development and Reporting teams in the
21 Renewable Development Organization. Our organization has successfully designed
22 and implemented programs that have developed renewable resources with an
23 expected total committed renewable capacity of more than 5,500 MW by 2025,¹
24 which gives Georgia Power one of the largest voluntary renewable portfolios in the
25 country.

¹ Georgia Power reports only the null energy output from some renewable generating facilities. Ownership of the associated renewable energy credits ("RECs") is specified in each respective power purchase agreement or program tariff. The party that owns the RECs retains the right to use and report them.

1 **Q. MR. MALLARD, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
2 **GEORGIA PUBLIC SERVICE COMMISSION?**

3 A. Yes. I testified in Docket No. 43814, Georgia Power's Application for the
4 Certification of the 2022/2023 Utility Scale Renewable PPAs; Docket Nos. 4822,
5 16573, and 19279, the Commission's Review of Georgia Power's PURPA Avoided
6 Cost Methodology; Docket No. 42625, Georgia Power's Application for the
7 Certification of the 2020/2021 REDI Utility Scale PPAs; Docket No. 41596,
8 Georgia Power's Application for the Certification of the 2018/2019 REDI Utility
9 Scale PPAs; and Docket No. 41734, Georgia Power's Application for the
10 Certification of the 2018/2019 REDI Utility Scale PPAs for the C&I Program.

11 **Q. MR. ROBINSON, PLEASE SUMMARIZE YOUR EDUCATION AND**
12 **PROFESSIONAL EXPERIENCE.**

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

27 From 2017 through 2020, I served as the Power Delivery Operations General
28 Manager for Georgia Power. I began my current role as Planning, Operations, and

1 Policy Vice President in 2021. I lead a team of 425 employees that consists of
2 Project Management, Planning and Policy, Systems and Standards, Storm Center
3 operations, Transmission and Distribution Operations, and North American
4 Electric Reliability Corporation (“NERC”) Compliance. This team is responsible
5 for the planning and operation of 75,000 miles of distribution lines, 17,000 miles
6 of transmission lines, and over 2,000 substations statewide.

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

8 A. Yes, I testified before the Commission in Georgia Power’s 2019 Rate Case in
9 Docket No. 42516.

10 **Q. MR. WEATHERS, PLEASE SUMMARIZE YOUR EDUCATION AND**
11 **PROFESSIONAL EXPERIENCE.**

12 A. I graduated from Auburn University in 1996 with a Bachelor of Science in
13 Mechanical Engineering, and in 1998 with a Master’s in Business Administration
14 degree. I began my career at Southern Company in 1998 at Plant Farley and joined
15 SCS in 1999. Over the next seven years, I progressed through roles of increasing
16 responsibility in System Planning, Fleet Operations, Asset Management, and
17 Southern Power Generation Development. I became the Energy Analysis Manager
18 in 2006 with responsibility for analyzing wholesale contracts, trading, and pool
19 transactions. In 2011, I became Manager of Financial and Contract Services, with
20 responsibility for the wholesale billing, settlement, and analysis of the
21 Intercompany Interchange Contract, the wholesale contracts of the operating
22 companies, and the Open Access Transmission Tariff. In December 2015, I moved
23 into the role of Strategic Generation Planning Manager with responsibility over
24 energy budgeting, scenario planning and forecasting, and asset valuations. In
25 September 2016, I was named Resource Planning Manager and assumed additional
26 responsibilities related to the coordinated planning process. My responsibilities
27 now include integrated resource planning, energy budgeting, evaluation of
28 Requests for Proposals (“RFP”), reliability and reserve margin analysis, scenario
29 planning and forecasting, and production cost modeling and analysis.

1 **Q. MR. WEATHERS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
2 **GEORGIA PUBLIC SERVICE COMMISSION?**

3 A. Yes. I testified in Docket No. 43814, Georgia Power's Application for the
4 Certification of the 2022/2023 Utility Scale Renewable PPAs; Docket Nos. 4822,
5 16573, and 19279, the Commission's Review of Georgia Power's PURPA Avoided
6 Cost Methodology; Docket No. 42625, Georgia Power's Application for the
7 Certification of the 2020/2021 REDI Utility Scale PPAs; Docket No. 42310,
8 Georgia Power's 2019 IRP; Docket No. 41596, Georgia Power's Application for
9 the Certification of the 2018/2019 REDI Utility Scale PPAs; Docket No. 41734,
10 Georgia Power's Application for the Certification of the 2018/2019 REDI Utility
11 Scale PPAs for the C&I Program; and Docket No. 39638, FCR-24.

12 **Q. WHAT IS THE IRP?**

13 A. The IRP is Georgia Power's benchmark plan that contains the Company's electric
14 demand and energy forecast for a 20-year period. The IRP contains the Company's
15 plan for meeting the requirements shown in its forecast in an economical and
16 reliable manner and contains the Company's analysis of all resource options,
17 including both demand-side and supply-side options. In addition, the IRP sets forth
18 the Company's assumptions and conclusions with respect to the effect of resource
19 options on the future cost and reliability of electric service. The IRP process is
20 governed by the Commission and benefits customers through the development of a
21 diverse resource mix that serves customers in an economical and reliable manner.

22 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

23 A. The purpose of our testimony is to present and seek approval of Georgia Power's
24 2022 IRP, including the Company's (i) Application for Decertification of Plant
25 Wansley Units 1-2 & 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant
26 Gaston Units 1-4 & A, and Plant Scherer Unit 3; (ii) Application for Certification
27 of the PPAs from Plant Harris Unit 2, Plant Wansley Unit 7, Plant Dahlberg Units
28 1, 3, and 5, Plant Dahlberg Units 2 and 6, Plant Dahlberg Units 8-10, and Plant

1 Monroe Units 1-2, and (iii) Application for Certification of Capacity from Blocks
2 2-4 and Blocks 5 and 6. We adopt the 2022 IRP as part of our testimony.

3 **Q. PLEASE SUMMARIZE THE TESTIMONY OF THE PANEL.**

4 A. Georgia Power's 2022 IRP offers a comprehensive plan with a balanced portfolio
5 of energy resources to provide customers with clean, safe, reliable, and affordable
6 electric service for years to come, even as customer preferences, society's energy
7 needs, technology, and the energy landscape continue to evolve. Georgia Power is
8 taking steps to effectively transform its generation fleet, prepare for the retirement
9 of its coal-fired generation resources, and integrate greater amounts of renewable
10 resources, while continuing to ensure that the Company can reliably serve its
11 customers across the state in a clean, safe, and affordable manner.

12 This IRP appropriately considers the continued economic challenges facing the
13 Company's coal-fired generation fleet, increasing policy and regulatory pressure
14 related to carbon and environmental standards, the significant increase in customer
15 expectations for renewable and other low or no carbon solutions, and the
16 availability of valuable supply-side market options resulting from the Company's
17 2022-2028 Capacity RFP.

18 It is no longer economic to operate the Company's coal units long-term, given the
19 increasing cost pressures from existing and future environmental requirements and
20 the current availability of more economic replacement capacity. The success of the
21 Company's 2022-2028 Capacity RFP offers demonstrated value for customers in
22 support of the fleet transition. The Company has laid out a strategic retirement plan
23 to responsibly transition its coal fleet without sacrificing reliability for customers.

24 The Company has proposed to continue its measured and steady growth of
25 renewable resources by adding 2,300 MW of resources to be online by 2029, with
26 a plan to achieve 6,000 MW by 2035. The Company intends to leverage the benefits
27 of renewable resources in a way that integrates these resources in an economic and

1 reliable manner through the addition of 1,000 MW of Company-owned storage by
2 2030, greater operational control of the renewable resources, and transmission
3 system enhancements. The Company proposes to expand its innovative renewable
4 programs to meet increasing customer requests for greater access to renewable
5 energy. The Company proposes to invest in the transmission system through its ten-
6 year plan and to accommodate the fleet transition in support of coal unit retirement
7 and renewable resource integration. The Company will continue to invest in the
8 hydro fleet, seek to renew its nuclear licenses with the Nuclear Regulatory
9 Commission for Plant Hatch Units 1 and 2, and invest in technology demonstration
10 projects for the benefit of customers. The Company is introducing the application
11 of distributed energy resources (“DER”) for grid resilience and greater reliability
12 in the DER Customer Program, as well as seeking to better understand DER as
13 potential distribution and transmission solutions.

14 The 2022 IRP demonstrates the Company’s continued focus on reliability with the
15 adoption of a winter target reserve margin and continued focus on seasonal
16 planning. The importance of seasonal planning has been reinforced by the
17 reliability events seen around the country since the 2019 IRP. The Company is also
18 introducing strategic initiatives like the North Georgia Reliability and Resilience
19 Plan, which incorporates near-term actions and long-term planning across
20 disciplines to solve transmission constraints and meet future generation needs.

21 Through the 2022 IRP process, the Company will continue to work constructively
22 with the Commission to invest in Georgia’s energy future and provide industry-
23 leading energy solutions that will benefit customers and Georgia’s communities for
24 future generations.

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

26 **A.** The remainder of our testimony is organized as follows:

- 27 • Section II covers reliability, the reserve margin, and seasonal planning.

- 1 • Section III discusses the Company's scenario planning.
- 2 • Section IV addresses the Company's supply-side strategy, including the
- 3 fleet transition strategy, the requested decertification of Plant Wansley
- 4 Units 1-2 and 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant
- 5 Gaston Units 1-4 and A, and Plant Scherer Unit 3, the requested certification
- 6 of the six PPAs executed as a result of the 2022-2028 Capacity RFP, the
- 7 proposed subsequent license renewal for Plant Hatch Units 1-2, and the
- 8 continued investment in the Company's hydro fleet.
- 9 • Section V addresses the North Georgia Reliability and Resilience Action
- 10 Plan.
- 11 • Section VI discusses Energy Storage.
- 12 • Section VII discusses the Company's renewable expansion plan, renewable
- 13 procurements, and renewable customer programs.
- 14 • Section VIII addresses the Local Reliability and Constraints DER Pilot.
- 15 • Section IX covers the Company's Transmission Plan.
- 16 • Section X outlines the Company's offer and requested certification of
- 17 wholesale-to-retail capacity from Plant Yates Units 6-7 and the oil-fired
- 18 combustion turbines ("CTs") at Plant McManus and Plant Wilson.
- 19 • Section XI addresses resilience considerations.
- 20 • Finally, Section XII addresses the Company's proposed accounting
- 21 treatment and cost recovery requests for the plans included in the 2022 IRP.

22 **Q. WHAT AREAS OF THE COMPANY'S CASE ARE ADDRESSED BY THE**
23 **OTHER WITNESSES' TESTIMONY?**

24 A. The Panel of Mark S. Berry and Aaron D. Mitchell provide additional information
25 on the Company's environmental compliance strategy, the carbon pressures facing
26 the Company's generation fleet, and research and development initiatives. The
27 Panel of Francisco Valle, Andy Phillips, Jeffrey K. Smith, and Lee Evans supports
28 the Company's Load and Energy Forecast, DSM Application, and proposed DER
29 Customer Program.

1 **II. RELIABILITY**

2 **Q. WHAT IS “RESOURCE ADEQUACY”?**

3 A. Resource Adequacy refers to the level of resources required to maintain an
4 appropriate level of reliability on the electric system. Accepted utility practice
5 requires that an electric utility maintain sufficient supply- and demand-side
6 resources to adequately serve the electricity needs of its customers. Georgia Power
7 continuously evaluates Resource Adequacy through its assessment of existing
8 resources on the system and calculation of peak demand and Target Reserve
9 Margin. The Company includes this analysis and the Reserve Margin Study in its
10 triennial IRP process.

11 **Q. WHAT IS THE RESERVE MARGIN AND WHAT IS ITS PURPOSE?**

12 A. The reserve margin represents the difference between the total existing and
13 committed capacity, including the impact of demand response programs, and the
14 Company’s projected peak demand. The reserve margin is generally expressed as
15 the percentage of existing and committed capacity above the projected weather-
16 normal peak demand (*e.g.*, a reserve margin of 16.25% means that existing and
17 committed capacity is 16.25% above the projected weather-normal peak demand).
18 In accordance with accepted utility practice, Georgia Power maintains capacity
19 reserves greater than the Company’s projected peak demand to achieve the
20 appropriate level of reliability in light of various risk factors (*e.g.*, weather,
21 economic growth uncertainty, generator unit performance, and market availability
22 risk) that could cause the actual peak demand, or generation available to meet the
23 peak demand, to differ from projections.

24 **Q. WHAT IS THE TARGET RESERVE MARGIN?**

25 A. The Target Reserve Margin is the reserve margin that the Company uses for
26 reliability planning purposes. The actual reserve margin will vary over time due to
27 variations in the actual peak demand and resource availability, among other things.

1 In contrast, the Target Reserve Margin remains fixed (until updated through a
2 Reserve Margin Study) and is used to guide the Company's resource planning
3 decisions. The Company evaluates three components in determining the Target
4 Reserve Margin: economics; risk tolerance; and reliability. The Target Reserve
5 Margin is set at a level that will minimize the combined expected costs of
6 maintaining reserve capacity, production costs, and customer costs associated with
7 service interruptions, while adjusting for risk and maintaining a minimum level of
8 reliability.

9 **Q. HOW DOES THE COMPANY DETERMINE ITS TARGET RESERVE**
10 **MARGIN?**

11 A. A Reserve Margin Study is conducted by SCS at least every three years. The study
12 identifies the Target Reserve Margin for the System considering both the costs and
13 risks to customers and the reliability of the System. The target planning reserve
14 margin for each of the retail operating companies is then determined taking into
15 consideration the benefits of System reserve sharing and load diversity.

16 **Q. WHY IS THE RESERVE MARGIN STUDY CONDUCTED AT A SYSTEM**
17 **LEVEL?**

18 A. The Reserve Margin Study is conducted at the System level because the entire
19 System is dispatched as a pool, providing numerous benefits to Georgia Power
20 customers, and the pooling arrangement requires a coordinated planning process.

21 **Q. HOW DO POOL DISPATCH AND COORDINATED PLANNING BENEFIT**
22 **GEORGIA POWER CUSTOMERS IN THE CONTEXT OF THE TARGET**
23 **RESERVE MARGIN?**

24 A. Because Georgia Power can "share" (*i.e.*, utilize) the reserves of the other operating
25 companies and because there is additional load diversity when considering all the
26 operating companies, Georgia Power can plan to a lower Target Reserve Margin
27 while the higher System target is maintained. This reserve sharing benefits

1 customers by lowering the amount of generation capacity needed by Georgia Power
2 to reliably serve customers, which ultimately lowers the cost of generation capacity
3 for which customers pay.

4 **Q. IS THE COMPANY PROPOSING TO CONTINUE USING SEASONAL**
5 **PLANNING AS APPROVED IN THE 2019 IRP?**

6 A. Yes. The Company's 2021 Reserve Margin Study supports Georgia Power's plans
7 to continue to use seasonal planning to address weather-related reliability risks
8 during the summer and winter periods. Given that customer load response and
9 resource availability and dependability vary across the summer and winter peak
10 periods, it remains necessary to independently evaluate Resource Adequacy in both
11 the summer and winter peak periods to ensure that System reliability has been
12 appropriately evaluated. Moreover, since the 2019 IRP, major reliability events
13 encountered across the country have reinforced the importance of seasonal
14 planning.

15 **Q. DO THE FACTORS IDENTIFIED IN THE 2016 AND 2019 IRP AS**
16 **IMPACTING WINTER RELIABILITY STILL IMPACT THE**
17 **RELIABILITY NEEDS OF THE SYSTEM?**

18 A. Yes. As noted in this IRP, the drivers of (1) the narrowing of the difference between
19 summer and winter weather-normal peak loads; (2) higher volatility of winter peak
20 demands relative to summer peak demands; (3) cold-weather-related unit outages;
21 (4) the penetration of solar resources; (5) increased reliance on natural gas; and (6)
22 market purchase availability continue to remain relevant System reliability factors.
23 The continued impact of these issues reinforces the need for the Company to
24 maintain seasonal planning and the importance of the Winter Target Reserve
25 Margin.

1 **Q. WHAT ARE THE COMPANY'S RECOMMENDED SUMMER AND**
2 **WINTER TARGET RESERVE MARGINS?**

3 A. The Company plans to maintain the current 16.25% long-term Summer Target
4 Reserve Margin and the 26% long-term Winter Target Reserve Margin for the
5 System. For the short term (2022-2024), the Company plans to use the System
6 targets of 15.75% for summer and 25.5% for winter. These values were used to
7 prepare the 2022 IRP filing.

8 **Q. WERE THERE OTHER RELIABILITY ANALYSES CONDUCTED BY**
9 **THE COMPANY AS PART OF THE PREPARATION OF THE 2022 IRP?**

10 A. Yes, one of which was the Renewable Integration Study.

11 **Q. WHY DID THE COMPANY CONDUCT THE RENEWABLE**
12 **INTEGRATION STUDY?**

13 A. As the fleet transitions away from a heavy reliance on conventional thermal
14 generating resources, the Company decided to expand its reliability analyses and
15 conducted the Renewable Integration Study to determine the most economical
16 means of reliably integrating large penetrations of solar resources.

17 **Q. WHAT DID THE RENEWABLE INTEGRATION STUDY CONCLUDE?**

18 A. The Renewable Integration Study identified that increases in operating reserves are
19 necessary to reliably integrate solar and other variable renewable resources. As
20 more solar resources are added to the System, more operating reserves are needed
21 to ensure the System can effectively balance generation and load. Operating
22 reserves represent the capacity above real-time load requirements that is available
23 to respond quickly to unexpected unit outages, variability in load or resource
24 output, or other system conditions that are difficult to predict. Operating reserves
25 are a critical tool used by System operators to balance load and generation in real
26 time while simultaneously managing inherent load and generation uncertainties.

1 In addition, the Renewable Integration Study determined that flexible resources,
2 such as battery energy storage systems (“BESS”), can provide these essential grid
3 services more efficiently by providing operating reserves at a lower production
4 cost. Maintaining a sufficient amount of flexible resources, such as stand-alone
5 storage capacity (approximately 15% of the installed solar capacity on the System),
6 significantly improves the cost-effectiveness of solar integration, reduces
7 renewable resource curtailment, and provides grid reliability services.

8 **Q. HOW DO THE RESULTS OF THE RENEWABLE INTEGRATION STUDY**
9 **IMPACT THE COMPANY’S PLANNING IN THIS IRP?**

10 A. The Renewable Integration Study supports the Company’s request for 1,000 MW
11 of energy storage resources by 2030, including the 265 MW McGrau Ford Battery
12 Facility, to ensure Georgia Power economically provides reliable service. Based
13 upon the amount of solar resources estimated to be on the system by 2030, the 1,000
14 MW being proposed represents a sufficient amount of energy storage resources to
15 improve the cost-effectiveness of solar integration and improve System reliability.
16 The Company also recommends using the integration costs identified in the
17 Renewable Integration Study as a component in the Renewable Cost Benefit
18 (“RCB”) Framework in place of the support capacity component.

19 **Q. WILL THE COMPANY UPDATE THE RENEWABLE INTEGRATION**
20 **STUDY?**

21 A. Yes. As the amount of intermittent renewable generation continues to grow, the
22 Company will periodically update the Renewable Integration Study. The Company
23 anticipates that the Renewable Integration Study will likely be revisited in future
24 IRPs, similar to the Reserve Margin Study and the RCB Framework.

1 **III. SCENARIO DESIGN & EXPANSION PLANNING**

2 **Q. DOES THE 2022 IRP CONTINUE TO USE A SCENARIO PLANNING**
3 **PROCESS?**

4 A. Yes, consistent with prior IRPs, the Company continued to evaluate economic
5 scenarios that aid in understanding some forms of future uncertainty as part of its
6 2022 IRP. Key uncertainties affecting planning include (i) the evolution of natural
7 gas prices; (ii) future environmental pressures—especially regarding carbon-
8 dioxide (“CO₂”); (iii) cost and performance of future generating technologies; and
9 (iv) future load growth.

10 **Q. HAVE THE SCENARIOS CHANGED FROM THE 2019 IRP?**

11 A. The design of the 2022 IRP scenarios has changed from the 2019 IRP. The
12 Company continues to evaluate both changes in natural gas prices and future
13 environmental pressures, including CO₂. In the 2019 IRP, the Company considered
14 a fee imposed for each ton of carbon dioxide the Company emits using scenarios
15 of \$0 per metric ton, \$10 per metric ton, and \$20 per metric ton. For the 2022 IRP,
16 the Company removed the \$10 per metric ton scenario and added a \$50 per metric
17 ton scenario. The Company also added a CO₂ intensity scenario that adds a
18 requirement that annual System CO₂ emissions fall to 10% of current levels by
19 2050, representing a mass-based pressure on CO₂ emissions. The Company also
20 added scenarios that consider changes in future load growth as well as changes in
21 generating technology cost and performance. Lastly, the Company’s scenarios use
22 fuel price paths from the Energy Information Administration 2021 Annual Energy
23 Outlook.

24 **Q. WHY HAVE THE SCENARIOS CHANGED FROM THE 2019 IRP?**

25 A. The Company’s scenario planning assumptions and evaluations of natural gas
26 prices, variations in loads, and carbon pricing are updated annually. However, since
27 the 2019 IRP, the energy landscape has continued to evolve with a growing

1 emphasis on carbon pressures and climate impacts. To adapt with these changes
2 and appropriately consider how to mitigate new and evolving risks for customers,
3 Georgia Power expanded its economic evaluations associated with carbon risk. The
4 scenarios and sensitivities address the potential for technology advancements,
5 numerous carbon pricing levels, electrification, and clean portfolio standards.

6 **Q. IS THE LONG-TERM SCENARIO PLANNING PROCESS THE BEST**
7 **METHOD TO EVALUATE RISKS FROM CARBON PRESSURE TO**
8 **GEORGIA POWER'S GENERATING FLEET?**

9 A. Yes. The Company's scenario planning process remains the best way to capture a
10 range of potential outcomes and allow for long-term planning to evaluate risks to
11 customers resulting from carbon regulation, policy, and legislation. These scenarios
12 are aligned and representative of the potential range of carbon pressures in the
13 recently proposed and anticipated future climate and clean energy legislation. The
14 Company will continue to work directly with the Commission to monitor and
15 evaluate the outcome of carbon-related executive, legislative, and regulatory
16 actions and incorporate any new information into the planning process as
17 appropriate.

18 **Q. WHAT IS THE PURPOSE OF THE RESOURCE MIX STUDY AND THE**
19 **GENERIC EXPANSION PLANS?**

20 A. The Company's expansion planning analysis determines the optimal mix of
21 resources that satisfy future capacity and energy demands in an economic and
22 reliable manner. In this step of the planning process, demand-side resources are
23 integrated with supply-side resources to provide a roadmap that informs long-term
24 resource planning decisions. Significantly, generic expansion plans do not
25 represent a resource planning decision by the Company but rather are indicative of
26 what may be an optimal mix of resources within various scenarios. These results of
27 generic expansion plan modeling are combined with the existing fleet of resources
28 as inputs into more detailed production cost modeling to produce hourly avoided

1 energy costs for each scenario. Using this information, the Company then performs
2 resource-specific economic evaluations for both demand-side and supply-side
3 options.

4 **Q. WHAT CHANGES HAS THE COMPANY MADE TO ITS RESOURCE MIX**
5 **STUDY?**

6 A. For the first time in a Georgia Power IRP, the 2022 IRP includes solar, battery
7 energy storage, and wind resources as generic resource options selectable by the
8 expansion planning model. Importantly, the Company's expansion planning results
9 reflect these new resource options as economically optimal in certain scenarios.
10 The results of the Aurora expansion planning analysis, along with the availability
11 of low-cost renewable resources as confirmed through recent Georgia Power
12 Renewable RFPs, supports the conclusion that continuing to add renewable
13 resources will benefit customers.

14 **IV. SUPPLY-SIDE STRATEGY**

15 **Fleet Transition**

16 **Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED SUPPLY-SIDE**
17 **PLAN.**

18 A. As set forth in the 2022 IRP, Georgia Power's current supply-side plan provides
19 customers with substantial reliability and economic benefits while establishing a
20 strategic plan for the incremental retirement of the Company's remaining coal
21 resources and corresponding transition to resources that will deliver clean, safe,
22 reliable, and affordable energy for decades to come. As described more fully below,
23 the Company continues to take action to increase the flexibility and maintain the
24 reliability of its diverse fleet of supply-side generation resources.

1 **Q. WHY HAS GEORGIA POWER PROPOSED A PLAN AND RETIREMENT**
2 **DATES FOR ITS COAL FLEET?**

3 A. As in every IRP, the Company evaluates whether its current pool of resources is
4 best suited to continue to serve customers economically and reliably. The
5 Company's coal resources now lack sufficient economic and flexibility attributes
6 to remain competitive within an electric system with large renewable penetration
7 and in a future with continued environmental cost pressures, including carbon. The
8 economic pressures and potential risks facing the Company's coal resources
9 necessitate the development of a strategic transition plan for these resources. The
10 Company's transition plan considers the Effluent Limitations Guidelines ("ELG")
11 Reconsideration Rule cessation of coal combustion option, which allows the
12 Company to comply with the rule by permanently ceasing coal combustion at a unit
13 no later than December 31, 2028. This compliance option provides the Company
14 with additional time to prepare the System for retirements by initiating transmission
15 projects that are necessary to accommodate the combined retirements and the
16 procurement of replacement capacity, while reducing or avoiding additional
17 environmental-related investments for certain resources.

18 By laying out the Company's strategic retirement plans for its coal units through
19 2028 and beyond, Georgia Power demonstrates its continued commitment to a
20 reliable and economic resource mix while acknowledging the need to transition the
21 fleet toward cleaner and more economical resources. Further, by outlining its long-
22 term plans for the coal fleet, the Company can ensure that it has the flexibility to
23 take advantage of opportunities and mitigate the impacts that this change has on
24 employees, communities, and customers.

1 **Decertification Requests**

2 **Q. HOW DO ISSUES WITH COAL UNIT FLEXIBILITY IMPACT**
3 **ECONOMICS?**

4 A. Coal units lack the necessary flexibility characteristics to efficiently respond to
5 large changes in the generating output of renewable resources. As solar penetration
6 increases, daytime marginal energy costs will be depressed, potentially as low as
7 \$0/MWh, because solar energy is abundant. Conversely, marginal energy costs may
8 increase at night as solar is offline. The Company's coal units are unable to start
9 and stop daily, thereby creating economic inefficiencies in a future state with
10 substantial intermittent resources. Gas units can turn on and off daily, increasing
11 their advantage over coal units.

12 **Q. IS THE COMPANY PROPOSING TO DECERTIFY ANY GENERATION**
13 **UNITS AS PART OF THE 2022 IRP?**

14 A. Yes. The Company is requesting decertification of Plant Wansley Units 1-2 and
15 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant Gaston Units 1-4 and A,
16 and Plant Scherer Unit 3 (collectively, the "Retirement Units"), for a total
17 decertification amount of 3,581 MW of Georgia Power-owned winter generating
18 capacity.

19 **Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED**
20 **DECERTIFICATION OF PLANT WANSLEY UNITS 1-2.**

21 A. Plant Wansley Units 1-2 are coal-fired units with a total capacity of 1,744 MW.
22 Georgia Power owns 53.5% of Plant Wansley Units 1-2, or 933 MW. The economic
23 conditions for Plant Wansley continue to deteriorate such that continued operation
24 of Plant Wansley Units 1-2 is uneconomical and not in the best interests of
25 customers. Georgia Power's reliability assessments indicate that Plant Wansley can
26 retire immediately without significant transmission impacts. Also, the results of the

1 2022-2028 Capacity RFP identified cost effective replacement capacity. As such,
2 the Company proposes to retire Plant Wansley Units 1-2 on August 31, 2022.

3 **Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED**
4 **DECERTIFICATION OF PLANT BOWEN UNITS 1-2.**

5 A. Plant Bowen Units 1-2 are coal-fired units with a total capacity of 1,432 MW. In
6 the 2019 IRP, Bowen Units 1-2 were identified as units facing potential economic
7 challenges by the unit retirement analysis conducted as part of that IRP. As directed
8 in the 2019 IRP Order, the Company has significantly reduced capital spending on
9 Plant Bowen Units 1-2, while the Company evaluated potential market options to
10 replace these resources. The economic analysis conducted as part of the Unit
11 Retirement Study in the 2022 IRP indicates that continued operation of Plant
12 Bowen Units 1-2 is uneconomical and not in the best interests of customers. Also,
13 the results of the 2022-2028 Capacity RFP identified cost effective replacement
14 capacity. Based on the Company's updated reliability assessments, the Company
15 requests retirement of Plant Bowen Units 1-2 upon the completion of necessary
16 transmission system improvements, which is projected to be no later than
17 December 31, 2027.

18 **Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED**
19 **DECERTIFICATION OF PLANT GASTON UNITS 1-4.**

20 A. Plant Gaston Units 1-4 are gas-fired steam units with a total capacity of 1,020 MW.
21 Georgia Power owns 50% of Plant Gaston Units 1-4 or 510 MW. These units have
22 been in service for Georgia Power retail customers since the early 1960s. The
23 requirements of the ELG rule are negatively impacting the Company's ability to
24 maintain coal backup for these units. This impact would likely require the Company
25 to eliminate coal backup and make long-term investments in expensive annual firm
26 gas transportation to ensure reliable operation. The Company has determined that
27 annual firm gas transportation is not economic for these aging units. Moreover,
28 Georgia Power identified replacement capacity in the 2022-2028 Capacity RFP that

1 will allow for the cost-effective replacement of this capacity and avoid the need to
2 make any long-term financial investment in firm natural gas transportation. The
3 Company proposes to retire Plant Gaston Units 1-4 by December 31, 2028. This
4 retirement date avoids expensive annual firm gas transportation, provides sufficient
5 time to prepare the transmission system for retirement, and supports a reliable fleet
6 transition.

7 **Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED**
8 **DECERTIFICATION OF PLANT SCHERER UNIT 3.**

9 A. Plant Scherer Unit 3 is a coal-fired unit with a total capacity of 860 MW. Georgia
10 Power owns 75% of Plant Scherer Unit 3, or 645 MW. The Company's economic
11 evaluations, combined with other operational considerations, led to the conclusion
12 that retirement of Plant Scherer Unit 3 is in the best interests of customers. Also,
13 the results of the 2022-2028 Capacity RFP identified cost-effective replacement
14 capacity. To support the reliable transition of the incremental planned retirement of
15 the Company's other coal resources, the Company plans to retire Plant Scherer Unit
16 3 on December 31, 2028. By establishing a known retirement date, Georgia Power
17 can gradually reduce operating costs while preparing the System for retirement.

18 **Q. DOES THE COMPANY PLAN TO RETIRE PLANT SCHERER UNITS 1-2**
19 **PRIOR TO 2028?**

20 A. No. Georgia Power plans to install ELG controls on Plant Scherer Units 1-2.
21 Georgia Power owns 8.4% of each Plant Scherer Unit 1 and Unit 2 or 144 MW.
22 While the economics of Plant Scherer Units 1-2 are challenged, by electing to
23 install ELG controls through the Voluntary Incentive Plan (VIP) option, the
24 Company has additional time to fully consider its ELG Rule compliance options.
25 However, to reduce the long-term reliance on these units, the Company will
26 undertake certain transmission system improvements to prepare for the ultimate
27 retirement of Scherer Units 1-2. As a minority owner, Georgia Power does not have
28 primary decision-making authority for Plant Scherer Units 1-2. For planning

1 purposes only, the Company has assumed a retirement date of December 31, 2028.

2 **Q. WHY DOES THE COMPANY RECOMMEND CONTINUING TO**
3 **OPERATE SCHERER UNITS 1-2 BUT NOT SCHERER UNIT 3?**

4 A. For the retirement of the three Scherer units, the Company's reliability assessments
5 have identified necessary transmission system improvements that would be
6 difficult to complete prior to the ELG rule deadline of December 31, 2028.
7 Therefore, the Company cannot retire all three units at Plant Scherer until
8 completion of these projects. However, retirement of a single Scherer unit is
9 achievable. For Plant Scherer Units 1-2, the Company will make certain retirement
10 preparations, such as transmission system improvements, to ensure the retirement
11 option remains achievable in the event economics worsen, while preserving the
12 ability to continue operating.

13 **Q. WHY DID THE COMPANY DECIDE TO INSTALL ELG CONTROLS AND**
14 **CONTINUE TO OPERATE PLANT BOWEN UNITS 3-4?**

15 A. The reliability risks associated with retiring Plant Bowen Units 3-4 are too
16 significant to retire the units at this time. While Plant Bowen Units 3-4 are not
17 isolated from the economic challenges facing the rest of the Company's coal units,
18 these units are critical to preserving System reliability and resiliency in north
19 Georgia, the geographical area of the state that contains a significant majority of
20 load served by the Integrated Transmission System ("ITS"). The Company will
21 continue to make prudent investments in the continued short-term operation of
22 Plant Bowen Units 3-4 while taking steps to reduce the long-term reliance on these
23 units as described in the North Georgia Reliability & Resilience Action Plan. For
24 planning purposes only, Georgia Power assumes that Plant Bowen Units 3-4 will
25 retire no later than December 31, 2035.

1 Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED
2 DECERTIFICATION OF THE OIL CT UNITS (BOULEVARD, WANSLEY
3 5A, AND GASTON A).

4 A. Plant Boulevard Unit 1, Plant Wansley Unit 5A, and Plant Gaston Unit A are oil-
5 fired CT units, with a total capacity of 60 MW owned by Georgia Power, that are
6 nearing the end of their useful lives. The Company proposes to retire Plant
7 Boulevard Unit 1, which is the last remaining unit at the site, and Plant Wansley
8 Unit 5A on August 31, 2022, shortly after the conclusion of the 2022 IRP. Georgia
9 Power proposes to retire Plant Gaston Unit A by December 31, 2028, to coincide
10 with the proposed retirement of Plant Gaston Units 1-4.

11 **Replacement Capacity Identified in 2022-2028 Capacity RFP**

12 Q. WHAT CAPACITY HAS BEEN SECURED TO REPLACE THE
13 COMPANY PROPOSED RETIREMENTS?

14 A. Consistent with the Commission's 2019 IRP Order, the Company successfully
15 issued and completed the 2022-2028 Capacity RFP. Georgia Power executed six
16 PPAs with a total capacity of 2,356 MW (winter rating) that offer economic options
17 with low capacity prices and attractive firm gas transportation rates. The Company
18 has requested certification of the six PPAs as part of this 2022 IRP.

19 Q. WHAT WAS THE STRUCTURE OF THE 2022-2028 CAPACITY RFP AND
20 WHAT WERE THE RESULTS?

21 A. The 2022-2028 Capacity RFP sought bids from dispatchable resources including
22 existing gas resources, new gas resources, new stand-alone storage resources, and
23 new storage plus renewable resources. The RFP allowed for bids for acquisitions,
24 purchased power agreements (10, 15 and 30-year terms), and Company-owned
25 Proposals. In accordance with the Commission's RFP rule, the Company developed
26 the Capacity RFP documents and pro-forma PPAs with the input from Commission
27 Staff and the Independent Evaluator ("IE"). The draft RFP documents were made

1 available to bidders and interested parties for comment and feedback with final
2 versions approved by the Commission. Georgia Power issued the 2022-2028
3 Capacity RFP seeking 1,000 to 3,000 MW from facilities sized between 100 and
4 1,200 MW.

5 The response to the 2022-2028 Capacity RFP was robust with multiple offers from
6 many resource types, facilities, and bidders. Georgia Power used a competitive tier
7 and refresh bid process in this RFP, which allowed each bidder a one-time
8 opportunity to refresh pricing and update its best final offer. Georgia Power
9 identified a short list of nine proposals. After further analysis and consultation with
10 Commission Staff and the IE, the Company selected six existing gas resources that
11 provided the most benefits for customers and executed contracts with the winning
12 bidders.

13 **Q. PLEASE DESCRIBE THE CAPACITY SELECTED FROM THE 2022-2028**
14 **CAPACITY RFP.**

15 A. The PPAs with the winning bidders will provide the Company with a total of 2,356
16 MW of capacity (winter rating) and energy. Five of the six winning PPAs have ten-
17 year terms that commence between December 1, 2024, and January 1, 2028. The
18 sixth winning PPA has a fifteen-year term that commences on December 1, 2024.
19 The winning bidders will supply capacity from existing natural gas facilities that
20 are in commercial operation in Heard County, Jackson County, and Walton County,
21 Georgia and Autauga County, Alabama. The capacity prices from these PPAs are
22 significantly below existing and recently expired Georgia Power natural gas PPAs
23 demonstrating the success of the solicitation. As coal retirements reduce the reserve
24 margins in the Southeast, access to these resources, or similar resources, at
25 competitive prices may be challenged in the future.

1 **Q. IS THE COMPANY REQUESTING AN ADDITIONAL SUM ON THE SIX**
2 **PPAS RESULTING FROM THE CAPACITY RFP?**

3 A. Yes, the Company is requesting an additional sum based upon the benefits the PPAs
4 provide. These values are \$8.63/kW-year, \$9.03/kW-year, \$8.67/kW-year,
5 \$8.12/kW-year, \$6.70/kW-year, and \$6.77/kW-year for the Wansley 7, Dahlberg 2
6 and 6, Harris 2, Dahlberg 1, 3, and 5, Monroe 1 and 2, and Dahlberg 8-10 PPAs,
7 respectively.

8 **Q. IS GEORGIA POWER BUILDING NEW NATURAL GAS CAPACITY TO**
9 **REPLACE THE COMPANY'S RETIRING UNITS?**

10 A. No. Georgia Power is requesting certification of six PPAs that will provide capacity
11 and energy from natural gas resources that already exist within the Southern
12 Company Balancing Authority Area. No new natural gas capacity is being built
13 because of the 2022-2028 Capacity RFP.

14 **Q. IS GEORGIA POWER INCREASING RELIANCE ON NATURAL GAS?**

15 A. No. Georgia Power will continue to maintain a diverse portfolio of resources with
16 the addition of these natural gas resources. Georgia Power already had natural gas
17 PPAs that recently expired. Additionally, four of the eight units from the proposed
18 Plant Dahlberg PPAs are associated with existing Georgia Power PPAs that expire
19 on May 31, 2025, and both units from the proposed Monroe 1-2 PPA are associated
20 with an existing Georgia Power PPA that expires on May 31, 2024. As a result, the
21 Company's natural gas capacity as a percentage of its total capacity is projected to
22 be lower in 2022-2028 than it has been in every year since 2014.

1 **Plant Hatch Subsequent License Renewal**

2 **Q. WHEN DO THE CURRENT LICENSES FOR PLANT HATCH UNITS 1**
3 **AND 2 EXPIRE?**

4 A. The current 60-year licenses for Plant Hatch Units 1 and 2 expire in August 2034
5 and June 2038, respectively.

6 **Q. WHAT IS GEORGIA POWER'S REQUEST IN THIS CASE REGARDING**
7 **SUBSEQUENT LICENSE RENEWAL FOR PLANT HATCH?**

8 A. Georgia Power requests Commission approval to pursue a subsequent license
9 renewal ("SLR") with the NRC for Plant Hatch Units 1 and 2, which is estimated
10 to cost approximately \$28 million for Georgia Power. The nuclear industry has
11 begun the process of extending nuclear operating licenses to 80 years. If the SLR
12 is granted, and continued operation remains beneficial for customers, the Company
13 envisions bringing to the Commission in the 2028 IRP a request to seek SLR
14 approval to extend operations at Plant Hatch Units 1 and 2 for up to an additional
15 twenty years beyond the current licenses.

16 **Q. DID GEORGIA POWER EVALUATE WHETHER IT WAS FEASIBLE**
17 **AND ECONOMIC TO CONTINUE TO OPERATE PLANT HATCH UNITS**
18 **1-2?**

19 A. Yes. The Company's feasibility study concluded that Plant Hatch Units 1 and 2
20 could operate an additional 20 years and did not identify any unexpected or major
21 required capital investments. The initial economic analysis further indicated that
22 continued operation would be beneficial for customers. The Company anticipates
23 being able to operate the units safely and economically for an additional 20-years.
24 Moreover, continued operation of Plant Hatch Units 1 and 2 would continue to
25 generate zero carbon energy and contribute to the Company's diverse resource mix.

1 **Hydroelectric Investment**

2 **Q. WHAT PROGRESS HAS GEORGIA POWER MADE IN ITS HYDRO**
3 **FLEET MODERNIZATION PROJECTS SINCE THE 2019 IRP?**

4 **A.**The Company has substantially completed the projects for Plant Terrora Units 1-2.
5 The scoping and engineering work is complete for the projects at Plant Tugalo, and
6 site work for Plant Tugalo Unit 1 is currently in progress. The scoping and detailed
7 engineering is in progress for Plant Bartletts Ferry, Plant Nacoochee, and Plant
8 Oliver.

9 **Q. IS GEORGIA POWER PROPOSING TO CONTINUE INVESTING IN ITS**
10 **HYDRO FLEET?**

11 **A.**Yes. The Company proposes to continue investing in its hydro fleet, focusing on
12 Plant Burton, Plant North Highlands, and Plant Sinclair for the 2022 IRP. The units
13 at each of these three Plants have the most pressing need of investment to avoid
14 extended outages in the near future. As proposed in the 2019 IRP, the Company
15 will continue to propose investment projects for its hydro fleet in batches as part of
16 its overall strategic plan to modernize the hydro fleet while optimizing resources,
17 design, planning, and project execution in an efficient manner.

18 **Q. WHY IS IT IMPORTANT TO APPROVE THE NEXT BATCH OF HYDRO**
19 **INVESTMENT PROJECTS?**

20 **A.**Georgia Power's continued investment in its hydro fleet will improve the efficiency
21 and integrity of the fleet and allow these flexible, dispatchable, and zero-carbon
22 resources to operate for at least another 40 years. Without this additional
23 investment, the Company risks near-term extended outages for these units.
24 Commission approval of these projects will help Georgia Power leverage the
25 existing momentum from the first round of hydro programs to take advantage of a
26 trained workforce and optimize the program schedule for these units.

1 **Technology Advancements**

2 **Q. HOW IS THE COMPANY PREPARING FOR POTENTIAL**
3 **TECHNOLOGY ADVANCEMENTS AND THE IMPACT TECHNOLOGY**
4 **MAY HAVE ON THE FUTURE OF ENERGY IN GEORGIA?**

5 A. Technology cost and performance improvements are at the forefront of planning
6 considerations. As the energy landscape continues to evolve, new and emerging
7 technologies have the potential to fundamentally alter the way energy is created,
8 transported, stored, and ultimately consumed. As a core component of the planning
9 process, the Company monitors technology advancements to ensure it is prepared
10 and ready to adopt new technologies that benefit customers. For the 2022 IRP, the
11 Company has identified long-duration storage, hydrogen, and tall wind
12 technologies as areas of focus. When these technologies mature, they have the
13 potential to fundamentally alter the energy landscape in Georgia. Additionally, the
14 Company is seeking to expand the utilization of DER on its power delivery system
15 with its local reliability and constraints pilot program.

16 **V. NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN**

17 **Q. WHAT IS THE NORTH GEORGIA RELIABILITY AND RESILIENCE**
18 **ACTION PLAN?**

19 A. The North Georgia Reliability and Resilience Action Plan is a multi-faceted
20 strategic plan that establishes a comprehensive and coordinated approach to address
21 the gap between generation and load in north Georgia. To serve the state in the most
22 reliable and economic fashion, the development of the generation supply system
23 and the transmission system must be considered as a whole. To that end, the North
24 Georgia Reliability and Resilience Action Plan provides an integrated transmission
25 and generation strategy addressing these concerns.

1 **Q. WHY IS THE COMPANY PROPOSING THE NORTH GEORGIA**
2 **RELIABILITY AND RESILIENCE ACTION PLAN IN THIS IRP?**

3 A. The existing transmission system is strained by the geographic distance separating
4 generation in south Georgia and load in north Georgia. The long-term planned
5 retirement of Plant Bowen Units 3-4 will exacerbate this geographic constraint. As
6 retirements in north Georgia occur, the Company must enhance its generation and
7 transmission systems and operational capabilities to avoid the potential for a major
8 loss of load (i.e., outages). The Company cannot achieve this process overnight, as
9 these projects involve very long lead times and considerable resources. Therefore,
10 given the number of System constraints and time required for investment and
11 execution, the Company's plan reflects continued operation of Plant Bowen Units
12 3-4 with ELG controls in place. This near-term decision will ensure reliability and
13 resilience of the system while the North Georgia Plan is executed.

14 **Q. WHAT ARE THE COMPANY'S ACTIONS THAT MAKE UP THE NORTH**
15 **GEORGIA PLAN?**

16 A. The Company projects that it will complete the transmission system improvements
17 identified in the 10-year transmission plan necessary to support the retirement of
18 Plant Bowen Units 1-2 by December 31, 2027. To reduce the long-term reliance on
19 Plant Bowen Units 3-4, the Company will (i) install ELG controls on Plant Bowen
20 Units 3-4 to allow for continued operation, (ii) issue the north Georgia Renewable
21 RFP, (iii) work with the ITS Participants to develop a strategic portfolio of projects
22 to address the long-term transmission planning and operational needs of north
23 Georgia beyond the retirement of Plant Bowen Units 3-4, and (iv) develop a
24 consolidated expansion plan addressing future generation needs for north Georgia.

1 **Q. IS GEORGIA POWER THE ONLY TRANSMISSION PROVIDER**
2 **SEEKING TO ADDRESS THESE CONCERNS?**

3 A. No. The Company will plan, coordinate, and work with the other ITS Participants
4 in executing the transmission expansion contemplated in the North Georgia Plan.

5 **Q. WHAT REQUESTS IN THIS IRP SUPPORT THE COMPANY’S NORTH**
6 **GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?**

7 A. The Company is seeking Commission approval of two actions in this IRP that will
8 support the Company’s North Georgia Reliability and Resilience Action Plan. First,
9 the Company proposes to install ELG controls at Plant Bowen Units 3-4. Second,
10 the Company seeks to issue its first utility scale renewable RFP as a geographically
11 targeted solicitation in north Georgia. In addition to these requests, the Company
12 will work with the ITS Participants to begin strategically planning for the long-term
13 transmission needs of north Georgia after Plant Bowen Units 3-4 are retired.
14 Finally, Georgia Power will begin preparing a strategy for new generation resources
15 to support future generation needs in the north Georgia region.

16 **VI. ENERGY STORAGE**

17 **Q. PLEASE DESCRIBE THE COMPANY’S PROPOSED DEPLOYMENT OF**
18 **ENERGY STORAGE SYSTEMS.**

19 A. As the penetration of renewable energy resources continues to grow, the Company
20 has identified the corresponding need to add energy storage systems (“ESS”) to the
21 System to ensure reliability most effectively for customers. As supported by the
22 Renewable Integration Study, Georgia Power proposes to own and operate 1,000
23 MW of ESS by 2030 to support System operational and reliability requirements as
24 renewable penetration increases. The Company is proposing the 265 MW McGrau
25 Ford Battery Facility as a part of this plan.

1 **Q. WHY IS THE COMPANY’S PLAN TO OWN AND OPERATE CERTAIN**
2 **ENERGY STORAGE RESOURCES NECESSARY TO MAINTAIN**
3 **RELIABILITY?**

4 A. The Company must be able to reliably serve customers. To ensure that reliability is
5 maintained, the Company must maintain a sufficient portion of the energy storage
6 resources on the system under its ownership and control to reliably serve its
7 customers in a cost-effective manner. The storage resources for which the Company
8 is requesting approval in this IRP will be utilized to efficiently provide essential
9 load balancing services or operating reserves. Historically, Georgia Power has
10 owned and operated many of the System’s baseload resources that have been relied
11 upon to economically serve load and provide essential load balancing services and
12 operating reserves. These resources have been the cornerstone of providing reliable
13 service to customers. As discussed in the Renewable Integration Study, as the fleet
14 transitions and the resource mix evolves to include more intermittent resources, the
15 Company will face many challenges that make Company ownership of ESS
16 resources essential. Georgia Power ownership and control of these energy storage
17 resources will enable the continued delivery of reliable electricity service our
18 customers count on.

19 **Q. DOES COMPANY DEVELOPMENT OF THESE PARTICULAR ESS**
20 **RESOURCES SUPPORT THE RENEWABLE MARKETPLACE IN**
21 **GEORGIA?**

22 A. Yes. The addition of ESS resources reduces the integration cost of new renewable
23 resources as demonstrated by the Company’s Renewable Integration Study. The
24 Company supports the measured addition of solar resources as cost-effective for
25 customers, and Company ownership of an appropriate amount of ESS will reduce
26 renewable integration costs while maintaining reliability. To ensure the best cost,

1 the Company will issue competitive solicitations to supply engineering,
2 procurement, and construction (“EPC”) services in support of this effort.

3 **Q. WILL THE COMPANY CONTINUE TO PROCURE STANDALONE**
4 **ENERGY STORAGE OR ENERGY STORAGE PAIRED WITH**
5 **RENEWABLE RESOURCES THROUGH THE COMPANY’S**
6 **RENEWABLE AND CAPACITY RFPS?**

7 A. Yes. The Company will continue to use the market in meeting needs that will
8 include opportunities for standalone storage resources and storage paired with
9 renewable resources to compete in future capacity RFPs, and the Company will
10 continue to welcome bids for energy storage paired with renewable resources in its
11 renewable RFPs. The Company-owned standalone ESS proposed in this IRP will
12 optimize operations and maintain System reliability as more renewable resources
13 are added.

14 **Q. PLEASE DESCRIBE THE MCGRAU FORD BATTERY ENERGY**
15 **FACILITY PROPOSED IN THE 2022 IRP.**

16 A. The Company proposes the McGrau Ford Battery Facility as a part of its plan to
17 add 1,000 MW ESS by 2030. The McGrau Ford Battery Facility would consist of
18 a 265 MW 2-hour lithium-ion storage device located in Cherokee County which
19 could achieve commercial operation by 2026. The Company’s initial analyses
20 indicate that the identified site is suitable for an ESS from an environmental, soil,
21 and interconnection perspective, and the facility itself is economical and would
22 provide benefits to customers for at least 20 years.

23 **Q. WHAT IS THE COMPANY ASKING THE COMMISSION TO APPROVE**
24 **IN THIS IRP AS IT RELATES TO ENERGY STORAGE?**

25 A. The request is two-fold. First, the Company requests Commission approval of
26 Georgia Power’s long-term plan to own and operate 1,000 MW of ESS by 2030
27 and to use the Renewable Integration Study for planning purposes. Second, the

1 Company requests authority to develop, own, and operate the McGrau Ford Battery
2 Facility as an initial project in support of the Company's long-term ESS plan.

3 **Q. WHAT IS THE STATUS OF THE 80 MW OF BATTERY ENERGY**
4 **STORAGE SYSTEM DEMONSTRATION PROJECTS APPROVED IN**
5 **THE 2019 IRP?**

6 A. The Company elected to develop three different BESS configurations to maximize
7 learnings and overall value to customers: (1) a large standalone transmission-
8 interconnected storage system; (2) a small standalone distribution-interconnected
9 storage system; and (3) a solar plus storage system. In October of 2021, the
10 Commission approved the Company's first project, a 65 MW, 4-hour lithium-ion
11 BESS located at the Mossy Branch Battery Facility in Talbot County, Georgia.
12 Engineering and procurement for that project is underway. The Company intends
13 to evaluate the real-time commercial operation performance of a transmission-
14 interconnected grid-charging storage asset and refine operation and maintenance
15 practices over time. Second, the Company is working with the Army to co-locate a
16 13 MW, 4-hour BESS with an existing on-site solar facility at Ft. Stewart to
17 evaluate the costs and benefits of storage integrated with solar resources. Finally,
18 the Company is evaluating options to install a 2 MW standalone battery on the
19 distribution system to validate the operational and performance capabilities of such
20 an asset in real time.

21 **Q. WHAT DID THE COMPANY LEARN THAT SUPPORTS ITS REQUEST**
22 **TO ADD 1,000 MW OF ENERGY STORAGE?**

23 A. Through these first three demonstration projects, the Company has expanded its
24 knowledge and understanding of ESS, including the development of standardized
25 EPC agreements and supporting control technology to optimize dispatch of current
26 and future ESS efficiently and economically. In addition, the Company has
27 developed relationships with industry participants that can be leveraged to

1 efficiently conduct EPC RFPs and effectively procure resources with the
2 specifications the Company seeks.

3 **Q. WHAT ARE THE COMPANY'S NEXT STEPS FOR ESS?**

4 A. The Company intends to implement its battery storage procurement action plan
5 identified in the 2022 IRP Main Document to further the goal of fulfilling 1,000
6 MW of ESS by 2030. Georgia Power will continue to identify and secure viable
7 sites across the state for new storage resources, complete site layout and
8 engineering drawings, and initiate transmission interconnection studies, as
9 appropriate. At the appropriate time in the development process, the Company will
10 issue a competitive RFP for turnkey EPC storage resources and select favorable
11 proposals based on its evaluations and supporting cost benefit analyses. Finally, the
12 Company will return to the Commission for approval of successful ESS projects.

13 **VII. RENEWABLE RESOURCES**

14 **Renewable Expansion Plan and Procurement Enhancements**

15 **Q. PLEASE DESCRIBE THE COMPANY'S RENEWABLE EXPANSION**
16 **PLAN.**

17 A. The 2022 IRP includes a long-term renewable expansion plan that proposes to add
18 6,000 MW of new renewable resources by 2035, more than doubling Georgia
19 Power's previously approved portfolio of renewable resources. This long-term
20 procurement plan is informed by the Company's expansion planning model, which
21 determines the economically optimal amount of renewable resource additions. This
22 plan expands upon the Company's measured and disciplined approach to the
23 addition of cost-effective renewable generation.

24 The Company's renewable expansion study evaluates various renewable expansion
25 plans based on scenarios with a range of potential carbon costs and fuel costs.
26 Greater amounts of solar or renewable energy are deemed economically optimal in

1 scenarios with higher fuel and emissions costs or lower-cost renewable
2 procurements. The results of these scenario evaluations demonstrate the need for
3 the Company's long-term resource procurement strategy to be adaptable to support
4 the economic procurement of resources. Thus, while the Company currently
5 anticipates the need to add 6,000 MW of renewable resources by 2035, the
6 Company will continue to monitor market conditions, System reliability needs, and
7 other key factors to ensure its long-term strategy remains in the best interests of
8 customers.

9 **Q. WHAT IMPROVEMENTS HAS THE COMPANY PROPOSED TO ITS**
10 **RENEWABLE PROCUREMENT AS PART OF THIS IRP?**

11 A. Based on feedback from market participants and to optimize its renewable resource
12 procurements, the Company has proposed several improvements to its
13 procurements: (1) operational requirements for renewable resources, like
14 operational flexibility achieved through Automatic Generation Control ("AGC");
15 (2) improved locational guidance to help developers site projects where
16 interconnection of renewable resources is more favorable; (3) a transition to best
17 cost procurements whereby the Company evaluates and selects the most valuable
18 resources to meet the established renewable energy need identified in the IRP; and
19 (4) an adaptable cadence of renewable procurements that provides the certainty of
20 continuing renewable solicitations but with the flexibility to adjust schedules and
21 in-service dates to improve efficiencies and the chances for successful solicitations,
22 as well as allow time to incorporate lessons learned from prior procurements.

23 **Q. WHY IS THE COMPANY SEEKING FLEXIBLE RESOURCES?**

24 A. As renewable resources continue to be added to the System, the need to control
25 these resources on par with other System resources becomes increasingly
26 important. Automated control will allow for economic load following as these
27 resources can adjust output in near real time to better match changes in load, thus
28 addressing System reliability issues and minimizing costs for customers. Therefore,

1 the Company is requiring that all new utility scale renewable resources include
2 AGC to help mitigate reliability issues and enable more economic operation of the
3 System. With AGC, System operators will have the ability to increase or decrease
4 the amount of solar generation based on System needs and solar availability.

5 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED IMPROVEMENTS**
6 **REGARDING LOCATIONAL GUIDANCE.**

7 A. For utility scale RFPs, the Company will issue one or more geographically targeted
8 RFPs. Georgia Power's first utility scale RFP will focus exclusively on north
9 Georgia, specifically targeting the addition of new renewable generation in counties
10 north of and intersected by Interstate 20. This North Georgia RFP supports the
11 Company's North Georgia Reliability and Resilience Action Plan discussed
12 previously.

13 For Distributed Generation ("DG") RFPs, the Company will continue offering
14 interconnection guidance to DG market participants, but will improve this guidance
15 by offering a web-based hosting capacity tool for DG resources. This hosting
16 capacity tool will enhance existing guidance to bidders and will indicate where
17 available capacity exists on the distribution system to help minimize
18 interconnection costs and increase the efficiency of project siting. As proposed,
19 Georgia Power will update the hosting capacity tool annually.

20 **Q. PLEASE DESCRIBE WHAT IS MEANT BY BEST COST**
21 **PROCUREMENT.**

22 A. In general, the Company will seek to procure energy from a certain amount of
23 renewable resources by selecting a portfolio of the most valuable or best cost
24 resources to fulfill the projected renewable energy need established in this IRP.
25 Under prior renewable resource procurement guidelines, the Company selected
26 renewable projects to fill the Commission-approved RFP targets so long as each of
27 those resources was evaluated to be below the Company's projected RCB avoided

1 costs (“RCB Avoided Costs”).² While the Company will continue to evaluate the
2 economics during bid evaluations, the Company proposes to cease applying this
3 threshold as an automatic disqualification for bids in the Company’s RFPs.
4 Therefore, the Company is proposing additional flexibility in how it identifies the
5 portfolio of best cost resources to fill the Company’s renewable energy needs as
6 identified by the Renewable Expansion Plan Analysis.

7 Importantly, including this flexibility within the evaluation process does not
8 undermine the core principle of the Company’s renewable resource procurements,
9 which is to ensure that the resources procured are cost effective and provide benefits
10 to customers. The Company, along with the Commission Staff and the IE, will
11 leverage the information gained through the RFP process, such as actual bid prices
12 (including the prices of Company-owned proposals), projected in-service dates,
13 updated interconnection costs, and other market intelligence, to remain adaptable
14 in procuring resources to meet the Company’s renewable energy need. The
15 Company, working with the Commission Staff and the IE, will determine the exact
16 criteria and methods of evaluation, ranking, and selection as part of the
17 Commission-approved RFP process.

18 **Q. WHAT IS DRIVING THE NEED TO CHANGE HOW THE COMPANY**
19 **EVALUATES RENEWABLE RESOURCES IN ITS RFPS?**

20 A. In contrast to prior IRPs, the Company performed an expansion plan analysis that
21 indicates that adding new renewable resources are in customers’ best interests when
22 considering a range of future scenarios. To better optimize its renewable resource
23 procurements and meet this renewable energy need, the Company is transitioning
24 its renewable procurement methodology to follow more closely that of traditional

² RCB Avoided Cost based on a moderate gas zero dollar carbon assumption.

1 procurements, which seek to add certain amounts of resources based on the RFP
2 criteria, market and system conditions.

3 **Q. HOW WILL THE COMPANY MODIFY HOW IT EVALUATES BIDS IN**
4 **ITS RENEWABLE RFPS?**

5 A. For the most part, the Company's evaluation process will remain unchanged. The
6 evaluation will continue to use the RCB Framework to measure the total costs and
7 benefits a resource provides the system and to Georgia Power's customers and
8 produce a ranking based on energy pricing and integration costs, including
9 transmission and distribution system impacts. The evaluation process will identify
10 the best resources to meet the renewable energy need but will no longer rely on the
11 MG0 RCB avoided cost threshold as the primary determinant of customer benefit
12 in its evaluation and selection of renewable projects. Consistent with prior RFPs,
13 the evaluation team, overseen by the Commission Staff and IE, will then take
14 additional factors into consideration in the selection of a proposed portfolio that
15 balances all appropriate impacts. The proposed portfolio will be filed for
16 Commission approval through the certification process, where the Commission
17 maintains the authority to review, modify, and approve the proposed portfolio.

18 **Q. WILL THE COMPANY IMPLEMENT THE BEST COST PROCUREMENT**
19 **APPROACH FOR THE DISTRIBUTED GENERATION RFP?**

20 A. Yes. The Company will modify the evaluation process for the DG RFP to more
21 closely align with the process used with Georgia Power's utility scale RFPs, using
22 a chronological evaluation process to identify the competitive tier, study
23 interconnection and transmission/distribution system impacts, and contract to meet
24 the identified solicitation target with projects that offer the most value for
25 customers. The Company is also considering additional programmatic
26 enhancements to its DG RFP based on feedback from the market and lessons
27 learned from the 2020 DG RFP as part of its implementation of this best cost
28 procurement approach.

1 **Q. HOW DOES THE COMPANY’S RENEWABLE PROPOSAL ALTER OR**
2 **IMPROVE THE FREQUENCY OF RENEWABLE PROCUREMENTS?**

3 A. The Company has historically refined and improved its RFPs based on best
4 practices and lessons learned from each RFP cycle. The Company will continue
5 doing so but with the additional ability to modify the timing, cadence, and required
6 commercial operation dates of resources sought through the procurement process.
7 For example, the Company may incorporate modifications to the schedule and
8 capacity targets of individual solicitations to adapt to customer needs, market
9 conditions, and System needs, while still tracking the Company’s long-term
10 renewable resource plan. To facilitate this improvement, the Company plans to
11 routinely issue utility scale and DG renewable RFPs until it reaches the long-term
12 plan of 6,000 MW of new renewable resources by 2035. This approach will promote
13 ongoing renewable opportunities and allow for the most efficient use of internal
14 and external resources that support these procurements.

15 **Renewable Procurements**

16 **Q. WHAT DOES THE COMPANY SEEK TO PROCURE FROM**
17 **RENEWABLE RESOURCES AS PART OF THE 2022 IRP?**

18 A. The Company is seeking to competitively procure energy from a total of 2,300 MW
19 of new renewable resources: 2,100 MW from utility scale resources; and 200 MW
20 from DG resources. This amount represents an appropriate level of near-term
21 procurement of new resources as the Company navigates the challenges of
22 renewable integration, such as transmission system limitations. At this level of
23 procurement, the Company continues its measured and disciplined approach to
24 renewable resource procurement to the benefit of customers.

1 **Q. HOW MANY RFPS WILL THE COMPANY OFFER AND WHEN WILL**
2 **THEY BE OFFERED?**

3 A. The Company proposes to issue three RFPs, staggering its utility scale and DG
4 solicitations. First, the Company proposes to issue a utility scale RFP in 2023 that
5 targets 1,050 MW of renewable resources in north Georgia to be online by 2026 or
6 2027. To remain adaptable, the Company will review the results of the first utility
7 scale RFP, or any other relevant RFP results, to determine what, if any, adjustments
8 are necessary to MW targets, timelines, or other elements as part of the certification
9 request to the Commission. Second, Georgia Power proposes to issue one 200 MW
10 DG RFP with two bid periods, 100 MW each in 2023 and 2024, with in-service
11 dates in 2024 and 2025, respectively. Finally, the Company generally expects to
12 issue a second utility scale RFP in 2025 seeking to procure renewable energy in an
13 amount sufficient to satisfy the total 2,100 MW US target, with proposed
14 commercial operation dates in 2028 or 2029. The table below summarizes the
15 Company's proposal:

RFP	Expected Issuance	Target (MW)	Expected COD
Utility Scale (North Georgia)	2023	1,050	2026/2027
Distributed Generation	2023	100	2024
<i>Distributed Generation</i>	2024	100	2025
Utility Scale	2025	1,050	2028/2029

16

17 In addition, the Company may petition the Commission between IRP cycles for
18 approval of additional procurements to supply customer needs through the Clean
19 and Renewable Energy Subscription ("CARES") Economic Development program.
20 As in the past, Georgia Power will update and propose future procurement plans in
21 the 2025 IRP.

1 **Q. HAS THE COMPANY PROPOSED ANY CHANGES TO THE RESOURCE**
2 **ELIGIBILITY REQUIREMENTS FOR ITS RFPS?**

3 A. Yes. The Company has proposed that resources greater than six MW AC are
4 eligible to participate in the utility scale RFP and resources between 250 kW AC
5 and up to and including six MW AC are now eligible to participate in the DG RFP.

6 **Q. WHAT ADDITIONAL SUM DOES THE COMPANY REQUEST FOR ITS**
7 **UTILITY SCALE AND DG RFPS?**

8 A. The Company requests a levelized \$7.50/kW_{AC} of the procured amount annually
9 for the term of each PPA entered into as a result of its utility scale and DG RFPS.
10 This revised additional sum methodology is based on the average additional sum
11 amounts received by the Company over its last four Renewable RFPS. It
12 appropriately incents the Company to competitively procure additional resources
13 and fairly considers lost revenues, changed risks, and an equitable sharing of
14 benefits consistent with the additional sum statute.

15 **Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS**
16 **RELATED TO ITS RENEWABLE PROCUREMENTS?**

17 A. Consistent with past practice, the Company proposes to recover the cost of its
18 renewable procurements through the fuel cost recovery ("FCR") clause. Any
19 participation charges designed to recover associated costs and paid by subscribing
20 customer(s) (as described below) would be applied to the fuel clause to reduce FCR
21 costs.

22 **Q. DOES THE COMPANY PROPOSE ANY CUSTOMER SITED**
23 **PROCUREMENTS?**

24 A. Yes. Georgia Power proposes to continue the Customer Connected Solar Program
25 on a year-round basis to allow solar resources located on or near a customer's
26 premises to provide energy to the grid through long-term, fixed price agreements

1 with the RECs retired on behalf of participating host customers. The Company will
2 receive applications on a rolling basis and will evaluate and select projects on a first
3 come, first served basis until the current 25 MW program capacity is filled. The
4 Company will update the Commission and Staff on subscription levels and propose
5 program updates as appropriate.

6 **Renewable Customer Subscription Programs**

7 **Q. WHY IS THE COMPANY PROPOSING TO MAKE ALL THE ENERGY**
8 **PROCURED THROUGH THE UTILITY SCALE RFPS AVAILABLE FOR**
9 **SUBSCRIPTION?**

10 A. Many Georgia Power customers continue to express increased interest in renewable
11 energy programs. In response to growing customer demand, the Company proposes
12 to expand its menu of renewable program options available to all customers and
13 make the energy from every MW procured by the utility scale RFP available for
14 subscription by qualifying commercial and industrial customers.

15 **Q. HOW DO THE PROPOSED SUBSCRIPTION PROGRAM DESIGNS**
16 **PROTECT NON-PARTICIPATING CUSTOMERS AND ENSURE THAT**
17 **BENEFITS FROM THE ADDITION OF RENEWABLE RESOURCES**
18 **ACCRUE TO ALL CUSTOMERS?**

19 A. The addition of renewable resources on the system generates benefits for all
20 Georgia Power customers, regardless of on whose behalf RECs are retired. The
21 addition of renewable resources on the system creates additional fuel diversity,
22 environmental benefits, and projects to create long-term cost savings for all
23 customers. In addition, the program administrative costs for the Company's
24 subscription-based programs are recovered from participating customers to avoid
25 subsidization by non-participants. Moreover, the customer agreements for the
26 Company's subscription programs will include terms and conditions that protect
27 non-participating customers from any future compliance risk.

1 **Q. PLEASE DESCRIBE THE CARES PROGRAM.**

2 A. The CARES program is the third iteration of the Company's C&I subscription
3 program designs. The CARES program incorporates feedback from customers and
4 builds on the success of the C&I REDI and Customer Renewable Supply
5 Procurement ("CRSP") programs. Similar to CRSP, the CARES program offers
6 qualifying C&I customers the ability to subscribe to a portion of the energy output
7 and RECs from a portfolio of new renewable resources. The CARES program
8 offers five different program options for specific subsets of the C&I customers.
9 Each program option has its own eligibility requirements and will be supplied by
10 specific portions of the targeted 2,100 MW portfolio.

11 Table 7 of the IRP Main Document provides a concise breakdown of the capacity
12 allocations and program requirements for each of the five CARES program options.
13 As with CRSP, the CARES program will continue to offer an existing load and new
14 load option. For the existing load option, 900 MW will be made available for
15 subscription by customers with a minimum annual peak demand of 3 MW up to
16 100% of the customer's preceding year's total annual energy consumption.
17 Subscriptions will be allocated on a pro-rata basis. For the new load option, 500
18 MW will be made available for subscription by customers with a minimum annual
19 peak demand of 15 MW up to 100% of the customer's preceding year's total annual
20 energy consumption. Subscriptions will be allocated on a first come, first served
21 basis.

22 The Company will make 50 MW available for subscription by municipal,
23 university, school and hospital ("MUSH") customers with a minimum annual peak
24 demand of 1 to 3 MW up to 100% of the customer's preceding year's total annual
25 energy consumption. Subscriptions in the MUSH option will be allocated on a pro-
26 rata basis.

27 Georgia Power will also make a block of renewable generation available for
28 subscription designed to provide renewable energy to serve a 100 MW subscription

1 around the clock by customers with a minimum annual peak demand of 25 MW up
2 to 100% of the customer's preceding year's total annual energy consumption. To
3 supply these subscriptions, the program design contemplates the procurement of
4 energy from 650 MW of renewable resources combined with BESS to store
5 renewable energy and deliver it in hours outside of normal renewable energy
6 production. Subscriptions will be allocated on a pro-rata basis. Participating
7 customers will receive energy and capacity credits based on their subscription
8 amounts. The energy generated from the renewable and BESS resources will serve
9 the needs of all retail customers but will be dispatched in a manner to deliver energy
10 beyond normal renewable resource production hours.

11 Finally, although not supplied by any of the initial 2,100 MW proposed to be
12 procured, Georgia Power is requesting the option to return to the Commission for
13 authority to procure additional MW to meet the incremental renewable needs of
14 customers with incremental, new load of 50 MW or more, pursuant to the CARES
15 Economic Development program. The ability for the Company to return to the
16 Commission and request to procure additional MWs is part of the Company's
17 adaptable procurement strategy.

18 **Q. HOW WILL SUBSCRIBING CUSTOMERS PARTICIPATE IN THE**
19 **CARES PROGRAM?**

20 A. Similar to the CRSP and C&I REDI programs, CARES customers will participate
21 pursuant to a tariff and will be required to enter a customer agreement specifying
22 the pricing, terms and conditions of their participation. If approved as part of the
23 2022 IRP, the Company will submit for Commission approval a comprehensive
24 program filing, including proposed timelines, tariffs, and customer agreements for
25 each segment of the CARES program.

26 Participating customers may select one of two subscription options. The first option
27 is similar to legacy C&I programs that allows customers to pay a monthly
28 subscription charge and receive hourly energy credits on their bill based on the

1 actual production of the renewable resources supplying the program, which vary
2 over time. The second option would provide for a fixed monthly subscription
3 charge on a per MWh basis determined at the time of contracting with no
4 corresponding hourly energy credits. Regardless of the subscription option chosen,
5 the monthly fee to participate will be assessed to CARES participants in addition
6 to the customer's regular monthly electric service payments.

7 **Q. PLEASE DESCRIBE THE EXISTING RESOURCE RETAIL REC**
8 **RETIREMENT ("R3") PROGRAM.**

9 A. The Company proposes to reallocate for subscription by interested and qualifying
10 C&I customers a subset of RECs from existing renewable resources previously
11 designated to be retired on behalf of all customers. Participating customers will be
12 able to subscribe to up to 1,000 MW of the current REDI I and REDI II renewable
13 resource portfolios approved in the 2016 IRP and up to 1,000 MW of the 2022/2023
14 and 2023/2024 renewable portfolios approved in the 2019 IRP once these resources
15 reach commercial operation.

16 Of these 2,000 existing MW, the Company will make available 1,000 MW for
17 subscription by existing customers with a minimum annual peak demand of 15 MW
18 up to 100% of their preceding year's total annual energy consumption.
19 Subscriptions by existing customers will be available on a pro-rata basis. The
20 remaining 1,000 MW will be made available for subscription by customers adding
21 new load of 50 MW or greater. Subscriptions by customers adding new load will
22 be available on a first come, first served basis. RECs from any portion of the total
23 2,000 MW of renewable capacity that are not subscribed by participating customers
24 will continue to be retired on behalf of all Georgia Power customers.

25 Participating customers will pay a fixed cost per MWh for the RECs that are
26 generated from these portfolios. As proposed, participating customers will enter
27 into a customer agreement with a term of up to five years that specifies the pricing,
28 terms, and conditions of their participation in the R3 program. The monthly fee to

1 participate in R3 will be in addition to the customer's regular monthly electric
2 service payments and will be based on the projected value of the RECs at the time
3 the customer agreement is executed.

4 **Q. IS THE COMPANY'S R3 PROPOSAL CONSISTENT WITH PRIOR**
5 **COMMISSION ORDERS?**

6 A. Yes. Consistent with the Commission's Orders in Docket Nos. 41596, 42625, and
7 43814, the revenues collected through the program will be applied to the FCR
8 account and will reduce costs for the benefit of all customers. Existing renewable
9 resources with RECs previously designated to be retired on behalf of all customers
10 are currently producing RECs with no financial benefit. This program monetizes
11 REC benefits and returns that financial benefit to all customers. In addition,
12 consistent with the Company's other renewable offerings, the Company proposes
13 that the costs to administer and implement the program will be collected through
14 fees from participating customers and continue to be recognized through the fuel
15 clause.

16 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED MODIFICATIONS**
17 **TO THE SIMPLE SOLAR PROGRAM.**

18 A. Georgia Power proposes to increase the price for Simple Solar from 1¢ per kWh to
19 1.25¢ per kWh due to the rising cost of RECs. In addition, the Company will no
20 longer offer the Simple Solar Large Volume option after 2022. Current customers
21 participating in the Simple Solar Large Volume option will transition to the
22 Company's proposed Flex REC program when their existing contracts expire.

23 **Q. WHAT IS THE FLEX REC PROGRAM?**

24 A. Current market conditions and solar REC availability in the voluntary REC market
25 indicate that Simple Solar may not meet the needs of all Georgia Power large
26 customers. Therefore, the Company has created the Flex REC program to provide
27 additional options for larger customers to help meet their renewable and

1 sustainability goals. The new Flex REC program will be supplied with RECs from
2 a variety of sources, including solar, wind, and potentially other renewable sources.
3 To continue to provide additional flexibility to customers, Georgia Power will also
4 transition the Simple Solar one-time purchase and Special Event purchase options
5 to the Flex REC program.

6 The Company proposes tiered pricing based on customer usage and current REC
7 market conditions. The Company will adjust program pricing for new subscriptions
8 to appropriately account for REC price increases as they occur to ensure costs are
9 recovered from participating customers. The Flex REC program pricing is designed
10 to include recovery of REC costs and program marketing and administration
11 expenses, which includes customer education, program promotion, and REC
12 tracking.

13 In addition, the Company proposes a new Economic Development Flex REC
14 option. To be eligible for this option, customers must (i) qualify for the large load
15 exception of the Georgia Territorial Electric Service Act,³ and (ii) purchase a
16 minimum of 2,000,000 kWh monthly through Flex REC or 24,000,000 kWh
17 annually for a fixed rate, quantity, and term. The Company proposes to negotiate
18 the Economic Development Flex REC pricing with each customer on a case-by-
19 case basis for a limited term (up to three years), during which Georgia Power will
20 procure and retire RECs on behalf of the customer. If approved as part of the 2022
21 IRP, the Company will submit for Commission approval a comprehensive program
22 filing including updated tariffs and customer agreements for the Simple Solar and
23 Flex REC programs.

³ O.C.G.A. § 46-3-8(a).

1 **Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO THE**
2 **COMMUNITY SOLAR PROGRAM?**

3 A. To increase program participation, the Company proposes to expand program
4 eligibility to commercial customers on the General Service tariff. In addition,
5 Georgia Power proposes to increase the program pricing for residential customers
6 from \$24.99 to \$27.99 per block per month. Also, to maintain the availability of
7 subscription blocks for new customers, the Company requests Commission
8 approval to develop additional Community Solar facilities once the available
9 capacity is 75% subscribed. Once the subscribed capacity target is achieved,
10 Georgia Power will file with the Commission plans to develop additional
11 Community Solar facilities.

12 **Q. PLEASE DESCRIBE THE INCOME-QUALIFIED COMMUNITY SOLAR**
13 **PROGRAM.**

14 A. Georgia Power understands that cost can be a significant barrier that prevents
15 income-qualified customers from supporting the growth of renewable energy. To
16 address this issue, the Company proposes the Income Qualified Community Solar
17 pilot program, which will offer up to 5,000 blocks of the existing 8,000 blocks of
18 community solar to income-qualified customers for \$6.99 a block (a 75% discount).
19 In return, eligible customers will get an energy credit on their monthly electricity
20 bill based on the production of the community solar facilities supplying the
21 program. Eligible customers must take service on the Residential R rate and have a
22 household income of less than 200% of the then-current federal annual poverty
23 level.

24 To offer this discounted program option, the Company will seek corporate
25 sponsorships to buy down the price of the standard community solar monthly
26 subscription. In exchange, 100% of the RECs produced by the subscribed blocks
27 will be retired on behalf of the donating corporate sponsor. All other program costs
28 will be recovered from the participating sponsor. If approved as part of the 2022

1 IRP, the Company will submit for Commission approval a comprehensive program
2 filing including an updated Community Solar tariff and other program documents.

3 **Q. ARE THESE PROGRAMS THE ONLY OPTIONS AVAILABLE FOR**
4 **CUSTOMERS TO SUPPORT RENEWABLE RESOURCES?**

5 A. No. As stated in the 2022 IRP, customers will continue to have options to offset
6 their own energy consumption behind the meter, offset their own energy
7 consumption and sell any excess output through the renewable and non-renewable
8 (“RNR”) tariff, or sell renewable energy to Georgia Power as Qualifying Facilities
9 (“QF”) under the Public Utility Regulatory Policies Act of 1978 (PURPA). Georgia
10 Power has interconnected more than 4,000 solar projects, including customers who
11 choose to offset energy usage with behind-the-meter solar installations, through
12 RNR or as a QF.

13 **Q. DOES THE COMPANY PROPOSE TO CONTINUE USING THE**
14 **MONTHLY NETTING CALCULATION FOR THE RNR TARIFF?**

15 A. No. The monthly netting option for RNR was approved in the 2019 Rate Case as a
16 limited program with defined participation. As of July 2021, Georgia Power had
17 enough applications to fully subscribe the 5,000-customer pilot program. The
18 Company’s initial analyses of the impact of this monthly netting option have
19 identified several concerns that warrant additional evaluation: (i) cost shifting to
20 non-participants; (ii) operational concerns with an increase in unplanned variable
21 energy resources; (iii) the infiltration of aggressive and uninformed solar marketers
22 misinforming customers; and (iv) noncompliance with the Company’s rules,
23 regulations, and program requirements for interconnection of behind the meter
24 generation. As a result of these issues, the Company does not support any expansion
25 of the RNR monthly netting program. The Company will continue to evaluate the
26 impacts of the monthly netting pilot and provide updates to the Commission and
27 Commission Staff.

1 **Renewable Cost Benefit Framework**

2 **Q. WILL GEORGIA POWER CONTINUE TO USE THE RCB**
3 **FRAMEWORK?**

4 A. Yes. The Company will continue to apply the RCB Framework to the evaluation of
5 renewable projects and pricing for the new procurement programs offered in the
6 2022 IRP.

7 **Q. DID GEORGIA POWER MAKE ANY CHANGES TO THE RCB**
8 **FRAMEWORK AS PART OF THE 2022 IRP?**

9 A. Yes. The Company has updated the current iteration of the RCB Framework to
10 incorporate learnings from its Renewable Integration Study on the impacts of
11 substantial renewable growth on the system. The majority of the core components
12 of the RCB Framework remain consistent with prior iterations. However, based on
13 the Company's Renewable Integration Study, Georgia Power has endeavored to
14 streamline and simplify the RCB Framework by removing the Generation Remix
15 component and replacing Support Capacity with a comprehensive Integration Cost
16 component. The Integration Cost component accounts for the operating reserves
17 needed to mitigate the impacts of solar intermittency and uncertainty previously
18 accounted for in the Support Capacity component. The introduction of the
19 Integration Cost component has also removed the need for the former placeholder
20 components of Ancillary Services and Bottom Out Costs, as each of these
21 components are also captured within the Integration Cost component of the RCB
22 Framework as identified in the Renewable Integration Study.

1 **Tall Wind Demonstration**

2 **Q. WHY DOES THE COMPANY BELIEVE THAT WIND IS A VIABLE**
3 **RESOURCE IN GEORGIA?**

4 A. In 2016, the U.S. Department of Energy and the National Renewable Energy
5 Laboratory (“NREL”) issued several studies supporting the potential for taller wind
6 turbines with larger rotors to achieve a capacity factor of greater than 30% in the
7 Southeast. In the Commission’s 2016 IRP Order, the Commission authorized
8 Georgia Power to study this high wind potential and validate certain site-specific
9 locations identified by NREL. The Company’s study results indicate that wind
10 resources in Georgia could be economically developed at hub heights of 120 meters
11 or higher.

12 **Q. WHAT DOES GEORGIA POWER AIM TO STUDY OR PROVE WITH ITS**
13 **REQUESTED TALL WIND DEMONSTRATION?**

14 A. The Company proposes to develop two wind turbines, up to four MW each, with a
15 hub height between 140 – 165 meters. The proposed towers will utilize innovative
16 spiral weld technology that employs on-site fabrication techniques. Georgia Power
17 has designed this demonstration project to prove the economic and technical
18 feasibility of tall wind in Georgia as well as validating the in-field construction
19 techniques required for the spiral weld technology at higher hub heights.

20 **Q. HAS GEORGIA POWER WORKED WITH ANY OTHER ENTITIES ON**
21 **THIS TALL WIND DEMONSTRATION?**

22 A. Yes. Georgia Power plans to team up with the wind turbine tower manufacturer that
23 specializes in this spiral weld technology to take advantage of funding awarded to
24 the manufacturer by the Department of Energy to further develop and demonstrate
25 this new and innovative fabrication technique.

VIII. DER PILOT PROGRAMS

1
2 **Q. IS THE COMPANY PROPOSING ANY PILOT PROGRAMS IN THIS IRP**
3 **RELATED TO DER?**

4 A. Yes. The Company is seeking Commission approval of the DER Local Reliability
5 and Constraints Pilot. Conducting small scale pilots allows the Company to test a
6 program in a controlled environment with limited financial or customer satisfaction
7 risks.

8 **Q. PLEASE EXPLAIN THE DER LOCAL RELIABILITY AND**
9 **CONSTRAINTS PILOT PROGRAM.**

10 A. Through the DER Local Reliability and Constraints Pilot, Georgia Power will
11 install one or more DER at seven strategic locations across the System to address
12 System operations and reliability needs, such as changing load requirements and
13 voltage, thermal, power quality, and other System constraints, that would otherwise
14 require upgrades to the distribution or transmission system. The pilot program
15 would allow Georgia Power to further evaluate the three use cases for deployment
16 of DER technologies identified through its research: (i) transition of wire capacity
17 – the ability of equipment to remain within design limits; (ii) system reliability –
18 the ability to ensure dependable service; and (iii) system resilience – the ability to
19 withstand and/or recover from outage events.

20 **Q. WHERE ARE THE SEVEN LOCAL RELIABILITY CONSTRAINTS**
21 **PILOT LOCATIONS AND HOW WERE THEY SELECTED?**

22 A. The Company proposes to install one or more DER at sites in Alpharetta, Atlanta,
23 Rome, Macon, Athens, and Savannah where the distribution system faces
24 constraints or reliability issues that could be alleviated by the introduction of the
25 DER.

1 **Q. WHAT DOES THE COMPANY HOPE TO LEARN OR ACHIEVE**
2 **THROUGH THIS PILOT?**

3 A. The Local Reliability and Constraints Pilot would permit the Company to assess
4 the benefits, operational considerations, and costs related to the siting, installation,
5 and ongoing operation and maintenance of DER technologies as potential
6 transmission and distribution system solutions. With the evolution of DER and
7 Distributed Energy Resource Management Systems (“DERMS”) technologies
8 since 2019, the time is ripe for the Company to evaluate how DER and DERMS
9 can be leveraged to diversify the Company’s options to reliably meet transmission
10 and distribution system challenges.

11 **IX. TRANSMISSION**

12 **Q. PLEASE DESCRIBE GEORGIA POWER’S TEN-YEAR TRANSMISSION**
13 **PLAN FILED IN THE 2022 IRP.**

14 A. The 2022 IRP includes an updated ten-year transmission plan, which identifies the
15 transmission improvements needed to maintain a strong and reliable transmission
16 system. The Company develops this plan in accordance with Southern Company
17 and ITS transmission planning guidelines and the most current NERC reliability
18 standards. Along with the ten-year plan, Georgia Power has included a
19 comprehensive and detailed bulk transmission plan of the Georgia ITS as required
20 by the amended rules adopted by the Commission in Docket No. 25981. Additional
21 transmission information is also provided as required by Docket No. 31081.

22 **Q. WHY IS TRANSMISSION CRITICAL FOR THE EFFECTIVE**
23 **TRANSITION OF THE FLEET?**

24 A. The Company’s generation fleet does not operate in a vacuum and cannot reliably
25 serve customers without a reliable transmission system. Georgia Power must
26 consider how resource planning decisions impact the transmission system,
27 especially in light of the planned fleet transition and retirement of the Company’s

1 coal resources. The Company identified transmission constraints relevant to fleet
2 transition both in the ten-year plan and other unit retirement scenarios that were
3 evaluated. For example, while Georgia Power can work with the other ITS
4 Participants to initiate and complete the transmission projects required to support
5 the retirements of Plant Wansley Units 1-2, Plant Bowen Units 1-2, and Plant
6 Scherer Units 1-3, the Company cannot complete the transmission projects
7 necessary to accommodate the retirement of Bowen Units 3-4 by year-end 2028 to
8 avoid ELG controls. As a result, the Company has proposed the North Georgia
9 Reliability and Resilience Action Plan to comprehensively address the generation
10 and transmission needs to reduce the long-term reliance on Plant Bowen Units 3-4
11 and prepare for their ultimate retirement.

12 **X. WHOLESALE TO RETAIL CAPACITY**

13 **Q. WHY IS THE COMPANY OFFERING WHOLESALE CAPACITY TO**
14 **RETAIL CUSTOMERS?**

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

20 **Q. HAS THE COMPANY PREVIOUSLY MADE WHOLESALE CAPACITY**
21 **OFFERS TO RETAIL JURISDICTION?**

22 A. Yes. Since the July 2008 Order, the Commission has certified several offers to bring
23 resources to the retail jurisdiction, including resources at Plant Scherer Unit 3 and
24 from Wholesale Blocks 1 through 6. The multiple wholesale offerings to the retail
25 jurisdiction have resulted in a range of Market Differential Adjustments ("MDA")
26 based on the generation resource(s) involved and the wholesale conditions present
27 at the time. Most recently, the Company offered 25 MW of Scherer Unit 3 capacity

1 to the retail jurisdiction in the 2019 IRP. However, the Commission declined to
2 accept the wholesale-to-retail offer in 2019.

3 **Q. WHAT WHOLESALE CAPACITY IS AVAILABLE AND WHY?**

4 A. Approximately 199 MW of wholesale block capacity is available from Plant Gaston
5 Units 1-4, Plant Yates Units 6-7, Plant Scherer Unit 3, and various oil-fired
6 generating units. The wholesale contracts for this capacity are set to expire within
7 the procurement period covered by the replacement capacity secured during the
8 2022-2028 Capacity RFP.

9 **Q. HOW MUCH OF THE AVAILABLE WHOLESALE CAPACITY TO**
10 **RETAIL IS THE COMPANY OFFERING IN THIS IRP?**

11 A. Georgia Power is only offering 88 MW of wholesale block capacity to the retail
12 jurisdiction because portions of the available wholesale capacity are generated from
13 units the Company is proposing to retire as part of this RFP. Thus, Georgia Power
14 excluded the wholesale capacity from Plant Scherer Unit 3 (approximately 61 MW)
15 and Plant Gaston Units 1-4 (approximately 50 MW) from the current wholesale-to-
16 retail offer. Regarding these 111 MW, the Company requests that the Commission
17 deem the Company's Docket No. 26550 obligations satisfied.

18 **Q. HOW DOES GEORGIA POWER VALUE OR PRICE THE CAPACITY**
19 **BEING OFFERED TO RETAIL JURISDICTION?**

20 A. Consistent with prior wholesale offers, Georgia Power proposes to use the
21 Commission-approved application of an MDA to meet the requirement that the
22 transaction be offered at then-current wholesale market terms. The MDA represents
23 the difference between the levelized market value and the levelized revenue
24 requirement of the net asset over its remaining useful life, expressed on a dollar per
25 kilowatt-month basis. Unlike prior offers where the Company had not recently
26 completed an RFP, the Company leveraged data from the 2022-2028 Capacity RFP
27 to help determine the market value of the wholesale block capacity.

1 **Q. IS THE COMPANY ALSO SEEKING TO CERTIFY THIS CAPACITY**
2 **AND INCLUDE IT IN RATE BASE?**

3 A. Yes. If the Commission accepts the Company's offer of 88 MW of wholesale block
4 capacity from Plant Yates Units 6-7 and the CTs at Plant McManus and Plant
5 Wilson to the retail jurisdiction, Georgia Power also asks that it be certified. If
6 certified, the generating assets supporting the capacity will be included in retail rate
7 base at their net book value using the MDA to determine the associated revenue
8 requirement rather than using a traditional revenue requirement calculation.
9 Following the MDA methodology previously approved by this Commission results
10 in a reduction to the retail base revenue requirement associated with the current
11 offer from Plant Yates Units 6-7 and an increase to the retail rate base revenue
12 requirement associated with the current offer from Plants McManus and Plant
13 Wilson as compared to the revenue requirement as calculated under traditional
14 ratemaking. As with other generating assets in retail rate base, all prudently
15 incurred actual fuel costs associated with the resource will be recovered through
16 the FCR process.

17 **Q. WHAT VALUE WILL PROCURING THESE 88 MW BRING TO**
18 **CUSTOMERS?**

19 A. These 88 MW represent added capacity from diverse resources already reliably
20 serving Georgia Power's customers and at good values as they are priced based on
21 the results from the 2022-2028 Capacity RFP.

22 **XI. RESILIENCE**

23 **Q. WHAT IS RESILIENCE?**

24 A. Resilience refers to the ability of the electric system to withstand or recover from
25 high impact events with a low probability such as physical attacks, cyber-attacks,
26 and extreme weather events. In addition to the ability to reliably provide customers
27 with the quantity and quality of power demanded, resilience addresses the ability

1 of the system and utilities to reduce magnitude, duration, and damage from high
2 impact disruptive events. A lack of resilience can impede a utility's ability to
3 reliably serve customers under these conditions.

4 **Q. HOW IS THE COMPANY ADDRESSING RESILIENCE IN THIS IRP?**

5 A. This IRP reflects the Company's continued commitment to maintaining a robust
6 and resilient electric system that is capable of reliably serving customers and
7 effectively responding to disruptive events. The Company's focus on resilience
8 planning remains critical as the generation mix evolves to include a larger share of
9 intermittent resources or resources without on-site fuel storage. The Company is
10 addressing these resilience considerations through its North Georgia Reliability and
11 Resilience Action plan. This plan preserves generation at Plant Bowen Units 3-4,
12 while also building out the appropriate transmission infrastructure to support
13 targeted renewable procurements. This combination of existing generation,
14 renewable growth, and transmission system investments will preserve reliability
15 and resilience in north Georgia.

16 Additionally, the Company's IRP includes additional future study of its blackstart
17 plan. For System emergency restoration purposes, certain generating units,
18 designated as "Blackstart Resources," provide the ability to start without power
19 from the grid so that they can begin restoring the transmission system from a
20 blackout condition. Continued evaluation and study of the blackstart plan will
21 support resilience considerations as the fleet transitions.

22 **Q. HOW DO THE COMPANY'S DER PROGRAMS SUPPORT RELIABILITY**
23 **AND RESILIENCE?**

24 A. The Company's proposed DER programs will provide additional reliability and
25 resilience benefits. Through the Demand Response Credit Tariff, described in the
26 pre-filed testimony of Georgia Power Witnesses Valle, Phillips, Smith, and Evans,
27 all customers will benefit from the capacity benefit or reliability benefits provided

1 from DER resources on the System. Participating customers will benefit from the
2 ability to anticipate, absorb, adapt to, and/or rapidly recover from grid disturbances,
3 including high-impact low-probability events.

4 **XII. ACCOUNTING TREATMENT AND COST RECOVERY**

5 **Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT BEING**
6 **REQUESTED BY THE COMPANY TO RECLASSIFY THE NET BOOK**
7 **VALUE OF PLANT BOWEN UNITS 1-2, PLANT WANSLEY UNITS 1-2,**
8 **PLANT WANSLEY UNIT 5A, PLANT SCHERER UNIT 3, AND PLANT**
9 **BOULEVARD UNIT 1.**

10 **A.** The Company proposes to reclassify the Plant Bowen Units 1-2, Plant Wansley
11 Units 1-2, Plant Wansley Unit 5A, Plant Scherer Unit 3, and Plant Boulevard Unit 1
12 net book value remaining as of the proposed retirement dates to a regulatory asset
13 account, consistent with treatment of such balances in the 2016 and 2019 IRP Final
14 Orders. The regulatory asset would be amortized ratably over a period to be
15 determined by the Commission in a future base rate case.

16 **Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT BEING**
17 **REQUESTED BY THE COMPANY TO RECOVER THE REMAINING**
18 **MATERIAL AND SUPPLIES INVENTORY BALANCES ASSOCIATED**
19 **WITH THE RETIREMENT UNITS.**

20 **A.** The Company proposes to reclassify any unusable material and supplies inventory
21 balance remaining at the unit retirement dates to a regulatory asset for recovery
22 over a period to be determined by the Commission in the Company's next base rate
23 case. This proposal is consistent with the treatment of the remaining material and
24 supplies inventory balances from the 2016 and 2019 IRP Final Orders. While the
25 Company will take appropriate steps to find uses for existing inventory, including
26 the sale of such inventory, it is reasonable to expect there will be some inventory
27 that cannot be sold or used at other Georgia Power generating plants.

1 **Q. IS THE COMPANY SEEKING APPROVAL OF ANY ENVIRONMENTAL**
2 **COMPLIANCE COSTS?**

3 A. Yes. The Company's environmental panel of Mark S. Berry and Aaron D. Mitchell
4 address Georgia Power's request regarding approval of environmental compliance
5 costs in their direct testimony.

6 **XIII. CONCLUSION**

7 **Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN**
8 **THE 2022 IRP?**

9 A. The Company seeks approval of its 2022 IRP as proposed, including the associated
10 Action Plan, which includes all the actions necessary for the Company to continue
11 to provide clean, safe, reliable, and affordable electric service for its retail
12 customers.

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

14 A. Yes.

1 MR. HEWITSON: And with your permission, I'd
2 like for Mr. Grubb to summarize the prefiled
3 testimony of this panel.

4 MADAM CHAIR PRIDEMORE: Go ahead.

5 WITNESS GRUBB: Good morning, Commissioners.
6 Georgia Power's 2022 IRP offers a comprehensive plan
7 with a balanced portfolio of integrated resources to
8 provide customers with clean, safe, reliable, and
9 affordable electric service for years to come, even
10 as customer preferences, society's energy needs,
11 technology, and the energy landscape continue to
12 evolve.

13 Georgia Power's taking steps to effectively
14 transform the generation fleet, prepare for the
15 retirement of its coal-fired generation resources,
16 integrate greater amounts of renewable resources and
17 invest in its transmission system.

18 The company has been focused on many
19 challenging issues since the 2019 IRP and the 2022
20 IRP presents a long-term plan that is in the best
21 interest of customers. Reliability, continued
22 environmental pressures, the continued transition of
23 the generation fleet, technology developments, and
24 the changing needs of many customers are just some
25 of the issues that this IRP addresses.

1 Specifically we're here today to present and
2 seek approval of Georgia Power's 2022 IRP, including
3 each of the specific items listed in Chapter 1 and
4 the action plan included in Chapter 19 of the IRP
5 main document.

6 The company also seeks Commission's approval of
7 the application for decertification of nine coal or
8 steam units and three oil-fired combustion turbines,
9 the application for certification of the PPAs from
10 six existing gas facilities resulting from the
11 successful 2022 to 2028 capacity IRP, and the
12 application for certification of capacity from
13 Blocks 2 through 4 and Blocks 5 and 6.

14 The IRP appropriately considers increasing
15 policy and regulatory pressure related to carbon and
16 environmental standards and the significant increase
17 in customer expectations for renewable and other low
18 or no carbon solutions.

19 It is no longer economic in the long term to
20 operate the company's coal units given the
21 increasing pressures from existing and future
22 environmental requirements and the current
23 availability of more economic replacement capacity.

24 The success of the capacity RFP delivers value
25 for our customers in support of the fleet

1 transition.

2 The company has laid out a strategic retirement
3 plan to rely -- to responsibly transmission --
4 transition its coal fleet without sacrificing
5 reliability for customers.

6 The company proposes to continue its measured
7 and steady approach and growth of renewable
8 resources by adding 2,300 megawatts of renewable
9 resources to be online by 2029 with a plan to
10 achieve 6,000 megawatts by 2035.

11 The company intends to leverage the benefits of
12 renewables in a way that integrates these resources
13 in an economic and reliable manner facilitated by
14 the following three items: Number one, the addition
15 of 1,000 megawatts of company owned storage by 2030.

16 Number two, greater operational control of the
17 renewable resources.

18 And, three, transmission system enhancements.

19 The company also proposes to expands its
20 innovative renewable programs to meet increasing
21 customer needs for more options to support renewable
22 energy.

23 The company proposes to invest in the
24 transmission system through its 10-year plan and to
25 accommodate the fleet transition in support of coal

1 unit retirements and renewable resource integration.

2 The company will also continue to invest in the
3 hydro fleet, seek to renew its nuclear licenses with
4 the Nuclear Regulatory Commission for Plant Hatch,
5 Units 1 and 2, invest in technology demonstration
6 projects, and do all this for the benefit of
7 customers.

8 The company is also introducing application of
9 distributed energy resources, also known as DER, for
10 grid resilience and greater reliability through the
11 DER customer program, as well as seeking to better
12 understand DER, this potential distribution in
13 transmission solutions.

14 The 2022 IRP demonstrates the company's
15 continued focus on reliability with the adoption of
16 a winter target reserve margin and a continued focus
17 on seasonal planning. The importance of seasonal
18 planning has been reinforced by the reliability
19 events seen across the country since the 2019 IRP.

20 The company has also included strategic
21 initiatives, like the North Georgia Reliability and
22 Resilience Plan, which incorporates near-term
23 actions and long-term planning across many
24 disciplines to solve transmission constraints and
25 meet future generation needs.

1 Our panel's testimony will cover the company's
2 supply-side plan and supporting analyses, proposed
3 decertification and certification requests,
4 expansion of renewable resources, energy storage
5 proposal, and the transmission plan.

6 The panel of Francisco Valle, Andy Phillips,
7 Jeffrey Smith, and Lee Evans will provide the
8 Commission additional information on the company's
9 load energy forecast, DSM application, and proposed
10 DER customer privilege.

11 The panel of Mark Berry and Aaron Mitchell will
12 provide additional information on the company's
13 environmental compliance strategy, carbon pressures
14 facing the generation fleet and research and
15 development issues.

16 As you can tell from our filing in this IRP,
17 the company addresses many opportunities and
18 challenges facing the electric utility industry
19 today. Through the 2022 IRP process, the company
20 will continue to work constructively with this
21 Commission to invest in Georgia's energy future and
22 provide industry leading energy solutions that will
23 benefit customers in Georgia's communities for many
24 years to come.

25 Thank you.

1 MR. HEWITSON: Thank you, Mr. Grubb.

2 Madam Chair, the panel is available for
3 questions from the Commission, as well as
4 cross-examination.

5 MADAM CHAIR PRIDEMORE: Thank you,
6 Mr. Hewitson.

7 Any Commissioners have questions for the panel
8 to get us started?

9 (No response.)

10 MADAM CHAIR PRIDEMORE: If not, I'm sure there
11 will be several as the day goes on.

12 So, with that, Georgia Public Service
13 Commission.

14 MR. WALSH: Thank you very much.

15 Gentlemen, my name is Dan Walsh. I'm
16 representing the Public Interest Advocacy staff.
17 I'm going to be addressing my questions generally to
18 the panel. And whichever one of you would be best
19 suited to answer, can go ahead and answer.

20 CROSS-EXAMINATION

21 BY MR. WALSH:

22 Q As part of this integrated resource plan, the
23 company's proposing to retire coal units, acquire
24 purchase power agreements, and add solar and battery
25 resources; is that correct?

1 A (Witness Grubb) That's correct.

2 Q Is it also correct that the analysis to retire
3 coal units was done independently from other analyses,
4 such as to evaluate the addition of the 6,000 megawatts
5 of solar and to acquire battery resources?

6 A (Witness Grubb) In -- in general, yes.

7 Commissioners, every model and every process
8 has a specific focus and there's a sequential nature to
9 what we do.

10 But the unit retirement studies for the coal
11 fleet took into account the impacts and information we
12 had to do that. The process is the same that we've done
13 in prior IRPs.

14 And so each -- each analysis by its nature
15 takes a different time, uses different models. And so we
16 have done that appropriately here in the case and we've
17 laid that out.

18 So the coal unit retirements are absolutely
19 based on the cost for continuing those coal units and the
20 RFP resources that we have available in the RFP.

21 A (Witness Weathers) And just to further
22 explain, the analyses are really not independent. When
23 you think about the unit retirement studies uses the
24 outputs of our base IRP analysis and so they're
25 intrinsically tied together because they're using the

1 same information, but it is a different analysis. It's
2 not done in one single optimization. There's a separate
3 analysis.

4 Q Are you familiar with the term "joint
5 optimization"?

6 A (Witness Weathers) You may have to give me
7 your definition of -- I've heard of the term, but what do
8 you mean by that?

9 Q Well, let me ask you whether this is your
10 understanding. Is your understanding of the term "joint
11 optimization" that it refers to where the determination
12 of what resources would be part of the least cost
13 reliable system is made by evaluating all of the
14 resources together?

15 Is that -- is that consistent with your
16 understanding?

17 A (Witness Weathers) That's fine. I'll accept
18 that definition.

19 Q Okay. And I understand, I think, what your
20 response was to my prior question, but just to put a
21 point on it. Would you agree that the company did not do
22 joint optimization in its evaluation of resources here?

23 A (Witness Weathers) Well, if you mean
24 specifically -- I think it's what you mean. Did we
25 evaluate the coal retirements in the same optimization

1 that we did our resource mix? Is that what you mean?

2 Q That is what I mean, yes.

3 A (Witness Weathers) We did not do that. And
4 so, again, we're looking -- it's really a two-step
5 process, but the unit retirement studies is a very robust
6 analysis. It uses outputs from the resource mixed
7 process, in particular the avoided energy costs, and it
8 performs a -- it performs an evaluation in a model, but
9 it is a separate process.

10 It captures things that we are not able to
11 fully capture in our resource mixed modeling, such as the
12 transmission cost, such as a number of other factors. We
13 capture those in our retirement study, but those are not
14 all inputs to the single optimization model.

15 Q And I'm not here this morning to debate which
16 is the better method because I'm not capable of doing
17 that. But can you say with certainty that the results of
18 your evaluations would be the same had you conducted
19 analysis using joint optimization, as we've discussed
20 this morning -- under the understanding of the terms
21 we've discussed this morning?

22 A (Witness Weathers) We have not conducted that
23 analysis either, but it's my belief that they would be
24 the same. I think the economics that we got from the
25 studies are pretty compelling.

1 We actually used the avoided energy cost from
2 the resource mix process. And we have for a long time
3 used the avoided energy cost outputs as essentially a
4 good proxy for running the whole analysis back through
5 the optimization models.

6 Q So it is your belief, but you can't say it with
7 certainty because you didn't do that analysis; correct?

8 A (Witness Weathers) That is correct.

9 A (Witness Grubb) But, Commissioners, the
10 important thing is the unit retirement studies that we've
11 done here in this IRP are the same as we've done in prior
12 IRPs, in terms of looking at what is the value of keeping
13 those coal units and the cost of keeping those coal units
14 versus your replacement options.

15 We have the capacity RP resources that we've
16 incorporated in this IRP. But, otherwise, the processes
17 we followed are a very robust analysis. They allow us to
18 study what we need to to come up with those
19 recommendations.

20 Q I'd like to move now to additional sum. When
21 the company builds new generation resources, the company
22 gets to charge customers for return on equity component
23 associated with that new resource; isn't that correct?

24 A (Witness Grubb) That's correct. It goes into
25 revenue requirements.

1 Q And when the company purchases capacity and
2 energy through a purchase power agreement, it doesn't
3 recover a return on equity component, but it does seek to
4 charge customers for an additional sum component; is that
5 correct?

6 A (Witness Grubb) As allowed by order, that's
7 correct.

8 Q And when a generating unit is analyzed in an
9 expansion plan optimization analysis and units such as a
10 combustion turbine or a combined cycle are evaluated, the
11 return on equity component is included in that economic
12 analysis; isn't that correct?

13 A (Witness Grubb) You're asking about which type
14 of analysis? A build?

15 Q A generating unit. Are you -- is there a
16 diff- -- if you're doing a self-build generating unit and
17 that's analyzed in an expansion plan optimization, would
18 the return on equity component be included in the
19 economic analysis?

20 A (Witness Grubb) For an expansion plant is what
21 your specific question is?

22 Q Yes.

23 A (Witness Weathers) Yes. If we're looking at a
24 generic expansion plan in our resource mixed study, we're
25 looking at the revenue requirements associated with the

1 generic unit. So it would include that.

2 A (Witness Grubb) And, Commissioners, that's how
3 we do our expansion plan is we -- we obviously include
4 any planning committed resources we have under PPAs.

5 But when you're talking about a 30-year plan on
6 which resources may be there, we don't know the PPA cost.
7 So we will build and model that generic company on the
8 proposal.

9 And then when you do RFPs is when you truly
10 figure out what would a PPA offer. So that -- the same
11 way we've been doing that for years.

12 MR. WALSH: Madam Chair, may I approach the
13 witness panel?

14 MADAM CHAIR PRIDEMORE: Yes.

15 MR. WALSH: Madam Chair, I'm having distributed
16 the company's response to STF-JKA-3-2. And I'd ask
17 that this response be marked for identification as
18 Staff Exhibit 1.

19 (The document referred to was marked for
20 identification as Staff Exhibit No. 1.)

21 BY MR. WALSH:

22 Q I'll give you a moment to take a look at that.
23 But let me know when you're ready.

24 A (Witness Grubb) Yeah. Ready.

25 Q Okay. Does this response indicate that the

1 additional sum was not included in the cost of the
2 RFP portfolio within the unit retirement study?

3 A (Witness Grubb) Yeah. That's correct.

4 And, Commissioners, from the company standpoint
5 when you're talking about retiring the coal unit and
6 replacing it with an RFP, the additional sum should not
7 drive that decision.

8 As a matter of fact, we're not even sure what
9 the additional sum will end up being. We propose one,
10 but it's always a point of contention in the case and
11 where you finally settle there. So to presume an
12 additional sum factored into unit retirement study is not
13 what should drive that decision.

14 That decision should be driven by, again, the
15 cost of staying in that coal unit, the benefits of that
16 unit compared to your replacement capacity. So we did
17 not include it. I'm not sure if it would have changed
18 the results. But, at the end of day, the additional sum
19 is a consideration for once we have decided to retire the
20 unit and determine which PPAs we would certify.

21 Q So if the company --

22 VICE-CHAIRMAN ECHOLS: Mr. Walsh, can you hang
23 on just a second?

24 On this -- on this topic on finances of Bowen.

25 So let me first ask you: How important is Bowen to

1 north Georgia reliability right now?

2 WITNESS GRUBB: Yeah. So I'll let Mr. Robinson
3 up here.

4 But it is important, Commissioner, all four
5 units, which is why our retirement of Bowen 2 is
6 timed upon completing some transmission projects.

7 Bowen 3 and 4, as we've stated, we cannot
8 accommodate the transmission projects by the time we
9 need to put ELG controls, but we know for the future
10 retirement of Bowen we would need to build some
11 transmission. So it is important. The timing of
12 our Bowen 1 and 2 decision is around making sure we
13 ensure that reliability.

14 VICE-CHAIRMAN ECHOLS: So Unit 2 that you're
15 proposing to close in the end of '28, didn't Unit 2
16 receive a new G Generator after the fire and the
17 accident there?

18 WITNESS GRUBB: Commissioner, it did. I don't
19 believe it was brand new, in terms of built in that
20 year. I think it was the same vintage as the other
21 one. But as far as -- I don't believe it had been
22 in service anywhere until that time.

23 WITNESS ROBINSON: That is correct. That unit
24 was in storage for that period of time. Same
25 vintage as the original unit. So it was in storage

1 for, subject to check, 40 years or so.

2 VICE-CHAIRMAN ECHOLS: And how many years of
3 life do you think is left on that G Generator on
4 Unit 2?

5 WITNESS ROBINSON: I can't speak to that.

6 VICE-CHAIRMAN ECHOLS: 1 or 10 or 20? Can you
7 give me a ballpark?

8 WITNESS ROBINSON: I'm a transmission expert.
9 I can't speak on generation.

10 WITNESS GRUBB: I think, Commissioner, it would
11 depend on, obviously, what you invest in that unit.
12 And so the fact that that unit was put into service
13 in 2013, we don't take that into account, in terms
14 of looking forward at the incremental cost of
15 Bowen 1 and 2 -- or Bowen 2.

16 So our recommendation is really not based on
17 the age or the condition of that unit. It's based
18 on the ability to replace it with more
19 cost-effective replacement generation and then also
20 avoid -- avoid future environmental risk.

21 VICE-CHAIRMAN ECHOLS: So is it true that if
22 you left Unit 2 operational to 2035, the same life
23 that you're planning on for 3 and 4, that they could
24 use the same scrubber wastewater system that you are
25 going to be spending money on for all three of the

1 units; that that additional expense isn't just for
2 3 and 4.?

3 It could be used at no additional cost for 2;
4 is that correct?

5 WITNESS GRUBB: (Witness Grubb) Yes,
6 Commissioner, that's correct. So the ELG treatment
7 is more for a plant-wide application, regardless of
8 the number of units. And our economics for Bowen 1
9 and 2 have reflected that you don't avoid that cost.

10 So it's only if you retire the entire plant do
11 you avoid that cost. So, you're right, it's not an
12 incremental cost to Bowen 1 and 2. We did include
13 that in our economics.

14 VICE-CHAIRMAN ECHOLS: And part of your
15 rationale for closing Units 1 and 2 is that you
16 delayed O&M on those units because of our decision
17 from 2019; is that correct?

18 WITNESS GRUBB: That alone isn't the driver for
19 retiring -- the retirement recommendation. Our
20 point there is if you don't retire those units, we
21 would have to go spend some more money on them.

22 We do know that if we have a set date on any of
23 our coal units that we can control the cost from a
24 budgeting standpoint that way. The point there was
25 we recognize that it was pressure and that we would

1 need to revisit that decision in the 2022 IRP, which
2 is exactly what we're doing.

3 So it's not that we -- that's not the only
4 driver. The real driver is you've got an
5 opportunity in the capacity RFP to take advantage of
6 some really, really good prices. And it's really
7 more around that future risk of coal. We just don't
8 see a lot of positives on the -- in the future for
9 the coal fleet. And so this ELG timing gives us an
10 opportunity to transition out of these units.

11 VICE-CHAIRMAN ECHOLS: Just two more quick
12 questions. How much money, ballpark, would be
13 needed to bring Unit 2 up to spec?

14 Do you have any idea?

15 WITNESS GRUBB: We would have those in the unit
16 retirement studies, Commissioner, for the 30-year
17 continue-to-operate that we study. I don't have
18 them off the top of my head or here. Again, there's
19 the O&M and then there's also the capital.

20 The spending order out of 2019 was really on
21 the capital side. So if we were going to keep those
22 units to '35 or so, we would have to put some more
23 money in them. So the unit retirement study has
24 a -- has an estimate on that. I just don't know off
25 the top of my head, Commissioner.

1 VICE-CHAIRMAN ECHOLS: And, finally, just
2 because you hypothetically kept Unit 2 in operation
3 until '35, it doesn't mean that you actually have to
4 use it every day and actually burn coal there;
5 correct?

6 WITNESS GRUBB: Yes, sir. So, I mean, the coal
7 units actually haven't been running a lot over the
8 last few years, which is some of the reasons they've
9 got some pressure on them. So I'll let Mr. Robinson
10 speak from a transmission standpoint.

11 There could be cases where we would need to run
12 them for transmission as we continue to do the work.
13 But, yes, you do not have to run it every day.
14 That's one of the things we try to factor into those
15 O&M budgets.

16 I think the important thing from us from a coal
17 standpoint is transmission and building that
18 transmission is really what gives us the option for
19 future rules, not to have to lock into those. If we
20 don't build transmission, we keep them. Another
21 rule comes, we may not have the options. And so if
22 you do keep it, the transmission component is still
23 very important.

24 WITNESS ROBINSON: Yes, Commissioner. And as
25 we build that transmission, we take outages on the

1 system to make improvements. It is going to become
2 important that we do run those units for
3 reliability. And that's one of the reasons Bowen 3
4 and 4 -- the dates that we are proposing or looking
5 forward to for those.

6 I tell you, one of the things that we are
7 interested in looking at -- we talked to our
8 generation partners about this is the potential
9 conversion of these units to synchronous condensers.
10 That's where you strip the boiler away and you keep
11 the turbine, the generator, the exciter, and you use
12 it for voltage support.

13 So it becomes basically a transmission asset
14 that you can use. Other utilities throughout the
15 United States have been successful in converting
16 large units like those to synchronous condensers.
17 And we have been talking to our generation partners
18 about potential of that conversion.

19 VICE-CHAIRMAN ECHOLS: Thank you.

20 MADAM CHAIR PRIDEMORE: To follow up on that,
21 Mr. Robinson. So when you say convert them to
22 synchro- -- say that again.

23 WITNESS ROBINSON: Synchronous condenser, Madam
24 Chair.

25 MADAM CHAIR PRIDEMORE: Synchronous condensers,

1 all right. That's a new one.

2 Is that -- are you talking about Bowen Units 1
3 and 2 or 3 and 4?

4 WITNESS ROBINSON: We'd be interested in the --
5 if we retire Bowen 1 and 2 first, but 1 and 2 units,
6 to convert those. Particularly Bowen 1 since it's
7 on the 230 kV system and closer to the load.

8 MADAM CHAIR PRIDEMORE: All right.

9 WITNESS GRUBB: And, Commissioners, those are
10 part of the things we'll look at for that North
11 Georgia Reliability Resilience Plan. Because we
12 know we'll need to retire Bowen 3 and 4 at some
13 point. We're planning on that.

14 That's that next step is: What do you do in
15 north Georgia? And those are the types of things
16 that we'll look at on Bowen 1 and 2 if they're
17 retired.

18 If they are converted that way, then they
19 aren't -- Commissioner Echols, to our discussion,
20 they aren't normally an economic dispatch. They're
21 not a capacity resource.

22 And so from the planning side, you still have
23 to replace them. But from a power delivery side,
24 it's got some transmission, but --

25 WITNESS ROBINSON: Right. The transmission

1 operators, Commissioners, would have that unit to
2 call upon to provide reactive support, whether it's
3 positive or negative, to help with voltage in the
4 north Georgia area.

5 MADAM CHAIR PRIDEMORE: Okay. Mr. Grubb, you
6 mentioned ELG. Why don't we go ahead and define
7 that acronym for those who don't know what it is and
8 where it came from.

9 WITNESS GRUBB: Yes, ma'am. Effluent
10 limitations guideline. So it's basically the
11 treatment of all the wastewater on the plant sites.

12 For anymore details, panel three can help you
13 there. They're a lot more versed on that than I am.
14 But, yes, it's wastewater treatment from the
15 scrubbers is really what we're looking at.

16 MADAM CHAIR PRIDEMORE: Who provided that ELG
17 guidance to the State?

18 WITNESS GRUBB: To the State? So that is a
19 federal rule that we apply through working with the
20 EPD in Georgia, but it is a federal rule.

21 MADAM CHAIR PRIDEMORE: Okay. Out of the
22 federal EPA?

23 WITNESS GRUBB: Yes, ma'am. That is my
24 understanding.

25 MADAM CHAIR PRIDEMORE: All right.

1 Thank you, Mr. Walsh. Go ahead.

2 MR. WALSH: Thank you.

3 BY MR. WALSH:

4 Q I want to finish up discussing on the
5 additional sum. You mentioned that the additional sum is
6 sometimes a disputed issue during these proceedings.

7 But if the company is awarded an additional sum
8 in association with the purchase power agreements, then
9 that will be a cost recovered from ratepayers that will
10 not have been included in the economic analysis; is that
11 fair?

12 A (Witness Grubb) That's correct. I don't think
13 it would change our recommendations. And, again, you
14 don't know exactly what that value is. We haven't put
15 that in there. But, yes, once you are granted additional
16 sum, it is a cost to customers.

17 Q You don't know what the value is, but the
18 company has been awarded additional sums previously;
19 correct?

20 A (Witness Grubb) On capacity RFPs, yes, they
21 have.

22 Q And the decision of whether to include or
23 exclude an additional sum from the modeling analysis
24 could potentially affect the comparison of a combustion
25 turbine with a power purchase agreement or of a combined

1 cycle and purchase power agreement; correct?

2 A (Witness Weathers) Well, I wouldn't say that
3 would be appropriate because really in the unit
4 retirement studies what we're looking to do is to
5 evaluate all of the incremental cost and benefits at
6 whatever resource we're looking at. So a coal unit
7 versus the incremental cost and benefits of a replacement
8 unit.

9 So once an additional sum is decided upon, then
10 that's not a -- that's a known cost. So that's a cost
11 that you know what it is. It's going to occur. It's --
12 the occurrence of that cost won't be dependent upon the
13 retirement of the unit.

14 So we're looking at costs that are affected by
15 the retirement or the continued -- the continuation of
16 the operation of the unit.

17 Q Okay. So I understand that your testimony is
18 then that it would be inappropriate to include it, but
19 the question of whether to include it or not could impact
20 the analysis; correct?

21 A (Witness Grubb) It could. I mean, it's a cost
22 that you're putting in there. I don't know that it
23 changes any of our recommendations. I don't think it
24 would.

25 Commissioners, we're looking at a 30-year study

1 on the unit retirement study. The PPA terms are ten
2 years or so. We've got a lot more moving pieces in
3 there.

4 So is it cost that customers pay? Yes. But
5 it's really one that's determined after you've made the
6 retirement decision and looked at what are you going to
7 replace it with.

8 Q For renewables, how is the company proposing to
9 calculate the additional sum?

10 A (Witness Mallard) So for renewable PPAs, the
11 company's proposing a change in the way that we calculate
12 the additional sum. In RFPs past, the additional sum has
13 been calculated based on shared savings and specifically
14 an 8.5 percent portion of the savings.

15 What we're proposing going forward is to
16 convert those numbers into a more simple dollar per
17 kW amount.

18 So really what we did, Commissioners, is take a
19 look at the average from the last four renewable
20 solicitations based on that 8.5 and then just converted
21 that into a dollar per kW. The resulting amount is \$7.50
22 per kW.

23 Q And is that the same additional sum calculation
24 that the company's requesting in connection with
25 distributed generation projects?

1 A (Witness Mallard) Yes. The calculation would
2 be the same for utility-scale and for distributed
3 generation.

4 Q And the Commission has not previously
5 authorized an additional sum for distributed generation
6 projects; correct?

7 A (Witness Mallard) One, it's never been awarded
8 through a certification process. However, the
9 stipulation -- the ordering language in the last IRP did
10 call for additional sum for distributed generation RFPs.

11 Q And while the IRP Act references an additional
12 sum, it does not dictate how much of an additional sum
13 the Commission should award; correct?

14 A (Witness Mallard) Correct.

15 A (Witness Grubb) Correct.

16 VICE-CHAIRMAN ECHOLS: Question for
17 Mr. Mallard. Would that additional sum be applied
18 towards homeowners who were net metering or would it
19 just be on those RFPs?

20 WITNESS MALLARD: Just the competitive RFPs,
21 Commissioner. Just the RFPs through which we run a
22 competitive solicitation, the utility-scale and the
23 distributed generation RFPs.

24 VICE-CHAIRMAN ECHOLS: And would it be
25 retroactive or just beginning with future RFPs going

1 forward?

2 WITNESS MALLARD: The new methodology is
3 proposed for the future RFPs going forward to
4 procure the energy from the 2,300 megawatts as we
5 proposed.

6 VICE-CHAIRMAN ECHOLS: Have you considered
7 requesting an additional sum for net metering and
8 expanding the net metering program?

9 WITNESS MALLARD: We certainly considered
10 expanding the net metering program. Collecting an
11 additional sum, I don't know that I've given that
12 much thought.

13 You would really need a long-term purchase
14 power agreement to lock in prices that were
15 beneficial to all customers to consider that. So
16 I'd have to say, no, we haven't -- we haven't really
17 considered that, Commissioner.

18 BY MR. WALSH:

19 Q I'd like to now ask a few questions about Bowen
20 Units 1 through 4. And the Commissioner's questions
21 earlier have addressed some of my questions, so this
22 should be fairly brief.

23 But the company assumes that Bowen 3 and 4 will
24 continue to operate past 2028; is that correct?

25 A (Witness Grubb) Yeah. We're not only assuming

1 it, we're planning for it and moving down that path.

2 WITNESS GRUBB: Commissioners, as we said
3 before, when we identify the transmission projects,
4 if we were going to avoid ELG at Bowen 3 and 4 and
5 retire it, we cannot complete those by the time we
6 would need to comply with ELG.

7 So, yes, we're planning on that, but it's
8 because that's what we need to move forward. So
9 it's not just a planning assumption is what I'm
10 trying to clarify. It's a request.

11 BY MR. WALSH:

12 Q Okay. And in order to do that, the company is
13 planning to install additional wastewater treatment
14 system for flue gas carbon effluent; is that correct?

15 A (Witness Grubb) That's correct. By the end of
16 2025, that's correct.

17 Q Okay. And the wastewater treatment installed
18 for Bowen 3 and 4 would also address that scrubber
19 effluent from Bowen 1 and 2; is that correct?

20 A (Witness Grubb) That's correct. The cost to
21 control wastewater really is a plant-wide cost. It's not
22 dependent on the number of units.

23 Q And, therefore, the company would not have to
24 incur incremental capital expenditures to treat Bowen 1
25 and 2 scrubber effluent; correct?

1 A (Witness Grubb) That's correct.

2 And, again, Commissioners, in the unit
3 retirement studies, we have shown that. In our unit
4 retirement studies if you avoid a plant and avoid -- if
5 you retire a plant and avoid an environmental cost, we'll
6 show that as a benefit or a cost reduction.

7 We did not do that on Bowen 1 and 2 because you
8 aren't avoiding that cost. So the economics reflect
9 that, as you just laid out.

10 Q Okay. And just so I understand, if Bowen 3 and
11 4 continue to operate, essentially the same environmental
12 costs would be incurred whether it's just Bowen 3 and 4
13 or it's all four units; is that correct?

14 A (Witness Grubb) For ELG capital projects,
15 that's correct.

16 Q Given that inflation is running higher than the
17 company anticipated when it conducted its IRP analysis
18 and that natural gas prices are rising, would it
19 provide the company and the Commission with additional
20 flexibility to, again, wait on finalizing a Bowen 1 and 2
21 retirement decision until the next IRP?

22 A (Witness Grubb) So that is the Commission's
23 decision obviously. The company's recommendation, again,
24 is based on a 30-year look. And so when we see current
25 run-ups on natural gas prices or inflation, we do not see

1 that changing the long-term nature of this decision.

2 So the company's recommendation is investing in
3 the coal units at 1 and 2 pose risk for a future coal
4 rule or carbon cost on those units. And so it's really
5 around that 30-year look that we're making that
6 recommendation.

7 A (Witness Weathers) And the replacement
8 capacity are purchase power purchase agreements that we
9 know what the price is. They're not subject to
10 inflation.

11 Now, the natural gas prices could impact it,
12 but we don't think that the fundamentals of the natural
13 gas market have really changed because of the short-term
14 run-up in gas prices that we've seen.

15 So we think we're looking at some -- we know
16 that we're looking at known power purchase agreement
17 prices. Now we have assumption on the back end for solar
18 storage, but that's not in the near term either.

19 A (Witness Grubb) And I think the other thing,
20 Commissioners, is these are immediate decisions on the
21 coal units, but the retirement dates are several years
22 down the road.

23 And so we will have these coal units for the
24 next four, five, six years to help us respond to changes
25 in gas prices, just like we have. It's just that

1 long-term view. We see more risks on the side of staying
2 in Bowen 1 and 2 than retiring.

3 VICE-CHAIRMAN ECHOLS: But isn't it true that
4 federal policy sometimes go back and forth; an
5 example of the Clean Power Plan that didn't ever
6 materialize?

7 WITNESS WEATHERS: That's correct,
8 Commissioner, it does go back and forth. And really
9 that's why we look at not just a single planning
10 scenario. We would look at a range of scenarios
11 that takes into account a range of natural gas
12 prices, a range of federal policy with regards to
13 carbon. Such as the Clean Power Plan, we looked at
14 that several years ago. That fit within the range
15 of carbon prices.

16 We think that the range of carbon prices that
17 we're considering today include the potential
18 scenarios, potential legislation, regulation policy
19 the federal government has.

20 WITNESS GRUBB: Commissioner, the other thing
21 that we look for on coal units is the -- as we
22 continue to add renewables, flexibility of resources
23 becomes even more important.

24 And so the energy value from the coal units
25 gets harder to achieve because you've got to commit

1 them, you've got to run them for several days.
2 They're not always in the money as they were five,
3 six years ago.

4 So there's several drivers that, from our
5 standpoint, we just don't see a lot of up-side. And
6 this ELG timing gives us a chance to transition out
7 that we may not have in the future.

8 MADAM CHAIR PRIDEMORE: From a cold start, how
9 long does it take to get a coal unit at maximum
10 output?

11 WITNESS GRUBB: So we've -- you can help me
12 here, Jeff. But I think we have a minimum
13 commitment time of a week on a coal unit. And I
14 think it's a 24-hour or so startup.

15 So if you're looking at days ahead or
16 volatility on the system, you really have to commit
17 a coal unit running at minimum to have it available
18 to when it does provide value. So it's a lot less
19 flexible.

20 They were designed to run a lot and run a lot
21 of time and they've served of us well for decades.
22 But as you get to where there's more volatility,
23 that flexibility starts to cause some issues.

24 WITNESS ROBINSON: And, Madam Chair, I believe
25 for those units it can take up to two days to get

1 the full maximum output for those units. And they
2 have very complicated starting schemes. They pull
3 off of each other and have sources internal to the
4 plant that they have to run in certain sequences, as
5 well.

6 MADAM CHAIR PRIDEMORE: Have we seen a
7 limitation in availability of fuel for coal?

8 WITNESS GRUBB: We did some, Commissioner,
9 in -- a few months ago when we were getting ready --
10 when we saw some of the natural gas run-up and we
11 really tried to start looking at getting more coal
12 to our coal piles. We had some challenges and so
13 what we did was we actually wanted to focus on the
14 winter to make sure we had the coal supply available
15 for the winter.

16 We actually didn't run our coal units quite as
17 much that the straight pricing would have shown to
18 make sure that we had the inventory to get through
19 the winter, but -- so we have. I don't think the
20 coal supply chain is really set up to ramp up a lot
21 and add new mines and add new locomotives. And so
22 we have seen some challenges here.

23 WITNESS WEATHERS: And, Madam Chair, to your
24 point, I mean, that really for us highlighted that
25 coal generation is not immune from some of the

1 market interactions that we're seeing today,
2 whether, you know, supply chain challenges,
3 transportation challenges. Because we did have some
4 limitations on coal delivery. And it did impact the
5 way we're able to economically operate those units.

6 They also, as we were talking earlier, have
7 challenges, in terms of flexibility. Because we
8 have more -- we have increasing need for flexibility
9 on the system as we continue to add solar
10 generation. Coal units are not able to provide the
11 flexibility needed in the most economical way to
12 integrate those solar units.

13 WITNESS GRUBB: And so, Commissioner, just --
14 that was that short-term run-up trying to handle
15 some of that volatility. We do -- we will be able
16 to make sure we have supply and coal transformation
17 -- transportation and coal commodities while we're
18 keeping coal units.

19 Because I don't want to make it sound like we
20 can't supply our coal units to 2027. We can do
21 that. It was just that short-term run-up is what we
22 were speaking to.

23 MADAM CHAIR PRIDEMORE: Okay. So I know that
24 we're going to talk more about ELG in forthcoming
25 panels, but I do want to unpack a little bit more

1 about the basis of ELG because it is the basis for
2 the closure of 1 and 2 to a great extent.

3 So the January 26th edition of the Wall Street
4 Journal had an article about EPA and their rules to
5 target power plant pollution. And it talked about
6 the fact that the EPA is doing this through their --
7 and I want to quote this: Through the Agency's
8 broad powers to oversee air and water pollution, as
9 well as wastewater disposable.

10 But they're doing it through rules versus it
11 going to Congress or across the President's desk.
12 It's being done through the rule-making process at
13 the EPA.

14 Has the EPA -- so this was from January. Have
15 they issued the guidance on ELG, or what's also kind
16 of considered NOPRs in some cases? Have they issued
17 that to utilities yet?

18 WITNESS GRUBB: I don't think so. I'm not
19 trying to completely punt to panel 3. They can give
20 you more details.

21 But those are the types of things,
22 Commissioner, that when we look at future coal
23 operations beyond just this ELG rule that we're
24 looking at. They have said they are going to
25 revisit the ELG.

1 So if you think back to 2019, the ELG rule was
2 supposed to take effect in 2023. And we're going to
3 have to have compliance by '23. The reconsideration
4 rule moved that date back to '25 and also gave us
5 this boiler cessation option in 2028.

6 The new administration I think has stated
7 they're going to revisit that. I think the EPA
8 always has the chance to revisit MATS rules that we
9 controlled four years ago, NOx, ozone. I think they
10 always have that to come back and revisit on it.

11 So those are the pressures that we're thinking
12 of when we say future environmental rules. And a
13 lot of it times those rules have time frames that
14 are shorter than us being able to build
15 transmission.

16 So we aren't -- we aren't basing our
17 recommendation on Bowen 1 and 2 on the avoidance of
18 ELG. The ELG is driving the timing of when we make
19 that decision. Because, again, as we've covered,
20 Bowen 1 and 2 don't cause any incremental ELG.

21 So that article and those other rules that the
22 EPA can use, that's the things that we see long term
23 posing more risk to the coal units.

24 WITNESS ROBINSON: And, Commissioners, when
25 Mr. Grubb talks about the time it takes to build

1 transmission, what we're looking at right now is
2 Greenfield 230 kV lines that are -- for any
3 distance, it's about six and a half years. To
4 acquire design, acquire the right-of-way, and build
5 that transmission. For 500 kV for any distance,
6 it's about eight years.

7 MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh.

8 MR. WALSH: Thank you.

9 BY MR. WALSH:

10 Q You stated that the retirement of Bowen 1 and 2
11 is still several years away under the company's plan; is
12 that correct?

13 A (Witness Grubb) That's right. We're
14 recommending the end of 2027. We cannot retire those
15 units until we complete transmission work. And those
16 transmission projects are projected to be completed by
17 the end of 2027.

18 Q So the Commission will have another integrated
19 resource plan from the company in between now and the
20 anticipated retirement date?

21 A (Witness Grubb) They will. But the decision
22 before the Commission and the company that we've been
23 working hard on the last several years is, again, the
24 opportunity to take advantage of the capacity RFP and
25 then the transmission construction.

1 So the ELG compliance is to be done by 2025.
2 If the Commission waits until 2025 and you've waited on
3 transmission and the capacity RFP, you have just missed
4 that opportunity.

5 A (Witness Robinson) Commissioners, one of the
6 projects that's needed for those retirements is a 40-mile
7 230 kV line. That's going to take six and a half years.

8 MADAM CHAIR PRIDEMORE: Is that part of the
9 North Georgia Transmission Plan you spoke of?

10 WITNESS ROBINSON: It is not. It is part of
11 the projects associated with the unit retirement
12 studies. And those projects are listed in the
13 Volume 3.

14 WITNESS GRUBB: So that accommodates the
15 retirement of Bowen 1 and 2, Madam Chair.

16 VICE-CHAIRMAN ECHOLS: So is the idea of
17 leaving the units in operation, but not using them
18 on a regular basis, just treating them as a big
19 generator for when we have a crisis or a polar
20 vortex or something like that?

21 Is that something that you all have considered?

22 WITNESS GRUBB: I believe that's something
23 we'll definitely look at, Commissioner, in terms of
24 the north Georgia plan. Mr. Robinson spoke about
25 synchronous condensers. You may be referring to

1 kind of an inactive reserve.

2 In other words, the plants, Bowen 1 and 2,
3 aren't there for normal dispatch, but they're there
4 if you have something happen. I don't know if we
5 know all the implications of that from an
6 environmental standpoint; all right?

7 Do you have to still control it? Do you have
8 to permit it? How does that work?

9 But I think in terms of how it may help on the
10 power delivery side, that's something we can look at
11 as part of that north Georgia reliability relief
12 plan. From a generation planning standpoint,
13 though, we are trying to make decision on: Do you
14 replace it? And do you no longer plan on it for
15 normal energy capacity service?

16 VICE-CHAIRMAN ECHOLS: And you may not know
17 this off the top of your head, but has there been --
18 has there been a time over the last three or so
19 years when we've had to go to a coal unit on the
20 system that wasn't really operational and fire that
21 unit up for reliability for our grid because of
22 weather-related events?

23 WITNESS GRUBB: Well, before we go, there's two
24 aspects to that. We'll address both. I think
25 Mr. Weathers will speak to the generation resource

1 accuracy and Mr. Robinson can speak to it from a
2 transmission standpoint.

3 WITNESS WEATHERS: Yeah. Thank you, Mr. Grubb.

4 We have done that in the past, Commissioner,
5 but we've had units on inactive reserve, which
6 generally means they are not counted on as firm
7 capacity in the company's resource plans. They're
8 generally available for resiliency needs maybe with
9 a few days' notice.

10 So we have had that occur in the past. So
11 that's something that happens on the system. Now,
12 the size of the unit -- you know, there's a lot of
13 things that go into -- must be taken into
14 consideration when thinking about placing a unit on
15 inactive reserve. But it has happened in the past
16 with smaller units with another operating company.

17 WITNESS ROBINSON: Commissioner, you typically
18 don't see those large coal units on what we call the
19 reliability commitment list in the wintertime for
20 transmission constraints because the system is not
21 constrained.

22 Where we see those units on a reliability
23 commitment list is in the spring and fall. At the
24 time we're in right now, where we have a lot of
25 outages on the system, a lot of projects going on, a

1 lot of generators are off-line for maintenance. And
2 so we actually utilize those units and have them run
3 during this period of time and -- which creates
4 challenges with coal, as we mentioned before.

5 And we've been working through that with system
6 operations and the transmission operators, as far as
7 feathering that as we move forward to make sure we
8 are making the right decisions.

9 WITNESS GRUBB: And, Commissioners,
10 Mr. Robinson, when he spoke about not being
11 constrained in the winter --

12 WITNESS ROBINSON: Transmission.

13 WITNESS GRUBB: Transmission and power
14 delivery. Because that doesn't change the risk we
15 see on the generation side. I want to make sure we
16 have --

17 COMMISSIONER McDONALD: Mr. Robinson, kind of
18 help me with the upgrade of the transmission system
19 when your long-range plan is to close down a portion
20 of generation in that area. Kind of bring those two
21 together for me, please.

22 WITNESS ROBINSON: Sure, Commissioner. So if
23 you go back and look at the growth in Atlanta and
24 the state of Georgia in the '50s and '60s, the
25 transmission system that we have today was built out

1 in the '60s, '70s, and '80s to serve the load in
2 Atlanta from these super critical plants that we are
3 now retiring.

4 When you flip the state and you've got a lot of
5 solar development in south Georgia, now you've got
6 the megawatts flowing from south Georgia to north
7 Georgia where the load is. We submitted a -- it's a
8 study that we did looking at just the simple delta
9 between load and generation forecasting out in time
10 if you look towards potential retirement of Bowen 3
11 and 4. And there's a 7000-megawatt deficit of load
12 versus generation in the Atlanta area and
13 north Georgia area.

14 So it's very important that we build the
15 transmission to move those megawatts across the
16 state to address those south-to-north flow issues
17 and eliminate the constraints that we're starting to
18 see in these studies long term.

19 COMMISSONER McDONALD: In our last neighborhood
20 conference in Washington, I attended a seminar or
21 whatever on transmission and it was talking about
22 the difference between twisted aluminum and
23 composite, as far as the wires are concerned.

24 WITNESS ROBINSON: Uh-huh.

25 COMMISSONER McDONALD: And I think somewhere

1 between there and where we are today, I asked the
2 question were we using composite. And I got the
3 answer was no. Is that correct?

4 WITNESS ROBINSON: No. Commissioner, we are.
5 We've used what's called ACCS, which is aluminum
6 composite. And what the composite is is it replaces
7 the steel core or all-aluminum core in the -- in the
8 conductor.

9 You still have to have the metal to be a
10 conductor, but what it allows you to do -- that
11 composite material that's in the center allows you
12 to operate that wire at a higher temperature.

13 So we actually can reconduct our lines. And
14 we've got several in the Savannah area that we've
15 done with that technology. And it also uses a
16 trapezoidal conductor so it gets the metal
17 conductor -- you can get more conductor in the space
18 because of the trapezoidal design.

19 But it allows you to operate that line at
20 200 degrees C -- 200 degrees Celsius versus
21 typically we could only go up to 100 degrees C on a
22 typical steel-core conductor.

23 COMMISSONER McDONALD: So you get over
24 20 percent more --

25 WITNESS ROBINSON: You can --

1 COMMISSONER McDONALD: -- use out of it; is
2 that correct?

3 WITNESS ROBINSON: Yes, Commissioner. You can
4 get more --

5 COMMISSONER McDONALD: The same size --
6 basically the same size wire; you don't have as much
7 sag in it?

8 WITNESS ROBINSON: That's correct.

9 COMMISSONER McDONALD: The weight of the --

10 WITNESS ROBINSON: That's correct. And we will
11 look at those when we look at this north Georgia
12 plan that we're currently working with the ITS
13 participants. We will look at that type of
14 technology in the future because we've had success
15 with it in the past, absolutely.

16 BY MR. WALSH:

17 Q So I was asking about the Commission having
18 another integrated resource plan proceeding in 2025,
19 which is before the date that the company is currently
20 planning for the retirement of Bowen 1 and 2.

21 Is it your testimony that if the Commission
22 were to wait until the 2025 IRP to decide on the Bowen 1
23 and 2 retirement decision, that it would be impossible to
24 retire it by the date that the company is currently
25 planning?

1 A (Witness Grubb) That's all going to depend on
2 what else the Commission approves in this IRP.

3 Q But it would be possible, depending on what the
4 Commission approves in this IRP?

5 A (Witness Grubb) With the transmission aspect
6 taken into account. That's really the timing driver.
7 And then what the Commission decides to do on capacity
8 replacement. So, yes, you can, but it depends on what
9 else is approved in the case.

10 A (Witness Robinson) Yeah. Commissioners,
11 because of the project that I mentioned before, the long
12 230 kV line that's greenfield, six and a half years, we
13 would need to go ahead and build that project to leave
14 the contingency open for that further date.

15 A (Witness Grubb) And then I think, as well, and
16 I've said it before, the capacity RFP resources are very,
17 very attractive prices. So that's another consideration
18 for this --

19 Q There are considerations, I understand.

20 A (Witness Grubb) Yes.

21 Q And one of the considerations would be that not
22 deciding to retire Bowen 1 and 2 as part of this
23 proceeding would provide the company some flexibility in
24 some manner; correct?

25 A (Witness Grubb) Depending on what else is --

1 is approved in this case.

2 Q I gotcha.

3 I would like to move now to a different
4 subject, Gaston 1 through 4. Is it correct that the
5 company considers that if it were to continue operating
6 Gaston 1 through 4 it would be preferable to obtain a
7 firm gas transportation contract, rather than to incur
8 the cost of environmental upgrades?

9 A (Witness Grubb) So we modeled that. We aren't
10 recommending either for Gaston 1 through 4. We are
11 recommending to retire Gaston 1 through 4 and do neither
12 a conversion to handle ELG or to get firm gas
13 transportation.

14 So those are the two options for operation
15 beyond 2028. We think the more appropriate one long term
16 would be to go get natural gas firm transportation, but
17 that is an expensive option, which is driving our
18 recommendation to retire Gaston 1 through 4.

19 Q In obtaining a firm gas transportation
20 contract, did the company assume that it would be
21 necessary to have a firm gas contract every day of the
22 year?

23 A (Witness Grubb) Yes, we did. And that is
24 because from our fuel policy that we use on the system
25 for a steam unit that is converted, we looked at -- I

1 forget the hours. But we looked to have firm gas
2 transportation on a daily basis just in a similar manner
3 we do for combined cycles. We've got to be able to have
4 access to the pipes to be able to generate through that
5 unit. So, yes, it's an annual firm transportation
6 contract.

7 Q Could the company have identified specific
8 months to have a firm gas transportation contract that
9 would have been cheaper than the options selected by the
10 company?

11 A (Witness Grubb) Possibly.

12 I think, again, Commissioners, we didn't get
13 into those details. Because when we look at Gaston 1
14 through 4 and replacement generation options that we have
15 in the capacity RFP, it's in the best interest of
16 customers to retire those units there.

17 Built in the 1950s. We don't see it benefiting
18 customers to either comply with the ELG rule there or to
19 do gas transportation when we have capacity RFP resource
20 that's available in the meantime.

21 A (Witness Weathers) I would like to just add to
22 that. I'm not a gas procurement expert, but I don't
23 think there really would be savings if you tried to
24 eliminate certain days of the year. It's a really -- the
25 gas pipeline capacity of the firm transportation is going

1 to be priced on what is most valuable to the pipeline.

2 So what are the constrained seasons? We're
3 looking at the winter season and the summer season. If
4 you're purchasing it for those seasons, then I think the
5 cost to have it other, you know, non-constrained times of
6 the year would be minimal.

7 Q Did you do that analysis to confirm that
8 belief?

9 A (Witness Weathers) I did not. But that's
10 my -- again, I'm not in the procurement, you know, part
11 of the company. But that's my -- that would be my belief
12 and my expectation of that analysis if it would be
13 performed.

14 Q Did the company perform -- when I said "you," I
15 meant the company, not just you specifically.

16 But did the company perform that analysis?

17 A (Witness Weathers) I don't think so. But
18 generally we're looking at -- you know, either you're
19 buying summer FT, firm transportation, or you're buying
20 winter, or you're buying annual and it really covers both
21 seasons.

22 You're not generally buying it, you know, for
23 some days of the year and excluding, say, an April date.
24 I think April is just going to come along for the ride if
25 you're buying winter or if you're buying summer.

1 VICE-CHAIRMAN ECHOLS: Let me ask you about the
2 firmness. I mean, we learned through the Texas
3 situation, right, that cheap gas alone is not
4 enough; right?

5 WITNESS WEATHERS: That's correct,
6 Commissioner.

7 VICE-CHAIRMAN ECHOLS: They need to be cheap
8 and firm?

9 WITNESS WEATHERS: It needs to be firm, yeah.
10 That's correct.

11 VICE-CHAIRMAN ECHOLS: So -- and the Transco
12 Pipeline hack was liquid pipe. But if it had been a
13 methane pipe that had been hacked, how much of our
14 generation would have been idled?

15 WITNESS WEATHERS: Well, I mean, I don't know
16 in terms of percentage. I mean, there is primarily
17 two gas pipelines that serve our generation fleet,
18 the Transco Pipeline and SNG. It is a significant
19 portion that is on Transco.

20 Those are the type of studies that we do from
21 time to time looking at resiliency. What if? We
22 look at the "what ifs". What if that happens?

23 We are looking at utilizing our gas storage.
24 We are looking at redispatching our system. You
25 know, running units on oil that have that capability

1 to try to recover from those type of events, you
2 know, as quickly as we can. So I don't have the
3 exact numbers, but it would not be insignificant.

4 WITNESS ROBINSON: Commissioner -- I'm sorry.
5 The transmission team also runs studies looking at
6 the loss of those pipelines, each individual
7 pipeline, to ensure that we have transmission
8 capability to serve the load throughout the
9 southeastern area. One of the things that's very
10 important in that study is our interface capability
11 to ensure that we can import megawatts from other
12 areas if we were to have that contingency happen
13 just to ensure that we can reliably serve the load.

14 VICE-CHAIRMAN ECHOLS: But it would have been a
15 crisis of epic proportions for our grid; right?

16 WITNESS WEATHERS: Well, I don't know if I
17 would say that. Because as Mr. Robinson said and as
18 I was alluding to, we do those type of studies. And
19 we are not depending on a -- dependent on a single
20 gas pipeline and we're not dependent on, you know,
21 natural gas as a single fuel source either.

22 So we have a diversity of fuel sources. We
23 have diversity of generators in our fleet. And we
24 have gas that -- gas units that can run on oil that
25 can pull from gas storage.

1 So we have a lot of diversity that helps with
2 that. It wouldn't be catastrophic, but it is
3 something we look at from a planning perspective.

4 COMMISSONER McDONALD: And that's where you
5 always have to look back at coal every once in
6 awhile, too; isn't it?

7 WITNESS WEATHERS: Yes, sir. We have --
8 certainly we have coal, as well.

9 VICE-CHAIRMAN ECHOLS: And would that be a
10 rationale for leaving these -- a unit like Unit 2 at
11 Bowen in an inactive reserve status because you
12 might be anticipating a hack in the future?

13 WITNESS WEATHERS: Well, that would be the type
14 of resiliency situation that if you had a unit like
15 Bowen that wasn't there for reliability anymore, but
16 was there within maybe a few days' notice to run for
17 resiliency purposes, that would be one of those
18 situations that it would run for.

19 MADAM CHAIR PRIDEMORE: Mr. Weathers, could you
20 clarify Bowen, as in Bowen Units 1 and 2 or 3 or 4?

21 WITNESS WEATHERS: We are talking about
22 Bowen Units 1 and 2.

23 MADAM CHAIR PRIDEMORE: Thank you.

24 VICE-CHAIRMAN ECHOLS: Thank you.

25 BY MR. WALSH:

1 Q I would like to ask you a few questions about
2 capacity expansion analysis. And before I get into the
3 specific questions, I would like to talk about a couple
4 of terms and make sure we share the same understanding.

5 Equivalent capacity value when you do an
6 analysis, what does that term mean to you?

7 A (Witness Weathers) Well, we have a term very
8 similar to that we call the incremental capacity
9 equivalency or ICE factor. So my understanding of the
10 term that you just used would be the ICE factor in our --

11 Q Did you use that term instead of mine because
12 you get to say ICE factor?

13 A (Witness Weathers) No. But it is a good word
14 to say.

15 But, real briefly, what the ICE factor is, is
16 the reliability contribution of a unit that's maybe an
17 energy limited unit or intermittent unit, variable energy
18 resource unit. They don't have a one-for-one capacity
19 value as you compare it to a firm dispatchable unit. So
20 we use an ICE factor.

21 Another common term in the industry is the
22 effective load carrying capability, or ELCC. Those are
23 both ways to take variable units or demand-side units
24 that can't operate all hours of the year and equvalate
25 them to firm capacity units on the system.

1 Q And are you also familiar with the term
2 "nameplate capacity"?

3 A (Witness Weathers) Yes.

4 Q What does -- what does that term mean?

5 A (Witness Weathers) That's just going to be
6 your normal rating of the unit. So what the unit can
7 operate under, you know, normal conditions, usually
8 summer conditions.

9 VICE-CHAIRMAN ECHOLS: Let me ask you a
10 question on the transmission side. You mentioned
11 the 6 1/2-year window to do a 230 kV line and an
12 8-year time period to do a 500 kV window.

13 We've talked before about using old coal
14 plants, like Plant Branch, where the switchgear, the
15 lines are still there; right?

16 We've closed it. Everything's been torn down,
17 but we still have that equipment there. And we've
18 got that, of course, with Bowen with it fully
19 operational.

20 If you self-built a massive solar array at or
21 near these plants with storage, would it have a
22 positive impact on transmission and possibly push
23 those dates where we need the transmission upgrade
24 out further?

25 WITNESS ROBINSON: Commissioner, that could be

1 useful. Those technologies are very expensive for
2 the megawatts that we would need, particularly if
3 you're looking at retiring a 760-megawatt unit and
4 replacing that with 760 megawatts of solar-plus
5 batteries. It gets pretty expensive.

6 As it relates to Branch, surprisingly almost
7 that -- most of that capacity is gone because of
8 changes in the system around it, because of solar
9 development in South Georgia.

10 The study that we filed in Volume 3 that
11 looks -- it's called an Optimal Transmission Siting
12 Study. It looks at where we can inject
13 300 megawatts throughout the state and not cause
14 transmission problems. Bowen is not one of those
15 listed there.

16 So we've -- we've pretty much eroded all
17 capacity at Bowen. It's surprising -- it is
18 surprising to hear that, but if you look at what's
19 going on in South Georgia in the development of
20 solar, that capacity -- that transmission capacity
21 has pretty much been eaten up.

22 WITNESS GRUBB: So, Commissioner, what
23 Mr. Robinson is talking about is the flow is on the
24 overall grid. The physical switchyards and
25 everything at Branch are still there. He's talking

1 about once you deliver to the bulk system. I just
2 want to make sure there's a clarification there.

3 VICE-CHAIRMAN ECHOLS: Thank you.

4 BY MR. WALSH:

5 Q When a company conducts capacity expansion
6 analyses, does it use the equivalent capacity value, or
7 ICE factor, for renewables?

8 A (Witness Weathers) Yes. Well, in the capacity
9 mix study all the existing renewables are in there with
10 their appropriate ICE factor.

11 Q So the company does not use then what is --
12 what we talked about as nameplate capacity for renewables
13 when it develops its expansion plan, does it?

14 A (Witness Grubb) Well, we do from an energy
15 standpoint.

16 A (Witness Weathers) Yeah.

17 A (Witness Grubb) So, Commissioners, the way we
18 would model, for example, a 100-megawatt solar PPA is
19 it's going to have a 100-megawatt profile in delivered
20 energy. We capture that in the models.

21 But when we look at the reserve margin and what
22 is able to meet that peak, that's when we use capacity
23 equivalence. 100-megawatts of solar does not contribute
24 the reliability the same way 100-megawatts CT does.

25 So we capture -- I'm sorry, Commissioner. A

1 lot of stuff on my desk. I need to stay closer.

2 So the nameplate or the megawatts of the
3 facility itself are modeled. And the generation from an
4 energy standpoint is captured, but the capacity
5 equivalence that it leads to certain peaks is where we --
6 where we reduce that.

7 A (Witness Weathers) Another way to think about
8 that is the resource ledger. When you're counting up
9 your capacity, comparing that to your peak demand, you
10 use the equivalence, use the ICE factor. So you only
11 want to count what you contribute to reliability.

12 But when we run our models, as Mr. Grubb said,
13 we model the full unit. And there's a profile. It will
14 dispatch the unit over the course of the day, but that
15 doesn't use the ICE factor. That uses the energy profile
16 of the unit.

17 Q So when the company tests if a purchase power
18 agreement renewables exceed the 30 percent purchase power
19 agreement requirement in the Commission rule, the company
20 uses the nameplate value of renewables; is that correct?

21 A (Witness Grubb) No. That is not correct. I
22 believe we filed a data request where we look at the
23 70/30 rule. We haven't talked about it in a long time.
24 But we look at it from a planning megawatt standpoint.

25 And so when we filed either in a DR or summary

1 of our testimony or our -- I forget where it was. We do
2 the equivalence. So if we've got 5,000 megawatts of
3 solar, we are not putting 5,000 megawatts of PPAs in that
4 calculation. We can do it both ways, but the one that we
5 filed was based on planning megawatts or those capacity
6 equivalents.

7 Q If you did use the nameplate value of
8 renewables for the testing, that would be reflecting that
9 the renewable resource would be fully dispatchable; is
10 that what that -- would that be the implication of using
11 nameplate for testing?

12 A (Witness Grubb) Well, I mean, they are -- the
13 renewable resources aren't dispatchable in that they
14 operate as they operate. What that would just be doing
15 would be looking at just, for lack of a better term, the
16 steel on the ground; right? The megawatts on the ground.

17 And so when we -- when we look at the origins
18 of the Commission's rule on the 70/30, it was a lot
19 around reliability. And so when we do that math, we do
20 it with planning megawatts or the capacity equivalents.

21 If you did use nameplate, well, then the PPA
22 amount would exceed 30 a lot faster and quicker than it
23 would looking at capacity equivalent. So it would -- if
24 you use nameplate, it would say that we were over the
25 30 percent by much more.

1 Q I need to ask you a few questions about winter
2 reliability. In this IRP, as in prior IRPs, the company
3 conducted the economic and reliability study of the
4 target reserve margin for the Southern Company System; is
5 that correct?

6 A (Witness Weathers) Yes.

7 Q And the purpose of that study is to determine
8 the amount of reserve or backup capacity or target
9 reserve margin that should be maintained on the system;
10 is that correct?

11 A (Witness Weathers) Yes.

12 Q And you would agree that while reliability
13 concerns are critical, maintaining the capacity reserves
14 at too high of a level can result in exposing customers
15 to significant expense; correct?

16 A (Witness Weathers) Yes. Absolutely. And
17 that's exactly why we do the reserve margin study.
18 Because it is an economics-based view of setting the
19 target reserve margin.

20 Because, to your point, Mr. Walsh, if you have
21 too much capacity on the system, you may be really,
22 really reliable, but that's expensive for customers. On
23 the other hand, if you have too little capacity on the
24 system, there's significant reliability costs that
25 customers see.

1 Q There's risk each way?

2 A (Witness Weathers) It goes each way. So our
3 target reserve margin finds the optimal point and also
4 adjusts that for the risk of outages that the customer
5 see.

6 Q And the goal for the company is to come up with
7 the least cost reliable system; is that fair to say?

8 A (Witness Weathers) Well, that is a point of
9 consideration. The goal is not necessarily to set the
10 target reserve margin at the least cost, but that is a
11 data point.

12 But we go beyond that to look at: Is there
13 value to customers by increasing the target reserve
14 margin some amount and reducing more risk than the cost
15 that you're increasing? So that's the risk analysis that
16 we do on top of the lowest economic cost point.

17 Q And I think I was careless with my word choice
18 there. Would it more accurate to say that you go -- you
19 look at maintaining a reliable system in a least cost
20 manner?

21 Would that be more accurate?

22 A (Witness Weathers) Yes. Appropriately
23 considering risk, we do.

24 Q Okay. And it's also fair to say that your
25 analysis involves a large number of detailed assumptions?

1 A (Witness Weathers) It does. We're modeling
2 the entire Southern Company System, all the existing
3 units on the system. We're modeling a range of 58
4 different weather years, looking at weather variability.
5 The model does random draws of unit outages.

6 So it's a very robust analysis to capture all
7 the variability around reserve margins. So when we make
8 a recommendation, it has all of that analysis behind it.

9 A (Witness Grubb) And, Commissioners, as
10 Mr. Weathers and team are putting that study together,
11 we're using information and sources that are our
12 operators on the system, our senior production officers.

13 So when we're looking at how our generation
14 performs or what our system does, we're using the
15 information from our experts to put that together.

16 Q And if any of the analyses are found to be
17 erroneous or overstated or contain assumptions that are
18 not realistic, then you run the risk of overstating the
19 target reserve margin; correct?

20 A (Witness Weathers) Well, potentially. But it
21 is a very robust analysis. And, as you mentioned,
22 Mr. Walsh, there are a number of data points that go into
23 it. So there are likely going to be some that are more
24 conservative than others.

25 But I think the analysis as a whole -- again,

1 it's modeling our system. It's modeling the conditions
2 in our system based on our actual experience on the
3 system.

4 And so I think the analysis -- and it has a
5 range of -- a range of results. But what we're looking
6 at is: What's the best cost estimate -- what's the best
7 cost number on behalf of customers considering least cost
8 economics, considering risk to customers, and also
9 considering reliability needs?

10 Q And I understand that you're looking at a
11 range -- like I'm just -- I'm just making the point that
12 it's important that the analyses be realistic or else it
13 could have the result of overstating the reserve margin.

14 A (Witness Weathers) It is important. And
15 that's why we use actual data on our system because that
16 is realistic. That's data that has happened on our
17 system.

18 So we're using -- we're not making up numbers.
19 We're using actual weather that may have occurred, unit
20 outages that may have occurred, load forecast differences
21 that we've incurred. All that data point is based on
22 actual conditions on the Southern Company system. And
23 that's why it's important to use that, to your point.

24 Q The Southern Company system as a whole or
25 Georgia Power Company's system specific?

1 It's Southern Company system as a whole?

2 A (Witness Weathers) It's Southern Company
3 system because we operate as a system and as a pool to
4 support it.

5 We plan as a system. So it's important that we
6 capture the whole system because reliability in Georgia
7 is not different than reliability on the system. The
8 reliability is going to be the same across the system.

9 A (Witness Robinson) Just like the transmission
10 system is planned as a whole, as well, because it
11 operates as a whole.

12 Q To account for potentially higher outages in
13 the winter, the company suggested it may require more
14 backup capacity in the winter; is that correct?

15 A (Witness Weathers) When you say "more," as
16 compared to what?

17 Q Well, I guess is backup capacity greater in the
18 winter than in other seasons?

19 A (Witness Weathers) The reserve margin target
20 is higher in the winter than it is the summer. And it is
21 in part due to, as you just mentioned, that when we get
22 extremely cold temperatures on the system, that our units
23 have demonstrated that they're more likely to have forced
24 outages.

25 Those have occurred in history. We have

1 assumed that those will occur in the future. Now, we've
2 also assumed that there will be improvements to the
3 historical outages because we have made significant
4 winterization improvements on our units since 2014.

5 Those improvements were captured in our study.
6 It doesn't mean the risk is zero. There could be
7 incremental cold weather outages, but it's smaller than
8 it was in the past.

9 WITNESS GRUBB: And so, Commissioners, while
10 the 26 percent number is greater than the 16 number,
11 they are based on a summer load, weather normal, and
12 a winter load, weather normal. So 26 percent is
13 multiplied against a smaller load. So it's not
14 megawatt to megawatt 10 percent greater.

15 But the important thing is we've seen those
16 risks moved to the winter as we've talked over on
17 the last IRPs, last two. And so the winter target
18 reserve margin needs to take into account those
19 different risk drivers. And that's what we --
20 that's what we've incorporated in the last several
21 studies.

22 BY MR. WALSH:

23 Q I think actually your response about the steps
24 you take -- you've taken leads into the next exhibit that
25 I was going to present you with.

1 MR. WALSH: Madam Chair, may I approach the --
2 may I approach the witnesses?

3 MADAM CHAIR PRIDEMORE: Yes. Go ahead.

4 And you can pass to Commissioner Johnson and we
5 can pass down the row. It's a lot easier for us.

6 MR. WALSH: Madam Chair, I would ask that this
7 next exhibit, STF-JKA-1-1, the company's response to
8 it be marked for identification as Staff Exhibit 2.

9 MADAM CHAIR PRIDEMORE: So moved.

10 (The document referred to was marked for
11 identification as Exhibit No. 2.)

12 MR. WALSH: I will give you a moment to look at
13 that exhibit. And it's front and back. So let me
14 know when you're ready for questions.

15 WITNESS GRUBB: Yeah. We are ready.

16 BY MR. WALSH:

17 Q This is your response. So I would assume that
18 you'd agree this an accurate summary of the actions taken
19 by the company in response to the NERC report?

20 COMMISSONER McDONALD: Couldn't that be
21 answered in just one word; "diversification"?

22 WITNESS GRUBB: I think it's reliability,
23 Commissioner. I mean, what we -- what we learned
24 after the polar vortex and what a lot of this is
25 talking around is we had gone 10, 11, 12 years

1 before we had a really cold winter. And we learned
2 a lot around resources that we had added in that
3 time frame on weatherization and winterization.

4 So what this DR is stepping through is what all
5 our generation teams did to improve the performance
6 of units in cold weather.

7 COMMISSONER McDONALD: Was not Texas'
8 generation mix less diversified than what we have in
9 Georgia?

10 WITNESS GRUBB: It could be. And this,
11 Commissioner, talks about -- I think there's another
12 one that the attachment -- this -- some of these are
13 steps taken in gas units and some of these are steps
14 taken in coal units. But, yeah, so each resource
15 has its benefits from a diversification standpoint,
16 Commissioner.

17 BY MR. WALSH:

18 Q Okay. And this response talks about the report
19 that NERC published in September 2014, which recommended
20 that utilities review and update power plant
21 weatherization programs; correct?

22 A (Witness Weathers) Yes.

23 Q And have there also been other written reports
24 and investigations conducted by FERC, as well?

25 A (Witness Weathers) Well, related to the polar

1 vortex or just in general?

2 Q In general, as far as what the utilities could
3 do to make them more resilient during cold weather.

4 A (Witness Weathers) Yeah. I think FERC has
5 following -- I mean, they have -- every year there's a
6 winter assessment that they do. But I think this is the
7 primary report coming out of the 2014 polar vortex.

8 Now, there was another one issued after the
9 2021 -- February 2021 outages that impacted Texas and a
10 lot of the Midwest.

11 Q Okay. And these steps that the company has
12 taken, what's the time frame for the actions outlined on
13 JKA-1-1?

14 Just generally, do you have a range of when the
15 company began these steps and when they --

16 A (Witness Weathers) We don't have the
17 attachment to it. I think it gives the time frame, but,
18 yeah, generally I think these are actions that obviously
19 occurred since 2014. I think the majority of them should
20 have already been completed.

21 Q Okay. And the company also has made
22 significant capital and O&M expenditures recently,
23 including implemented changes to gas-fire generating
24 units to be able to withstand low temperature events; is
25 that correct?

1 A (Witness Grubb) I don't remember the -- recall
2 the totals, but yeah.

3 Again, Commissioners, what we've done is we've
4 continued to look at, you know: What can we do to make
5 the gas resources specifically more -- you know, more
6 protected from cold weather?

7 So there was a phase of actions that we're
8 taking about here after the polar vortex. Like
9 Mr. Weathers, I don't have the attachment. I can't
10 remember exactly dates. But we're continuing to look at
11 that because winter is really where we're seeing our
12 reliability focused at.

13 Q And you would say that the company has been and
14 is continuing to be proactive at preparing its units for
15 winter cold weather events and has successfully prepared
16 and mitigated the impacts of cold weather events?

17 A (Witness Weathers) Well, yeah. I would say,
18 yes, the company continues to be proactive. The company
19 has mitigated those impacts, but they're -- again,
20 they're not zero.

21 So there are still risks. When the
22 temperatures get really cold, there's still risk on our
23 system that the units will have an outage.

24 A (Witness Grubb) So, Commissioners, as
25 Mr. Weathers spoke to, as we've done these measures

1 across the fleet, we've improved that assumption in the
2 reserve markets there and we'll continue to do that.

3 So if we take actions across the fleet, we will
4 capture that in the next study. But, again, the focus
5 has really been around the reliability of those units.
6 And our reserve margin study is very robust and looks at
7 seven hundred and something thousand different iterations
8 to recommend that 26 percent in the winter.

9 A (Witness Weathers) And these type of things,
10 these improvements that we've made to the performance of
11 our units at cold temperatures is the reason why we
12 expect the system to be more reliable at 26 percent than
13 it was expected to be three years ago.

14 So the company has made strives forward.
15 Reliability is expected to be improved based on -- with
16 the same target reserve margin. It's based on economics
17 for customers. We expect a little bit higher
18 reliability.

19 Q Would you agree it's appropriate for the
20 Commission to consider the success that the company has
21 had in mitigating the impacts of cold weather events in
22 determining what the target reserve margin should be?

23 A (Witness Weathers) Yes. And it is a
24 consideration in our analysis. We do consider these type
25 of events. But, really, our analysis is being driven by

1 economics.

2 So we did -- we did a sensitivity. If we were
3 to remove all the cold weather outages from our model and
4 basically assuming that the units are reliability --
5 reliable down to whatever the lowest temperature is that
6 we see, that doesn't really change the economics. It
7 changes the reliability and makes our system more
8 reliable. And there's benefit for customers to do that,
9 but it doesn't change the target reserve margin.

10 Q The company charges customers for the
11 improvements that it's made to generating units; correct?

12 A (Witness Grubb) Yes. So there's a cost to
13 recover for customers, but it has the benefit of those
14 resources being more reliable, as well.

15 Q And a primary benefit, in fact, of the
16 winterization expenditures is less expected outages;
17 correct?

18 A (Witness Grubb) That would be one of them,
19 that's correct.

20 Q And customers who are paying for the
21 winterization expenditures shouldn't have to pay the same
22 for backup capacity as if these winterization efforts
23 never took place, should they?

24 A (Witness Weathers) Well, again --

25 Q If you can answer yes, no, and then you can

1 explain.

2 A (Witness Weathers) Can you ask the question
3 again, please?

4 Q Customers who are paying for winterization
5 expenditures should not have to pay the same for backup
6 capacity as if these winterization efforts never took
7 place, should they?

8 A (Witness Grubb) I would --

9 A (Witness Weathers) Yes. Yes, they should.
10 Because what you're -- if the target reserve margin were
11 based only on reliability, then it would be true that
12 those actions would have a direct impact on the target
13 reserve margin. But it's not. It's based on economics.

14 So it is -- it is economic for customers to
15 carry 26 percent reserves based on our study. Based on
16 studying our system, it's economically advantageous for
17 customers.

18 A (Witness Grubb) And, Commissioners, also,
19 Mr. Walsh has referred to it as backup capacity. I would
20 not qualify it that way.

21 What we're talking about is the resources that
22 we have on the fleet to be available to customers when
23 they need them. Some run less than others, but it's not
24 backup in that we're planning for one and we had some
25 extras. That's the target to make sure we have the

1 resources there to balance those economics and
2 reliability to customers.

3 So as we continue to invest in those units,
4 they become more reliable. It may or may not change, to
5 Mr. Weathers' point, the ultimate reserve margin, but
6 it's still a more reliable resource. And as we continue
7 to see winter as the risk, it makes sense to invest in
8 those and we do study them. The 26 percent captured
9 those impacts.

10 Q So, in summary, the company's position is that
11 even though it has incurred expenses to mitigate the
12 impacts of cold weather events, and even though those
13 expenses have been recovered from customers, and even
14 though those efforts have been successful, the customers
15 are still going to be paying to support the same target
16 reserve margin as it did had these winterization
17 expenditures never taken place?

18 A (Witness Weathers) Well, yes. And it's
19 actually a lower cost to customers. When we do our
20 reserve margin study, we look at the -- we look at
21 reliability and we look at economics.

22 So if you were to pick solely based on
23 reliability, which is -- the general planning criteria is
24 one outage event every 10 years. So if you're looking at
25 just that number, that's actually higher cost than the

1 26 percent reserve margin. Because we consider all the
2 costs to customers; the capacity costs, the energy costs,
3 and any reliability costs.

4 In addition, you're really looking at having
5 one outage every 10 years. So Texas had a -- had a --
6 they had to shed load in 2011. They did it in 2021.
7 That was a very expensive toll on the economy, not to
8 mention lives were lost during the event last year.

9 So we're not planning on just -- we're planning
10 for reliability, but the economic reserve margin -- it
11 provides additional reliability benefits, but at a value
12 to customers to do that.

13 So less -- the 26 percent is the less cost to
14 customers than the 1 and 10 marker in our study, which
15 would be 20 percent.

16 Q You're saying it's the least cost reliable
17 system for customers to maintain the same reserve margin?

18 A (Witness Weathers) It is least cost for
19 customers considering the risk adjustment that we do.
20 And it's more -- it's more beneficial for our customers
21 to have the 26 percent target reserve margin than it
22 would be to only plan for reliability.

23 So your questions were very important questions
24 to consider when you look at cold weather outage
25 improvements. Those benefit customers because they make

1 our system more reliable. But it doesn't change our
2 reserve margin recommendation because we're not basing it
3 only on reliability. We're also basing it on economics
4 and primarily on economics.

5 Q I'd like to ask a few questions about hydro
6 modernization. In this IRP the company is seeking
7 approval to modernize Plant Burton, Plant North
8 Highlands, and Plant Sinclair hydro facilities; is that
9 correct?

10 A (Witness Grace) That's correct.

11 Q The goal of hydro modernization is to keep
12 units running for a very long time; correct?

13 A (Witness Grubb) Yes. I mean, the real goal of
14 the modernization, as we discussed in the 2019 IRP, is a
15 lot of the hydro facilities are getting -- they are well
16 up in age. They were starting to see more forced outage
17 on those units.

18 And so investment in those units to allow them
19 to continue to operate, to make sure we can maintain our
20 FERC license, and, yes, it adds to those generation
21 resources for another 40 to 50 years.

22 Q And will modernizing these units cost hundreds
23 of millions of dollars in capital investment?

24 A (Witness Grubb) Yes. And so what we've
25 proposed the next three -- that number is trade secret,

1 but it is -- but it's the same discussion we had in 2019.

2 As we look at these hydro units, the values
3 they bring to the system, the values they bring to the
4 state and the communities, the risk of not investing,
5 those units not operating, risking the FERC license and
6 what you do with the dams, we just feel like these are
7 resources that we continue to invest in.

8 So we've got the five plants that were approved
9 in '19. We're recommending the next three, which are the
10 three most in need of maintenance. And they allow us to
11 keep the momentum going that we've gotten from the first
12 five.

13 MADAM CHAIR PRIDEMORE: Mr. Walsh, can we
14 unpack that for just a minute?

15 On page 27 of your prefiled direct testimony --

16 WITNESS GRUBB: Yes, ma'am.

17 MADAM CHAIR PRIDEMORE: Let me give you a
18 minute to get there. You talk about the fleet
19 modernization for hydro from the 2019 IRP. And
20 you've substantially completed projects at Plant
21 Terrora?

22 WITNESS GRUBB: Yes, ma'am.

23 MADAM CHAIR PRIDEMORE: Where is that?

24 WITNESS GRUBB: It is in -- all of the -- it's
25 in northeast Georgia. It's in north Georgia.

1 MADAM CHAIR PRIDEMORE: Rabun County?

2 WITNESS GRUBB: Up that way, yes, ma'am. There

3 is six of them in a row up there.

4 MADAM CHAIR PRIDEMORE: Okay. So they are all

5 in Rabun, okay.

6 And then talk to me on line 21 of that same

7 page where the company states: The integrity of the

8 fleet and allow these flexible, dispatchable, and

9 zero carbon resources to operate for at least

10 another 40 years.

11 Explain to me dispatchability on hydro.

12 How long does it take to fire one up; do you

13 ever shut it down?

14 WITNESS GRUBB: We don't run them all the time

15 because they're energy limited, right, from a water

16 standpoint. But they are super fast to start up. I

17 mean, it's within minutes, I believe. So they are

18 very flexible.

19 A lot of times the value we see from hydro is

20 usually across the peaks to avoid some of the more

21 expensive generation coming on. But, yes, they are

22 very flexible.

23 As we modernize them, they will become more

24 flexible. The modernization includes putting more

25 AGC on the hydro units as we do those.

1 MADAM CHAIR PRIDEMORE: AGC define, please.

2 WITNESS GRUBB: Automated generation control.

3 MADAM CHAIR PRIDEMORE: Got it.

4 WITNESS GRUBB: But, again, yes, Madam Chair,

5 they are very flexible resources and come on in a

6 matter of minutes and can start and stop as they

7 need to.

8 WITNESS ROBINSON: And, Madam Chair, we can

9 also use those units in what's called motoring. We

10 can use them as synchronous condensers, as I

11 mentioned before, where you're producing no real

12 power, but you're using reactive power outlet to

13 control voltage and help the power system and

14 transmission system reliability area.

15 COMMISSONER McDONALD: Starting at Lake Burton,

16 you use the same water how many times?

17 WITNESS GRUBB: There's six dams in a row,

18 Commissioner.

19 MADAM CHAIR PRIDEMORE: How will this

20 modernization increase the -- increase hydro in the

21 overall generation mix?

22 Will it?

23 WITNESS GRUBB: So it's not -- it's not a real

24 change on the energy side. We don't expect them to

25 generate a lot more, Commissioner. What we're

1 facing now is their ability to actually be available
2 and to run. We've got some that they just get to
3 the end of their lives and they can no longer
4 function.

5 So what modernization does is allows us to go
6 into a facility -- for example, if there is
7 four units. Update all four of those units in a
8 very programmatic fashion as opposed to one fails,
9 you replace it, you wait for the other one to fail.
10 So it's a very structured and methodical way to
11 reinvest in these.

12 And so it's -- they will be more efficient.
13 They'll use less water to get those megawatt hours
14 out. And so it will be more efficient. It won't
15 increase hydro's share of the energy mix, but what
16 it does is allow us to have hydro for the next
17 several decades as we continue to invest in it.

18 MADAM CHAIR PRIDEMORE: So it's really to
19 secure the percentage of hydro that's in the
20 generation mix now?

21 WITNESS GRUBB: That's correct. And to remove
22 the risk of losing the FERC license and what do you
23 do with the dams.

24 MADAM CHAIR PRIDEMORE: Okay. Thank you.

25 BY MR. WALSH:

1 Q The company hasn't provided any economic
2 analysis for any decision to upgrade or retire the units,
3 has it?

4 A (Witness Grubb) On the hydro units, we have
5 not.

6 Q I'm sorry. If I could -- clarifying question.
7 Have you performed any studies and not included them in
8 the plan or have you not performed any studies?

9 A (Witness Grubb) Thanks for that clarification.
10 We did not perform them.

11 Q Thank you.

12 A (Witness Grubb) Yes. So reasons being, if you
13 look at just energy capacity, there's other aspects of
14 the hydro fleet you would need -- you would need to
15 capture the value that they bring to the system.

16 Q And the company hasn't prepared any capital
17 revenue requirement analysis either, has it, for these
18 units for --

19 A (Witness Grubb) The three additional ones?

20 Q Yes.

21 A (Witness Grubb) So we provided the costs and
22 the budgets for those hydros. In terms of revenue
23 requirements, those would be captured in any kind of rate
24 base -- the rate case analysis that we would do. We just
25 provided the budgets in the supplemental information in

1 the filing.

2 Q Thank you. I would like to now talk
3 specifically about the status of existing modernization
4 projects, in particular Plant Tugalo.

5 A (Witness Grubb) Tugalo.

6 Q Georgia Power has spent -- I'm sorry. I want
7 to be careful about trade secret dollars. Is it trade
8 secret the amount of money that the company has spent on
9 modernization at Plant Tugalo?

10 A (Witness Grubb) That we filed in the reports
11 to staff, I do not believe historical spends are trade
12 secret. So I think we're -- future ones would be, but I
13 don't think historical ones are.

14 Q Okay. So has the company spent approximately
15 \$26 million on the modernization of this plant through
16 December 2021?

17 A (Witness Grubb) Subject to check. I don't
18 have the latest report that we filed with staff.

19 Q Okay. Is it correct that the company submitted
20 a non-capacity amendment at FERC in September of 2021?

21 A (Witness Grubb) That is correct. And we have
22 stated in the filing -- for any of the modernization
23 work, we filed those FERC amendments. Did so with
24 Terrora, as well.

25 Q And is this plan the same as or similar to the

1 plan and schedule for the modernization program for the
2 Tugalo Plant as was approved in the 2019 IRP?

3 A (Witness Grubb) The plan that we filed at
4 FERC?

5 Q Yes. Is the amended plan the same or similar?

6 A (Witness Grubb) Yeah. I don't believe the
7 scope has changed on any of the modernization work at any
8 of the hydro facilities.

9 Q Is FERC still reviewing the amendment
10 application?

11 A (Witness Grubb) Yes. That's my understanding.

12 Q Has Georgia Power started construction on this
13 work?

14 A (Witness Grubb) Not on the work that is
15 contained in the amendment. We did work to remove the
16 turbine generator. We've done some site preparation
17 work.

18 There's potential -- there's maintenance work
19 we would have to do on Units 2, 3, and 4 if it came up.
20 But in terms of the work that is in the FERC amendment,
21 no, we have not begun that work.

22 Q What would happen if the amendment application
23 is not approved?

24 A (Witness Grubb) In terms of at Tugalo?

25 Q Yes.

1 A (Witness Grubb) It would depend on -- I'm not
2 a hydro FERC expert, but I guess it would depend on what
3 FERC puts in that license amendment and what they would
4 want the company to do.

5 It doesn't change our plans for the rest of the
6 hydro fleet. But for Tugalo, it would depend on what
7 FERC -- what FERC stated.

8 Q Would that have any effect on the work that you
9 have completed thus far and the \$26 million, subject to
10 check, that you spent on it?

11 A (Witness Grubb) Yeah, it would. Because, I
12 mean, that's scoping and engineering and all the work
13 getting ready to do that. So it would.

14 But we've always known that we would have FERC
15 amendment filed for any of the hydro modernization work.

16 Q But would it put at risk, I guess, is what I'm
17 asking, as far as -- if the amendment application is not
18 approved by FERC, would that put in jeopardy the work
19 that you've already done at the plant?

20 A (Witness Grubb) It would if it were forever
21 halted.

22 Q Okay.

23 A (Witness Grubb) It would depend on what FERC
24 ruled.

25 Q Okay. I would like to move now to discuss

1 energy storage systems.

2 A (Witness Grubb) Okay.

3 Q The company asserts that it has determined that
4 1,000 megawatts of energy storage systems, resources, by
5 2030 are required for the -- to cost-effectively maintain
6 reliability.

7 Is that an accurate statement?

8 A (Witness Grubb) That's right. Based on the
9 renewables integration study that we filed with the IRP,
10 that's correct.

11 Q I apologize. You were so agreeable in the last
12 round, I got ahead of myself.

13 A (Witness Grubb) If it moves us faster, I'll
14 agree to --

15 Q Are you familiar with the resource mix study?

16 A (Witness Grubb) Yes.

17 Q And it's the company's position, is it not,
18 that the purpose of the resource mix study is to provide
19 information regarding the optimal least cost resource mix
20 or generic expansion plan?

21 A (Witness Grubb) That's correct.

22 Q Did any of the portfolios that the company
23 developed in the resource mix study show 1,000 megawatts
24 of battery storage being added by 2030?

25 A (Witness Grubb) So I will let Mr. Weathers

1 help me here. The storage that the resource mix is
2 looking at in that study are resources -- four-hour or
3 eight-hour batteries that would be really deployed solely
4 for the provision of energy capacity to serve loads.

5 The renewable integration study and the 1,000
6 megawatts is based on an intermittent five-minute
7 reliability study looking at our operating service
8 system.

9 So, again, the generation resource mix is an
10 hourly model, what resources are best to serve energy
11 capacity. The renewable integration study was around
12 operating --

13 A (Witness Weathers) Yeah. Mr. Walsh, just to
14 add, the answer is no. Our resource mix studies did not
15 include -- they did not select a 1,000 megawatts by 2030.
16 But, as Mr. Grubb said, that's not the purpose of those
17 studies.

18 So those studies are selecting capacity and
19 energy in order to meet system needs. Where the 1,000
20 megawatts comes from, those type of resources were
21 identified in a different study, a renewable integration
22 study. So that study looked on a five-minute level and a
23 five-minute basis and identified that there are
24 flexibility issues on the system as renewable generation
25 continues to grow.

1 So those intra-hour flexibility issues are
2 not -- they are not discernible in our hourly integrated
3 modeling. So that model would not pick that up. It
4 would not select it.

5 Those issues are resolved by increasing the
6 operating reserves in our system. So basically having
7 more units online at any given point in time. But it's
8 more economically resolved if you add battery storage.

9 So that's where the 1,000 megawatts come from
10 is to more economically enable the integration of
11 renewable generation on our system.

12 MR. WALSH: Madam Chair, I would like to
13 present the panel and the Commissioners with a trade
14 secret exhibit. It's an attachment to the company's
15 response to STF-JKA-4-12.

16 MADAM CHAIR PRIDEMORE: So moved.

17 MR. WALSH: I would ask that this document be
18 marked for identification as Staff's trade secret
19 Exhibit 3.

20 MADAM CHAIR PRIDEMORE: So moved.

21 (The document referred to was marked for
22 identification as Staff Exhibit No. 3.)

23 MR. WALSH: Thank you.

24 MADAM CHAIR PRIDEMORE: Be mindful that it is
25 trade secret. So when we break, it breaks with you.

1 MR. WALSH: I will give you a minute to take a
2 look at this exhibit. And if you could just let me
3 know when you're ready.

4 WITNESS GRUBB: We are ready.

5 BY MR. WALSH:

6 Q There are a number of pages to the exhibit and
7 they each have different headings, as far as which
8 expansion plan we're looking at. I don't need you to go
9 through each page, but can you just tell me generally
10 what's indicated by what type of expansion plans you're
11 looking at here.

12 A (Witness Weathers) Sure. These are the three
13 low gas -- sorry -- the three \$0 carbon cases and the two
14 that are \$20 carbon cases.

15 Q And does this -- does this exhibit confirm your
16 testimony earlier that none of the portfolios that the
17 company developed in the resource mix study show a 1,000
18 megawatts of battery storage being added by 2030?

19 A (Witness Weathers) That's right. And, again,
20 as I said earlier, they wouldn't do that.

21 Q I understand the caveat to your --

22 A (Witness Weathers) Okay.

23 Q -- to your question -- to your answer.

24 A (Witness Weathers) Okay.

25 Q I just wanted to provide the visual for the

1 Commissioners.

2 MADAM CHAIR PRIDEMORE: Mr. Weathers clarified
3 that the first three sheets are the \$0 carbon and
4 the second two are the \$20 carbon; is that true?

5 WITNESS WEATHERS: Yes, ma'am. That's correct.

6 BY MR. WALSH:

7 Q I would like to move now to ask some questions
8 about the renewable integration study.

9 A (Witness Grubb) Okay.

10 Q The renewable integration study was not
11 intended to identify the optimal level of battery storage
12 to accompany the solar resources; is that correct?

13 A (Witness Weathers) That was not the purpose of
14 the study. The purpose of the study was to identify the
15 impacts on our system for integrating renewable resources
16 and specifically looking at -- not -- impacts that are
17 not captured by our hourly integrated models, but within
18 an hour of the real-time five-minute level impacts.

19 Q Could I get you to turn to page 14 of your
20 direct testimony.

21 A (Witness Grubb) Yes.

22 Page 14?

23 Q Yes.

24 A (Witness Grubb) Yes.

25 Q And specifically I was going to ask that you

1 look at lines 10 and 11 of your testimony.

2 A (Witness Grubb) Okay.

3 Q You testified that the renewable integration
4 study supports the company's request for a 1,000
5 megawatts of energy storage resources by 2030?

6 A (Witness Grubb) Yes.

7 Q On page 2 of the renewable integration study,
8 if you could refer to that.

9 A (Witness Grubb) Just a second.

10 Okay. We're there, Mr. Walsh.

11 Q Okay. Thank you.

12 Table 2 on that page shows that Scenario C of
13 the study tested 1,150 megawatts of battery storage to
14 help integrate 8,000 megawatts of cumulative solar
15 capacity.

16 A (Witness Weathers) Yeah. Well, it shows 1,150
17 were added in that scenario. The study didn't select
18 those. Those were added through an iterative process in
19 order to mitigate the impacts of the renewables.

20 Q Is that the scenario that's most closely
21 aligned with the IRP?

22 A (Witness Grubb) Yes. Well, in terms of when
23 we look at 2030, we looked at the intermittent megawatts
24 that would be on Georgia Power's system by then.

25 A (Witness Weathers) Yeah. I think -- I think

1 probably most aligned with it -- these are system
2 numbers, not Georgia Power specific numbers, so...

3 Q So Southern Company system numbers?

4 A (Witness Weathers) Southern Company system
5 numbers. So there's a little bit of a difference there.
6 So it would either be that number or possibly -- between
7 that one and the next scenario.

8 Q I'm sorry. Could you -- possibly which
9 scenario? I'm sorry.

10 A (Witness Weathers) Well, you know -- so the
11 scenario you're asking is Scenario C. So it contains
12 8,000 megawatts of solar on the system.

13 And you asked does that mostly --

14 Q Yes.

15 A (Witness Weathers) -- most closely align with
16 Georgia Power's expected 2030 --

17 Q Yes.

18 A (Witness Weathers) -- renewable penetration?

19 And I think it depends on what actions the
20 other operating companies take; right?

21 So I think it would either be that one or
22 Scenario D possibly, depending on other operating
23 company's actions.

24 Q Okay. Thank you.

25 A (Witness Robinson) As well as the EMCs and

1 municipalities, as well, too.

2 A (Witness Weathers) That's correct. Those do
3 have an impact on -- this study was specifically for the
4 Southern Company system, as Mr. Robinson said. Other
5 solar generation in the region does have an impact on the
6 grid.

7 Q Would that other impact be relatively minor
8 compared to the other Southern Company system, or would
9 it be a significant impact?

10 A (Witness Grubb) It depends on which system
11 you're speaking it through. Mr. Robinson is talking
12 about from power delivery, distribution, transmission
13 standpoint.

14 But, again, Mr. Walsh, the 1,000 megawatt
15 request here matches up to Georgia Power's level of
16 intermittent resources that will be on the system by
17 2030.

18 Q Did the study test any sensitivities to see
19 whether a different amount of battery storage would
20 produce a different integration cost?

21 A (Witness Weathers) Well -- so the amount of
22 battery storage is really determined through an iterative
23 process when the study was conducted. So we looked at
24 through modeling techniques, you know: What is the
25 intermittency impacts on the system because of

1 renewables?

2 What we saw is there's pressure on the
3 real-time balancing of load generation within an hour.
4 So there's adequate capacity on the system for the hour,
5 but it's not flexible enough to respond to the solar
6 ramping and solar intermittency within an hour.

7 So you either have to increase your operating
8 reserves, which is have more units online that can move,
9 and there's a cost to customers to do that, or you add
10 batteries.

11 So this amount of batteries was determined
12 to -- that was appropriate to mitigate the impact, the
13 similar level that adding operating reserves would.

14 Q So would you say that you did or did not test a
15 different amount of battery storage?

16 A (Witness Weathers) It was tested in the
17 interim nature determining the amount. So these were the
18 amounts that were selected to provide the appropriate
19 mitigation back to the level of intra-hour reliability
20 before you added the solar.

21 Q When you say that you did it in iterative
22 methodology, are you saying that -- was there another
23 amount of battery storage that you looked at that
24 produced a different integration cost result?

25 A (Witness Weathers) Well, ultimately no. I

1 mean, there was one study that integration costs were
2 calculated based on these numbers. Based on numbers that
3 aligned with a roughly 15 percent of solar nameplate
4 capacity, which is the 1,000 megawatts by 2030. So
5 that's what calculated integration costs are.

6 But the levels of batteries, the megawatts of
7 batteries was determined to be a sufficient amount to
8 mitigate the impacts of solar to the current reliability
9 levels on the system.

10 Q Did the renewable integration study consider
11 the capital costs of the battery resources in this
12 analysis?

13 A (Witness Weathers) It did not. This is only
14 the benefit side. So this is the value that the
15 batteries were, in terms of benefits.

16 Now, any specific battery analysis, such as the
17 one provided in this IRP for the McGrau Ford facility,
18 that captures all the costs and the benefits.

19 WITNESS GRUBB: Again, Commissioners,
20 Mr. Weathers laid that out exactly right. The model
21 that we're talking about here is a reliability model
22 that doesn't factor in: What does it cost to add
23 it?

24 That's why we added the other analysis. But
25 both of those -- basically what we've studied is

1 intermittent reliability. We can save customers
2 money by using batteries, instead of the existing
3 resources, coal units on minimum, those types of
4 things. And because that study didn't capture the
5 capital costs, we did another benefit that looks at
6 costs and benefits of battery that shows it's
7 positive for customers.

8 MADAM CHAIR PRIDEMORE: But the storage is
9 reliant upon the additional load coming from the
10 solar. And the solar is market procured. What if
11 the company is unable to procure the expected level
12 of solar that's in this IRP?

13 WITNESS GRUBB: So, Commissioner, that's a
14 great question. There is a certain level of this
15 storage that would benefit customers based on what
16 we've plainly committed to now. So the 5,000 or so
17 that we have by the end of '25 or so, there's an
18 amount of storage that would help there.

19 But you're correct. What we did was we studied
20 several tranches of renewables to look at that
21 value. If there is not as many renewables, you
22 wouldn't need as much storage. But, you know, we
23 are looking at 2030. That was the study that we
24 provided. As all of our other studies, we'd adjust
25 these as we go forward.

1 MADAM CHAIR PRIDEMORE: For decades the Georgia
2 Power Company has prided itself in owning and
3 developing its own generation and all that goes with
4 that; the ability to manage it, the ability to
5 resource plan against it, to control it.

6 What do you see to be any downside to having
7 more generation than is outsourced?

8 Which, look, I understand, it's part and
9 parcel. It's a trend in the industry. We're seeing
10 other utilities across the country move in this
11 direction. But I'd like hear from the panel: What
12 do you see, if any, downside to that?

13 WITNESS GRUBB: So I think -- there will be
14 several of us who could probably weigh in here,
15 Madam Chair.

16 I think both ownership and PPAs have their
17 benefits. So I think that's why the prior
18 Commission had a balance of those. That's why the
19 RFP rule is there is to go to the market. Customers
20 can benefit from PPAs.

21 But I think by the fact that the Commission in
22 the past has had that 70/30, they recognize that
23 there are reliability benefits to company ownership.
24 Nothing against PPAs. We've had very successful
25 PPAs on the capacity side from gas resources. We've

1 had successful ones from the renewable side. But
2 there is a balance between value from a PPA and
3 company ownership on some resources.

4 And so I think the ability to be able to
5 understand what's coming in the next 20 years, the
6 company doesn't have to lock that down and know it.
7 We can adjust as things change.

8 A PPA, you have to kind of set that and live
9 with it. Our prior capacity RFPs had all the
10 capacity weight in the summers because ten years ago
11 that's what we had.

12 We've now shifted to putting equal balance in
13 summers and winters. That's something we learned,
14 but that we couldn't change in the PPAs. From a
15 company-owned resource, we could respond
16 immediately.

17 So I think that both have benefits. I think
18 the bigger challenge in my point of view would be
19 company ownership gives us the ability to react to
20 changes, whether it be on the cybersecurity side or
21 the use case of a certain resource. We can adapt to
22 that through purview with you all and reviewing the
23 costs there as opposed to having a contract that
24 says: You can do A, B, or C.

25 WITNESS WEATHERS: And power purchase

1 agreements, they're going to have terms and
2 conditions. They're going to have operating
3 procedures. They're going to have predefined
4 maintenance scheduling windows and things that are
5 worked out between counter-parties.

6 Ownership provides ultimate flexibility. It
7 provides being able to update to latest maintenance
8 practices, latest cybersecurity measures, outage
9 scheduling flexibility. We're talking about
10 batteries, changing the use case throughout the
11 course of the day, even within an hour, enabling the
12 system to deploy those resources according to
13 wherever the greatest system needs are. Those are
14 some of the reasons.

15 Especially when you're looking at batteries,
16 the company plans to rely on -- to provide operating
17 reserves, which is a very critical, realtime
18 function on our system. If there's any
19 contingencies on our system, the units that are
20 serving operating reserves, those are the ones that
21 are going to respond.

22 So having those be reliable, having those --
23 having the ultimate flexibility in the hands of the
24 system operators are advantages versus a power
25 purchase agreement, which are great for passing the

1 energy. But for some services, ownership is going
2 to be more appropriate.

3 MADAM CHAIR PRIDEMORE: The classic 70/30 split
4 that this Commission worked under and the company's
5 worked under for many years now, how does this plan
6 change that?

7 Have we moved to a 60/40 or have we done the
8 analysis yet to determine if we're still within the
9 classic 70/30 split?

10 WITNESS GRUBB: So what we've -- by looking at
11 what we're recommending on retirement of the coal
12 units and the certification of the six PPAs, in '29
13 and '30, we go a little above 30 on the PPA side for
14 about two years.

15 MADAM CHAIR PRIDEMORE: Define little bit.

16 WITNESS GRUBB: It's 80 megawatts or so and
17 then 180 megawatts or so over. That does not
18 include the storage request. It doesn't include the
19 wholesale to retail.

20 But then shortly thereafter, in the summer of
21 2030, we have about 2,000 megawatts of PPAs are lost
22 so it immediately goes back down. So right now
23 we're -- we're right at that 70/30 balance when you
24 look at the year of need in this case.

25 WITNESS MALLARD: Madam Chair, just to add on

1 to that. Cultivating this mix of PPAs and
2 company-owned resources is really the best way for
3 us to balance the economic benefits that we can get
4 through PPAs. And we definitely are getting some
5 good ones through renewable PPAs. We expect to
6 continue to get those. Really good benefits through
7 the capacity RFP.

8 But maintaining company ownership over those
9 critical reliability resources is the most
10 important. And that's -- those -- outsourcing that
11 responsibility we don't feel like is appropriate;
12 thus, the requirement for Georgia Power ownership of
13 the battery storage.

14 WITNESS GRUBB: And tying it back to our
15 discussion we've just had on weatherization and cold
16 weather, those are owned units that we're doing that
17 on. We're putting that money in to make those more
18 reliable.

19 If those were PPA resources, they may or may
20 not do that. They would look at: Do I -- do I risk
21 it from an availability percentage?

22 It might be something that the PPA might be: I
23 don't know that I need to invest that money.
24 Winters come around every few years. I may not
25 actually go through that extra cost.

1 But we are because we're looking at that
2 reliability aspect of it.

3 WITNESS WEATHERS: Or they would want to
4 extract additional payments to do that from our
5 customers.

6 MADAM CHAIR PRIDEMORE: Mr. Robinson, it's a
7 hot topic. Do you want it?

8 WITNESS ROBINSON: Madam Chair, as a
9 transmission operator, ownership is always
10 preferred. But I understand that you have to
11 balance economics. But very good point.

12 MADAM CHAIR PRIDEMORE: Okay.

13 VICE-CHAIRMAN ECHOLS: Question on the battery
14 performance. The batteries where the Southern
15 Company or Southern Power or Georgia Power, whatever
16 you've had access to the performance data, have you
17 seen a pattern with these utility scale
18 containerized batteries in not performing as they
19 were sold to you or as you -- as the warranty
20 stated?

21 Are they underperforming or over-performing?

22 WITNESS MALLARD: So, generally speaking,
23 Commissioner, they're performing within the range.
24 There's degradation that's expected. Some have
25 degraded. That is, produced more energy -- produced

1 less energy than what was expected over time.

2 Most battery projects have a planned
3 augmentation to make sure they can maintain the
4 performance that they're committed to. What we see
5 more of is changes in technology, changes in safety
6 requirements. Fire suppression, for example. So
7 lots of -- lots of changes that have happened.

8 And we do have access to study across the
9 industry, Southern Company, RFP projects and, of
10 course, as you referenced, Southern Power's
11 experience, as well.

12 VICE-CHAIRMAN ECHOLS: From a ratepayer
13 perspective, are we better off financially with PPAs
14 if batteries aren't performing as they're supposed
15 to, where those companies are paying liquidated
16 damages, the contractor, third party, or whatever,
17 or are we better off you owning them where you, you
18 know, have larger arrays and you can go to the
19 provider and demand that the product be replaced and
20 perform as it should?

21 WITNESS MALLARD: I might reframe the
22 proposition just a little bit, Commissioner. Let's
23 think about these differently. These are required
24 for reliability.

25 A little different than what we've maybe

1 thought about our solar renewable resources, where
2 they're providing energy benefits. If they don't
3 perform, it's a loss of economic benefit.

4 Here, this -- we need these resources for
5 reliability. And so it's not just: Can we collect
6 money back or are we protected?

7 It's: Can we reliability that the system
8 needs? That's where we feel like company ownership
9 gives us an advantage and the reliability with
10 ownership will be higher.

11 VICE-CHAIRMAN ECHOLS: Thank you.

12 COMMISSONER SHAW: Mr. Walsh, while we're on
13 this line of questioning on the energy storage, I
14 don't think we've really touched on: What have we
15 learned from the 80 megawatts from the '19 IRP?

16 Correct me if I'm wrong, but haven't we
17 approved only 65 megawatts at this point?

18 WITNESS MALLARD: You're exactly right,
19 Commissioner Shaw. And it's not online yet. The
20 65 megawatt project was approved by this Commission
21 last October. So not online.

22 Construction is planned to start here in a
23 couple months. And it's projected to be online by
24 September of next year. So we don't have any
25 operational experience.

1 But that's not to say we haven't learned a ton
2 from these projects. Going through the site
3 development, going through the RFP to choose, the
4 EPC vendor, developing all of the agreements, the
5 long-term service agreements, the purchase power
6 agreements, study and control systems, studying fire
7 suppression, studying safety systems. We really
8 have learned a lot through the development of that
9 project.

10 Two more projects are being developed; a
11 13 megawatt project co-located with solar and also a
12 2 megawatt distribution project.

13 None of the projects are online. So we don't
14 have the operational experience, but we really have
15 gained lots of knowledge and experience and feel
16 like we're well suited to be successful in
17 developing the McGrau Ford project.

18 WITNESS GRUBB: Commissioner, we will have --

19 COMMISSONER SHAW: The 13 megawatts you
20 mentioned, that's the one at Fort Stewart; correct?

21 WITNESS MALLARD: Yes, sir.

22 COMMISSONER SHAW: All right. So would you
23 say -- I know Mr. Walsh had mentioned it. Capital
24 cost was not a part of one of the main studies
25 you've referenced. But would you say that the

1 capital cost portion is something we've learned a
2 lot from the '19 IRP?

3 WITNESS MALLARD: Absolutely. As it relates to
4 storage, getting EPC vendors to actually provide
5 firm bids and understanding the dynamics in the
6 marketplace that are driving the costs behind these,
7 both on sort of site preparation, interconnection
8 costs, but then probably what most people go to and
9 think about is the actual cost of the equipment and
10 material.

11 And I can tell you, based on the -- we've
12 already heard comments about inflation, supply chain
13 pressures, all those things. Those are absolutely
14 impacting the costs and potential future costs for
15 battery energy storage projects, as well.

16 COMMISSONER SHAW: One more question. Tell me
17 what -- how you think this will impact -- if we end
18 up approving your 1,000 megawatts that you've filed
19 for, or a number around that, how will that impact
20 our solar developer community when they're bidding
21 in on these additional megawatts of renewables that
22 will be forthcoming?

23 How will that impact their ability to bid in
24 solar plus battery storage, for instance?

25 WITNESS MALLARD: So let me answer that in a

1 couple of ways, Commissioner Shaw. First of all,
2 it's absolutely going to help them because it's
3 going to facilitate our ability to add more solar to
4 the system.

5 We're getting to the point now where we're
6 going to have to curtail a lot of solar. There's
7 just no where to use that excess solar energy on low
8 load days. Having battery energy storage is going
9 to be critical to maximize the value of more storage
10 to the system.

11 Secondly, we'll absolutely still accept bids
12 of solar plus storage in our RFPs. There is
13 different use cases. There's a smoothing use case,
14 a firming and smoothing use case, and even a
15 scheduled storage use case.

16 Those can still bid in and still have a good
17 chance to compete. Think about it differently,
18 though. The grid-connected storage can do lots more
19 things for the entire grid.

20 And, in fact, it receives signals from the
21 whole system and can operate in a way that benefits
22 the whole system, as opposed to a solar plus storage
23 is really just mitigating the impacts of that
24 particular solar facility. And so it can smooth
25 that particular facility. What it can't do is help

1 with other system conditions that might be created
2 upstream from the -- from that generator.

3 So two sort of different use cases, but they
4 both definitely go together. And there's definitely
5 still a role for solar plus storage to compete in
6 our RFPs.

7 WITNESS GRUBB: Commissioners, I'm sorry. That
8 would also apply to the capacity RFPs that we do
9 going forward.

10 COMMISSONER SHAW: Sure.

11 WITNESS GRUBB: The last one we allowed solar
12 plus storage in and standalone storage in. We
13 completely will allow those in future capacity RFPs.
14 We want storage to perform well in those as we look
15 forward.

16 So, again, you've got the capacity RFPs that we
17 do. We have got the renewable RFPs. Both of those
18 will absolutely allow storage bids from the market.
19 We are speaking about this one particular operating
20 reserve case.

21 WITNESS WEATHERS: And, Commissioner Shaw, I'll
22 also add that the biggest impact that we saw in our
23 renewable integration study is the ramping of solar.
24 So, generally, as the sun goes up, goes down, all
25 the solar generation in the state is ramping in and

1 out together.

2 So in order for the system to be able to
3 dispatch and serve and balance load and generation,
4 some other units have to respond when solar is
5 ramping all at the same time. So those other units
6 that are responding, that's the operating reserves
7 that we're talking about.

8 That's what the batteries help with. They help
9 mitigate the impact on the system so that it enables
10 renewable generation procured through future RFPs to
11 be able to be integrated economically for customers.

12 WITNESS ROBINSON: And, Commissioner, although
13 we've stayed compliant with NERC standards, when we
14 talk about these ramping periods, ramp up and ramp
15 down, we have seen some frequency issues during
16 those periods of time with the amount of solar that
17 we have on the system today. And these batteries
18 will certainly help with mitigating those issues
19 that we've seen.

20 MADAM CHAIR PRIDEMORE: In the 2019 IRP, this
21 Commission approved the 85 megawatt battery storage
22 program to be a pilot, but allowed the Southern
23 Company to be the one to manage the pilot so that
24 the knowledge could be shared across all three
25 opcos.

1 This 1,000 megawatts of battery storage
2 proposed in this plan, though, is it exclusive to
3 Georgia Power or is the company seeking it to go to
4 the holdco?

5 WITNESS GRUBB: So I will let Mr. Mallard speak
6 to -- Georgia Power is running the 65 megawatts.

7 WITNESS MALLARD: That is right.

8 WITNESS GRUBB: He can comment on that. But
9 the 1,000 megawatts would be Georgia Power
10 resources.

11 MADAM CHAIR PRIDEMORE: Okay.

12 WITNESS GRUBB: And so when you look at how we
13 handle things in the southern pool, it would be a
14 Georgia Power resource. So energy and capacity
15 values from that 1,000 megawatts is Georgia Power's
16 in the pool for our customer's use.

17 MADAM CHAIR PRIDEMORE: Can I ask you a
18 question -- go ahead, Mr. Mallard.

19 WITNESS MALLARD: I was just going to add. The
20 65 megawatt project that's being developed, the
21 large-grid scale and the other two projects, they
22 are managed by Georgia Power, but absolutely with a
23 lot of help and support from our Southern Company
24 partners.

25 And that energy -- that information flow goes

1 both ways. We are able to share information with
2 them that we are learning throughout the project,
3 but we also get a lot of information. A lot of the
4 same folks who work on battery projects across the
5 country and other jurisdictions are able to share
6 information with us, as well. So it's a two-way
7 flow of information.

8 MADAM CHAIR PRIDEMORE: In a February 2022
9 article in the Wall Street Journal -- yes, I read
10 other things besides the Wall Street Journal, but it
11 is a favorite. It talks through California's
12 situation and how -- how in particular net metered
13 solar has affected the state and affected the
14 state's utilities, but -- the name of the article
15 is: California Solar Power Welfare State.

16 But it mentions that the state sometimes
17 generates so much solar power that it must pay other
18 states to take it to stabilize the grid.

19 WITNESS MALLARD: I'm familiar.

20 MADAM CHAIR PRIDEMORE: Is Georgia in that
21 position with the amount of solar that we've
22 currently procured through PPAs, or do you foresee
23 that it could be in a situation such as that if this
24 plan is approved as filed?

25 WITNESS WEATHERS: We are not currently in that

1 situation. I don't expect this plan is filed to put
2 us in that situation.

3 In our planning cases, as we're modeling future
4 generic solar on the system, we do expect there to
5 be curtailment of solar. So it's important that
6 we -- that we have the ability to curtail that solar
7 generation to avoid having to over-generate or pay
8 someone to take it.

9 So having that flexibility in our contractual
10 arrangement to curtail it and really ideally to
11 precisely curtail it with automatic generation
12 control enables us to more effectively integrate it
13 and minimize those opportunities for that to happen
14 like you're describing.

15 MADAM CHAIR PRIDEMORE: Can curtailing with AGC
16 be absorbed in storage or is that above and beyond
17 storage?

18 WITNESS GRUBB: So that's one of the benefits
19 of storage. Is that if you do have it where you've
20 got storage on the system, one of the first places
21 you want to go to charge that would be: If I am
22 about to curtail solar, now I can put a load on the
23 system.

24 It's very similar to how we do pump storage
25 hydro. The initial pump storage hydro is: I've got

1 nuclear overnight. Let's load up this pump storage
2 hydro and pump it.

3 So if you have renewables that you're about to
4 curtail, but you've got storage, then that's a load
5 you can put and that's megawatt hours you can use
6 later.

7 WITNESS WEATHERS: In our renewable integration
8 study, we studied two different things. We studied
9 more renewables on the system only relying on the
10 current system. There was significant curtailments
11 in that situation.

12 As renewables grow, there's significant
13 curtailments and it costs more if you're only
14 relying on the current system. As you add
15 batteries, there still will be curtailments. But
16 there will be less curtailments with the batteries
17 because of their ability to store that generation
18 and they'll release it in other hours.

19 And, plus, it's a less-costly solution because
20 the batteries are able to more effectively provide
21 those reserves cheaper than if you're relying on the
22 rest of the system that is not quite as flexible.

23 WITNESS ROBINSON: And, Madam Chair, our
24 transmission planning team to address the issue that
25 you referenced in the Wall Street Journal article is

1 continually looking at studies out in time, looking
2 at assumptions of generators that may be proposed to
3 be retirement -- or retired in Alabama and
4 Mississippi. Our proposed solar expansion is to
5 ensure that we have a reliable system in the future
6 and we don't get into that situation.

7 BY MR. WALSH:

8 Q I'm going to ask a few questions on the
9 renewable integration study. Do you have that available?

10 A (Witness Weathers) Yes.

11 Q The renewable integration study is used to
12 calculate the new integration cost component of the
13 renewable cost benefit framework; is that correct?

14 A (Witness Weathers) Yes.

15 Q Could I get you to turn to page 22 of the
16 study. It's Section 3.5 entitled: Integration Cost
17 Calculations.

18 A (Witness Weathers) Yes.

19 Q Is it correct that the mitigation cost is based
20 on the change in total system production cost between a
21 case with no additional operating reserves and a case
22 with additional operating reserves to address solar
23 output volatility?

24 A (Witness Weathers) That is correct. It is a
25 system impact cost that that solar occurred on the

1 system.

2 Q And key components of production cost, would
3 that include fuel prices and variable O&M expense?

4 A (Witness Weathers) Yes.

5 Q Would there be any other major components of
6 production cost?

7 A (Witness Weathers) Those are the major ones.

8 Q Are natural gas prices a primary element of the
9 change in production cost driving the mitigation cost
10 calculation?

11 A (Witness Weathers) Well, they are a primary
12 component, yes. Fuel costs are a primary component of
13 which -- of which of that natural gas is -- is a primary
14 component, yes.

15 Q And the production cost metric is calculated
16 within the SERVVM model; is that correct?

17 A (Witness Weathers) Yes.

18 Q Can I get you to look at page 17 now of the
19 renewable integration study. This is Section 3.1
20 entitled: Established Flexible Violation BenchMark
21 Target.

22 A (Witness Weathers) Yes.

23 Q I was going to -- well, first of all, what is a
24 flexibility violation?

25 A (Witness Weathers) So a flexibility violation

1 is when -- in the SERVVM model, so the model that we used
2 for the study, we determine that in a particular hour
3 there is enough resources on the system, but the model is
4 not able to balance load and generation in at least one
5 of the five-minute increments.

6 So what that means is you've got adequate
7 resources, they're just not flexible enough. So you need
8 more flexible units on the -- so you either have to have
9 more units online, or you need to replace the units that
10 are online with more flexible resources.

11 Q Could I direct your attention to the bottom of
12 the first paragraph under 3.1. The last sentence says:
13 Therefore, the flexibility violation metric should not be
14 interpreted as actual outage conditions.

15 A (Witness Weathers) That's correct.

16 Q Does this mean that even though there are
17 flexibility violations in the base case, it does not
18 necessarily mean that there would be a system outage?

19 A (Witness Weathers) That is correct. Yeah,
20 when we studied this -- as you mentioned, Mr. Walsh,
21 within our base case there is some flexibility
22 violations. That doesn't mean that there is outages on
23 our system.

24 So there is some room within the NERC
25 compliance guidelines for those type of conditions and

1 returning the system to where it should be. So not every
2 situation is an outage, but it represents pressure on the
3 ability of our operators to balance load and generation
4 in real time.

5 Q Could I get you to turn to page 19 of the
6 study?

7 A (Witness Weathers) Okay.

8 Q I'm going to ask you to look at the first
9 paragraph under table 13. Does this paragraph state, in
10 effect, that for purposes of this analysis reserves were
11 increased to address flexibility violations?

12 A (Witness Grubb) Could you state your question
13 one more time, please, Mr. Walsh?

14 Q Sure. I am trying to summarize this paragraph
15 under table 13 on page 19. And I'm asking whether it is
16 accurate to say that this paragraph is stating that for
17 purposes of the analysis it's discussing, reserves were
18 increased to address flexibility violations?

19 A (Witness Grubb) Okay.

20 A (Witness Weathers) It is true that we did
21 that. I don't -- I don't see in this particular
22 paragraph where it addresses that. But it does address
23 the -- it describes the table, which is talking about the
24 flexibility violations, the intra-hour pressure on
25 balancing load and generation.

1 Q Okay. I was looking -- focusing in part at the
2 last clause which says: Higher levels of energy
3 deficiency requiring greater operating reserves to
4 mitigate the flexibility violations.

5 A (Witness Weathers) Okay. Yes, that is
6 correct.

7 Q Okay. Is it correct that the increase in load
8 following reserves is only based on the SERVVM model
9 analysis and not based on Georgia Power's actual system
10 operations?

11 A (Witness Weathers) Well, the SERVVM model
12 analysis is modeling the company's system. So it is --
13 so it is modeling within the system with different levels
14 of renewable penetration, which haven't occurred yet.

15 So it's all -- you're all in modeling world.
16 But the actual use of the system, the actual
17 characteristics of those units, and the actual load
18 forecast that we have, all those things are what goes
19 into the model.

20 Q Is it based on Georgia Power's experience with
21 integrating solar on its system?

22 A (Witness Weathers) It is -- the results are
23 consistent with it. So we have seen pressure on
24 operational flexibility within realtime operations, both
25 from ramping and also from intermittency impacts.

1 The model confirms that. It also projects that
2 to continue in increasing amounts as you add additional
3 solar on the system.

4 Q I just want to make sure we're talking about
5 the same thing. When you say the results confirm that, I
6 was asking whether the experience -- whether the SERV
7 model analysis was based on the actual Georgia Power
8 Company experience with integrating solar on its system.

9 Not whether the results confirm, but whether
10 the model is based on it.

11 A (Witness Weathers) Well, I don't know if this
12 is the way that you're asking -- it's not -- it's not
13 historical looking. It's not looking at actual results,
14 but is using actual units and projecting operations. So
15 it is the units on our system, but it's not backward
16 looking. It's a forward-looking modeling process.

17 Q But as far as what inputs are being included
18 into the model analysis, was that based on actual
19 experience?

20 A (Witness Weathers) Yes. In terms of the solar
21 generation, the profiles, the intermittency impacts based
22 on weather, all those are in terms of actual data.

23 Q And the actual data for integrating solar on
24 the system?

25 A (Witness Weathers) Yes. For our solar

1 generation. We used our solar generators. We modeled
2 those on the system and then we applied volatility around
3 that based on a weather that occurs across our service
4 territory.

5 So it's all based on observed or actual data,
6 units that we have, but it's a model. So it's projecting
7 future operation. It's not going to exactly align with
8 any particular hour in the past, but it's projecting the
9 future operations.

10 Q Is it easier to avoid flexibility violations if
11 you have more flexible resources?

12 A (Witness Weathers) Yes.

13 Q Would that be like more flexible resources like
14 combustion turbines or batteries on the system, rather
15 than large coal plants?

16 A (Witness Weathers) Well -- so those are
17 different degrees of flexibility. So certainly large
18 coal -- of those three, large coal plants would be the
19 least flexible. Combustion turbines provide more
20 flexibility because you can start and stop those either
21 within 15 minutes or maybe within an hour.

22 But the batteries will provide the most
23 flexibility. They can come on nearly instantaneously and
24 respond to these intra-hour five minute -- and even more
25 realtime than that flexibility issues that we saw in the

1 model.

2 Q And does the renewable integration study
3 analysis consider that Georgia Power is planning to
4 retire multiple coal units and will be adding more
5 flexible resources?

6 A (Witness Weathers) It does consider -- so it
7 doesn't necessarily consider specific retirements. But
8 really there's a contrast in the model between the
9 existing system being able to provide the flexibility
10 needed to integrate solar and batteries being able to do
11 it.

12 So a lot of the -- when the existing system is
13 provided in the model, a lot of that is from natural gas
14 units. So the coal units aren't operating a lot in the
15 model anyway.

16 So what you're doing is you're replacing
17 operating reserves from a variety of resources, but
18 natural gas is a large part of it, with battery resources
19 being able to provide that more efficiently and more
20 economically.

21 Q Let me summarize what I think I heard there.
22 The model -- the study analysis did not consider that
23 Georgia Power is planning to retire multiple coal units,
24 but you don't believe that coal was operated that much in
25 the model anyway?

1 A (Witness Weathers) It does consider the
2 retirement of some units. I'll have to -- I would have
3 to go back and verify which specific units were in or out
4 of the model.

5 But when -- but there is some coal in the
6 system. So the model that's reflected there, there's
7 some coal in the system, but it's not only coal providing
8 reserves. Gas units provide reserves, as well.

9 There's some base level of operating reserves.
10 It's going to be the same no matter what. So our
11 existing system provides those reserves. What we're
12 talking about here are the additional operating reserves
13 that will be required to mitigate the impact of future
14 expansion of solar.

15 There's value to providing those additional
16 reserves with the battery storage devices as opposed to
17 continuing to rely on the rest of the system which
18 doesn't have the same level of flexibility.

19 Q Does the renewable integration study itself
20 state that it considers that Georgia Power is planning to
21 retire multiple coal units or is that reflected somewhere
22 in the company's filing?

23 A (Witness Grubb) I don't believe it's stated,
24 as Mr. Weathers said. So to check we'd have to go back
25 and look at the years that we studied and what basis --

1 some of the coal units probably were retired. It's
2 probably not all of them. We'd have to go back and look.

3 MADAM CHAIR PRIDEMORE: Mr. Walsh, we're going
4 to break at noon to allow -- and my question -- for
5 you all to receive nutrition and hydration. We want
6 to make sure you can do so without the folks across
7 the street getting in your way. So let's do a hard
8 stop at noon.

9 MR. WALSH: Okay. Thank you, Madam Chair.

10 BY MR. WALSH:

11 Q I'm going to ask a lengthy question. You're
12 going to only have time for a very short answer.

13 A (Witness Grubb) I can't see the clock. So I'm
14 at your mercy, Mr. Walsh. I have no idea what time it
15 is.

16 Q I'm going to ask you a very -- hopefully a
17 short line of cross on the ownership of energy storage
18 service.

19 A (Witness Grubb) Uh-huh.

20 Q You've testified that the company is proposing
21 to own the storage resources, rather than contract for
22 them under third-party ownership; is that correct?

23 A (Witness Grubb) That's correct.

24 Q Okay. And you've testified that the company
25 will face many challenges that make company ownership of

1 energy storage service resources essential.

2 Does technology exist that would allow Georgia
3 Power to control and dispatch battery resources, even if
4 it does not own them?

5 A (Witness Grubb) Yeah. Mr. Mallard may help me
6 here. I mean, I believe there are AGC and other things.
7 You can own batteries.

8 And, again, it's not that we couldn't put a
9 contract in place on those batteries. It's that we
10 shouldn't. In terms of reliability resources.

11 I mean, these operating reserves --
12 Commissioners, we've been talking a lot about operating
13 reserves. We're talking about the ones that we will not
14 commit other resources for knowing that these batteries
15 are there to handle unit outages, changes in loads.

16 So from a generation standpoint, operating
17 reserves are the reliability backbone of the system. So
18 our position is we need to own that, 20-year assets,
19 making sure they're reliable, making sure that we're able
20 to have the flexibility to handle the different uses that
21 we may need over 20 years.

22 And so their technology to be able to control
23 it, we would deploy that ourselves, I'm sure. So it's
24 not that that's not available. It's the -- it's the
25 ownership piece and having the party responsible for

1 reliability have ownership of those resources that's
2 driving our request.

3 Q Does the company rely on generating capacity
4 for resource adequacy that it does not own?

5 A (Witness Grubb) We do.

6 A (Witness Weathers) In part.

7 Q And is it possible that developers could
8 develop battery resources more cost effectively than
9 Georgia Power?

10 A (Witness Grubb) They're able to be able to bid
11 into the capacity RFP. And as we mentioned, we totally
12 expect and welcome them to bid into future capacity RFPs
13 where we would have contracts.

14 We have PPAs that are seeking certification
15 here on gas units. Not as new as batteries are. We've
16 got more experience with them.

17 But from a resource that you're -- that you're
18 supplying capacity energy out of, we've got experience
19 with past resources, feel comfortable with those PPAs,
20 would allow storage to bid in there. Again, this comes
21 back to the specific resources that are critical to
22 reliability.

23 Q So the answer though is yes then; right?

24 A (Witness Grubb) They could -- I don't know
25 that they can do it cheaper. We'll have to see. We

1 wouldn't know that until we did an RFP, but they could --

2 Q It's possible?

3 A (Witness Grubb) They can develop them.

4 Q So it's possible it could be less expensive?

5 A (Witness Grubb) It's possible.

6 A (Witness Weathers) It's possible, but it's
7 also important that -- as we said earlier, batteries are
8 very flexible devices. They can operate a wide variety
9 of purposes, according to whenever the system needs them.

10 It's really difficult to anticipate all the
11 different uses of the system in the terms and conditions
12 of the contract and to allow that flexibility to
13 operators. So they need to be able to have assurances
14 that batteries will be maintained according to current
15 system standards, whatever those are and however those
16 evolve over time. And also they have the ability to --
17 to operate and call those devices as needed for system
18 purposes without the encumbrance of any terms and
19 conditions that may limit that.

20 Q Is it your testimony that could not be done,
21 unless Georgia Power owns it?

22 A (Witness Weathers) I think anytime you
23 introduce a contractual arrangement, there are going to
24 be terms and conditions. So either -- either there's --
25 the more flexibility you build into the contract, the

1 more expensive it is. Because the provider, the seller,
2 will have to anticipate that the company uses it in a way
3 that provides the most wear and tear to the units as
4 possible so they recover their costs.

5 Q And then it would just be a question whether
6 you could build that flexibility at a cost that was more
7 cost effective than Georgia Power owning it; correct?

8 A (Witness Weathers) Yeah, that would be the
9 question. But I think it is important, as Mr. Grubb
10 said, when talking about operating reserves and essential
11 reliability services on the system that operators rely on
12 in realtime operations. That's something you don't want
13 to outsource.

14 You want the company to be able to control that
15 and own that and operate that and know that they can
16 depend on that. Because without it, there's no other
17 units committed and it's going to cost customers a lot
18 more for the system to react.

19 MR. WALSH: That completes that line of cross.

20 Thank you.

21 MADAM CHAIR PRIDEMORE: Very good, Mr. Walsh.

22 I want to give you an opportunity to show off that
23 good looking tie in the cafeteria.

24 We're going to break until 1:00 p.m. See y'all
25 back here.

1 (Whereupon, a lunch break was taken.)

2 MADAM CHAIR PRIDEMORE: Mr. Walsh, are we

3 ready? Witnesses, are we ready?

4 THE PANEL: Yes.

5 MADAM CHAIR PRIDEMORE: Let's take it from

6 where we left off.

7 VICE CHAIRMAN ECHOLS: Mr. Walsh, can I jump in

8 because there wasn't time before lunch?

9 On solar, and I'm thinking mainly on the

10 distribution grid -- on the transmission grid so

11 maybe, Mr. Mallard, this would be you.

12 But is it true that as we put more solar on our

13 distribution grid that we've nudged voltage up a

14 little bit, or not necessarily?

15 WITNESS MALLARD: So it can be, and I'll ask

16 Mr. Robinson to help here. It just depends. It's

17 locationally independent when solar is producing and

18 creating output. Generally, yes, it's supporting

19 the system; but it's the variability, Commissioner,

20 that solar without storage adds to the grid that can

21 make that more challenging to manage.

22 WITNESS ROBINSON: And, Commissioner, part of

23 the interconnection and study process we do is

24 ensure that voltages stay within appropriate levels

25 so we're not overvolting the system or creating

1 situations where we're under voltage as well.

2 MADAM CHAIR PRIDEMORE: Mr. Robinson, speak in
3 that mic for us, please. Thank you.

4 VICE CHAIRMAN ECHOLS: So in the same way, I
5 guess, as you're wanting to, you know, have more
6 control over whether it's the battery system or the
7 curtailing the solar rate yourself, you know,
8 automatically with the automatic controls, does
9 it -- does the smart inverters, do they -- do they
10 help with that? We don't necessarily require those,
11 do we?

12 WITNESS MALLARD: So we do. We are -- we have
13 upped the requirements on our inverters -- most
14 inverters out of the box these days are smart
15 inverters, Commissioner.

16 What we need on the other side now is a DERs, a
17 management system for these distributed energy
18 resources so that we can communicate with them and
19 control them. That is under development for sure.
20 There's some elements to this IRP that support
21 distributed generation management in that way.

22 And that's absolutely a future state that we're
23 moving towards where we will have better line of
24 site and better operational control of
25 distributables.

1 VICE CHAIRMAN ECHOLS: All right. Thank you.

2 MADAM CHAIR PRIDEMORE: Go ahead, Mr. Walsh.

3 MR. WALSH: Thank you.

4 CONTINUED CROSS-EXAMINATION

5 BY MR. WALSH:

6 Q. Before the break, we discussed that the
7 renewable integration study quantifies the change in
8 production costs as recorded in the SERVIM model for each
9 scenario to prevent flexibility violations.

10 Has Georgia Power quantified the production
11 costs that it is currently incurring to avoid flexibility
12 violations due to the solar that it is -- that is already
13 on the system?

14 A. (Witness Weathers) No. It's -- it's not
15 really something that is easily done. And so in the
16 model we're able to do it because we have -- we can
17 model -- we can model with and without the solar.

18 So the difference of those two is the
19 production costs, the integration costs associated with
20 that. In actual operations, you only have actuals, so
21 there's no comparison case to compare that to.

22 So we know that there are impacts from ramping
23 of solar and intermittency of solar, but exactly the cost
24 of those is not determinable.

25 Q. So you can't do any kind of comparison, then,

1 between the results of the renewable integration study
2 and the actual comparison?

3 A. (Witness Weathers) No. In terms of the
4 integration costs, it's really not something we have
5 in -- we can't quantify in actual practice. But that's
6 why we have the model. So the model actually enables us
7 to quantify that, both for an existing level of solar and
8 for increasing levels of solar.

9 Q. And just to be clear, when you say you can't do
10 it, is it an impossibility, or is it something that the
11 company believes is not worth doing?

12 A. (Witness Weathers) It's an impossibility
13 without the use of a model that presents some other
14 scenario different than reality, because you only have
15 one actual case. So you want to compare that versus an
16 alternate actual case, you're having to introduce
17 modeling elements.

18 Q. I'd like to ask you a few questions about
19 McGrau. The company is seeking approval to build the
20 265-megawatt McGrau Ford BESS system which it states is
21 part of its ESS deployment strategy; is that correct?

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

23 Q. Okay. And there's nothing in the company's
24 filing, is there, that shows whether the company examined
25 any alternatives to the McGrau Ford system that could

1 have produced operating reserves at a lower cost?

2 A. (Witness Mallard) So the company continuously
3 evaluates potential sites for generating resources,
4 renewables battery energy storage as well. And so as
5 outlined in the company's battery storage procurement
6 action plan, the company is continuously looking for
7 these desirable locations. So yes, we have absolutely
8 evaluated different locations. McGrau Ford is the one
9 that was chosen for this first battery storage project.

10 Q. Is that reflected in the company's filing, that
11 the company examined alternatives to the McGrau Ford
12 system?

13 A. (Witness Mallard) So maybe it's not. I
14 don't -- it's not in the battery energy storage section
15 in the main doc or in the testimony.

16 Q. Okay. A few questions for you related to
17 biomass.

18 Is it correct that the company was unable to
19 finalize a purchase power agreement with any of the
20 bidders from the 2022 through 2028 capacity RFP?

21 A. (Witness Grubb) Yes. And the biomass was
22 actually a part of that capacity RFP. But, yes, we were
23 unable to procure resources under the -- the aspects and
24 the particulars of that RFP in the pro-forma PPA.

25 We worked with Commission staff and the IE and

1 went through the entire process. But, yes, there was --
2 there has been some specifics that we could not meet with
3 some of the other resources.

4 Q. Is it also correct that the biomass bids
5 received in response to the capacity RFP were not
6 economic relative to purchase power agreements proposed
7 for certification?

8 A. (Witness Grubb) So the capacity RFP and the
9 biomass RFP were separate solicitations. They were the
10 same schedule and those types of things, but from an
11 evaluation standpoint the biomass bids competed against
12 other biomass bids. We did not compare them to the
13 capacity RFP. But the prices that biomass bid in were
14 higher.

15 Q. So they were not economic -- understanding you
16 didn't do that comparison, had you done that comparison,
17 the biomass would not be economic in comparison to the
18 purchase power agreements?

19 A. (Witness Grubb) Yes. Biomass prices are
20 higher than what we saw in the capacity RFP.

21 Q. Were the biomass bids more economic or less
22 economic than the most competitive solar plus storage bid
23 in that RFP?

24 A. (Witness Grubb) So the capacity RFP did not
25 have a solar only bid. I think if you looked at prices

1 that we have seen on solar, or the renewable RFPs, then,
2 yes, those prices are lower than biomass. But I think
3 that's been recognized by many parties, that biomass is
4 economically different from those others.

5 Q. Did the company's evaluation of the biomass
6 bids show a net benefit to customers?

7 A. (Witness Grubb) From a straight energy and
8 capacity standpoint, they would not have, but then again,
9 we were just looking to get the best price biomass
10 resources we could. But I think this commission in the
11 past has noted there's other aspects to biomass that they
12 have often included. But from a straight energy and
13 capacity standpoint, they just competed with each other.

14 Q. What was the amount of the net loss to
15 customers from the most competitive biomass bid?

16 A. (Witness Grubb) I can't -- I can't remember
17 what the total net -- net cost was there. I just can't
18 recall.

19 Q. Can you say whether the net loss is more or
20 less than 100 million?

21 A. (Witness Grubb) I can't recall. We didn't
22 execute a contract, so I don't know. I can't recall
23 the -- the final evaluation there.

24 Q. Okay.

25 A. (Witness Grubb) But a 20-year biomass contract

1 is a lot of -- lot of money over the life of that
2 contract.

3 Q. I'd like to ask you a few questions about
4 accounting deferrals.

5 A. (Witness Grubb) Okay.

6 Q. The company is requesting several accounting
7 deferrals, primarily related to plant retirements; is
8 that correct?

9 A. (Witness Grubb) If by "accounting deferrals"
10 you mean moving the net book value into regulatory asset?

11 Q. Yes.

12 A. (Witness Grubb) Yes, we are.

13 Q. And the Commission is not required by IRP
14 statute to address the company's request for accounting
15 deferrals for amortization periods in an IRP proceeding;
16 is that correct?

17 A. (Witness Grubb) That is my understanding. I
18 know we have made several of those recommendations in the
19 past few IRPs for the Commission to consider. So we've
20 often requested for the net book values upon retirement
21 to be moved to a regulatory asset.

22 In this case, we're asking for that again but
23 stating that the -- the actual amortization periods and
24 the dates will be determined across the next few rate
25 cases.

1 Q. And the company, in fact, is scheduled to file
2 its next rate case later this year; correct?

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

4 Q. Will the company, do you know, be seeking to
5 establish a new three-year rate plan covering the years
6 2023 through 2025?

7 A. (Witness Grubb) I believe that's the time
8 frame for the rate case. I'm not involved in the rate
9 case strategy of those developments, but that's my
10 understanding of the time frame.

11 Q. Okay. And it is your understanding that the
12 company would also be on schedule to file its next IRP
13 and another base rate case in 2025?

14 A. (Witness Grubb) That is correct.

15 Q. Okay. Would you agree that since the company
16 filed its 2022 IRP there have been significant
17 developments that were not known to the company at the
18 time that it filed -- that it made its filing, such as
19 increased volatility in the world energy markets?

20 A. (Witness Grubb) In which markets? I am sorry.

21 Q. The world energy markets.

22 A. (Witness Grubb) Yeah. I mean, there has been
23 a lot going on the last few months. I think we hit on it
24 a little bit this morning. Again, we are looking at
25 30-year studies, long-term decisions. Don't think that

1 would change any of our recommendations; but, yes, some
2 things have changed. I think they're more short term in
3 nature than long term in nature.

4 Q. Are all of the units for which the company is
5 seeking early retirement in the current IRP sourced with
6 fuel sources that are produced in the United States?

7 A. (Witness Grubb) Yeah. I mean, I think almost
8 all of our resources are fueled from within the United
9 States. I think the gas -- all of our domestic supply --
10 all of our gas supply is domestic. Coal supply is
11 domestic. I think our uranium may be globally. But
12 almost everything is domestic from a supply standpoint.

13 Q. I'd like to ask you a few questions about
14 procuring renewables beyond the 2,300 megawatts.

15 A. (Witness Grubb) Okay.

16 Q. The company is seeking approval to procure
17 2,300 megawatts of new renewable projects in the next
18 three years; is that correct?

19 A. (Witness Mallard) Correct.

20 Q. And this megawatt target is the result of the
21 analysis summarized in the renewable expansion plan; is
22 that correct?

23 A. (Witness Mallard) Correct.

24 Q. And also the resource mix study?

25 A. (Witness Weathers) Well, the renewable

1 expansion plan which is a resource mix study, it's not
2 the same as the IRP base case study, but it is a resource
3 mix study.

4 Q. Okay.

5 A. (Witness Weathers) And those renewables are
6 reflected in the resource mix -- resource mix study in
7 all the planning scenarios as well.

8 Q. Okay. So did the resource expansion plan
9 analysis indicate that there were market conditions that
10 would suggest that more renewables would provide economic
11 benefits to customers?

12 A. (Witness Weathers) Yes.

13 A. (Witness Grubb) Could you re- -- okay. I was
14 going to ask, are you talking about the -- you're asking
15 about the renewable expansion plan that we filed or the
16 expansion plans in 2022 that included? I just want to
17 make sure I didn't miss your question.

18 Q. I'm talking about the renewable expansion plan
19 analysis that was filed.

20 A. (Witness Grubb) Okay.

21 A. (Witness Weathers) Yeah. I mean, it
22 considered a range of scenarios and in those scenarios
23 represents a range of renewable expansion. So if you
24 have, for example, very high carbon prices, then
25 renewables are more economic, and it would be more

1 economic to add more earlier.

2 Q. If the Commission were to approve the company's
3 request for approval of the 2,300 megawatts, will the
4 company continue to monitor market conditions and
5 potentially propose additional procurements if it
6 determines that there would be additional benefits?

7 A. (Witness Mallard) So absolutely. That's one
8 of the hallmarks of our renewable plan this time is some
9 added adaptability and flexibility to market conditions
10 that are continuously changing these days.

11 As Mr. Walsh referenced, there's lots of --
12 lots of things impacting the supply of the components for
13 renewable resources and batteries: Inflation, the supply
14 chain pressures that we're all familiar with.
15 Additionally, the impacts to our transmission system as
16 we integrate more of these.

17 And so having some flexibility, Commissioners,
18 as we go forward on the -- the timing and maybe the total
19 amounts and being able to make some adjustments there
20 based on market conditions, we feel like that's important
21 to ensure that we continue an efficient procurement.

22 Q. I'm going to be referring to page 1-8 of the
23 main IRP filing. You may be able to answer the question
24 without reference, but it may help to get there.

25 A. (Witness Mallard) You can proceed with your

1 questions.

2 Q. Thanks. Do you see where the company says it's
3 proposing a longer plan through 2035 that includes the
4 addition of 6,000 megawatts of renewable resources?

5 A. (Witness Mallard) Yes.

6 A. (Witness Grubb) Yes.

7 Q. If the Commission were to approve the company's
8 IRP, would you consider that to be approval of the
9 company's longer plan to add the 6,000 megawatts?

10 A. (Witness Mallard) So not explicit approval.
11 And here is the thing. The 6,000 is a long-term target,
12 and the models do show that adding that amount of
13 renewable resources is going to be in customers' best
14 interests. The only thing that we really need approval
15 of in this IRP cycle is the 2,300 megawatts. That'll get
16 us through issuing the two utility scale RFPs, one
17 distributed generation RFP with two bid periods.

18 And by that time, we will be back in front of
19 the Commission in the 2025 IRP. Our expectation is we'll
20 make adjustments to that long-term target of
21 6,000 megawatts based on the current market conditions.

22 Q. So would you characterize that statement about
23 the 6,000 megawatts of renewable resources by 2035 to be
24 less a request for approval and more just an explanation
25 of the company's longer term plans?

1 A. (Witness Mallard) Yeah, I would agree with
2 that.

3 A. (Witness Grubb) Again, I think, Commissioners,
4 one of the things that that longer term plan gives us is
5 the ability to plan for both on the generation side and
6 the transmission side.

7 So past IRPs, we had that one number that we
8 were doing for three years and really no guidance beyond
9 that. This extra guidance allows us to study it from a
10 transmission standpoint as well.

11 A. (Witness Robinson) And, Commissioners, it's
12 going to be very important that we're looking out in time
13 beyond the ten-year window, looking towards that 2335
14 date. We anticipate the future retirement of Bowen 3 and
15 4, an additional 6,000 megawatts of renewables in South
16 Georgia.

17 Hopefully, we're successful in steering some of
18 those to North Georgia with the North Georgia reliability
19 resiliency plan that we proposed. But we're going to
20 need significant transmission built that's not in this
21 plan. We're working on that with the ITS participants
22 today to move those megawatts from South Georgia to
23 North Georgia to address those constraints that we are
24 starting to see on the system today.

25 MADAM CHAIR PRIDEMORE: And since you're not

1 seeking the 6,000 megawatts in this cycle, you're
2 saying that the 6,000 could go up, or it could also
3 go down?

4 WITNESS MALLARD: Correct.

5 MADAM CHAIR PRIDEMORE: Okay.

6 WITNESS ROBINSON: And, Madam Chair, another
7 thing that's very important is not being the only
8 utility in the state, EMCs and municipalities also
9 have renewable development goals. Their customers
10 are doing the same thing. So you could easily see
11 that 6,000 megawatts be 9,000 megawatts if you add
12 the EMCs and the municipalities into the equation as
13 well.

14 MADAM CHAIR PRIDEMORE: That's for another day,
15 Mr. Robinson.

16 BY MR. WALSH:

17 Q. The company proposes to procure 2,100 megawatts
18 of utility scale renewables in this IRP cycle and to make
19 all of that capacity available to C&I customers through
20 the CARES program; is that correct?

21 A. (Witness Mallard) Yes.

22 Q. When renewable resources are subscribed by a
23 C&I customer, does that mean that other customers do not
24 get the full benefit of that renewable resource?

25 A. (Witness Mallard) No, I don't think that's the

1 case. I think all customers get all of the benefits of
2 the renewable resources.

3 Really, Commissioners, what we're talking about
4 here is on whose behalf the REC is retired, the renewable
5 energy credit or the attribute. And that renewable
6 energy credit is important to a lot of our large
7 customers, especially, who have sustainability or carbon
8 or renewable energy goals.

9 The benefits of adding renewables to the system
10 accrue to all Georgia Power customers regardless of who
11 owns the REC. Additionally, the CARES design will allow
12 those RECs to be sold, if you will, retired on behalf of
13 the subscribing customers, and the proceeds will go to
14 the fuel bucket in hopes of putting downward pressure on
15 rates for all customers.

16 Q. So it's your testimony that all customers
17 benefit equally?

18 A. (Witness Mallard) All customers will benefit
19 from the addition of the 2,300 megawatts of renewable
20 resources as we -- as proposed. The same cost benefits,
21 the same environmental benefits, the same renewable
22 benefits, do accrue to all customers.

23 What is different is some customers will be
24 able to subscribe to the renewable energy credit. That
25 is the ability to claim the renewable attribute, to

1 advertise the renewable attribute, or to use it for
2 compliance with an internal or external goal. That's
3 really the key to this program is allowing those
4 renewable energy credits to be assigned to a specific
5 customer.

6 Q. And will those customers that get to subscribe
7 benefit more than those customers that don't get to
8 subscribe?

9 A. (Witness Mallard) They benefit in the sense
10 that they get access to the renewable energy credit that
11 is important to them. But if that renewable energy
12 credit is not important to another customer, then they
13 have no need for it. They benefit just as much.

14 VICE CHAIRMAN ECHOLS: Just a question for
15 Mr. Mallard on this. Mr. Mallard, really, since
16 Commissioner McDonald's motion in 2013, all the
17 solar that we've done at utility scale that's been
18 below avoided costs, it's actually had an accrued
19 benefit for every customer on the system; right?

20 WITNESS MALLARD: The benefits accrue to all
21 customers, yes, sir.

22 VICE CHAIRMAN ECHOLS: And do you anticipate
23 even with this solar dumping, this -- this dumping
24 policy that's been put in place and solar prices
25 ticking up, do you anticipate us still being able to

1 deliver the savings to the customers?

2 WITNESS MALLARD: So what we do,
3 Commissioner -- and what we're proposing here is to
4 look at those benefits a little bit differently.
5 Our models are able to choose renewable resources
6 now looking forward, where they haven't been able to
7 do that before.

8 That's the -- the output that we have been
9 talking about where it shows that 6,000 megawatts,
10 if added at prices similar to what we modeled, will
11 be of benefit to all customers. We do expect that
12 to continue.

13 Now, all the things that you're talking about,
14 there is volatility in the solar market.
15 Absolutely, prices can go up and down. It's our
16 expectation that long-term solar will continue to
17 deliver value to customers; but we'll model that,
18 and we'll run these RFPs and get a, you know, get a
19 real good idea of exactly what those prices look
20 like, work with staff, work with the IE, and then
21 ultimately present to the Commission for approval
22 what portfolio of resources is in the best interests
23 of customers.

24 WITNESS WEATHERS: And, Commissioner Echols,
25 I'll add also, as Mr. Mallard said, the model is

1 selecting solar. So it's looking at not just one
2 scenario, but across a range of scenarios of gas
3 prices and carbon prices, and the only reason the
4 model selects it is because it produces energy
5 savings for customer.

6 It's cheaper to have the solar than to not have
7 the solar. So all the solar that's proposed has
8 been selected by an optimization model that selects
9 it because it produces savings for customers.

10 VICE CHAIRMAN ECHOLS: Thank you.

11 BY MR. WALSH:

12 Q. I want to go back and discuss this one point,
13 if I understood your last answer.

14 A. (Witness Mallard) Sure.

15 Q. Because I was asking whether the customers who
16 had the option to subscribe receive a greater benefit
17 than the customers who don't receive the option, who
18 don't have that option. And I believe you said that if
19 the subscription wouldn't benefit the customer, then
20 nothing's lost if they don't have the opportunity to
21 subscribe. But I'm just trying to make the point that
22 if -- not every customer will have the opportunity to
23 subscribe; right?

24 A. (Witness Mallard) Not every customer will have
25 the opportunity to subscribe to the CARES program.

1 However, all Georgia Power customers do have options
2 available to them to subscribe to the output of renewable
3 resources.

4 Q. But for this program, they would not; and so
5 they don't have every option to receive the full benefit
6 that the customers who have the opportunity to subscribe?

7 A. (Witness Mallard) I guess my position,
8 Mr. Walsh, is unless an individual customer finds value
9 in having that renewable energy credit retired on their
10 behalf, they're better off under the CARES program
11 because their bill will be lower, and the customer that
12 does find value in the renewable energy credit will also
13 be more satisfied. They will have -- they will have paid
14 a subscription fee and the REC would be retired on their
15 behalf.

16 Q. But would there be customers who would benefit
17 who -- but who would not have the opportunity to
18 subscribe?

19 A. (Witness Mallard) Well, there is -- not every
20 customer will have the opportunity to subscribe to the
21 CARES program, because we do have subscription levels,
22 minimum subscription levels, and it's targeted for our
23 larger customers. But as I mentioned, we've got a
24 portfolio of programs, including Simple Solar, including
25 Community Solar. All Georgia Power customers have the

1 opportunity to subscribe to a solar program or a
2 renewable program one way or the other.

3 Q. And I'm asking specifically about the CARES
4 program.

5 A. (Witness Mallard) Um-hum.

6 Q. So for the customers who don't have the
7 opportunity to subscribe, they may not be able to receive
8 a benefit under this particular program that they would
9 be able to receive if they were allowed to subscribe?

10 A. (Witness Mallard) The only benefit that
11 they're going to miss out on is if they find value in the
12 renewable energy credit. The cost savings, the
13 environmental benefits, the fuel diversity, all of those
14 things that solar and renewable resources bring to the
15 system, those still accrue to all customers regardless of
16 the REC ownership.

17 MADAM CHAIR PRIDEMORE: So on the CARES
18 program, though, it's designed to be able to assist
19 the economic development mission in the state of
20 Georgia; right?

21 WITNESS MALLARD: Partially, yes, ma'am. Some
22 is also reserved for existing customers, but some is
23 for new load as well, yes, ma'am.

24 MADAM CHAIR PRIDEMORE: Okay. And so as the
25 state of Georgia has seen an increasing number of

1 corporations that want to put a second headquarters
2 or an outlet here of some sort, but the corporate
3 entity has, we'll call, an RPS on their corporation.
4 And that -- that is what is allowing Georgia to be
5 competitive with other states, such as North
6 Carolina, Florida, those that we compete with on a
7 regular basis for jobs.

8 That gives an opening, though, so that it makes
9 Georgia equally or, in my opinion, more attractive
10 than other programs that have been reviewed and
11 implemented in those states; is that right?

12 WITNESS MALLARD: Yes. That's definitely the
13 case based on my experience. Almost all -- I wish I
14 had a percentage, but it seems like almost all of
15 the customers seeking to relocate or add load to
16 Georgia, the large customers we have dealt with in
17 the last couple of years, almost 100 percent of them
18 have some sort of renewable or carbon goal.

19 And so having this option available definitely
20 helps Georgia be more competitive to bring the load
21 to Georgia and then helps Georgia Power be more
22 competitive in the customer choice market as we
23 compete for these jobs.

24 MADAM CHAIR PRIDEMORE: Thank you.
25

1 BY MR. WALSH:

2 Q. Can I get you to refer to page 36 of your
3 prefiled direct testimony. I'm going to be looking at
4 the Q and A that begins on line 20.

5 A. (Witness Mallard) Can you say the page one
6 more time?

7 Q. 36.

8 A. (Witness Mallard) Yes, sir.

9 Q. It's the question where you ask, "Please
10 describe what is meant by best cost procurement."

11 A. (Witness Mallard) Yes, I'm there.

12 Q. On line 23, you describe it as "most valuable
13 or best cost resources." Do you see that?

14 A. (Witness Mallard) Yes.

15 Q. Would you agree with me that calling it the
16 most valuable doesn't give a lot of specifics as to what
17 the company means by "best cost" or "most valuable"?

18 A. (Witness Mallard) Well, it does -- it does to
19 me, and maybe I am speaking in the world of evaluating
20 renewable resources. But it's creating the most value
21 for our customers. It's based on price and then also
22 based on the generation profile and the associated
23 benefits that each of these renewable resources would
24 bring to the system.

25 Q. Okay. But, I mean, in your answer, you just

1 say most valuable; right?

2 A. (Witness Mallard) Yes, sir.

3 Q. Okay. If you could turn to the next page, 37.

4 A. (Witness Weathers) Mr. Walsh, we do talk
5 about -- we do further describe that in this same
6 response.

7 Q. And I'm getting to further in the response.

8 A. (Witness Weathers) Okay.

9 Q. My next question addresses further in the
10 response.

11 A. (Witness Weathers) I was just going to say, we
12 didn't limit it to that one term. We also describe what
13 that meant in terms of the RCB framework.

14 Q. And that's what I'm getting to in my next
15 question.

16 A. (Witness Weathers) Okay, good. Thank you.

17 Q. On the next page, still in the same question,
18 you say, "Therefore, the company is proposing additional
19 flexibility in how it identifies the portfolio of best
20 resources to fill the company's renewable energy needs."

21 Again, that doesn't give a lot of specifics
22 about what the company would be approve- -- what the
23 Commission would be approving if it approved the
24 company's best cost approach, does it?

25 A. (Witness Mallard) So I'm happy to expound on

1 that for the Commissioners, and it goes back to the
2 discussion we were having just a second ago.

3 Q. Well, actually, what I'd ask is just if you
4 could say -- if you could agree that that answer in your
5 testimony about providing additional flexibility in
6 identifying the portfolio of best cost resources, doesn't
7 that -- that response does not provide a lot of detail as
8 to what the company anticipates in the best cost
9 approach?

10 A. (Witness Mallard) No, I don't know that I
11 could --

12 MR. HEWITSON: Madam Chair -- well, I think --
13 I think he is going to explain anyway, but I would
14 like the witness to be able to explain their answer
15 before the follow-up comes.

16 MR. WALSH: And I would just say that the -- I
17 did not get an answer to my specific question before
18 the further explanation, and that's what I was
19 asking for.

20 MADAM CHAIR PRIDEMORE: These are technical
21 terms. Sometimes we have to rephrase the way that
22 we ask a particular question, or just ask it again.

23 BY MR. WALSH:

24 Q. Okay. Well, why don't I skip to this question.
25 Maybe it'll move things along.

1 Will the company be agreeable to working with
2 the staff and the independent evaluator during the RFP
3 development process to work out the specifics of the best
4 cost procurement approach?

5 A. (Witness Mallard) Yes, definitely. And some
6 of the specifics in the best cost approach, some of the
7 additional items that will be considered as part of the
8 evaluation process, they are listed in the next
9 paragraph. They are down below about halfway down on
10 page 37.

11 MADAM CHAIR PRIDEMORE: Line?

12 WITNESS MALLARD: Starting about 11, 12, and
13 13, Madam Chair.

14 MADAM CHAIR PRIDEMORE: Okay. Thank you.

15 BY MR. WALSH:

16 Q. I'd like to ask you about the Commission's
17 final order in the capacity and energy payments to
18 cogenerators under PURPA in Docket 4822. This was an
19 order issued March 11, 2021. And I can -- I can show you
20 the order if needed, but let me just ask the first
21 question; and then if you need to look at the order, I'll
22 provide it to you.

23 A. (Witness Grubb) Okay.

24 Q. But are you aware that in that final order the
25 Commission ordered that the support capacity component

1 shall be set to zero until the public interest advocacy
2 staff reviews the internal Southern Company operational
3 data and the Commission approves the data and methodology
4 used in calculating short-term production cost impacts?

5 A. (Witness Grubb) Yes. I recall that from the
6 motion, and that is specific to payments to qualifying
7 facilities on a day-ahead basis.

8 Q. If the Commission were to adopt the company's
9 proposal to replace the support capacity component with
10 the integration cost component, would that in any way
11 modify the requirement ordered by the Commission in 4822?

12 A. (Witness Grubb) Well, I don't have the exact
13 order as you just mentioned, but I think our thoughts
14 were always that as the RCB changes, if it's applicable
15 to qualifying facilities, that that would be updated as
16 well.

17 So that would be -- in that docket, we would
18 have to have that discussion on how to incorporate the
19 integration costs for qualifying facilities.

20 Q. I can provide you with a copy of the order if
21 it would be helpful.

22 A. (Witness Grubb) I'm good right now.

23 Q. Okay.

24 So just to put a finer point on it, are you
25 saying that you believe that it would require an update

1 to what was ordered in 4822?

2 A. (Witness Grubb) If we were going to apply on
3 the QFs, it obviously would. I think the reason that we
4 have support capacity in the qualifying facility payments
5 is because as those QFs deliver intermittently, just like
6 anything else, it does put a cost on the system.

7 Again, the order ended up having that value at
8 zero because of more discussion with staff. So the
9 company's position would be for the -- you know, to
10 benefit customers, that is a cost that a qualifying
11 facility would impose on the system just like others. So
12 we would -- we would want to have that discussion under
13 that docket.

14 Q. If the Commission were to approve the
15 integration cost component in this filing, would that
16 mean the company is not planning to provide the
17 operational data to staff?

18 A. (Witness Weathers) Well, the company already
19 provided the operational data to staff. It reviewed that
20 with staff. So -- so it was never our intention to not
21 do that. The company provided that data.

22 The integration cost component is similar to
23 the support capacity function. It's a little bit -- it's
24 different in the way that it's calculated and compiled.
25 But it provides a similar function in that you're

1 capturing the reliability impacts of the intermittency
2 resource -- of the intermittent resources on the system.
3 It's different because you don't -- you don't break apart
4 some of the components like you did with the old support
5 capacity.

6 So I think those conversations -- the company
7 would need to have those with staff about how to best
8 utilize the integration cost component with renewable
9 cost benefit framework consistent with the order that you
10 just read.

11 Q. Okay.

12 MADAM CHAIR PRIDEMORE: To be clear, though,
13 that's Docket No. 4822 that's been heavily discussed
14 here at the Commission, just as recently as last
15 Thursday. I believe we've got an item before us
16 tomorrow related to it. But that is for PURPA QFs
17 and does not apply to the solar that the company is
18 proposing in this IRP in Docket No. 44160; correct?

19 WITNESS GRUBB: That is correct.

20 WITNESS MALLARD: Correct.

21 BY MR. WALSH:

22 Q. I'd like to ask you some questions on plant
23 held for future use. And prior to beginning the
24 questions, I'd like to provide you with the company's
25 response to STF-LA-14-4.

1 MR. WALSH: Madam Chair, may we provide this to
2 the witnesses and the Commission?

3 MADAM CHAIR PRIDEMORE: Yes, you may. You may
4 approach.

5 MR. WALSH: And as it's being circulated, I
6 would ask that this response, again, to STF-LA-1-44
7 be marked for identification as Staff Exhibit 4.

8 MADAM CHAIR PRIDEMORE: So moved.

9 (The document referred to was marked for
10 identification as Staff Exhibit 4.)

11 BY MR. WALSH:

12 Q. If you could please turn to the second page of
13 the attachment that you were just provided.

14 Does this show that as of December 31, 2021,
15 the company had \$106.6 million in plant held for future
16 use?

17 A. (Witness Mallard) Yes.

18 A. (Witness Grubb) Yes, it does.

19 Q. And does that include \$22.9 million for St. Joe
20 timberland in Stewart County?

21 A. (Witness Grubb) It does.

22 Q. The \$22.9 million that was spent for land in
23 Stewart County is not currently providing service to
24 ratepayers, is it?

25 A. (Witness Grubb) It is a site that the company

1 has for future deployment of generation. But there is no
2 generation on site at this time.

3 Q. So it's not currently providing service to
4 ratepayers?

5 A. (Witness Grubb) Not from a generation
6 standpoint; that's correct.

7 Q. When you say not from a generation standpoint,
8 are you saying that it is providing service to
9 ratepayers --

10 A. (Witness Grubb) It's not providing electric
11 service. There's value to customers of us having that
12 site for future use.

13 Q. Okay. There -- you're saying there's value,
14 but I'm saying, right now, it's not providing a service?

15 A. (Witness Grubb) That is correct.

16 Q. Okay.

17 A. (Witness Grubb) Whereas, I think that that
18 applies for most of the items in plant held for future
19 use.

20 Q. Will the company ask this commission for
21 authorization to recover from its customers the dollars
22 spent for the land in Stewart County?

23 A. (Witness Grubb) So I -- you know, I think one
24 thing here, Mr. Walsh, is I believe this was all
25 addressed in the 2019 rate case and that the IRP would

1 bring forth reviews on plant held for future use once it
2 had been in that category for 15 years, which none of
3 these apply.

4 So I don't know exactly all the treatment from
5 a rate case standpoint and everything; but, again, the
6 plant held for future use discussion in the IRP was
7 really once it has been in that account for 15 years.

8 MADAM CHAIR PRIDEMORE: Mr. Grubb, for the
9 record, can you go through what the 2019 rate case
10 did to treat Stewart County and the plant held for
11 future use, if you recall that?

12 WITNESS GRUBB: Madam Chair, I don't know the
13 exact wording. I know in our response here, we talk
14 about we're complying with the agreed-upon time
15 frames and forums for review of plant held for
16 future use as provided in paragraph 16 of the
17 stipulation approved by the Commission in the 2019
18 rate case in Docket 42516.

19 I don't know exactly what the wording was. But
20 my understanding was it was once something had been
21 in an account, whether it was generation,
22 transmission for 15 years, then we would bring it
23 forward in the IRP to determine the status at that
24 point.

25

1 BY MR. WALSH:

2 Q. The company does not currently have any
3 Commission authorization or plans to build future
4 generation on the Stewart County site, does it?

5 A. (Witness Grubb) Nor any other -- any other
6 site. We're not building anything right now; that's
7 correct. But, again, it's a -- it's a site that has a
8 great value when you look at sites across the state for
9 generation.

10 MADAM CHAIR PRIDEMORE: Mr. Walsh, are you
11 thinking about buying this site? Tends to come up
12 about every three years. I just wonder, are you
13 looking at it? You want to move to Stewart County?
14 It's pretty down there.

15 COMMISSIONER McDONALD: We are not through with
16 it yet, I can assure you.

17 MADAM CHAIR PRIDEMORE: Just saying. It's
18 just --

19 MR. WALSH: I don't quite have the money that's
20 listed in the balance here, so...

21 MADAM CHAIR PRIDEMORE: Okay. Just making
22 sure.

23 WITNESS ROBINSON: And, Commissioners, there
24 are three properties that came off of this list that
25 we've moved out of this account for future projects,

1 three substation projects. I believe we answered
2 that in one of the data requests.

3 BY MR. WALSH:

4 Q. Well, why does the company show the projected
5 use date for Stewart County land as later than 2030 and
6 not later than 2040? Does Georgia Power Company have
7 plans for that Stewart County land between 2030 and 2040?

8 A. (Witness Grubb) Well, I think there's a lot of
9 things in flux. I mean, the main reason we put greater
10 in 2030 is if you look at our needs, we don't have -- we
11 have some needs in '29 and '30. We have a lot of PPAs
12 that roll off in 2030.

13 So you're really thinking from a company
14 standpoint, if we worked to propose self-build
15 generations for company-owned proposals, it's likely in
16 that '30 to '40 time frame.

17 Q. But you don't have any anything specific, but
18 that's -- okay.

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

20 Q. All right. So if Georgia Power sells any
21 timber on the Stewart County land, will all the net
22 proceeds from such timber sales be credited back for the
23 benefit of ratepayers?

24 A. (Witness Grubb) I don't know the treatment of
25 timber sales at Stewart County.

1 Q. Okay. For a significant portion of the
2 company's plant held for future use, the projected use
3 dates are 2040 or beyond; correct?

4 A. (Witness Grubb) Correct. Again, most of these
5 have not -- you know, haven't fallen in that 15-year
6 window, so we didn't come prepared to speak to every
7 possibility of it; but I think there is -- there is value
8 in having these parcels. But, yeah, again, I'm not
9 prepared to speak to every one of them.

10 Q. And I have no intention of asking --

11 A. (Witness Grubb) Okay.

12 Q. -- about every one of them. I'm trying to keep
13 the questions big picture.

14 A. (Witness Grubb) Okay.

15 Q. But it would be fair to say that the company
16 has tens of millions of dollars of land for which it has
17 no plans to use within the ten-year IRP planning cycle;
18 correct?

19 A. (Witness Grubb) Currently. I have spoken to
20 the generation one. I think from a transmission and
21 distribution standpoint, we're projecting that same time
22 frame.

23 A. (Witness Robinson) So the -- Commissioners,
24 the South Dahlonga, Clermont properties, Dawson
25 Crossing, South Dahlonga that were entered into 2008,

1 2009, there is potential that those properties could be
2 used in the North Georgia studies that we are working on.

3 That's one of the things our engineers continue
4 to look at is the property that we have. There's also
5 some property that Georgia Transmission Corporation has
6 that was associated with this original plan in the mid
7 2000s that we continue to study and could show benefit in
8 this ten-year window.

9 It is just not in this plan here, because of
10 the assumptions that I'm talking about are looking beyond
11 the ten-year plan, looking at the year 2035 with
12 additional renewables in South Georgia and potential
13 retirement of Bowen 3 and 4.

14 Q. I'd like to ask some questions now about the
15 solar tariff. As part of the IRP, the company is -- has
16 requested changes to the Simple Solar and Community Solar
17 tariffs; is that correct?

18 A. (Witness Mallard) Yes.

19 Q. And the Commission typically reviews and
20 approves tariff changes as part of the rate case. Do you
21 understand that?

22 A. (Witness Mallard) So I would say that the
23 history on renewable programs has been that, generally,
24 the concepts are teed up in the IRP going all the way
25 back to the great energy program back in 2001 where the

1 concept was teed up and then approved subsequent to the
2 IRP after that. That's been the general -- the general
3 order of operations for renewable programs, where
4 conceptually they are introduced in the IRP, and they are
5 approved, the tariff and the rest of the program, either
6 in a rate case or in a subsequent filing.

7 Q. And the company's filing, as we've talked about
8 a rate case later this year?

9 A. (Witness Mallard) That's right.

10 Q. I'd like to talk to now talk to you about tall
11 wind projects.

12 A. (Witness Mallard) Yes.

13 Q. And I'm going to be referring at some point
14 during these questions to page 51 of your direct
15 testimony.

16 A. (Witness Mallard) Okay. We are ready.

17 Q. Okay. The company proposes to develop two wind
18 turbines up to 4 megawatts each with hub heights between
19 140 and 165 meters; is that correct?

20 A. (Witness Mallard) Correct.

21 Q. And those are taller than conventional on-shore
22 land-based wind turbines; correct?

23 A. (Witness Mallard) That's right.

24 Q. The company refers to that as its tall wind
25 demonstration project; is that correct?

1 A. (Witness Mallard) Correct.

2 Q. And making wind turbines taller involves
3 additional cost; is that correct?

4 A. (Witness Mallard) That's right. The cost of
5 the tower and the construction of the tower to reach the
6 higher hub heights requires more capital cost, more
7 construction cost.

8 Q. And the company doesn't expect the energy
9 produced by those tall wind turbines to be economic, does
10 it?

11 A. (Witness Mallard) No. That's the reason for
12 the demonstration project. We're looking to test the
13 wind resource and test this revolutionary in-field tower
14 spiral welding technology that we're excited about that
15 will allow tall towers to be built without significant
16 additional cost, hopefully making -- proving the
17 economics here and introducing wind as a viable resource
18 here in the southeast.

19 Q. No site has been selected for the tall wind
20 project; is that correct?

21 A. (Witness Mallard) That's right.

22 COMMISSIONER McDONALD: You said no site?

23 WITNESS MALLARD: No -- no site. We're
24 evaluating several sites. We're looking at a good
25 number of them, but we have not selected a final

1 site at this point.

2 COMMISSIONER McDONALD: Such as?

3 WITNESS MALLARD: If it's all right with you,
4 I'd like to not discuss them publicly, sir, because
5 that might make a run on interconnections and
6 property to be purchased in those areas. But we
7 will present that -- assuming this is approved,
8 we'll come back to the Commission with a detailed
9 filing once we have the site identified and all the
10 particulars.

11 MADAM CHAIR PRIDEMORE: Are you proposing it on
12 land or on sea?

13 WITNESS MALLARD: These are land-based.

14 MADAM CHAIR PRIDEMORE: Okay.

15 BY MR. WALSH:

16 Q. Does the -- and the company does not have any
17 anticipated energy amounts available for the tall wind
18 demonstration project, does it?

19 A. (Witness Mallard) That's correct. It's hard
20 to do the estimate without the particular site chosen and
21 the particular profile of the wind resource at that site.

22 Q. And the company is proposing this project at a
23 time when the cost of solar is declining; correct?

24 A. (Witness Mallard) So the cost of solar has
25 been declining over time. And it is projected to

1 continue to decline out into the future. We're in a
2 period right now where there's some volatility in solar
3 pricing.

4 COMMISSIONER McDONALD: What is the length of
5 our contract with New Mexico and Oklahoma on wind?

6 WITNESS GRUBB: So, Commissioner, we've got
7 20-year wind deals from Blue Canyon in Oklahoma that
8 we are, gosh, six years into now.

9 WITNESS GRUBB: I'll look.

10 WITNESS MALLARD: Mr. Grubb is going to check
11 and tell you how far, but we're not quite halfway
12 through those EPAs.

13 COMMISSIONER McDONALD: Is that not delivered
14 FOB destination?

15 WITNESS MALLARD: I'm sorry. Repeat the
16 question.

17 COMMISSIONER McDONALD: Is that not delivered
18 to Georgia FOB destination?

19 WITNESS MALLARD: It's delivered, and it's
20 firmed up. That's a really good wind deal. It's
21 the wind delivered with the counterpart taking on
22 the transmission risk, and the wind is firmed up
23 with gas to back it up. So we get a blocked
24 schedule of wind delivery.

25 WITNESS GRUBB: And so, Commissioner,

1 Mr. Mallard was right. It started in 2016. It
2 expires at the end of 2035.

3 VICE CHAIRMAN ECHOLS: Mr. Mallard, a question
4 about the foundation of some of these wind turbines.

5 Do you remember the other wind turbines that we
6 approved back in, was it, 2013?

7 WITNESS MALLARD: I do.

8 VICE CHAIRMAN ECHOLS: You remember the
9 foundation issues we had with those?

10 WITNESS MALLARD: I do. And I will say we
11 learned a lot from that -- from that demonstration
12 project. Not all demonstration projects prove that
13 technology works. A valuable lesson could be
14 learned to prove that -- and in this case what
15 Commissioner is referring to is a small wind
16 demonstration project. Very low hub heights that
17 didn't prove to be economical.

18 VICE CHAIRMAN ECHOLS: So how will these
19 projects which are probably going to require even
20 more foundation work, right, because they are
21 taller -- how are these going to be viable on the
22 coast if we couldn't do a small one?

23 WITNESS MALLARD: Right. So first of all, I
24 wouldn't expect these tall wind turbines to locate
25 at or very near the coast. They could, but that's

1 the whole -- the whole thing about the new tall wind
2 technology is wind resource in, say, central and
3 South Georgia, very far inland.

4 If you get high enough, that wind resource is
5 significant, and it can create economical wind. So
6 the expectation would be that these resources would
7 be installed, typical Georgia geography, not
8 necessarily near the coast.

9 I wouldn't anticipate any foundation issues;
10 but, again, we won't know that for sure until we
11 pick the site.

12 VICE CHAIRMAN ECHOLS: All right. Thank you.

13 WITNESS ROBINSON: Commissioner, one of the
14 aspects of wind is it tends to blow in the evening
15 hours at night versus solar being available during
16 the day. So if these sites were in South Georgia,
17 then they could offset the congestion that we see
18 with future and continued solar development in that
19 area.

20 MR. WALSH: Madam Chair, I would like to
21 present the panel with the company's response to
22 STF-DEA-2-30, which I'd ask be marked for
23 identification as Staff Exhibit 5.

24 MADAM CHAIR PRIDEMORE: You may approach. So
25 moved.

1 (The document referred to was marked for
2 identification as Staff Exhibit 5.)

3 BY MR. WALSH:

4 Q. I'll give you a moment to review that, and when
5 you're ready for questions, tell me.

6 A. (Witness Grubb) Thank you. Okay.

7 Q. Okay. In this response, if you look near the
8 bottom of the first paragraph, the company states that
9 the hosting capacity tool will provide an annual snapshot
10 of distribution circuit availability capacity in a
11 geographic -- geographical GIS-based format.

12 By distribution circuit, does the company mean
13 individual feeders?

14 A. (Witness Robinson) Yes, that's correct. The
15 2,356 feeders that we have throughout the state of
16 Georgia.

17 Q. And does this response mean that the only
18 information that will be supplied by the hosting capacity
19 tool is the available capacity, or will it give more
20 specific information?

21 A. (Witness Robinson) So we're still working
22 through the details of that tool. We're working with a
23 consultant to develop the models that would go into the
24 tools that you run to develop the hosting capacity.

25 So the initial development is for hosting

1 capacity. If there were further uses for that
2 information in those models that could be beneficial in
3 other capacities, we would be looking at those in the
4 future. But initially, it would be based on capacity on
5 each individual feeder as it relates to additional solar
6 development. Distributed generation.

7 Q. So down the road, it might provide something
8 like peak load? Would that be something that that would
9 be in play?

10 A. (Witness Robinson) It could. It could also
11 provide locations for optimal volt/VAR siting, so
12 volt/VAR control where you could put devices at the end
13 of feeders to allow for additional solar development,
14 renewables to be put on the system.

15 So there are -- there are many uses for this
16 type of a model, but the initial development and efforts
17 that we'll be taking forward will be more in the hosting
18 capacity tool.

19 Q. Have you looked at those other capacities for
20 it yet, or has that just been kind of put on the table
21 until you get through this phase?

22 A. (Witness Robinson) We're generally familiar
23 with those additional use cases, talking to, like,
24 utilities, talking to Eaton, who is the manufacturer of
25 the CYME disc software that is the tool that you would

1 use to run this hosting capacity.

2 And so we are generally knowledgeable of those
3 additional uses for the models; but as I said before, the
4 initial deployment will be for hosting capacity.

5 A. (Witness Mallard) And, Commissioners, if I
6 could just add, this hosting capacity tool is something
7 that we've heard from the market is something that could
8 be really useful to help locate distributed generation on
9 circuits that have the available capacity.

10 As Mr. Robinson stated, what we're proposing
11 here, it really is a first step. It's an opportunity for
12 us to begin that development. What we propose is to put
13 out a tool that will be useful to the marketplace. We'll
14 just be updated annually on a snapshot we've been
15 benchmarking to some other utilities here in the
16 southeast and other places as to what's best practice and
17 sort of most bang for the buck, if you will.

18 But we'll absolutely be evaluating that as we
19 go, be soliciting feedback from the marketplace from the
20 users, and certainly have the opportunity to make
21 improvements as we go through time.

22 Q. I'd like to ask some questions about
23 transmission now. And if I could get you to look at
24 Section 13.1 of the main IRP document, and it is on
25 page 13-91.

1 A. (Witness Grubb) You said 13-90?

2 Q. 13-91, and it's Section 13.1 entitled "Battery
3 Energy Storage System Demonstration Projects."

4 A. (Witness Grubb) Thank you.

5 A. (Witness Robinson) 13.1?

6 Q. Yes, Section 13.1.

7 A. (Witness Robinson) Okay.

8 Q. What siting or reliability criteria did the
9 company use to select the McGrau Ford and Fort Stewart
10 sites for the energy storage systems?

11 A. (Witness Mallard) So let me clarify here. Are
12 you asking about McGrau Ford or Mossy Branch that's --
13 that's discussed here at the bottom of 13-91?

14 Q. I was asking about McGrau Ford. Is that not
15 applicable?

16 A. (Witness Mallard) Sure.

17 A. (Witness Robinson) What's referenced in this
18 paragraph is Mossy Branch and the --

19 A. (Witness Grubb) -- the 80 megawatts from the
20 last IRP.

21 A. (Witness Robinson) Correct.

22 A. (Witness Grubb) Not that we won't answer
23 McGrau. We're just making sure that we're responding
24 correctly.

25 Q. I will -- well, let me ask you this: Would the

1 reliability criteria be different for each -- for each
2 site?

3 A. (Witness Mallard) So it could be. It's
4 important to remember the 80 megawatts was approved as an
5 early deployment. The siting criteria there was based on
6 ensuring that a location could be -- the facility could
7 be sited at a location that would allow Georgia Power to
8 test all of the use cases and gain all the different
9 learnings as proposed in that early deployment.

10 So that's -- that was really the basis of
11 choosing the Mossy Branch site is to make sure we've got
12 a spot on the transmission system, minimizes
13 interconnection costs, but also allows for that
14 flexibility to test all the things that we want to test
15 and learn from that -- from that facility.

16 The same would be true, generally, for the Fort
17 Stewart site; although, obviously, locating that site was
18 limited by where there's a solar facility already. And
19 so choosing to locate that Fort Stewart, that site made
20 lots and lots of sense based on the land availability
21 and, again, minimizing interconnection costs there.

22 Q. Did the criterion include siting the energy
23 storage service on circuits that had a poor record of
24 reliability?

25 A. (Witness Mallard) So, no. And these are --

1 it's important to note that the Mossy Branch facility,
2 that's a transmission interconnected facility. It's not
3 interconnected at the distribution level. It's
4 interconnected to the transmission system.

5 A. (Witness Robinson) Right. And none of these
6 battery systems are being proposed for any type of
7 reliability purpose, whether it be transmission or
8 distribution connected.

9 Q. And that would be true for McGrau Ford as well?

10 A. (Witness Robinson) Correct.

11 A. (Witness Mallard) Yes.

12 VICE CHAIRMAN ECHOLS: Can I ask you about the
13 Fort Stewart facility? So there's no arrangement
14 for the military to tap into that in case they need
15 it?

16 WITNESS MALLARD: So there's not yet. As you
17 may remember, Commissioner, the original agreements
18 that easements with the bases allowed for the base
19 to have access to the energy in times of grid
20 outage. However, there's -- there's a good bit of
21 work that has to be done to make that happen, to put
22 all the control and switching equipment in there. I
23 think most of the military bases have indicated
24 interest in doing that at some point.

25 None of the facilities at this point have been

1 converted or configured in that way. So that still
2 remains an option, and siting a battery storage
3 facility adjacent to the solar facility is
4 another -- another tool, if you will, that could be
5 used there at the Fort Stewart location. But as of
6 now, there is -- the ability does not exist to turn
7 that power inward to be used in times of grid
8 outage.

9 VICE CHAIRMAN ECHOLS: How far is the batteries
10 from the Fort Stewart's 30 megawatt array?

11 WITNESS MALLARD: It's adjacent or maybe even
12 in the same easement. It's -- it's very close.

13 VICE CHAIRMAN ECHOLS: Okay.

14 MADAM CHAIR PRIDEMORE: This was part of a
15 project in the last administration where the
16 military was attempting to be able to operate off
17 the grid for a ten-day period in cases of, you know,
18 catastrophic energy outage.

19 Are you seeing the same level of commitment to
20 these projects now, since January of 2020? '21?

21 WITNESS MALLARD: I would say so. It seems
22 like the commitment from the military has shifted a
23 little bit from just renewables to more of a
24 resiliency play. That continues to be the feedback
25 that we get. They do want to be able to island, if

1 you will, to be able to operate in times of grid
2 outage for 10 to 14 days, maybe even more than that.

3 So I have not noticed a change in that desire.
4 I think they all still have that as a long-term
5 goal.

6 WITNESS ROBINSON: And, Madam Chair, we are in
7 recent discussions with one of our military bases
8 through DoE, DoD, and EPRI on this very project.
9 And so just as recent as last week, I got an -- I
10 got a notification about moving ahead with one of
11 these projects.

12 MADAM CHAIR PRIDEMORE: Okay.

13 WITNESS ROBINSON: So, yes, we are seeing the
14 commitment.

15 VICE CHAIRMAN ECHOLS: Okay. And, Mr. Mallard,
16 at the last NARUC, I had a conversation with -- you
17 remember General Aycock who came down and was
18 responsible, I guess, for really making the pitch
19 for doing this. Southern has now, I think, hired
20 one of his former assistants. And they told me that
21 the administration, the presidential administration,
22 was moving towards a requirement that all bases, all
23 federal facilities, including VA hospitals, USDA
24 offices -- pick -- pick an acronym -- that they were
25 going to be moving towards a requirement that those

1 facilities be provided with a zero CO2 form of
2 energy with what they called a 24-hour match.

3 Are you familiar with that terminology and what
4 they are talking about?

5 WITNESS MALLARD: Yes, sir, I am. And it's
6 akin to the CARES CFE ATC program which is designed
7 to provide customers with carbon-free energy around
8 the clock. That's the ATC. So it's developed
9 specifically for needs like what is expressed by the
10 military, but also from some other large customers
11 of ours.

12 VICE CHAIRMAN ECHOLS: And are you not
13 anticipating this happening within, you know, the
14 performance of this IRP, the three-year period? Are
15 you -- because we're not really talking about it.
16 And talking about the requirement.

17 WITNESS MALLARD: So I do. The feedback from
18 important customers like the military, like our
19 governmental customers, like our very large
20 manufacturers and data centers, all of that is
21 absolutely plowed into our plans. That's why the
22 CARES program exists as it is. That's why the
23 request for the R3 program is what it is. It's so
24 that we can help these customers down the path
25 towards meeting their goals.

1 VICE CHAIRMAN ECHOLS: Great. Thank you.

2 COMMISSIONER McDONALD: They have learned a lot
3 from Georgia Power experience over the years,
4 because three or four years ago I was on the -- on
5 the dais with the base commander from Fort Stewart,
6 and he said to me, he said, I'll tell you what. The
7 Georgia Power outlawyered the Army in developing
8 those 30 megawatt rates.

9 MADAM CHAIR PRIDEMORE: Now might be a good
10 opportunity, though, to talk about MUSH, questions
11 about MUSH. Is it part of CARES, or is it
12 standalone? And describe and define it, please.

13 WITNESS MALLARD: Yes, ma'am. MUSH is --
14 stands for municipals, universities, schools, and
15 hospitals. It's just a segment of our commercial
16 customer base. These customers -- it's a carve-out.
17 It's part of CARES. It's part of the total CARES
18 allocation.

19 But what we found is these customers tend to be
20 smaller. They tend to maybe not be as quick and
21 able to participate in our application, our notice
22 of intent periods, and so creating a carve-out for
23 these customers so that they can participate at a
24 smaller size. Instead of a 3 megawatt minimum, it's
25 just a 1 megawatt minimum.

1 What we find is a lot of our cities, they can
2 aggregate their load. They can meet the 1 megawatt
3 minimum; whereas, some of them couldn't meet the
4 3 megawatt minimums. So it really is CARES. It's
5 just a subpart of CARES specifically allocated for
6 customers in that segment.

7 MADAM CHAIR PRIDEMORE: Thank you.

8 BY MR. WALSH:

9 Q. I want to revisit real quick the question of
10 whether energy storage service sites are ever -- ever
11 factor in an issue of reliability.

12 Does the company have any plans for placing
13 small scale energy storage system on circuits with poor
14 reliability as a potential nonwires alternative to
15 address reliability issues?

16 A (Witness Robinson) Yes, Commissioners, we do.
17 In the seven pilot projects, the local restraints and --
18 local reliability constraints program that we proposed is
19 seven systems that are very much what you had mentioned
20 deployed for three use cases, the first being wires
21 capacity, so that's the deferment of reconductering of
22 distribution lines or even at the substation level.

23 The second use case is reliability. So looking
24 at improving reliability for the customers that would be
25 served off those systems.

1 And then the third is resilience. So that's
2 the ability for those customers served off those systems
3 to withstand long events or multiple contingencies.

4 And so we are very interested in those seven
5 pilots that we have proposed in IRP and how we can deploy
6 future pilots or future systems -- not pilots, but future
7 systems, as it relates to batteries paired with
8 traditional RESIPs, as well as even solar.

9 Q Does the company consider energy storage
10 systems to be a generation asset or a transmission asset?

11 A (Witness Grubb) I think it's going to depend
12 on the use case; right. So the pilots that Mr. Robinson
13 has just covered are assets to use for power delivery
14 aspects, and so they would be driven -- you know, they
15 would be controlled and dispatched for transmission and
16 distribution needs. The storage that you're looking at
17 for operating reserves or capacity RFPs or renewable RFPs
18 are generation resources. So it depends on the use.

19 Q I want to ask you about the ten-year
20 transmission plan. What retirements were assumed as part
21 of the ten-year transmission plan?

22 A (Witness Robinson) So the retirements of
23 generation?

24 Q Yes.

25 A (Witness Robinson) The retirements in the

1 ten -- in the ten-year transmission plan that are
2 included are Wansley 1 and 2 and Bowen 1 and 2. The
3 Scherer decisions had not been made at the time that the
4 ten-year plan version of cases was created. So that was
5 in the August time frame. And so the Scherer decisions
6 or the Scherer recommendations are not in the ten-year
7 plan that you have in the IRP.

8 Q What about Plant Gaston?

9 A (Witness Robinson) Plant Gaston is assumed --
10 first two units in -- subject to check -- '27, '28, and
11 the second set in '30.

12 Q Are there reasons related to transmission
13 projects that the company's position is that Bowen 3 and
14 4 cannot be retired before 2035?

15 A (Witness Robinson) Yes. So when we looked at
16 the retirement of Bowen 3 and 4 on top of the other
17 units, in the rank order that we used to study those, we
18 saw significant transmission that needed to be completed.

19 So looking at the outage schedule and
20 incorporating those projects in to building all of that
21 transmission and making that work so that you could
22 retire Bowen 3 and 4 along with the same timeline as the
23 other units, the decision was made by the integrated
24 transmission system, our participants -- GTC, MEAG, and
25 Dalton Utilities -- to build strategic transmission to

1 look at not having to do a piecemeal approach to all of
2 those issues that you have to go fix.

3 So when you retire Bowen 3 and 4, you have a
4 significant amount of transmission that overloads and
5 needs to be reconductored. And so it's going to be very
6 hard for us, as we move forward, to get the operational
7 outages to coordinate that work. And so we are seeing
8 the need for additional transmission, Greenfield
9 transmission, if you will -- we are working on those
10 studies right now -- to bring those megawatts from
11 South Georgia to North Georgia, to replace that capacity
12 that's in North Georgia, because most of the load that
13 we're serving is in the Atlanta area.

14 Q Did you consider any specific alternatives that
15 would permit you to retire the plant before 2035 without
16 jeopardizing reliability of the system?

17 A (Witness Robinson) We are still working on
18 those studies right now with the ITS participants as it
19 relates to transmission solutions; but we will look at
20 multiple technologies, additional Greenfield transmission
21 lines. I mentioned the potential conversion of units to
22 synchronous condensers. We see that as a potential
23 benefit for us in the future as well.

24 Q So is it possible that the company may at some
25 future IRP recommend an earlier retirement date for Bowen

1 3 and 4?

2 A (Witness Grubb) I think that's all going to
3 depend, Commissioners, on what we discover in this North
4 Georgia reliability and resiliency plan. As we have
5 stated, we need -- we are going to control Bowen 3 and 4
6 to support North Georgia. After this IRP and what comes
7 out of this, we'll start looking at that next, that next
8 part of that study, what -- what do we need to do to not
9 keep Bowen forever; right.

10 We know there is pressure on that unit as well,
11 and so we have said no later than 2035. So it's all
12 going to depend on transmission solutions, what are your
13 generation options, what comes out of this case. So it's
14 something that we will study.

15 It could, but I think it's going to all depend
16 on what we discover from a generation and transmission
17 standpoint.

18 A (Witness Robinson) And marry that also with
19 the assumptions that come out of the IRP as it relates to
20 additional renewables. Renewable development in
21 South Georgia. Hopefully we are successful in the
22 approach. We're targeting North Georgia with additional
23 renewables. But all of that has to be incorporated into
24 those future studies.

25 That transmission has to be built to

1 accommodate that date in the future, in 2035, when we
2 look at 6,000 megawatts of additional renewables,
3 retirement of Bowen 3 and 4. And then, as I mentioned
4 before, not being the only utility in the state, we have
5 to look at what the EMCs and municipalities are doing as
6 well as it relates to renewables and decisions on
7 their -- their resources.

8 VICE CHAIRMAN ECHOLS: And you think we can
9 build utility scale solar, below avoided cost north
10 of I-20?

11 WITNESS MALLARD: So what we are going to do is
12 we are going to run the RFP and we are going to see.
13 And again, Commissioner, remember, we're going to
14 look at -- look at evaluating these resources a
15 little bit differently. The model has chosen solar
16 at the 6,000 megawatt mark, moving in that
17 direction, adding those resources at its energy
18 benefit to our customers. And so running the RFP,
19 see what the market delivers, and then evaluating
20 that with staff in the IE. That's -- that's -- we
21 are going to see what the market can bear.

22 WITNESS ROBINSON: And, Commissioner, we think
23 it's very important to target North Georgia first to
24 buy us that time to study, develop, and build that
25 transmission to ensure that we can continue

1 developing South Georgia. I think if we don't
2 develop in North Georgia, I think what we're going
3 to end up seeing is transmission constraints that we
4 can't get resolved in time, delaying of CODs,
5 pushing these projects out because we can't get the
6 transmission projects done in time.

7 MR. WALSH: Madam Chair, I would like to
8 present the witness panel with a page from the IRP
9 filing, and it is a trade secret page. I would like
10 to provide the witnesses and the commissioners with
11 the trade secret version and the rest of the parties
12 here with the redacted version.

13 MADAM CHAIR PRIDEMORE: Please, go ahead.

14 MR. WALSH: And if I could have it marked, the
15 trade secret marked, I believe, as -- the next
16 exhibit number is 6, and the public disclosure as 7.

17 MADAM CHAIR PRIDEMORE: So moved.

18 (The documents referred to were marked for
19 identification as Staff Exhibits 6 and 7.)

20 MR. WALSH: Thank you.

21 MADAM CHAIR PRIDEMORE: You may approach.

22 The quicker we pass the paper, the quicker we
23 get to keep moving.

24 BY MR. WALSH:

25 Q. When you are ready for questions, let me know.

1 A. (Witness Grubb) I am ready, Mr. Walsh.

2 Q. Okay. Thank you.

3 I wanted to ask you about -- hold on one
4 second. I wanted to ask you about some of the projects
5 that were included in the transmission retirement
6 projects. And I believe from your answers to my previous
7 question you identified -- I'm sorry.

8 Could you -- could you identify again which
9 projects -- which projects were included in the ten-year?
10 I don't want to mess it up. I'm sorry for having to ask
11 that again, but...

12 A (Witness Robinson) Which are --

13 Q Which of the generating units --

14 A (Witness Robinson) So this is transmission
15 retirement projects associated with the unit retirement
16 studies. What's in the ten-year plan is a different set
17 of assumptions.

18 Q Right, right, I understand that; and I was
19 going to ask you a couple of questions on it. But my
20 understanding -- I just want to make sure, because I
21 think you mentioned a few of the plants that were
22 included as part of the ten-year transmission project, a
23 few of the generating plants.

24 A (Witness Robinson) Right.

25 Q And was that Wansley 1 and 2 and Bowen 1 and 2?

1 A (Witness Robinson) That is correct.

2 Q Okay.

3 A (Witness Robinson) And I believe Gaston 1 and
4 2 and 3 and 4.

5 Q Okay, great. Thank you.

6 A (Witness Robinson) And Scherer 4. We assumed
7 that the -- last year.

8 Q Okay. Thank you.

9 Now turning to the page that I've -- I've
10 handed you, would you be doing any of these transmission
11 retirement projects listed on this page, these
12 transmission projects listed on this page, absent the
13 retirements that we just discussed?

14 A (Witness Robinson) There are a couple of these
15 projects that are advancement projects or projects that
16 were already in flight. So, yes, there are a couple
17 projects that we would be doing that are not directly
18 linked to the transmission retirement projects listed
19 here. So either they were advancing in time or they were
20 a project already in flight.

21 Q Could you identify which ones?

22 A (Witness Robinson) One is the arc right load
23 Schulz 115 line. That is a transmission line rebuild.
24 That was a project that was already in flight. And so
25 the project associated with reconductering the line with

1 a larger conductor was an easy decision to make. The
2 rebuild of the line was already a project in flight.

3 Q Are there any others?

4 If you are not aware sitting there, we can --

5 A (Witness Robinson) None that I am familiar
6 with.

7 Q Okay. Could I make that as a hearing request,
8 for the company to identify which of these transmission
9 retirement projects would be -- would still take place
10 absent the retirements?

11 A (Witness Robinson) Whether they are an
12 advancement of a project or whether they were a project
13 already in flight, like the one I just mentioned?

14 Q Yes.

15 A (Witness Robinson) Yes.

16 Q Okay. Thank you.

17 I'm going to ask you a few questions about
18 substation capacity. What steps does the company have to
19 take any time it increases a substation's capacity?

20 A (Witness Robinson) So our area planning
21 engineers are looking at our substation capacity and they
22 are looking at certain criteria for bank loading. And so
23 when we forecast out the bank, that's either -- looks to
24 be 90 percent loaded in the future, based on the
25 assumptions for that area, or there is a contingency

1 loading we look at as well, which is 100 percent of
2 emergency rating.

3 Any time it is forecasted, the substation or
4 bank, and that substation's forecasted to hit those, we
5 trigger a study and look at the replacement of those --
6 either upgrading the bank or looking at adding another
7 bank or transformer to the substation, looking at tying
8 that load to an additional feeder or an additional source
9 out in the field.

10 Q And is that 90 percent, is that consistent with
11 what other utilities use?

12 A (Witness Robinson) I am not familiar with what
13 other utilities use, but it is consistent with what our
14 sister companies do.

15 Q And how much lead time is required in advance
16 of that targeted percentage?

17 A (Witness Robinson) Depends on the type of
18 project. If it's just putting a transformer in an
19 existing substation that you already have space for, so
20 you have built the space for expansion, it could be 12 to
21 18 months, 24 months, depending on availability of that
22 bank. If you've got to go purchase land to build a new
23 substation, it could be 24 to 36 months.

24 One of the things that we are being challenged
25 with right now is supply chain. Transformer slots are

1 moving out, right now they are at about two years.

2 MR. WALSH: Madam Chair, that's all the
3 questions that staff has. I would ask that Staff
4 Exhibits 1 through 7 be admitted into evidence.

5 MADAM CHAIR PRIDEMORE: So moved.

6 (The documents referred to as Staff
7 Exhibits 1 through 7 were admitted into
8 evidence.)

9 MR. WALSH: Thank you very much for your time.

10 MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh.

11 Before we run through the intervenors' list, I
12 have a couple of questions. I was just going to let
13 Mr. Walsh finish to make sure that he didn't ask any
14 questions I had.

15 Page 7 of your prefiled direct testimony. I
16 would just like for you to talk through lines 14 and
17 15 with me. You say "increasing policy and
18 regulatory pressure related to carbon and
19 environmental standards, the significant increase in
20 customer expectations for renewable and other low or
21 no carbon solutions."

22 I want to understand how significant is
23 weighted with customer expectations on reliability
24 and affordability?

25 WITNESS GRUBB: So I think there's two pieces

1 here, Madam Chair, when we think about the
2 coal-fired generation fleet. The pressure we see
3 here is what we talked to some this morning, is
4 future coal rules and also carbon. So when we
5 looked at the unit retirement studies, we did do
6 transmission studies on what those impacts to
7 customers are from a -- I think the next part is
8 talking as much around the program offers that we
9 do, like CARES. So from a unit retirement study,
10 it's absolutely taken into account when we do those
11 transmission studies.

12 On the renewable side, it's similar in that we
13 know that our pace of procurement that we have
14 mentioned is going to have to have transmission
15 investments there, too.

16 WITNESS MALLARD: Yes. Madam Chair, the
17 reliability and price are absolutely the overarching
18 goals. Adding renewables has got to be done under
19 that umbrella. And as we think about adding
20 renewables for the benefit of all customers, which
21 is what we do when we do the models, we run those,
22 it shows that adding 6,000 megawatts by 2035 does
23 present economic benefits for all customers.

24 So it is then within that plan that does
25 balance reliability and price that we add

1 renewables. And then we're able to respond with our
2 program options to this ever-growing contingent of
3 customers that does want to support renewable
4 energy.

5 And, yeah, I would say it's that -- customer
6 count is still relatively small, but the amount of
7 megawatts in total energy sales made by the company,
8 it is a pretty significant amount, because it is
9 some of our largest customers, some of the largest
10 segments that are more interested and we continue to
11 work with day after day to try to meet their
12 renewable energy needs, their carbon needs, but to
13 do it in a way that absolutely doesn't violate our
14 renewable energy principles. We don't want to shift
15 any cost, we don't want to raise any rates. We want
16 to do it in the competitive procurements and we want
17 to make sure that we allocate those costs and
18 benefits accurately.

19 So taking all that into account, that's what
20 really is the backbone of the plan where we are
21 going to add renewables for the benefit of all
22 customers, but then offer the programs for
23 subscription by a smaller number of customers.

24 MADAM CHAIR PRIDEMORE: Go ahead.

25 WITNESS WEATHERS: Madam Chair, I will add, if

1 I could, just for further clarification to your
2 question, when the 6,000 renewables was selected
3 through the optimization studies, it was only
4 looking at reliability and economics, and so
5 external factors were not considered in the model.
6 And so as Mr. Mallard said, those are taken into
7 consideration in the program design. But as far as
8 the selection of the amount, the 6,000, that was
9 based on the model that only looked at reliability
10 and economics.

11 MADAM CHAIR PRIDEMORE: Okay. Thank you.

12 A lot of this is just that -- these -- some
13 terms are not defined in other places in your
14 prefiled testimony.

15 So, okay. Page 17, line 10. The results of
16 the Aurora expansion planning analysis, what is the
17 Aurora expansion planning analysis?

18 WITNESS GRUBB: So that is the mixed study that
19 we spoke about this morning. We had some questions
20 from Mr. Walsh.

21 MADAM CHAIR PRIDEMORE: Also known as the mixed
22 study?

23 WITNESS GRUBB: The mixed study. So,
24 Commissioner, that's -- those are the models that we
25 run that look at the next 30 years and what is the

1 most economic resources to add. And so what we are
2 noting here is that this is the first IRP that we
3 have proposed here in Georgia that has generic
4 selections for wind and solar and storage as some of
5 those options.

6 MADAM CHAIR PRIDEMORE: Okay. All right.

7 WITNESS WEATHERS: Madam Chair, I will add to
8 that, if I could. So it's the model -- as Mr. Grubb
9 said, the model -- we call it the mixed study, but
10 we are running a model that optimizes the build-out
11 of capacity on the system over time. And they are
12 looking at generic additions.

13 So we are now able to, in that process -- we
14 have converted to a new software product called
15 Aurora. So it is able to incorporate generic solar
16 and wind and battery storage into the optimization
17 process. And that's something that we didn't have
18 in the past with our old model.

19 MADAM CHAIR PRIDEMORE: Okay. It means the
20 same thing. Thank you. That's what I need to know.

21 Page 19, starting on line 19 through 26. If
22 this plan is approved, what will Georgia Power do
23 with the Plant Wansley site because of the -- of
24 those in this section it's -- in this filing, it's
25 the only one to fully close?

1 WITNESS GRUBB: Yes. So, Commissioner, I mean,
2 we obviously have, like we've done with prior
3 plants, Mitchell and Kraft, we will put together a
4 plan on how to do the demolition at the site. I
5 know there's reasons from an ash pond standpoint
6 that we'll need to stay on-site and monitor those.

7 So I think it would be similar to Plant Branch,
8 that Commissioner Echols mentioned this morning.
9 Once we demolish the plant, we will have that site
10 as considerations going forward. I don't know that
11 we put that -- all those plants together, but we
12 would -- we would do the same thing similar that
13 we -- that we would do at Mitchell and that we will
14 also do at Hammond and others.

15 COMMISSIONER JOHNSON: Okay. Mr. Grubb, are
16 there any plans to work with that community, or
17 those being displaced by jobs, or to place folks in
18 jobs as they -- as you close that plant?

19 WITNESS GRUBB: Yeah, Commissioner, I don't
20 know all the specifics. But I know our generation
21 group, from an employee standpoint, at Plant
22 Wansley, is looking at offering them opportunities
23 at other plants. As we look further down to
24 retirements of Bowen and Scherer, we will have to
25 consider those. I know that's something will be

1 there. That's from an employee standpoint.

2 From a community standpoint, we are obviously
3 going to stay engaged in all of our community
4 development aspects that we do, citizens wherever we
5 serve, in that kind of engagement.

6 In terms of impacts to the County, I don't know
7 that answer, because you do have a tax base loss
8 there. But it's always something that we're
9 considering when we go back with projects, that
10 there's a benefit to plant sites.

11 So hadn't figured it all out, but we'll
12 definitely stay involved from a community
13 standpoint.

14 COMMISSIONER JOHNSON: Okay, thank you.

15 WITNESS ROBINSON: And, Commissioner, our new
16 transmission control center, it's sited in Douglas
17 County, which is on that side of town. We've had a
18 good amount of success in having boiler turbine
19 operators and AEOs, or auxiliary equipment
20 operators, become transmission operators.

21 We are actively marketing those vacancies that
22 we have and thinking more creatively in how we can
23 onboard those, make it more flexible for those
24 employees to make that jump from generation to
25 transmission.

1 COMMISSIONER JOHNSON: And as you close more
2 and more of these plants, that becomes so important,
3 that these communities that you're kind of leaving
4 behind just a little bit, that we work with these
5 communities to make sure -- and those that are being
6 displaced from their jobs.

7 WITNESS GRUBB: And I think, Commissioner, one
8 of the -- that's one of the benefits of a longer
9 transition on these coal units that we have
10 recommended is it's not -- other than Wansley. Even
11 though that we've notified them in the past, I
12 believe -- it's not an overnight or immediate. And
13 so while it's an impact to the county, they do have
14 several years to plan for it and take that into
15 account as well.

16 WITNESS ROBINSON: And we can manage a lot of
17 that change through attrition.

18 COMMISSIONER SHAW: Mr. Grubb, I will just
19 point out I've heard from some of our friends across
20 the street that hail from that area around Wansley,
21 that, to be specific, the impact to the local
22 schools' budget there in Heard County, 40 percent of
23 their budget comes from the taxes on Wansley.

24 WITNESS GRUBB: Yes, Commissioner. And I don't
25 mean to sound like it's not a consideration, it's

1 not an impact. We understand that that is, and we
2 understand it's something that the Commission takes
3 into account.

4 I think -- but when we look at coal unit
5 retirements, we've got to step back and look
6 holistically for all the customer base. Very
7 similar to Branch. Branch had a major impact down
8 there as well. But when you look at the entire
9 state and the customer base, that's what we are
10 basing our decisions on. But, absolutely, we
11 understand --

12 COMMISSIONER SHAW: And I understand that. But
13 these folks aren't calling you; they're calling me.

14 WITNESS GRUBB: I understand. That's why
15 they're recommendations, Commissioner.
16 Recommendations.

17 MADAM CHAIR PRIDEMORE: Okay. Page 21, lines
18 18 to 28. And the first line of the following page
19 is about the potential of retiring Plant Scherer
20 Units 1 and 2.

21 To Commissioner Shaw's point, this is an area
22 where Commissioners have heard significantly from
23 the majority owner on Plant Scherer 1 and 2.

24 On line 28 on page 21, as well as the top of
25 page 22, "For planning purposes only, the company

1 has assumed a retirement date of December 31, 2028."

2 Talk me through how you do that when you are
3 not the majority owner.

4 WITNESS GRUBB: So, Commissioner, that's
5 two things that we'll look at. So from our
6 standpoint, that gives us a little bit of guidance
7 on the generation standpoint, what we might need to
8 do in that '29, '30 time frame.

9 But the more important impact, I think, is to
10 the transmission planning side of things.

11 WITNESS ROBINSON: Yes.

12 WITNESS GRUBB: So being able to plan for the
13 retirement of those units, similar to what we talked
14 about this morning, gives us the option that what
15 we -- what we are looking at at Plant Scherer 1 and
16 2, from an ELG compliance standpoint, is two
17 parallel paths. There is the physical, chemical,
18 bio wastewater treatment; and then there's the
19 voluntary incentive program, the VIP, that's a later
20 compliance date, different type of technology. So
21 the co-owners are looking at that.

22 And so as we continue down those parallel
23 paths, ultimately the decision will be made. We
24 want to go ahead and proactively plan the
25 transmission so if things do shift and it's in

1 customers' best interests to retire Scherer 1 and 2,
2 that we have that option.

3 WITNESS ROBINSON: And, Madam Chair, the
4 exhibit that Mr. Walsh just passed out with the
5 transmission project list, the lower half of that
6 table are all associated with Scherer 1, 2, and 3,
7 With the lead time of -- from 12 months to 54 months
8 for the transmission that needs to be done to retire
9 those units.

10 MADAM CHAIR PRIDEMORE: Give me the first --
11 give me the first letter of the line that's you say
12 lower half. Give me the first letter of the top
13 line, because it is trade secret.

14 WITNESS ROBINSON: "M."

15 MADAM CHAIR PRIDEMORE: "M." Thank you.

16 Page 23.

17 WITNESS GRUBB: Yes, ma'am.

18 MADAM CHAIR PRIDEMORE: "Describe the
19 environmental benefits of retiring the oil-fired
20 units from a cost and reliability perspective as
21 well."

22 That's -- if you can expand on lines 4 through
23 10, please. These are oil-fired units.

24 WITNESS GRUBB: Yeah. I am just -- real quick.
25 I'm sorry. Just reading real quick.

1 Yeah. I mean, the main decision on the CTs
2 here, Madam Chair, is that two of them are at sites
3 where we are retiring the coal units and another is
4 at a site by itself. And so there is really no
5 benefit from customers when we have studied those
6 and filed them in the retirement studies. So it's
7 really just a cost standpoint. They are pretty
8 small CTs. And while they help from reliability
9 standpoint, there's just not a lot of benefit to
10 maintaining those as a single unit site. And so we
11 have incorporated that into our plans.

12 And just -- oil-fired, we were able to use
13 them, but just thinking long term, there will likely
14 be continued pressure on oil-fired resources in the
15 future as well.

16 MADAM CHAIR PRIDEMORE: Are you getting federal
17 pressure on oil-fired resources now?

18 WITNESS GRUBB: I don't think we are getting
19 them on oil right now, other than the potential for
20 carbon pressure. I don't know that there's
21 oil-specific rules.

22 And we still have a lot of other oil CTs that
23 are crucial to the system. So we're really -- we
24 didn't study and recommend retiring a lot of
25 oil-fired CTs.

1 MADAM CHAIR PRIDEMORE: Okay.

2 WITNESS GRUBB: They are very important from a
3 reliability standpoint. Black-start resources as
4 well. But with these three being solo sites, if you
5 retired the coal units, it was just best interest to
6 close those.

7 MADAM CHAIR PRIDEMORE: Okay. Page 26,
8 line 10. "\$28 million sought in this docket to
9 extend the life of Plant Hatch 1 and 2."

10 What is comprised in the 28 million? Doesn't
11 have to be specific; just top line.

12 WITNESS GRUBB: So, Madam Chair, the 28 million
13 is the cost -- Georgia Power's cost for the
14 five-year process to go to -- to develop our
15 subsequent license renewal and work through that
16 process with the NRC.

17 At the end of that five-year, we would have a
18 ruling from them on can we extend the lives of
19 Hatch 1 and 2. So, again, we're asking for cost
20 recovery to go forth with getting that option. We
21 would bring back to the Commission, if we get that
22 license, if we're going to extend the 20 years.
23 This is the 28 million to do that work.

24 MADAM CHAIR PRIDEMORE: But it's application,
25 legal fees. You are not making technical

1 adjustments to the plant; correct?

2 WITNESS GRUBB: That's correct.

3 MADAM CHAIR PRIDEMORE: Okay.

4 WITNESS GRUBB: It is a five-year process to
5 cover all those types of costs; that's correct.

6 COMMISSIONER SHAW: Lot cheaper than building a
7 new one.

8 MADAM CHAIR PRIDEMORE: Okay. Let's see.
9 Page 34. Define "economically optimal" on line 24,
10 please. Sorry, 26. I can't read my own writing at
11 this point.

12 WITNESS MALLARD: So I'll start and
13 Mr. Weathers can chime in. We're referring back
14 here to the model, that Aurora model, and the
15 ability for us now to have solar and wind and
16 battery storage resources selected in the model in
17 the generic expansion plan.

18 So because of that change, because of that
19 enhancement, we are able to identify and preselect,
20 if you will, the addition of renewable resources
21 going forward that will provide economic benefits to
22 our customers.

23 MADAM CHAIR PRIDEMORE: There you go. Good
24 from what I thought.

25 Page 35. AGC. It is included in the new RCB

1 framework as proposed, but is that a cost to the
2 developer or Georgia Power?

3 WITNESS MALLARD: AGC is a cost to the
4 developer. There is some cost to Georgia Power as
5 well to be able to communicate with the device, but
6 the developer has to provide communication equipment
7 on site. The -- an RTU.

8 I think we answered a data request, Madam
9 Chair. I can get that for you. I believe we
10 estimated the price of those at about \$50,000.
11 So --

12 MADAM CHAIR PRIDEMORE: Okay.

13 WITNESS MALLARD: -- not insignificant, but in
14 the scheme of things in the development of a large
15 solar site, we think it's a reasonable expense.

16 MADAM CHAIR PRIDEMORE: Okay. Makes sense.
17 The last one I have for you, page 44. What is
18 BESS, B-E-S-S?

19 WITNESS MALLARD: BESS is --

20 MADAM CHAIR PRIDEMORE: Line 8.

21 WITNESS MALLARD: -- ESS's cousin. So ESS is
22 energy storage system. A BESS is going to be a
23 battery energy storage system.

24 MADAM CHAIR PRIDEMORE: There you go.

25 WITNESS MALLARD: But there's other energy

1 storage systems. You could have a pump storage
2 hydro or kinetic storage or any storage. But a BESS
3 is going to be a battery storage.

4 MADAM CHAIR PRIDEMORE: That's okay. It's the
5 only place it was referred to in your prefiled
6 testimony.

7 That's it. That's all I've got. Thank you.
8 You have helped me a great deal.

9 Let's go through the list. Americans for
10 Affordable Clean Energy.

11 MR. GALLOWAY: Madam Chair, no questions.

12 MADAM CHAIR PRIDEMORE: Commercial Group.

13 MR. JENKINS: Sorry to disappoint, but no
14 questions.

15 MADAM CHAIR PRIDEMORE: Thank you, Mr. Jenkins.
16 You always do a good job of keeping me in the loop.
17 Concerned Ratepayers for Georgia.

18 MR. PRENOVITZ: No questions, Madam Chairman,
19 for this panel or the other two panels.

20 I do have one housekeeping suggestion, though.
21 It might be helpful, since it's like four people on
22 the panel, if they kind of had nameplates or
23 nametags on, kind of like they do in congressional
24 hearings. That would make it easier to follow, at
25 least, you know, from a Zooming point of view.

1 MADAM CHAIR PRIDEMORE: Thank you,
2 Mr. Prenovitz. I will take your suggestion to the
3 executive secretary's office.
4 MR. PRENOVITZ: Thank you.
5 MADAM CHAIR PRIDEMORE: Cyprus Creek
6 Renewables, LLC.
7 MR. STAIR: No questions.
8 MADAM CHAIR PRIDEMORE: Georgia Association of
9 Manufacturers.
10 MR. CHARLES JONES: I have some questions.
11 MADAM CHAIR PRIDEMORE: Not surprising,
12 Mr. Jones.
13 MR. CHARLES JONES: Sorry to disappoint. Thank
14 you, Madam Chair.
15 Good afternoon, Panel.
16 WITNESS MALLARD: Good afternoon.
17 WITNESS WEATHERS: Good afternoon.
18 MR. CHARLES JONES: It's kind of impersonal to
19 call you "Panel," but it's good to see you.
20 CROSS-EXAMINATION
21 BY MR. CHARLES JONES:
22 Q. Before I get into my questions, I wanted to go
23 back to something you were talking about with Mr. Walsh
24 for just a minute, on pages 36 to 38 in your testimony,
25 just generally. And, actually, let's go to page 38 of

1 your testimony.

2 This is where you're talking about best cost
3 analysis versus the avoided-cost analysis. And on page
4 38, lines 10 and 11, you say, "The company will no longer
5 rely on the MgO RCB avoided-cost threshold as the primary
6 determinant of customer benefit in its evaluation of
7 renewable projects."

8 Is that accurate?

9 A (Witness Mallard) That's right.

10 Q So does that mean that you could end up
11 selecting for procuring resources that are priced higher
12 than avoided-cost energy that's derived in this IRP?

13 A (Witness Mallard) So, yes. It's really a
14 redefining of what avoided cost is, and it goes back to
15 the discussion about the Aurora model and the ability to
16 preselect these renewable resources as beneficial to
17 customers.

18 In times past, Commissioners, the model hasn't
19 been able to select these resources. And so we really
20 depended on that MgO avoided-cost ceiling to ensure that
21 those resources benefited customers.

22 Now that the model is able to select these
23 resources, it is really a different way of thinking about
24 it. If we can go and get resources from the market that
25 are generally priced in line with the assumptions in the

1 model, the model shows that those resources do provide
2 benefits across a range of scenarios for our customers.

3 And so really just a different way of thinking
4 about it, if you will, Mr. Jones. It's a -- it's a
5 different way of defining "avoided cost." But the
6 primary change, and you have hit on it, is to no longer
7 disqualify benefits that might be above that Mg0 avoided
8 cost.

9 Q So just to put a fine point on it, yes, it
10 could result in higher prices, higher than avoided cost?
11 Procuring energy at a higher price than avoided cost?

12 A (Witness Weathers) It could -- it could be
13 higher than the Mg0 avoided cost; but here is the other
14 thing, is that not only are we looking across a range of
15 scenarios as Mr. Mallard said, but the Mg0 avoided cost
16 now have all the generic solar are already factored into
17 it. And so it's -- it's by nature a different number
18 than it was in the past when we didn't have that. You
19 could come in below it, you know there's a value.

20 Now the value is determined on the front end
21 through the optimization process. On the back end,
22 looking at after-the-fact Mg0 prices alone is not the
23 best measure of being above or below what it cost.

24 Q Okay.

25 A (Witness Robinson) Commissioners, another

1 benefit is, as mentioned before, we are going to become
2 more and more constrained in South Georgia particularly.
3 So seeing more and more transmission costs associated
4 with this. So this gives us flexibility across a
5 portfolio of projects versus just kicking individual
6 projects out because of transmission constraints.

7 Q So if you're going to employ this approach in
8 future RFPs, do you think the Commission should have the
9 opportunity to review your avoided-cost projections you
10 are going to use in those RFPs before you do them?

11 A (Witness Mallard) Yes.

12 Q. Okay.

13 A. (Witness Mallard) And the Commission does and
14 will. And, yeah, just to be clear, we are still going to
15 use an avoided cost to compare the bids against. That's
16 still part of the modeling. That's still a part of the
17 valuation exercise.

18 Q Well, that was kind of my next question, what
19 role you see envisioning the avoided-cost threshold plan?
20 I know you said you're going to use it. How do you --
21 how do you envision its importance going forward as part
22 of the process?

23 A (Witness Weathers) It won't be so much looked
24 at, the Mg0, as a threshold, but the Mg0 is a component
25 of the renewable cost benefit framework. So we're going

1 to continue to evaluate all of the bids according to the
2 renewable cost benefit framework for both the cost the
3 system incurs, but also the benefits.

4 So the -- you talk about the avoided cost in
5 reviewing those, the RCB framework, of course, is filed
6 with each IRP. But what's more important to the amount
7 of solar is not the avoided cost but the optimization.
8 So the renewable expansion plan analysis for this IRP,
9 that determined the amount of solar.

10 So when we execute on those in the PPAs, we are
11 still using Mg0 as part of RCB framework, but it is not
12 appropriate to be a threshold anymore.

13 Q All right. Let's talk a little bit about the
14 target reserve margin. Maybe you want a drink of some
15 caffeine before we do that.

16 A (Witness Grubb) We may not need to do that;
17 everybody else will.

18 Q Well, I have got some right here.

19 A. (Witness Mallard) We love this stuff.

20 Q. So the target reserve margin study was
21 conducted at the Southern Company level; right? That's
22 what we have said before?

23 A (Witness Grubb) Yes.

24 Q And then translated into a target reserve
25 margin for each operating company, such as Georgia Power?

1 A (Witness Weathers) That's correct. Based on
2 the diversity across the system. Each operating
3 company's actual target is a little bit lower than the
4 system target.

5 Q And in doing that, you develop three different
6 metrics, or use three different metrics: loss of load
7 expectation, or LOLE; economic optimum reserve margin,
8 EORM -- these names, we can shorten them up, right,
9 instead of having to spell them -- and risk-adjusted
10 EORM, or value at risk, VAR.

11 Are those familiar terms to you?

12 A (Witness Weathers) Yes, that's right.

13 Q And those are the three different metrics you
14 used in your study?

15 A (Witness Weathers) Yes.

16 MR. CHARLES JONES: Madam Chair, I would like
17 to show the witnesses an exhibit, if I may.

18 MADAM CHAIR PRIDEMORE: You may approach.

19 MR. CHARLES JONES: Thank you.

20 BY MR. CHARLES JONES:

21 Q. Okay, gentlemen, I am showing you what I've
22 marked as Exhibit --

23 MR. CHARLES JONES: And, Madam Chair, I will
24 ask that it be marked as Exhibit GAM 1.

25 (The document referred to was marked for

1 identification as Exhibit GAM 1.)

2 BY MR. CHARLES JONES:

3 Q Give you a minute to look at it.

4 A (Witness Weathers) I'm good, Mr. Jones.

5 Q Okay. Do you agree that this exhibit
6 accurately reflects the information in your file? And
7 there is a source there for where that information comes
8 from.

9 A (Witness Weathers) Yes, it looks correct.

10 Q Okay. All right.

11 Let's talk about LOLE first. This is
12 considered an industry standard approach to determining
13 target reserve margins. Do you agree with that?

14 A (Witness Weathers) Yes. There is no
15 particular standard as far -- in terms of, say, a NERC
16 standard or something like that. But it is widely used
17 across the industry and widely accepted as a best
18 practice.

19 Q Okay. You say -- in fact, you even say that in
20 your testimony, that it's an industry standard for
21 reliability, I think.

22 A (Witness Weathers) Yes, it is an industry
23 standard; but in terms of a specific NERC standard, I
24 can't point to anything that I am aware of. But it is an
25 industry standard.

1 Q And the industry standard is to use what they
2 call a 1-to-10 LOLE, which represents 1 outage event in
3 10 years; is that right?

4 A (Witness Weathers) That's correct. On a
5 planning basis from a reliability perspective, we plan to
6 have no more than one firm low shed event every 10 years
7 as related to generation resource accuracy.

8 Q Okay. And you're familiar with SERC, right,
9 the SERC Reliability Corporation?

10 A (Witness Weathers) Yes.

11 Q And that's the entity that's responsible for
12 ensuring reliable and secure electric grid across, I
13 believe, about 16 southeastern states, central states as
14 well; is that about right?

15 A (Witness Weathers) Yes.

16 Q. You don't have to get the number right.

17 A (Witness Grubb) I don't particularly know the
18 number.

19 (There was simultaneous speaking.)

20 A. (Witness Weathers) Subject to check.

21 A. (Witness Grubb) Subject to check.

22 BY MR. CHARLES JONES:

23 Q. 16. But the important one is Georgia, and the
24 Southern Company is included in that region; right?

25 A (Witness Grubb) Yes.

1 Q Would you agree with me that using a 1-to-10
2 LOLE, SERC has determined a reference reserve margin of
3 15 percent for SERC southeast?

4 A (Witness Weathers) I am aware that that has
5 been -- has been stated for a number of years related to
6 our territory. But I think important to note, that is
7 a -- that is more general in nature. So that's not
8 specific. That's not related to a specific reserve
9 margin study for our -- for a southern system.

10 So our -- our study is the one that models our
11 specific system to develop the target reserve margins.

12 Q And in your study, the LOLE results in a winter
13 reserve margin of 20 percent and a summer reserve margin
14 of 15.75 percent; correct?

15 A. (Witness Weathers) Yeah. The 20 percent would
16 be the minimum L- -- the minimum reserve margin to
17 satisfy the 1-in-10 LOLE criteria. So as long as we --
18 we check -- we run our optimization process; and as long
19 as it is above 20 percent, then you're fine.

20 If it were -- if it happened -- the economics
21 indicate it should be below 20 percent, we would need to
22 raise it to get to that minimum level.

23 Q Okay. But from a reliability perspective under
24 that metric, a 20 percent winter reserve margin and a
25 15.75 percent summer reserve margin would be adequate for

1 the company's reliability needs; correct?

2 A (Witness Grubb) As a minimum.

3 Q The minimum?

4 A (Witness Weathers) The 20 percent would as a
5 minimum. The 15.75 percent is really only a
6 summer-looking result. So since we -- since obviously we
7 have the whole year to consider, the summer and the
8 winter, so if you're having a 20 -- if you only had a
9 20 percent winter reserve margin, you would need a higher
10 than that in the summer because -- in order for the whole
11 year to come out to the 1-in-10 criteria.

12 So it's a little bit confusing, because they're
13 presented as different results here. But you have to
14 take the combination of those two into consideration when
15 you determine the system target reserve margins.

16 Q All right. So --

17 MADAM CHAIR PRIDEMORE: Do me a favor,
18 Mr. Jones, speak into your mic a little bit.

19 MR. CHARLES JONES: I'm sorry.

20 MADAM CHAIR PRIDEMORE: Thank you.

21 MR. CHARLES JONES: I thought I was pretty
22 close, but I guess I need to get closer.

23 Thank you, Madam Chair.

24 BY MR. CHARLES JONES:

25 Q. So, now, referring back to the exhibit again,

1 you used two other metrics in your target reserve margin
2 study; right?

3 A (Witness Weathers) Yes.

4 Q And you would agree that, as I understand it,
5 EORM is an economic-based metric that balances -- tries
6 to balance the estimated cost of having too little
7 capacity versus having too much. Is that roughly what it
8 does?

9 A (Witness Weathers) That's correct. In terms
10 of costs to customers.

11 Q And then VAR is kind of an extension of that.
12 Also economic based that measures, I want to say
13 riskiness of financial entities, portfolios of assets
14 that you might already have?

15 A (Witness Weathers) Well, yeah, it considers
16 the risk of higher cost outcomes and then the value of
17 mitigating that risk and can you do that in such a way
18 that it provides value to customers.

19 Q And again, LOLE, though, is what SIRC has
20 relied on in the past and continues to rely on?

21 A (Witness Weathers) Well, the SIRC doesn't set
22 the reserve margin for -- for the company, and so that's
23 determined by this Commission, so...

24 And again, LOLEs is one of the metrics; but we
25 think it is very important to consider cost to customers,

1 and really that cost to customers and the value to
2 customers is the primary metric that we use.

3 A (Witness Grubb) And so, Commission, what we're
4 saying is -- looking at the economics, is that LOLE is
5 just a measure that you can use in any -- we have an LOLE
6 related to any reserve margin.

7 If you just wanted to look at 1 in 10, you
8 wouldn't have to run any economics. But the company
9 places value in -- I can -- we can add generation that is
10 more economic than -- it's cheaper to add that generation
11 for the value of reliability that you get. So that's
12 what we start looking at beyond the minimum. And then
13 the value at risk is really looking at the probability of
14 those cases.

15 And so it's a balance of we don't want to just
16 be the minimum, especially if economically the cost of
17 reliability that you avoid is greater than the cost of
18 generation that you add. So that's what the reserve
19 margin study is looking at.

20 Q All right. Let's talk a little bit about your
21 unit retirement study. The goal of the unit retirement
22 study is to quantify the impact of continued operation of
23 the existing coal and other steam units with the impact
24 of retiring and replacing those units with a portfolio of
25 new resources. Is that a fair summary?

1 A (Witness Grubb) That's correct. Some form of
2 replacement generation.

3 Q And you considered a number of coal and CT
4 units for retirement; correct?

5 A (Witness Grubb) We did.

6 Q And the replacement portfolio you're comparing
7 it against is comprised of the six power purchase
8 agreements that you sought certification for in this
9 case?

10 A (Witness Grubb) That's correct. For the --
11 for the portions that that would cover and for the
12 duration that that covers.

13 MR. CHARLES JONES: Madam Chair, I would like
14 to show the -- introduce another exhibit to the
15 witnesses. I want to caution them that it includes
16 trade secret information. So I've already discussed
17 that with Georgia Power. I'm going to give a copy
18 to Georgia Power's staff, to each of the
19 commissioners, and the panel, and the -- and leave
20 it up here.

21 MADAM CHAIR PRIDEMORE: You may approach.

22 MR. CHARLES JONES: Thank you.

23 (The document referred to was marked for
24 identification as Exhibit GAM 2.)

25 BY MR. CHARLES JONES:

1 Q. Okay. Panel, what I'm showing you here is
2 Exhibit GAM 2, or I have marked as GAM 2, which contains
3 trade secret information from your unit retirement study
4 from Appendix A. And I'm not going to mention specific
5 numbers on this chart, and I would caution you not to
6 either in response to my questions.

7 So are we in agreement on that?

8 A (Witness Mallard) Yes.

9 Q Okay. And I'll give you a minute to look at
10 it.

11 A (Witness Grubb) Okay. So yeah -- so,
12 Mr. Jones, this is Mg0 only looking at --

13 Q That's right.

14 A (Witness Grubb) Okay. I was trying to get
15 oriented --

16 Q Yeah, we'll get there.

17 A (Witness Grubb) All right.

18 Q Okay. Do you agree with me that this exhibit
19 accurately reflects information that's in your filing?

20 A (Witness Grubb) I was only able to check the
21 unit term study net benefit, but spot-checking those,
22 they look accurate.

23 Q Okay. But subject to check?

24 A (Witness Grubb) Subject to check. But, yeah,
25 I'll take you for that accuracy, yes.

1 Q Great, thank you.

2 So this chart shows the results of the unit
3 retirement study under a moderate gas price, zero carbon
4 cost scenario, known as Mg0 for short.

5 Do you agree?

6 A (Witness Grubb) That's correct.

7 Q And as your filing and testimony indicates, you
8 ran several other scenarios as well; right?

9 A (Witness Grubb) That's right.

10 Q Low cost gas, high cost gas, and then adding in
11 a carbon adder as well at times?

12 A (Witness Grubb) That's correct. Seven --
13 seven different scenarios.

14 Q Is it fair it say that sort of an Mg0 case
15 would be considered a reference case?

16 A (Witness Grubb) So I wouldn't say that
17 necessarily. There are places in the IRP where we do
18 model comparisons against a reference case and we pick
19 Mg0.

20 For a -- for a recommendation to the
21 Commission, we -- we use the scenarios and would say that
22 they are all equally -- equally probable when you're
23 looking across 30 years of the company.

24 So we don't put any more emphasis on Mg0 for a
25 coal unit retirement than we do any of the other

1 scenarios that we look at.

2 Q Okay. But it's certainly a pretty standard
3 reasonable possible scenario, moderate gas, zero carbon
4 you look at in doing these analyses?

5 A (Witness Grubb) As all of them would be.

6 Q. Okay.

7 A. (Witness Grubb) It's the case that we base our
8 avoided cost on, because it's based on existing rules.
9 But again, for the scenarios that we look at in the unit
10 retirement study, we note that they're all equally
11 probable.

12 Q So your testimony is that a \$50 carbon tax is
13 just as likely as a moderate gas zero carbon tax, you
14 think?

15 A (Witness Grubb) Over 30 years and for guiding
16 a unit retirement study, yes.

17 Q All right. Now, when conducting a unit
18 retirement study, the goal is to determine with respect
19 to each units -- each unit the net benefits of not
20 retiring the unit and the net benefits of retiring the
21 unit; right?

22 A (Witness Grubb) That's correct.

23 Q Okay. And you would agree with me that a
24 negative net benefit, which is shown here in some cases
25 in parentheses, would indicate that early retirement is

1 more economical than the status quo?

2 A (Witness Grubb) So you say early retirement,
3 we just say retirement.

4 Q. Okay.

5 A. (Witness Grubb) We're studying at 25 through
6 whatever. Yes, retiring it within this IRP time frame,
7 yes.

8 Q Gotcha. Fair -- fair clarification.

9 A (Witness Weathers) Based on this one scenario,
10 as you said.

11 Q That's right. So we can agree that under the
12 Mg0 scenario, this study clearly supports the retirement
13 of Plant Wansley Units 1 and 2 and Gaston Units 1 to 4,
14 would you agree?

15 A (Witness Grubb) If you were to base it just on
16 the negative numbers, yes. I think another thing that we
17 would need to look at is, like we spoke to this morning,
18 Commissioners, there's no future coal risk in these
19 models, either, in terms of -- there's carbon, but
20 there's no other change in the MATS rule, change in ELG.

21 So if you're looking at just negative numbers
22 strictly to guide that decision, then, Mr. Jones, you're
23 correct, it would say Wansley 1 and 2 and Gaston.

24 Q And I know these numbers are trade secret, so I
25 won't say them, but there are three other cases on here

1 that are very near zero.

2 A (Witness Grubb) Right.

3 Q And if you're struggling to break even with
4 moderate gas prices with no carbon pressure, then you
5 can -- then you know that lower gas prices are having any
6 carbon pressure will mean that it's this.

7 A (Witness Grubb) Or any other future coal
8 requirement for environmental controls.

9 MADAM CHAIR PRIDEMORE: Recently I was at Plant
10 Scherer, and Unit 4 JEA and FPL decided to shut down
11 last year. But Unit 3, based upon its output and
12 ability, it doesn't operate that frequently. So, I
13 mean, getting it to near negative is -- makes sense.

14 WITNESS GRUBB: Yeah, Madam Chair. We've seen
15 over the last few years the capacity factors in the
16 units run a lot less. There are times that they run
17 for transmission, and so we've talked about the need
18 to do that.

19 But, yes, there is continued pressure on coal
20 from lower natural gas prices, more renewables, you
21 know, those types of things; and so the capacity
22 factors are lower. This evaluation captures that.

23 BY MR. CHARLES JONES:

24 Q So you've been reading my cross, I think. I
25 might have put it on the internet or something. I don't

1 know. But you apparently know what my next question was
2 going to be, which is that the study doesn't show under
3 this scenario any compelling benefits to retirement of
4 Plant Bowen Units 1 to 2 or Scherer 1 to 2 or Scherer 3;
5 right?

6 A (Witness Grubb) It -- I think it -- it -- it
7 doesn't show benefits to retirement. It also doesn't
8 show benefits to -- to continue to operate. I mean, the
9 numbers are pretty small. And again, I think there's
10 future risk on the coal side. We have not seen the
11 economics of coal units getting better over the last
12 several IRP cycles.

13 And so when you have results that are barely
14 above zero, a few digits of millions of dollars that
15 we're looking at here, that doesn't -- it may not say
16 retire it, but our position would be it doesn't say keep
17 it because you've got future pressures. We think there's
18 a lot more risk than there are benefits.

19 A (Witness Weathers) And, Mr. Jones, I know this
20 is labeled unit retirement studies. But again, as we
21 said, it really only is the Mg0 scenario.

22 Q. Okay.

23 A. (Witness Weathers) And so I don't think
24 it's -- I wouldn't characterize these results as being
25 reflective of the study, because the study compared --

1 also considers six additional scenarios. And if you only
2 look at one scenario in the future and count gas prices
3 being moderate forever and there not being any carbon
4 pressure, any additional pressures on coal, I think that
5 that -- that's disadvantaging customers because you're
6 not looking at -- you're not taking risks into
7 consideration. So I think it's -- that's why we look
8 across the range of scenarios.

9 Q So if you looked at a higher gas scenario,
10 though, these numbers would be even less compelling for
11 retirement; is that correct?

12 A (Witness Weathers) Higher gas zero carbon
13 scenario is going to be the best case for coal.

14 Q. All right.

15 A. (Witness Weathers) But lower gas will be
16 worse, and any carbon pressure is going to be worse.

17 Q Now, certainly the -- this particular scenario
18 doesn't show any compelling reason to retire Plant Bowen
19 Units 3 and 4; right? And you've elected not to do that
20 in this case, or to ask for that in this case?

21 A (Witness Grubb) Yeah, correct. And again,
22 part of that is because we knew we needed to control
23 Bowen 3 and 4 to maintain reliability. The capacity RFP
24 is not reflected in these economics.

25 But again, I think when you're talking about

1 these levels, it may not be compelling to retire, it's
2 also not compelling to keep. And so to Mr. Weathers'
3 point, if you look at the entire unit retirement study,
4 there's a lot more risks in a lot of these scenarios than
5 there are benefits.

6 Q And you would agree with me --

7 VICE CHAIRMAN ECHOLS: I -- a question on the
8 chart.

9 So we talked earlier today about the inactive
10 reserve. So on Bowen 1 and 2, if 2 was put in
11 inactive reserve, that number that's listed there,
12 would it go -- if it wasn't -- if it wasn't being
13 used, it would go up or down, that number at the
14 very bottom under the net benefit?

15 WITNESS GRUBB: So, Commissioner, I'll let
16 Mr. Robinson add in here as needed. The -- if we --
17 if you do inactive reserve on a coal unit, we would
18 not project any capacity benefit, any energy
19 benefit, anything here, so it would get a lot worse
20 here, because it would have absolutely no value.
21 We'd have to look at the cost.

22 It really then becomes what is the value from a
23 transmission standpoint.

24 WITNESS ROBINSON: Right. Commissioner, we'd
25 be running it for reliability purposes on the system

1 or for resiliency.

2 VICE CHAIRMAN ECHOLS: And do you quantify that
3 number ever?

4 WITNESS ROBINSON: Specifically referring to
5 resiliency, it's very hard to quantify resilience.
6 On reliability, there are redispatch costs that we
7 can look at, the cost of running those units as it
8 relates to transmission reliability. But those are
9 also difficult to quantify, depending on the time of
10 season, how long you have to run it. If it's a
11 short period of time, can the unit respond and run
12 for that short period of time and then come offline.

13 VICE CHAIRMAN ECHOLS: Yeah. If there were a
14 reliability issue in North Georgia, would it be
15 better to have a unit like Bowen to there or to buy
16 energy off the spot market out of -- out of some
17 surrounding state? Which -- which would be better?

18 WITNESS ROBINSON: Commissioner, from a
19 transmission perspective, it's always a good thing
20 to have generation close to load. But there are
21 economic decisions that go into that as well.
22 That's why we're thinking about and talking to
23 generation about converting those units to
24 synchronous condensers where we can get the VAR
25 support or voltage support in the area. And that's

1 one of our concerns as well as relates to
2 reliability in North Georgia.

3 WITNESS GRUBB: And, Commissioner, to the
4 inactive reserve point. If you've got a unit that's
5 set up in that manner, you're really talking now
6 about events that are multiple days. Like we talked
7 about earlier, some pipeline destructions or
8 something.

9 It's not one that you could bring on, you know,
10 because you're going to have issues tomorrow. It's
11 days and weeks. And so to be able to have it
12 respond, even though coal units take a little while,
13 you actually have to keep it as it is now. So the
14 inactive reserve is really for those low
15 probabilities but high impact events that we talked
16 about some this morning.

17 VICE CHAIRMAN ECHOLS: And a voltage event --
18 because I visited the Georgia transmission voltage
19 facility in Winder. Voltage events are resolved
20 pretty quickly; right? That's not something that
21 you're doing over days?

22 WITNESS ROBINSON: The SBC that you referred to
23 in Winder, yes, it's very quick. It is always
24 there, ready to respond, come online. A synchronous
25 condenser would be the same, so the operators could

1 manipulate the absorption or production of VARs from
2 that facility. The two static VAR systems that we
3 have proposed in the ten-year plan, also same.
4 Offer voltage support to the North Georgia area and
5 are online and available to act within milliseconds
6 of an event, yes.

7 VICE CHAIRMAN ECHOLS: Thank you.

8 MADAM CHAIR PRIDEMORE: Does the Georgia Power
9 fleet today have inactive reserve that is coal in
10 it?

11 WITNESS GRUBB: No, ma'am.

12 MADAM CHAIR PRIDEMORE: No? Okay, thank you.

13 BY MR. CHARLES JONES:

14 Q. Mr. Grubb, a minute ago you said that -- I
15 don't want to misquote you, so correct me if I
16 mischaracterize what you said. But I believe you said
17 you were looking at these numbers where it didn't give a
18 compelling reason to retire but didn't give a compelling
19 reason to keep it.

20 Then you went on to say that the coal --
21 economics of the coal plants are not getting any better.

22 Is that a fair summary of what you said?

23 A (Witness Grubb) Yes. I said there's not --
24 not. Make sure I hear -- I said it does not offset. It
25 doesn't compel one to keep it either.

1 Q. Gotcha.

2 A. (Witness Grubb) So, yes, I did say that.

3 Q Okay. Fair enough.

4 So given that -- but the decision that's being
5 made here is being made now; right? So even if you think
6 the economics are going to get worse in the future, we're
7 still looking at a decision point of now, and there will
8 be another IRP three years from now; correct?

9 A (Witness Grubb) Yeah, that's correct. I mean,
10 we've talked about the retirement dates are down the
11 road, but the decision is here now. But again, that's --
12 when we see the trends and when we look forward, we just
13 don't see the coal economics getting better. So when you
14 have, for lack of a better term, marginal results, we
15 would tend to say there's more risk to keeping it than
16 retiring it.

17 A (Witness Weathers) And then the opportunity is
18 now in terms of the replacement power through the
19 purchase power agreements. So those -- those are really
20 good deals that customers will benefit from. And those
21 deals are not likely to be there, certainly at those
22 prices, if the decisions were delayed.

23 Q Well, we don't know. I mean, there could be --
24 three years from now, we don't know what prices are going
25 to be?

1 A (Witness Weathers) We don't know, but we've
2 also -- we know the market is getting tighter than it
3 used to be. We know the region is getting tighter. So
4 our expectation would be that it would not be available
5 at least at those prices.

6 Q Okay. Well, let's talk about a different
7 expectation. You, in your scenarios, talk about, in
8 various scenarios, carbon taxes of \$20 per metric ton and
9 \$50 per metric ton; correct?

10 A. (Witness Weathers) That's correct.

11 A (Witness Grubb) Yes.

12 Q And you used to look at \$10 per metric ton, but
13 you dropped that one for this case; right?

14 A (Witness Weathers) That is correct.

15 Q There's no tax on carbon right now; is that
16 correct?

17 A (Witness Weathers) That's right.

18 Q Okay. And even though we've been talking about
19 carbon tax scenarios down here for nearly a decade,
20 Congress still hasn't enacted a carbon tax, have they?

21 A (Witness Weathers) They have not, but there
22 are a number of proposals that they have considered, a
23 range of proposals. So we're looking at -- we're looking
24 at future decisions and the evolution of the fleet over
25 the next 30 years. So in terms of risk to customers, is

1 a real risk to customers that there will be carbon. In
2 fact, the \$50 price very well aligns with some of the
3 recent proposals in potential bills that Congress has
4 discussed.

5 Q Well, what about the Build Back Better bill
6 that was proposed last year? In that bill Congress
7 considered the -- the climate change provisions were more
8 focused on incentives -- right? -- not on carbon taxes?

9 A (Witness Weathers) They were. They were more
10 focused on incentives. They had the same objective,
11 which was to decarbonize the electric sector and really
12 to decarbonize, you know, the industry.

13 There's a different pathway to get there. The
14 company considered a different pathway in its planning
15 scenario process, which is a lowering of emissions over
16 time. We called it our "carbon intensity scenario." But
17 in looking at that, it is very similar to the \$50
18 scenario in that it drives the fleet to decarbonize over
19 time.

20 So pressures may come in different forms. It
21 could be carbon tax. It could be some type of clean
22 energy standard. It could be tax incentives and/or
23 penalties similar to what's in the Build Back Better
24 Plan.

25 But we think that the risk of carbon is real,

1 and that's why we factored it into our scenario planning.

2 Q Okay. Now, in making this comparison between
3 the cost of keeping the units and -- instead versus
4 adopting this portfolio PPAs, as you said -- as you went
5 through with Mr. Walsh, you're also asking for additional
6 sums in regard to those PPAs; correct?

7 A (Witness Grubb) That's correct.

8 Q And just confirming, as staff crossed you on,
9 those weren't taken into consideration in your unit
10 retirement study; right?

11 A (Witness Grubb) That's correct.

12 Q All right. Let's talk a little bit about cost
13 recovery of the units that you proposed to retire.

14 MR. CHARLES JONES: And, Madam Chair, I'd like
15 to approach the witness with an exhibit?

16 MADAM CHAIR PRIDEMORE: You may approach.

17 (The document referred to was marked for
18 identification as Exhibit GAM 3.)

19 BY MR. CHARLES JONES:

20 Q Again, Panel, this does not include trade
21 secret information. I'll represent to you that the
22 chart, as it says, is sourced from information reflected
23 in the responses to data requests STF-LA-1-28 and 1-29
24 marked as Exhibit GAM 3.

25 You see that?

1 A (Witness Grubb) Yes, sir.

2 Q And subject to check, do you agree that this
3 reflects -- accurately reflects what you had in your
4 responses to those data requests?

5 A (Witness Grubb) I do.

6 Q Okay. Thank you.

7 Now, this chart summarizes the proposed plant
8 retirements and remaining net book value as of
9 December 31, 2021; right?

10 A (Witness Grubb) That is correct.

11 Q So for Wansley 1 and 2, the 2017 depreciation
12 study. Now, when we say that, that was what was used to
13 determine the retirement date in the last full rate case;
14 is that fair?

15 A (Witness Grubb) For depreciation purposes;
16 that's correct.

17 Q For depreciation. And for Bowen 1 and 2 is
18 2030, and for Scherer 3 is 2047?

19 A (Witness Grubb) That's correct.

20 Q And then the second column has your proposed
21 retirement dates, and the third column has the remaining
22 net book value of those assets?

23 A (Witness Grubb) At the end of last year;
24 that's correct.

25 Q At the end of last year. All right.

1 Now, Georgia Power is seeking recovery of the
2 net book balance of these plants even after they're
3 retired and no longer providing service; correct?

4 A (Witness Grubb) Yes, that's correct. We're
5 requesting that the net book value upon retirement would
6 be moved to a regulatory asset.

7 Q And the company will also seek to earn a return
8 on the unamortized balance after the plants are retired;
9 would you agree?

10 A (Witness Grubb) As it goes through rates -- my
11 regulatory accounting can't speak to all those, but, yes,
12 we would continue to recover it as we have.

13 Q And you would agree with me that in this filing
14 you haven't stated over what periods of time you will
15 seek to recover those costs, have you?

16 A (Witness Grubb) Yes, that's correct. We've
17 stated that that would be discussed in the rate case or
18 future rate cases.

19 We do, though, however, expect the remaining
20 net book value to be less upon the retirement dates than
21 they are right now.

22 Q. Sure.

23 A. (Witness Grubb) But yes, we have not laid
24 those out.

25 Q The total would probably be less than

1 3.1 billion?

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

3 Q. It would be something less than that?

4 A (Witness Grubb) That's correct.

5 Q Would you expect it to be north of 2 billion?

6 A (Witness Grubb) I don't know. I don't know,
7 Mr. Jones, what our rate case strategy will be on terms
8 of proposed depreciation dates.

9 Q Oh, I'm sorry. I mis- -- I didn't state the
10 question correctly.

11 A. (Witness Grubb) Okay.

12 Q. Would you expect the remaining net book value
13 if these retirement dates are approved to be north of
14 \$2 billion? Not what you had requested, but that --

15 A (Witness Grubb) Yeah, I don't know, because I
16 think that will depend on two things. One, how much
17 money we spend between now and then and what comes out of
18 this IRP. But the other is, what is that depreciation
19 date that's approved in the rate case. So I don't know.

20 Q So Georgia Power might seek to recover these
21 costs prior to the retirement dates that were established
22 in the last rate case; right? You would reserve the
23 right to request that?

24 A (Witness Grubb) I think we have that right;
25 but, again, I'm not in those discussions. I don't

1 believe we would request it to be before we retired it,
2 though.

3 Q Okay. And -- but if you were to seek, say, an
4 accelerated recovery, and the Commission were to grant
5 that request, that would place upward pressure on rates,
6 wouldn't it?

7 MR. HEWITSON: Objection. I think that's been
8 asked and answered. I think the witness just said
9 he didn't think we would seek it, so asking a
10 hypothetical, if you did seek it, seems to me
11 that --

12 MADAM CHAIR PRIDEMORE: Sustained.

13 MR. CHARLES JONES: Madam Chair, may I respond
14 to the objection? I mean, I'm asking a question
15 about -- he hasn't committed to not -- the company
16 hasn't committed to not seeking accelerated
17 recovery, so I'm just asking if they did, what would
18 be the rate impact. I'm not -- that's not -- that's
19 not asked and answered. That's a different
20 question.

21 MR. HEWITSON: It would be a great question to
22 ask during the rate case, but that's not part of the
23 IRP.

24 MADAM CHAIR PRIDEMORE: Sustained.

25 MR. CHARLES JONES: All right.

1 BY MR. CHARLES JONES:

2 Q Your unit retirement study didn't take any of
3 that into consideration, did it?

4 A (Witness Grubb) By "that," meaning the net
5 book value balance?

6 Q Meaning the recovery period of when you would
7 seek to recover these costs.

8 A (Witness Grubb) Right, that is correct.
9 Exactly as we've done in prior IRPs and unit retirement
10 studies, we look at the incremental cost of maintaining
11 the coal units and running them versus retire and
12 replace.

13 The -- the net book value treatment, whether
14 you retire it or not, we see being the same, the way
15 we've done it in the past. So to us, it's a -- it's a
16 cost that is the same regardless of if we retire the unit
17 or not, so we do not include it.

18 Q So back to the additional sums on the PPAs.
19 You propose to replace the retired coal units with these
20 six capacity PPAs and the additional sum. Those
21 additional sums are considerably higher than the \$2.30
22 per kilowatt year figure used in a lot of prior PPAs;
23 right?

24 A (Witness Grubb) Yeah, they are higher. The
25 \$2.30 has its genesis of about 20 years ago. And so they

1 are higher, really reflecting the great values that we
2 got in the capacity IRP.

3 Q Okay. And the additional sum, just as a
4 mechanism, acts as a -- would you agree acts as a proxy
5 for a return on those supply-side options which are
6 treated as expenses not included in rate base? Is that
7 right?

8 A (Witness Grubb) So it's a -- it's added to
9 revenue requirements, I think is -- if that's what you
10 were asking, then, yes.

11 Q It's not technically a return, but it's an
12 additional sum that acts as sort of a proxy for that
13 because you don't get a return on those PPAs that don't
14 go into rate base; right?

15 A (Witness Grubb) I believe that's fair to say.

16 Q And you recover the cost of those PPAs
17 typically through the fuel cost?

18 A (Witness Grubb) That's correct. But I'm not
19 sure additional sum goes to the fuel cost. Subject to
20 check. I believe it's revenue requirements through the
21 rate base, but I'd have to confirm that.

22 Q By contrast, rate base costs, you earn a
23 return, including a return on equity for Southern
24 Company, your shareholder; correct?

25 A (Witness Grubb) Correct.

1 Q Okay. For example, you'll earn a return on the
2 retired generating plants if the Commission approves this
3 plan because they're rate-based assets for as long as
4 those assets are to be recovered; right?

5 A (Witness Grubb) Are we net book value plant
6 service out -- but, yes, I mean, we -- we do.

7 Q Okay. And then through the additional sum
8 mechanism, you'll be earning that as well on the PPAs,
9 meaning in effect, ratepayers will pay a return, but the
10 capacity of the coal units that are no longer in service
11 and on the capacity PPAs that replace them?

12 A (Witness Grubb) So the additional sum is
13 require- -- is allowed by statute, so that's correct. So
14 we would -- we will continue to do that.

15 Again, the -- the -- what we look at the unit
16 retirement decision is the 30-year benefit to customers,
17 and so that's why we're recommending retirement.
18 Regardless of the rate case treatment over 30 years, it's
19 in the best interest of customers economically to retire
20 them.

21 A (Witness Weathers) And the additional sum is
22 directly proportional to the savings that customers will
23 realize through the power purchase agreements. So the
24 reason why it is larger, as Mr. Grubb said, is because
25 there is substantial savings from retiring these units

1 and replacing them with these power purchase agreements
2 instead of alternate company-owned capacity.

3 Q And you would assume that in designing the bids
4 for the PPAs, the bidders and the ones you've selected,
5 have factored in a bid price that includes a return to
6 their shareholders?

7 A (Witness Grubb) I would --

8 Q Would that be fair to say?

9 A (Witness Grubb) I'm not a bidder. It's a fair
10 assumption. I don't know how much or those types of
11 things. That's up to the bidders.

12 MR. CHARLES JONES: Madam Chair, I think that's
13 all I have today. Thank you.

14 MADAM CHAIR PRIDEMORE: Okay.

15 MR. CHARLES JONES: Thank you.

16 Madam Chair, let me ask about the trade secret
17 exhibit that I distributed. I know I need to leave
18 one with the court reporter. Mr. Hewitson has said
19 that he can keep his and the staff can keep theirs.
20 What would you like me to do with regards to the
21 ones you have? I am about to gather them back up.

22 MADAM CHAIR PRIDEMORE: Commissioners can keep
23 theirs as well.

24 MR. CHARLES JONES: Okay.

25 MADAM CHAIR PRIDEMORE: We are privy to trade

1 secret information.

2 MR. CHARLES JONES: Yes. Thank you, Madam
3 Chair. I appreciate it.

4 MADAM CHAIR PRIDEMORE: Thank you, Mr. Jones.
5 Georgia Center for Energy Solutions?

6 MR. HUBBARD: Thank you, Madam Chair, it's --

7 MR. CHARLES JONES: Madam Chair, I'm sorry, may
8 I move my exhibits to be admitted? I apologize.

9 MADAM CHAIR PRIDEMORE: So moved.

10 (The documents referred to as Exhibits
11 GAM 1 through 3 were admitted into evidence.)

12 MR. HUBBARD: Because I plan to offer direct
13 testimony on behalf of Georgia Center for Energy
14 Solutions, it's my understanding that the Commission
15 rules preclude me directing direct testimony, so
16 I'll step down from that role.

17 MADAM CHAIR PRIDEMORE: It's one or the other,
18 Mr. Hubbard.

19 MR. HUBBARD: Yep.

20 MADAM CHAIR PRIDEMORE: Yeah. Thank you.
21 Georgia Coalition for Local Governments?

22 MS. BROWN: Good afternoon, Commissioners,
23 panel members.

24 A. (Witness Weathers) Good afternoon.

25 A. (Witness Mallard) Good afternoon.

1 CROSS-EXAMINATION

2 BY MS. BROWN:

3 Q. Just as a matter of road mapping, we'll be
4 jumping right in with the CARES program, which is one of
5 your big programs for customers like the local
6 governments within our coalition.

7 So my first question is, as currently proposed,
8 that program includes a \$5,000, what you're calling NOI
9 fee for pre-administration purposes.

10 Are there any plans to work out alternative
11 solutions for some of the smaller entities that might be
12 taking advantage of that program, like a local government
13 or a school, and they struggle to come up with \$5,000 for
14 something that may not work out?

15 A (Witness Mallard) So certainly we could
16 consider that. And again, Commissioners, as we have with
17 prior Commission-approved programs, we're really just
18 proposing the concept here with CARES.

19 Now, once approved in this IRP, a more robust
20 and complete program filing will follow, much like CRSP
21 and much like C&I REDI before, so the opportunity to
22 consider particular changes like that will certainly have
23 that chance and can be considered.

24 Q All right. Thank you.

25 And it's my understanding that CARES is an

1 iteration of the CRSP program that's been running since,
2 I believe, the 2019 IRP.

3 In your experience, has that been a premium
4 program or a cash neutral program or a money-saving
5 opportunity?

6 A (Witness Mallard) So it's -- I think it's all
7 of the above. What the program offers is the ability to
8 subscribe to the output. And the subscription price is
9 based on the cost of the purchase power agreements plus
10 the administrative fee to cover the company's cost to,
11 again, try to protect -- make sure the program is cost
12 neutral to nonparticipants.

13 In return for that, the participating customer
14 gets a credit that's based on the marginal cost to
15 generate electricity as -- as -- as in hours that the
16 solar energy that they've subscribed to is producing.
17 And so it -- it really just depends on what those actual
18 avoided costs turn out to be over time.

19 So there is a chance that the participating
20 customer could benefit at the end of time. Could have
21 paid more. There's a chance the participating customer
22 could have paid less. There's a chance if our forecast
23 is really close to what actuals turn out to be, that it
24 would be cost neutral at the end of the time period.

25 Q So would you say that it's most analogous to a

1 virtual power purchase agreement?

2 A (Witness Mallard) I don't know that it's
3 analogous to a virtual power purchase agreement. Really
4 it's the ability to subscribe to the output. Georgia
5 Power is the deliverer -- the provider of energy to all
6 of our customers. We procure resources that benefit all
7 customers. And so we make the decision, this Commission
8 approves through the certification process the portfolio
9 of resources that will deliver benefits to all customers.

10 During the term of the subscription period, the
11 customers get the RECs, they get the ability to benefit.
12 So in that way, they are subscribing to the particular
13 output. So maybe there's some similarities in that
14 respect, but I wouldn't call it analogous to a virtual
15 PPA.

16 Q Okay. In your filing for this CARES program,
17 you mentioned a community adder fee. There was only
18 about a paragraph on that.

19 Can you speak to that further?

20 A (Witness Mallard) Yeah. So that's a concept
21 that we've gotten feedback from some of our interested
22 customers that they would like the opportunity to support
23 community programs in addition to just subscribing to the
24 output of these renewable resources.

25 I will tell you that the -- that -- the mention

1 is really a nod to that concept to show that we are
2 interested and committed to developing a community adder
3 program like that, but we don't have any of the details
4 developed at this point.

5 It's important to remember the CARES projects
6 are still four to seven years down the road from coming
7 online; and so if there's interest from CARES customers
8 in participating in that, we'll further develop that
9 option, we'll bring that back before the Commission for
10 approval.

11 Conceptually, though, we're going to collect an
12 adder from the participating customers, and those funds
13 would then be used to support a community program related
14 to renewables or energy efficiency or possibly some other
15 options like that.

16 Q Okay.

17 MADAM CHAIR PRIDEMORE: Mr. Mallard, do you
18 find it in the company's experience, though, that
19 when an entity has some skin in the game, as
20 Commissioner McDonald likes to say, that they're
21 making some level of investment to accomplish their
22 goals with these renewable programs, that the
23 arrangement tends to work out better because they --
24 they are invested in it and they're making some
25 level of participation to identify that?

1 WITNESS MALLARD: Yes. Yes, Madam Chair, I
2 think that's absolutely true; and I think our
3 experience has shown that, that collaboration and
4 commitment is much more when both entities are
5 working together towards the same goal and when,
6 yes, the other entity has some skin in the game.

7 BY MS. BROWN:

8 Q. So we certainly appreciate the inclusion of a
9 municipal, university, schools, and hospitals carve-out
10 in that CARES program given that each of us has these
11 renewables goals and may not meet -- or at one point may
12 not have met that 3 megawatt threshold.

13 But as you may know, our goals, most of them,
14 are community-wide and not just for our city operations.
15 So is there any interest in taking this CARES program and
16 allowing representatives like ourselves who aren't just
17 concerned about our own energy use but are concerned
18 about our communities, would there be a chance to
19 subscribe on behalf of our community above and beyond our
20 own energy use?

21 A (Witness Mallard) So I don't think we've
22 contemplated that in the program designs thus far. I'm
23 not saying it's not something we couldn't consider down
24 the road. But as it's designed right now, the first step
25 towards a carve-out specifically for the MUSH market we

1 feel like is an appropriate next step to test that market
2 to understand how we can try to satisfy those customer
3 needs.

4 I mentioned earlier, I'll mention again, we do
5 have programs available for customers in all classes, in
6 all rates at Georgia Power, and so we certainly could
7 work towards helping to market and expand our programs,
8 like Simple Solar, like Community Solar.

9 But other program design concepts like you're
10 talking about is certainly something the company would be
11 interested and willing to discuss in more detail.

12 Q Appreciate that.

13 And as far as that MUSH carve-out, I believe
14 it's currently 50 megawatts; is that correct?

15 A (Witness Mallard) That's right.

16 Q What is that size based on?

17 A (Witness Mallard) So the size is based on the
18 overall amount of subscribable capacity, which is
19 2,000 megawatts. The demand that we've seen from all of
20 the segments and then interest that we've seen from
21 potential participants in the MUSH segment.

22 So it's based on all of those things. It's
23 based on direct feedback and interaction from these
24 customers that we deal with and then us using our
25 judgment as we design the program to try to do the most

1 good for the most customers, if you will, and allocate
2 those megawatts for subscription across segments where
3 there's customer interest.

4 Q To that point, about customer demand and
5 customer interest, you include in your filing that the
6 Simple Solar program is going to go from a 1 cent per
7 kilowatt hour premium to a 1.25 cent per kilowatt hour
8 premium based on current changes in REC prices?

9 A (Witness Mallard) That's right.

10 Q In your opinion, what is driving that increase
11 in REC prices?

12 A (Witness Mallard) So I think what's driving
13 the increase in REC prices are more customers with
14 voluntary renewable energy goals who are seeking to meet
15 those goals through purchases of voluntary RECs. And so
16 what we've seen are REC prices that have been in the
17 neighborhood of a tenth or 2/10s of a cent per kilowatt
18 hour, go all the way up to north of 6, maybe close to
19 7/10s of a cent.

20 They've settled back down now. I think most
21 recently back in the 2 or 3/10s of a cent range. But
22 those -- that volatility and that demand is driven by
23 customers trying to meet their voluntary goals.

24 Q So if an increase in demand is being driven by
25 these voluntary goals, wouldn't it make sense to provide

1 even further supply than is being proposed to meet that
2 demand?

3 A (Witness Mallard) So the amount that we can
4 offer for subscription is based on the total amount of
5 renewable resources that we can procure.

6 As we've talked about, we've really spent a lot
7 of time using our models, using our experience here to
8 map out this plan towards adding 6,000 megawatts of
9 renewable resources to benefit all customers.

10 To go faster than that can introduce costs and
11 risks. To go slower than that can introduce costs and
12 risks. Our plan to get to 6,000 and the 2,300 megawatts
13 that we propose this time is our best -- in our judgment,
14 what's best for customers. The best growth of renewable
15 resources that also takes into account the impacts to our
16 generation system, our transmission system. It takes all
17 of those impacts into account. It's a pace that we feel
18 like maximizes the benefits for customers.

19 Q So you mentioned extensive reliance on
20 modeling, and you have mentioned dozens of models
21 throughout today's hearings; and there's been a specific
22 focus on reliability in North Georgia and how if certain
23 plants close, there is going to be reliability concerns
24 from that.

25 As a part of those reliability studies, have

1 you considered a demand-side-focused option with
2 demand-side solar, demand-side batteries, as a quicker
3 and more -- less space-constrained option as opposed to
4 the transmission and utility scale renewables that you
5 have focused on?

6 A (Witness Robinson) What do you mean by
7 demand-side solar?

8 Q Like rooftop solar, behind-the-meter solar.

9 A (Witness Mallard) So sure. We consider all
10 sorts of resources that can help meet generation needs
11 and resource adequacy needs. What you will see in our
12 proposal for distributed generation procurements is that
13 hosting capacity tool that we have talked about that will
14 hopefully provide information that will guide renewable
15 developers to circuits where there is capacity available.
16 I would expect a good number of those would be in North
17 Georgia in and around the metro Atlanta area.

18 So in that way, we are absolutely encouraging
19 distributed generation to locate in the areas where
20 that -- those resources can be integrated to the system
21 with the least cost and provide the most benefits.

22 A (Witness Robinson) And, Commissioners, it's
23 important when you are thinking about transmission
24 constraints and reliability, and you are resolving those
25 with demand-side resource, as counselor proposes, those

1 resources have to be available and online when that
2 contingency happens.

3 And if that contingency happens at six o'clock
4 in the evening, going into the evening hours, and solar
5 is not available, that -- that demand-side resource does
6 no good from a transmission constraint perspective absent
7 storage.

8 Q. And on the subject of behind-the-meter solar,
9 we have had multiple listening sessions with Georgia
10 Power about new programs are being developed around
11 income-qualified Community Solar, and, of course,
12 extensions of your income-qualified energy efficiency
13 programs.

14 But I can't help but notice that there isn't
15 any income-qualified option for behind-the-meter solar,
16 which, of course, rooftop is the only kind of solar that
17 could provide those customers with resiliency benefits
18 through the addition of storage. So I was just wondering
19 what the rationale was for the lack of income-qualified
20 behind-the-meter.

21 A (Witness Mallard) Yeah. We've certainly
22 considered that and evaluated program designs in other
23 parts of the country. In our opinion, it's -- it's
24 difficult to do on-site solar on -- for income-qualified
25 customers based on the quality of the housing stock,

1 based on the integrity of the roofs.

2 Those programs can be done. They require a lot
3 more analysis of the quality of the housing stock. They
4 require a lot more information from -- from those
5 customers. I think that's something that the company can
6 definitely consider in the future, but it's our -- it's
7 our position that the income-qualified Community Solar
8 program is really the best way for income-qualified
9 customers to get access to solar. We don't have to worry
10 about installing solar on the rooftop.

11 These customers are going to have the ability
12 to subscribe to the output of a Community Solar facility,
13 which we've got 8 megawatts worth here in the state;
14 5 megawatts we are going to make available for
15 income-qualified customers. In that way, these customers
16 can subscribe, and they can reap the benefits of solar
17 without the complexity of a rooftop installation at
18 their actual -- at their actual residence.

19 Q We are no strangers to the conditions of
20 low-income housing. That's something we work with every
21 day.

22 MADAM CHAIR PRIDEMORE: Would Georgia Power
23 seek rate recovery for income-qualified
24 behind-the-meter solar?

25 WITNESS MALLARD: If we could design a program,

1 Madam Chair, where costs would not be shifted and
2 the benefits could accrue to all customers and
3 benefit the income-qualified customer as well, I
4 think we might. But that's -- that's a math
5 equation that I -- we haven't been able to solve as
6 of yet.

7 MADAM CHAIR PRIDEMORE: You just answered my
8 question by asking the same question back to me, so
9 I am going to ask it to you again. Would Georgia
10 Power seek to recover in rates income-qualified
11 behind-the-meter solar?

12 WITNESS MALLARD: Yes.

13 MADAM CHAIR PRIDEMORE: Yes.

14 WITNESS MALLARD: If we could design a program
15 that protected nonparticipants that benefited the
16 participants and made cost-effective sense for all
17 Georgia Power customers, then yes, I think that's a
18 pretty good --

19 MADAM CHAIR PRIDEMORE: Mr. Mallard, would that
20 not socialize the cost of solar across the rest of
21 the Georgia Power rate base?

22 WITNESS MALLARD: So that's the big "if" there.
23 We are going to make sure we protect other
24 customers.

25 MADAM CHAIR PRIDEMORE: That's a "yes" or a

1 "no." Would it not?

2 WITNESS MALLARD: It depends. So Community
3 Solar income-qualified? We have the third party
4 that's going to sponsor that. They are going to buy
5 down the Community Solar for the participants.

6 So in that way, we are protecting all other
7 customers. There is a corporate sponsor that's
8 going to volunteer to support that program. A
9 similar design could be done for on-site or rooftop
10 solar with a third party who is willing to buy down
11 the program cost.

12 MADAM CHAIR PRIDEMORE: So if a third party was
13 to buy down the program costs to zero to the rest of
14 the Georgia Power rate base for income-qualified
15 behind-the-meter solar -- say that five times
16 fast -- then that would be a program that Georgia
17 Power would not have to seek to recover in rates,
18 because a third party, an independent third party
19 would cover the cost of it; correct?

20 WITNESS MALLARD: If we're -- if it's going to
21 be Georgia Power that's building and installing the
22 solar, I think we still need certification from the
23 Commission to do that. It's just the cost recovery
24 is going to be subsidized by the third party.

25 So that's still a program that we would

1 absolutely bring to the Commission and get
2 Commission approval. And, you know, I can see that
3 working on maybe new construction, so maybe the
4 rebuild of affordable housing, that type of thing,
5 where a new construction solar could be integrated
6 into the -- into the initial design and
7 construction.

8 Certainly something that we could pursue
9 further, but absolutely we would -- we would want to
10 see a design that protected nonparticipants, Madam
11 Chair.

12 MADAM CHAIR PRIDEMORE: This third party that's
13 out there that covers the cost of Community Solar
14 for income-qualified recipients, when did that
15 program start and how long has that been going?

16 WITNESS MALLARD: It has not. It's been
17 proposed for approval here this IRP.

18 MADAM CHAIR PRIDEMORE: Okay. Thank you.

19 BY MS. BROWN:

20 Q. So continuing the line of questioning around
21 behind-the-meter solar, a hot topic today, as we all
22 know, is probably going to be the monthly netting pilot
23 and how it has reached its cap.

24 You list in the main IRP document that you are
25 continuing to evaluate the rate impacts of that program.

1 When can we expect that study?

2 A (Witness Mallard) Well, we still don't have
3 all of the 5,000 customers online yet. We reached
4 capacity last summer with customers who had signed up.
5 We are north of 4,000. I haven't gotten the update
6 today. It is probably on the website. But we are within
7 six or eight weeks of having all 5,000 customers online.

8 Once we have all 5,000 customers online, we
9 really do want to monitor and get a full year's worth of
10 usage to see that, all the seasons, all the months of the
11 year, and to be able to evaluate those impacts.

12 I can tell you, Commissioners, that based on
13 early analysis and customers who've already had solar
14 installed and we just moved over as of January of last
15 year, what we are seeing is a cost shift just based on
16 the energy pushback to the grid of more than \$1.5 million
17 a year from the 5,000 customers.

18 So it is going to be at least that much. And
19 then once we get all the customers online and can do a
20 more in-depth analysis, we will have better figures to be
21 able to show the amount of upward rate pressure.

22 Q When evaluating that program, like with that
23 study, is this looking at just a near-term window or is
24 this looking over the life of the solar asset using the
25 renewable cost-benefit framework?

1 A (Witness Mallard) So we used the renewable
2 cost-benefit framework, but we really just have
3 year-to-year agreements with these customers; and so it
4 uses the best view of current cost and benefits, which
5 represents the Mg0 that we've talked about. Each year's
6 RCB adjusted avoided cost is calculated, and that's the
7 amount of compensation the customers receive for the
8 energy pushback.

9 Q On the subject of that renewable cost-benefit
10 framework, my understanding is that involves variable
11 O&M, fuel, fuel handling, line losses and things of that
12 nature; is that correct?

13 A (Witness Mallard) Yes.

14 A (Witness Grubb) That's correct.

15 Q When we talk about line losses, it's simple
16 physics, that you have greater line losses when it's
17 warmer, when there is more energy going through the line.

18 Does this value that's included in the avoided
19 cost use an average line loss, or does that use a
20 marginal line loss based on the actual conditions when
21 the solar is being produced?

22 A (Witness Grubb) I hadn't dug into the line
23 loss study in a while, but I think it's an average. It's
24 an annual average, I believe, based on level.

25 A (Witness Weathers) Yeah, I think that's

1 correct. Subject to check.

2 A. (Witness Grubb) Subject to check.

3 Q So if we are adequately measuring cost and
4 benefits of solar, and we're looking granularly at the
5 energy, wouldn't it make sense to also take a granular
6 look at the line losses?

7 A (Witness Grubb) So I think when we say
8 granular on the energy, I am not -- we don't look at that
9 at each circuit type of level, and I think losses would
10 have to be down to that level. I don't think you would
11 see as drastic of a change. But to have losses for every
12 single account would be quite administratively
13 burdensome, if we could even do it.

14 A (Witness Robinson) It would be a significant
15 challenge from a transmission and distribution
16 perspective to calculate those losses on the basis of
17 which you're speaking.

18 Q Could it be hourly like you do with energy?
19 Across the system?

20 A (Witness Grubb) Again, I'm not familiar enough
21 with the loss study to know that it's across every hour,
22 because I think your losses are driven by --

23 A (Witness Robinson) Yeah, we do not have the
24 models to support that type of calculation. It would be
25 significantly costly for the company to develop those

1 models, if they could be developed, to calculate that
2 loss on an hourly basis.

3 Q And final question on the behind-the-meter side
4 of things. Again, as local governments, we have a few
5 more policy goals than just renewable energy. We are
6 also interested in jobs, we are also interested in the
7 resilience that comes through adding storage, we are also
8 interested in preserving our green scapes. And all of
9 those things come together with rooftop solar in many
10 cases being our best option to uphold all of those goals.

11 With the closure of the monthly netting, the
12 calculations for how large the system should be, what
13 kind of budget that we need to set aside gets a little
14 more complicated.

15 So in your experience, if we are on the RNR
16 instantaneous tariff that you get put on now that monthly
17 netting is full, what information do you need to make the
18 best decision from a financial perspective?

19 A (Witness Mallard) Sorry. Can you repeat that
20 one more time?

21 A (Witness Grubb) And before you do, you are
22 asking -- and before you do, you are asking from the
23 customer's perspective?

24 Q Yes.

25 A. (Witness Grubb) Okay.

1 Q. To simplify it, under monthly netting, your
2 calculation for how much money you need to have and what
3 your payback will be is quite simple. It's the retail
4 rate times what's being produced is how much that you are
5 saving.

6 But under instantaneous netting, it's a little
7 more complicated, because most customers don't have a
8 concept of how much energy I am using at any moment and
9 how much my solar is generating at any moment. So how do
10 we as customers, and particularly as local governments,
11 make the most informed decision about the solar that we
12 want to put on our sites?

13 A (Witness Mallard) Sure. So -- and we are
14 absolutely committed to helping local governments, to
15 helping all customers, and to grow rooftop solar,
16 frankly. Gosh, the renewable development team, I think
17 we talked to over 12,000 customers last year alone to
18 help them along their journey to evaluating solar at
19 their home or residence or business and help them make
20 the best decision.

21 And so you are right, it's a more complicated
22 calculation than just that -- your retail rate. But that
23 in and itself is not justification to overpay through
24 monthly netting of that energy to push back to the grid.
25 That energy is only valued at the Commission-approved RCB

1 avoided cost, which is about 2.7 cents this year, that
2 also really lines up well with what the market can
3 deliver as far as price and value of solar.

4 It's my experience that we can estimate how
5 much solar is consumed on-site based on the size of the
6 solar panel and the load of the house. And we can help
7 that customer understand if 50 percent, two-thirds,
8 75 percent, is consumed on-site and thus reducing retail
9 rates, and how much is pushed back to the grid and is
10 credited at that avoided cost.

11 So we are here to help. We have got a team
12 full of folks that can help. But just the simplicity of
13 the -- of the retail monthly netting, to me, is -- that
14 in itself is not a good reason to overpay for that energy
15 that's pushed back to the grid.

16 Q Yes. But my question is, what information do
17 we need to make sure that we send as little back to you
18 guys as possible?

19 A (Witness Mallard) Right. So, again, we can
20 help and we've got a -- we've got a team of folks that
21 can help. We can look at your -- if it's a business
22 account, we have likely got more information. If it's
23 over a megawatt, we've got hourly information. We can
24 bump that, your hourly usage up against the solar
25 production curve based on the size of the solar system

1 that you might put on your rooftop or beside your
2 business or residence.

3 We can help a customer estimate how much is
4 consumed on-site, how much is pushed back, put values on
5 both of those and help produce a payback analysis for
6 customers that are interested.

7 Q So what if my building is not over a megawatt?
8 What do I have to do to get the hourly information that
9 you need to make this analysis?

10 A (Witness Mallard) Yes. So if you're on a
11 time-of-use rate, then we'll have your rates by -- your
12 usage by the time-of-use period, and we can overlay the
13 solar production curve on that as well and estimate how
14 much is going to be credited at the off-peak, the
15 on-peak, and then how much might be pushed back.

16 For residential customers, it's a little
17 less -- we don't have the granular information, but we
18 still are able to make some assumptions and help
19 customers estimate just how much energy would be consumed
20 on-site and how much would be pushed back to the grid.
21 So not as accurate without all of the billing
22 determinants, but still we're able to make a relatively
23 informed decision.

24 For the most part, if a solar facility is sized
25 correctly, the majority of the energy will be and should

1 be consumed on-site, really minimizing the amount that's
2 pushed back to the grid.

3 Q Are you aware that at this point local
4 governments like the City of Savannah, Atlanta, DeKalb
5 County, the ones in our coalition are currently being
6 asked to pay \$50 per meter per month to have access to
7 hourly interval data?

8 A (Witness Mallard) I am not aware of that; but
9 if you are telling me that that's true, I will accept it
10 subject to check.

11 Q Well, I was going to ask you to speak to the
12 cost causality of that. I may need to find someone else.

13 Anyone want to take that question?

14 A (Witness Mallard) Yeah. So all of our
15 programs, all of the information that we provide to
16 customers, we really do try to assign the cost to the
17 cost causer. And so although I am not familiar with the
18 \$50-a-month charge, my expectation is, that's been --
19 that amount has been determined based on the cost of the
20 meter and the cost of gathering the metering information,
21 the cost of interpreting it, and the cost of producing it
22 back to the customer. And so those fees are designed to
23 collect the costs from the cost causer, and do not shift
24 those costs to the entirety of all Georgia Power
25 customers.

1 Q Shifting to Community Solar and this idea of
2 income-qualified. Absolutely thrilled to see that you
3 are offering that, but I'm a little disappointed to see
4 that the standard subscription is going up; and I am
5 curious as to why that is happening when, to my
6 knowledge, these sites have already been built. So can
7 you explain the, I believe it's \$3 increase in the
8 standard subscription?

9 A (Witness Mallard) Yes. And the subscription
10 price for Community Solar, Commissioners, is calculated
11 based on the same notion that we've talked about a couple
12 of times already. To prevent costs from being shifted.

13 And so as you guys -- you guys are aware our
14 residential rate is an energy-only rate, and so the
15 entirety of the cost of providing electricity is
16 recovered through those -- those kilowatt hours. All of
17 the costs are recovered, save the base charge, through
18 the energy charge.

19 And so in order to make sure the Community
20 Solar participants continue to pay their fair share for
21 their portion of the grid, their portion of the
22 generating plant, the transformer, the wire, the customer
23 service, all those things, we have to design the
24 Community Solar participation price at an amount that
25 ensures that we still recover the correct amount of costs

1 for those customers.

2 And so it's in anticipation of increases that
3 we have seen in fuel rates and expected increases in base
4 rates, that we have estimated that that price needs to be
5 raised by the \$3 to make sure that we continue to cover
6 those costs from those participants and costs are not
7 shifted to nonparticipants.

8 VICE CHAIRMAN ECHOLS: Mr. Mallard, we have had
9 trouble getting subscribers to it. So what you are
10 telling me is your answer to this is "Let's raise
11 the price \$3."

12 Is that what you are saying?

13 WITNESS MALLARD: I want subscribers more than
14 anybody; I promise. We meet about this monthly,
15 Commissioners, but I do not want subscribers at the
16 expense of shifting costs to nonparticipating
17 customers. So we've got to stay true to that
18 principle; and in order to keep from shifting costs,
19 we've got to adjust that amount.

20 Now, we are going to continue to market regular
21 Community Solar. We have actually seen some pretty
22 good growth here lately, with north of 2,000 blocks
23 sold just in the last month or two. And then we are
24 really counting on that income-qualified Community
25 Solar pilot to -- that's going to use up to 5,000 of

1 the blocks to really help grow the subscriptions to
2 the Community Solar program.

3 VICE CHAIRMAN ECHOLS: How many months out of
4 the year are customers that subscribed cash positive
5 on this? Do you have any idea? Is it one? Is it
6 any months? Anything?

7 WITNESS MALLARD: It definitely is. It depends
8 on -- so in the summer, there is an inclining block
9 and bills are more expensive than the other eight
10 months of the year. The residential rate is a
11 declining block, so bills are less. I can tell you
12 over the course of 12 months, generally we say a
13 customer is going to end up averaging about \$5 in
14 addition on their monthly bill.

15 So they are going to pay -- if it's 24.99 now,
16 it's proposed to go up. They will get a credit
17 back; and over the course of a year, they will end
18 up paying, on average, about \$5 more a month. But
19 there are some months where the credit is bigger and
20 some months when it's less.

21 VICE CHAIRMAN ECHOLS: I am not being snarky
22 here. Does it bother you that the EMCs are able to
23 do this virtual net metering and have it be cash
24 positive more for their customer's companies like
25 Walton EMC?

1 WITNESS MALLARD: I'm not intimately familiar,
2 Commissioner. It would depend on the rate design
3 that the customers were on. All I can tell you is
4 from a rate and program design perspective, the
5 Georgia Power renewable development, we just don't
6 want to design a program that depends on shifting
7 costs to nonparticipants to make it work for the
8 participants.

9 VICE CHAIRMAN ECHOLS: And you are aware with
10 my original motion, right, that created this, and
11 shame on me for not being more specific, right, back
12 when we did this long ago. Okay. Thank you.

13 BY MS. BROWN:

14 Q. So to make sure I am understanding, when we pay
15 for a subscription price, we are not paying for the price
16 of the solar farm. We are actually paying for the price
17 of the energy that's being offset? And it will continue
18 to go up as energy prices go up?

19 A (Witness Mallard) Yes. So you are -- what a
20 participant is paying for is their subscription to the
21 block of Community Solar energy. And what they get for
22 that subscription price is a credit on their bill at a
23 retail rate, so those kilowatt hours are reduced from
24 their bill at the retail level and the RECs are retired
25 on their behalf.

1 The price, the subscription price is developed
2 based on the relationship to Georgia Power base rates and
3 to ensure that those customers don't shift costs to other
4 customers when those kilowatt hours are reduced from
5 their monthly billing determinants.

6 Q To Commissioner Echols' point, I mean, most
7 programs are set up. If they are not immediately cash
8 flow positive, they at least allow you over a period of
9 time to hedge against fluctuations and natural gas
10 prices.

11 So I guess the question is, with this Community
12 Solar, how is it functionally different than any of the
13 other Simple Solar programs? You are still purchasing
14 energy at a premium and retiring a REC; is that correct?

15 A (Witness Mallard) Yes, you are -- it's a
16 premium to retire the REC. It's different from Simple
17 Solar in a good number of ways. First of all, you are
18 supporting Community Solar facilities developed here in
19 Georgia. All of our facilities are local facilities,
20 Athens, Augusta, Savannah area. You know exactly where
21 your REC is coming from, where the block of energy is
22 being produced.

23 And then additionally, it's -- as -- as we do
24 sell out the program -- and I am optimistic we are going
25 to -- the new income-qualified program is going to

1 increase our sales significantly -- we will grow that
2 program by building more Community Solar facilities here
3 in Georgia.

4 Contrast that to the Simple Solar program which
5 is supplied by RECs that are not bundled with energy. We
6 just purchase those RECs in the competitive REC market.
7 Generally try to target solar RECs from Georgia, but
8 there is a limit. It's a limited number of available
9 voluntary RECs here in Georgia.

10 And so those are some major differences between
11 Community Solar and Simple Solar.

12 Q One other question is, with Community Solar and
13 with the understanding that your customers do typically
14 expect that a Community Solar program will provide some
15 opportunity to truly invest and to ultimately, not only
16 add more solar to the system, but maybe perhaps again
17 hedge against changes in natural gas prices like we are
18 seeing right now, are you considering any creative means
19 of finding additional value streams from those programs?
20 Like, for example, reducing arrearages for individuals
21 who might be energy burdened at the moment and ultimately
22 be supported by other customers like
23 Commissioner Pridemore has been talking about?

24 A (Witness Mallard) Yeah. I haven't considered
25 any designs like that. We analyzed Community Solar

1 programs from across the country as we were developing
2 ours and developing the income-qualified portion of the
3 Community Solar program. It's our position that the
4 rollout of the income-qualified Community Solar pilot is
5 what makes sense. It's a great way to, in a pilot
6 format, grow our Community Solar, help income-qualified
7 customers, allow for these third parties to help sponsor
8 and create a community benefit, and it is -- that's
9 what's most appropriate way for us to grow Community
10 Solar at this point.

11 Q All right. Thank you.

12 MADAM CHAIR PRIDEMORE: Miss Brown, I have a
13 question for you, because I am just truly
14 interested. So the five commissioners that you are
15 before today were all elected statewide. We travel
16 across the state, and we hear from different people
17 from different regions, different economic
18 backgrounds, et cetera.

19 You mentioned at the beginning of your comments
20 what was important to the people that you represent,
21 in order: Renewable energy, sustainability, and
22 green space preservation. Right?

23 MS. BROWN: Well, I was speaking on behalf of
24 my government.

25 MADAM CHAIR PRIDEMORE: Okay.

1 MS. BROWN: I was not speaking on behalf of
2 every single --

3 MADAM CHAIR PRIDEMORE: Of the coalition. But
4 on behalf of your government -- okay. All right.
5 In that order that you listed them, I am interested
6 on behalf of your government, how important is a
7 monthly bill and a tax increase to the people of
8 Savannah?

9 MS. BROWN: We are not proposing any tax
10 increases, Commissioner.

11 MADAM CHAIR PRIDEMORE: I am not saying that
12 you are. I am asking you a question. How important
13 is that? If renewable energy, sustainability, green
14 space preservation are important -- and they are. I
15 am not saying they are not. I am not discounting
16 them. I am interested, though, how important is
17 that monthly bill to the people of the City of
18 Savannah in tax increases?

19 MS. BROWN: We are certainly concerned about
20 the take-home income of every citizen in Savannah
21 and the other cities here, and that's one reason
22 that we are here at the Commission is to make sure
23 that utility bills are put on downward pressure.

24 And one thing that we are seeing right now,
25 Commissioner, is volatility in fossil fuel prices,

1 volatility in construction schedules for traditional
2 resources like Plant Vogtle. So we are here
3 advocating as best we know how about how to keep
4 those price under control.

5 As far as tax increases, that is well beyond my
6 pay grade as an energy analyst at the City of
7 Savannah.

8 MADAM CHAIR PRIDEMORE: Okay. All right. Just
9 interested. All right. Thank you, Ms. Brown.

10 MS. BROWN: Thank you, ma'am.

11 MADAM CHAIR PRIDEMORE: Georgia Interfaith
12 Power & Light and the Partnership for Southern
13 Equity.

14 Hello, Ms. Kysor.

15 WITNESS GRUBB: Madam Chairman, is there any
16 way we could have a quick break? I don't know what
17 time it is, but --

18 MADAM CHAIR PRIDEMORE: I was planning to break
19 at 3:55.

20 WITNESS GRUBB: I don't even -- I have no idea
21 what time it is.

22 MADAM CHAIR PRIDEMORE: I'm sorry. You-all
23 need a clock.

24 WITNESS GRUBB: I intentionally forgot one.

25 MADAM CHAIR PRIDEMORE: It is 3:42.

1 WITNESS GRUBB: Okay.

2 MADAM CHAIR PRIDEMORE: Do we need to do it

3 now, or can we go at 3:55? 3:55 it is.

4 Ms. Kysor, we are going to break at 3:55.

5 MS. KYSOR: That sounds great.

6 MADAM CHAIR PRIDEMORE: I was just getting

7 ready to --

8 MS. KYSOR: I have to finish by 3:55.

9 MADAM CHAIR PRIDEMORE: No, I was just getting

10 ready to tell you we were going to break at 3:55;

11 but our witnesses have been in that little box

12 together for a while.

13 CROSS-EXAMINATION

14 BY MS. KYSOR:

15 Q. Hello, gentlemen. Jill Kysor, and I'm here

16 representing Georgia Interfaith Power & Light and

17 Partnership for Southern Equity. Nice to see you.

18 A. (Witness Grubb) Good afternoon.

19 A. (Witness Mallard) Nice to see you.

20 Q. Y'all have had a long day. I'll direct my

21 questions generally to the panel, and anyone can answer.

22 But, Mr. Mallard, just a heads-up, I think my

23 first couple lines of questioning will focus on you. And

24 I'm going to start by distributing --

25 (The document referred to was marked for

1 identification as GIPL Exhibit 1.)

2 MS. KYSOR: If you don't mind if I approach --

3 MADAM CHAIR PRIDEMORE: You may approach.

4 MS. KYSOR: -- Madam Chairwoman, or Chairwoman.

5 I have what I have marked for identification as GIPL

6 PSC Exhibit 1, and what it is is Georgia Power's

7 response to staff data request DEA-3-37. And there

8 are trade secret components to it, but I haven't

9 included any of those here, so I think everything

10 I've got is public knowledge.

11 BY MS. KYSOR:

12 Q. Mr. Mallard, are you generally familiar with

13 this data request and response?

14 A (Witness Mallard) I am.

15 Q And I have only included the first two summary

16 tables. I don't intend on digging into any of the

17 detailed tables that I have not included.

18 A (Witness Mallard) Okay.

19 Q Okay. So Georgia Power conducted a preliminary

20 high-level analysis of the monthly netting program;

21 correct?

22 A (Witness Mallard) That's right.

23 Q And Georgia Power has not yet performed an

24 analysis on lost revenue due to the energy customers are

25 consuming on-site; right?

1 A (Witness Mallard) That's right.

2 Q You would agree with me that customers have the
3 right to buy less electricity from Georgia Power; right?

4 A (Witness Mallard) Absolutely.

5 Q Okay. I have a couple quick clarification
6 questions about the tables, just to make sure I
7 understand them.

8 And to recap, does DEA-3-37 still represent all
9 of the studies and analysis that Georgia Power's
10 conducted to date on the cost shift topic with RNR
11 monthly netting?

12 A (Witness Mallard) I believe it does. This
13 study was conducted based on the customers that were on
14 RNR monthly netting at the time. There are more
15 customers that have been added now, but I am not aware
16 that the study has been updated.

17 Q And Georgia Power has not conducted any
18 cost-of-service study analyzing customers with rooftop
19 solar?

20 A (Witness Mallard) That's right. This analysis
21 is based just on the energy that's pushed back to the
22 grid, just for the energy that's produced in excess of
23 what the customer's using and pushed back to the grid for
24 compensation.

25 Q And has the company conducted any other studies

1 or analysis on its monthly netting program?

2 A (Witness Mallard) The company hasn't done any
3 other studies on its own monthly netting program. I can
4 tell you that we have evaluated month -- net metering
5 programs and subsequent programs after net metering has
6 been rolled back and multiple other states that have been
7 evaluating this same topic over the last few months and
8 years.

9 Q And if any of the studying you have done has
10 been distilled into an analysis, could I make that a
11 hearing request?

12 A (Witness Mallard) Yes. I don't think there is
13 any analysis. It's mainly talking points related to some
14 of the cost shifts that we have seen in places like
15 California, \$3 billion I think the utilities have
16 estimated there. In Florida, something like 700 million
17 in cost shifting. We have got some other figures from
18 states like Louisiana that have rolled back net metering
19 as well.

20 MS. KYSOR: Chairwoman Pridemore, could I make
21 that a hearing request, if it exists?

22 MADAM CHAIR PRIDEMORE: Certainly.

23 MS. KYSOR: Thank you.

24 MADAM CHAIR PRIDEMORE: You know, the State of
25 Florida, just through their legislature, rolled back

1 net monthly netting.

2 WITNESS MALLARD: Yes, ma'am.

3 BY MS. KYSOR:

4 Q. So sadly, in the handout I gave you, you can't
5 see, but it's Column B titled "Accounts." So do you see
6 where that's labeled "Accounts" at the top?

7 A (Witness Mallard) Yes.

8 Q I just want to confirm, is this limited to
9 accounts, RNR accounts that are on the monthly netting
10 tariff only? It does not include any instantaneous
11 netting?

12 A (Witness Mallard) Correct.

13 Q Okay. And then under "Generated kWh," is that
14 roughly equivalent to exported kWh?

15 A (Witness Mallard) That would be exported kWh.
16 We don't have line of site into how much energy is
17 generated on-site and then consumed, how many less
18 kilowatt hours the customer purchased. The only thing we
19 have is what goes back through the meter and is pushed
20 back to the grid.

21 Q And you would agree that monthly netting
22 customers are compensated at the avoided cost rate if
23 they have net excess at the end of a monthly billing
24 period; correct?

25 A (Witness Mallard) Correct.

1 Q And I just want to confirm that the generated
2 kWh number only includes those exported kilowatt hours
3 that occurred during the course of the billing period and
4 that it does not include any exported energy that may
5 have been tagged at the avoided cost rate?

6 A (Witness Mallard) My assumption is that that
7 is correct, but I can't say that for sure. Subject to
8 check. And I can also -- I can also confirm that for
9 you.

10 Q Thank you.

11 And then Column L on Attachment A, I think --
12 sorry. You actually can't see that because I didn't
13 include it. At the very bottom, near the far right of
14 the page, there is a number, 764,194.

15 A (Witness Mallard) Yes.

16 Q I think that number is an error. I think it
17 adds up -- I think it is the sum of all the numbers above
18 it.

19 A (Witness Mallard) Okay.

20 Q And I believe that the \$382,097 is the sum of
21 the ones below that, so I just want to confirm whether
22 that \$764,000 number is an error.

23 A (Witness Mallard) I do not know. It should be
24 the sum of all of the numbers in the column. I can't say
25 for sure, Ms. Kysor, but I can doublecheck that as well.

1 Q Thank you.

2 And then you mentioned the 1 1/2 million when
3 you were talking to the previous intervenor.

4 A (Witness Mallard) Yes.

5 Q Looking at Attachment B, the last page there.
6 It looks like the total there is just shy of \$1 million.
7 I was curious, is the one-and-a-half million dollar
8 number you reference, is that a more updated analysis?

9 A (Witness Mallard) It's really just based on an
10 extrapolation to try to estimate the total impact for all
11 5,000 customers. And so you will see here this analysis
12 is run, we have only got 3,600 customers that were
13 on-line as of this point. And so we just did some simple
14 math to extrapolate, and that was the estimate for what
15 that would look like when all 5,000 customers get on.

16 Now, obviously it will be different depending
17 on the types of customers that sign up. What we have
18 seen is an increase in the average size of solar panel,
19 but -- on residential, but then also C&I customers that
20 are also installing larger solar installations. So it
21 could actually be higher than that 1.5. Again, we will
22 know once we get all 5,000 online and we can get a year's
23 worth of analysis on them.

24 Q And I am going to dig into an example here, and
25 I am looking at Attachment A specifically. So this table

1 is designed to represent revenue erosion from monthly
2 netting customers; correct?

3 A (Witness Mallard) It's really designed to
4 represent the payment difference for the energy pushed
5 back to the grid that would have been compensated at
6 RCB-avoided cost, that 2.7 cents. And instead, those
7 kilowatt hours were rolled back from the customer's bill
8 and were actually credited at the retail rate.

9 So that's meant to really isolate that
10 difference. Rough math on the residential rate is 12
11 cents to three cents, and so Georgia Power residential
12 rates averaging about 12 cents a kilowatt hour, 2.7,
13 we'll round that up to 3. And so it's meant to isolate
14 that difference between RCB-avoided cost and what was
15 credited under monthly netting.

16 Q And the title says "Revenue Erosion," which is
17 why I used that term. So that's the goal of the table,
18 to show that.

19 So nonparticipating customers won't actually
20 pay more for their electricity than they otherwise would,
21 unless there is a rate adjustment by this Commission that
22 addresses any alleged revenue erosion; right?

23 A (Witness Mallard) So nonparticipating
24 customers, yeah, it is -- what it creates is a revenue
25 shortfall on base rates. And so through the next rate

1 case, rates will be adjusted, redesigned. And whether
2 rates go up or down, costs will absolutely be shifted.
3 Costs that were recovered from these customers before
4 they had solar and monthly netting, now we are no longer
5 recovering those costs from those customers. Those costs
6 still remain to be recovered, and so they would be
7 recovered from all other customers.

8 Q The revenue shortfall is just where I was going
9 next. So according to this table, Georgia Power
10 experienced a \$382,000 revenue shortfall or erosion in
11 2020 associated with the monthly netting program; right?

12 A (Witness Mallard) Yes.

13 Q And subject to check, Georgia Power had a
14 total -- had total operating revenues in 2020 of about
15 7.5 billion; right?

16 A (Witness Mallard) Subject to check. I am not
17 familiar with that number.

18 A. (Witness Grubb) Subject to check. It's a lot
19 larger than that, but I don't know the specifics.

20 Q And subject to check -- and I have some of the
21 ASR documents, but subject to check, Georgia Power had a
22 total of net return in 2020 of about 1,716,785,000.

23 Does that sound in the ballpark?

24 A (Witness Mallard) Subject to check.

25 Q Okay. So making Georgia Power's return on

1 equity about 11.9 percent in that year, 2020?

2 A (Witness Mallard) Subject to check.

3 Q And so are you saying in the absence of the RNR
4 monthly netting program, Georgia Power's net return
5 resulting from the reduced revenue would have been about
6 roughly 300ths of a percent higher?

7 A (Witness Mallard) I am not even sure that the
8 return would be different.

9 I think it comes into play in the rate design
10 in a rate case, Commissioners, where the total amount of
11 expected revenue from a particular class or rate grouping
12 of customers is analyzed. What monthly netting does is
13 it reduces the amount of revenue recovered from those
14 customers in the historical year that's then translated
15 into the test year that then gets translated into rate
16 design into a rate case.

17 And so I am not even sure if that -- how that
18 would impact. I think the company's rate of return is
19 set based on -- based on Commission decision in the rate
20 case. But what I am saying is I think that rates would
21 be differently -- the residential rate would be designed
22 differently based on that amount of revenue that was
23 under recovered from those -- from those customers with
24 monthly netting.

25 Q So given the revenue erosion that you have

1 represented here, you know, just under 400,000 for 2020,
2 do you expect that the company would anticipate an actual
3 cost shift that would cause you to adjust rates as a
4 result?

5 A (Witness Mallard) Eventually, yes.
6 Absolutely. And that's the whole -- the whole basis
7 behind designing programs that don't shift costs. You
8 really want to make sure your program is designed to
9 protect nonparticipating customers, from the very first
10 customer that signs up, from the very first kilowatt hour
11 that's generated. It's a mistake, in my opinion, to
12 design a program that you know is going to shift costs
13 with the expectation that one day once it gets big enough
14 we will identify that, we will isolate it, and we will
15 try to come up with an alternative program design.

16 I just really think that's a bad way to go,
17 Commissioners. I look at these other states that are
18 trying their best to unwind net metering, and customers
19 who have made their financial decision based on it.
20 Solar installers, business people who have built their
21 entire business model around counting on net metering.

22 And then once we see places like California or
23 Florida with really big penetrations of customers decide
24 that, "Oh, gosh, this is now such a large amount, we have
25 got to undo this," that just doesn't make any sense at

1 all to me. You are creating a problem that's going to
2 hurt customers. It's going to hurt the solar industry.
3 It's not sustainable.

4 And so even though the amounts are small now,
5 it's -- it's my testimony that it's absolutely
6 inappropriate to design a program or to grow a program
7 that creates cost shift even as small as the first
8 kilowatt hour.

9 VICE CHAIRMAN ECHOLS: Let me -- let me -- oh,
10 we have got a restroom break. I'll ask you when you
11 get back.

12 MADAM CHAIR PRIDEMORE: Are you sure?

13 VICE CHAIRMAN ECHOLS: Yeah.

14 MADAM CHAIR PRIDEMORE: Are you sure? Okay.
15 All right. Let's take a break.

16 (A recess was taken.)

17 CROSS-EXAMINATION (CONTINUED)

18 BY MS. KYSOR:

19 Q. Mr. Mallard, I think this is still going to be
20 directed at you, but switching topics to Community Solar.

21 A. (Witness Mallard) Okay.

22 Q. So roughly starting at the top of page 48 of
23 your testimony I think you start covering Community
24 Solar. And the pricing on the program -- so that covers
25 program costs, like administrative and labor costs. And

1 I believe I heard you say it also covers costs like lost
2 revenue. I don't think you used that term, but is
3 that --

4 A. (Witness Mallard) I'm sorry. Give me the page
5 reference again, please.

6 Q. Sorry. Page 48 --

7 A. (Witness Mallard) 48. At the top?

8 Q. Generally lines 3 through 11, but line 6 where
9 you talk about the cost of the program.

10 A. (Witness Mallard) Yeah. I'm there now.

11 Q. And does the cost of the program cover labor
12 costs, administrative costs, and also lost revenue?

13 A. (Witness Mallard) That's right.

14 Q. And do you know approximately how much of the
15 monthly cost is intended to recover lost revenue versus
16 the programmatic expenses?

17 A. (Witness Mallard) I don't have that in front of
18 me. I believe a data request has been submitted that
19 provides at least some of that information. I know a
20 data request has been provided that shows the
21 administrative cost assigned to the program.

22 Q. And then I have a copy of it, but I'm hoping
23 not to have to go through the -- passing it out because
24 I'm not going to ask about the details. But in response
25 to one of the data requests you talked about the revenue

1 from the Community Solar Program. Do you recall that --

2 A. (Witness Mallard) Yes.

3 Q. -- generally?

4 And then just, big picture, what does that
5 revenue number consist of? It's the monthly program
6 subscription fees and what else would go into it?

7 A. (Witness Mallard) So the revenues attributed to
8 the Simple Solar Program or the Community Solar Program?

9 Q. The Community Solar Program.

10 A. (Witness Mallard) The Community Solar Program.
11 So it is specifically the revenues collected from
12 subscriptions from participants of the program.

13 Q. And that's it?

14 A. (Witness Mallard) That's it.

15 Q. Okay. And on the -- you had another data
16 response, which I have, but I'll ask you just generally
17 about it. I'm happy to share it with you, if you need
18 it.

19 You had another data response that covered the
20 program costs of the Community Solar Program and the
21 expected costs of the Income Qualified Community Solar
22 Program. Do you recall that?

23 A. (Witness Mallard) Yes. Generally.

24 Q. And generally do you recall that the Income
25 Qualified Community Solar Program, the pilot, is quite a

1 bit pricier than the standard Community Solar Program?

2 A. (Witness Mallard) I don't know that I could
3 agree with quite a bit pricier. The cost for the Income
4 Qualified Community Solar Program could certainly be
5 higher than the cost on a per-block basis than the
6 regular Community Solar Program.

7 Q. I'll put it in front of you just so --

8 MS. KYSOR: Madam Chairman -- Chairwoman --

9 MADAM CHAIR PRIDEMORE: You may approach. You
10 can call me Chairman.

11 MS. KYSOR: Thank you. It's a long word,
12 Chairwoman.

13 BY MS. KYSOR:

14 Q. Okay. My colleague is handing out what has
15 been marked for identification as GIPL PSC Exhibit 2 and
16 it's Georgia Power's response to STF-LA-2-30.

17 Do you recognize this document?

18 A. (Witness Mallard) I do.

19 Q. Great. And on the back side of that handout it
20 lists projected costs for various programs. And I'm just
21 focused in on the Community Solar and the Income
22 Qualified Community Solar Programs.

23 A. (Witness Mallard) Yes.

24 Q. And so I'm looking at mainly 2023 through 2025
25 because the Income Community Solar Program hasn't been

1 approved yet. So you're anticipating most of the costs
2 hitting after 2023?

3 A. (Witness Mallard) Right.

4 Q. Okay. So I'm just curious maybe what would
5 drive such a high program cost for that compared with the
6 regular Community Solar Program.

7 A. (Witness Mallard) Yeah. This is subject to
8 check. I don't have the data behind this in front of me.
9 But I believe these numbers include not just the
10 marketing and program administration, but also the cost
11 of the buy-down of the blocks that would be recovered
12 from the corporate sponsor.

13 Q. I'm sorry. Could you say that another way for
14 me?

15 I didn't -- the buy-down of the blocks, what do
16 you mean by that?

17 A. (Witness Mallard) Right. So the Income
18 Qualified Community Solar Program, the way it's going to
19 work, Commissioners, is the -- Georgia Power is going to
20 partner with a corporate sponsor who will be responsible
21 for the buy-down, the paying down of the price of the
22 block for the participant from the retail price down to
23 \$7 roughly a discounted price at about 75 percent.

24 So I think, Ms. Kysor, this amount right here
25 includes not just the marketing of the program but also

1 the cost of the buy-down that would be recovered from the
2 corporate sponsor.

3 Q. So is it maybe -- okay. And maybe the
4 marketing. Do you expect that those costs are higher for
5 the program --

6 A. (Witness Mallard) I would, yes. I think the
7 acquisition costs will be higher. We already started
8 developing a preliminary customer acquisition plan
9 whereby we target customers who would be a good fit.
10 Obviously they need to qualify for the income qualified
11 portion and that would be under 200 percent of the
12 federal poverty level.

13 And then, additionally, we're going to try to
14 target that in some specific locations. But to
15 procure -- to acquire those customers will be a little
16 bit more costly on a per-block basis than what we've seen
17 with the traditional Community Solar Program.

18 Q. And then you expect -- y'all submitted a
19 response to a data request that looks like customers
20 would save on average maybe about \$15 a month. Does that
21 sound right?

22 A. (Witness Mallard) That does.

23 Q. And that is inclusive of -- or nets out the \$6
24 or \$6.99 monthly fee?

25 A. (Witness Mallard) That's exactly right. So

1 that's meant to represent the amount that the customer
2 does pay the non-discounted amount of \$7 a month and then
3 as an estimate based on the value of the energy produced
4 by each block and the value of those kilowatt hours on
5 the customer's retail bill.

6 Q. And is Georgia Power open to having some sort
7 of bill savings assurance built into the program or at
8 least a bill neutrality provision?

9 A. (Witness Mallard) So as it's designed right
10 now, we don't have a provision like that, but what we do
11 have is the ability to target customers that we believe
12 will save money. We've already pulled a sample of just
13 north of 50,000 income qualified customers to study.

14 What that analysis showed, Commissioners, is as
15 long as customers have a minimum usage. And I don't know
16 that number of kilowatt hours, but something -- something
17 a little bigger than just a really small customer. They
18 are going to see the savings. They're going to see that
19 solar-produced savings on their bill.

20 It would only be customers with very small
21 monthly usage that might not save as much. And so it's
22 our intent to target customers that do have the larger
23 bills. The Community Solar Income Qualified is going to
24 benefit them more and it will insure that those customers
25 save and don't end up with any months where they're

1 actually a net positive on their bill.

2 Q. Do you agree that the extra fee or the extra
3 line item on the bill could be a deterrent if folks don't
4 have any assurance that they could achieve a savings each
5 month?

6 A. (Witness Mallard) So it could be. Part of the
7 Income Qualified Community Solar Program, the intent is
8 to educate these customers. It's not just a bill
9 discount. It's the ability to participate in solar and
10 to understand how solar works, how solar production
11 varies month by month, how the customer does pay some
12 towards it and you get that credit back.

13 And so we'd absolutely explain and educate
14 that. Additionally, on bills of customers that
15 participate in Community Solar, we identify the amount of
16 kilowatt hours that the Community Solar produced and save
17 the customer money. So in that way I would hope that we
18 could educate customers and show that for the \$7 a month
19 monthly subscription fee they're getting much more
20 benefits on their bill.

21 MADAM CHAIR PRIDEMORE: But the \$7 a month
22 monthly subscription fee, the sponsor's paying \$15 a
23 month per customer?

24 WITNESS MALLARD: They're paying the difference
25 between 28 and 7. It's, what, \$21 a month. They're

1 paying -- the sponsor will pay 21.

2 The 15, Madam Chair, is meant to represent the
3 monthly savings on the customer's bill. So they
4 will actually pay \$7. They'll get \$22 worth of
5 credit on average.

6 Again, these are averaged across customer data
7 set. They would average netting about a \$15 savings
8 a month.

9 MADAM CHAIR PRIDEMORE: Okay. So let's walk
10 this back because it's late in the day and I need
11 you to repeat yourself.

12 WITNESS MALLARD: Okay.

13 MADAM CHAIR PRIDEMORE: So qualifying customers
14 will pay the \$7 a month?

15 WITNESS MALLARD: They will.

16 MADAM CHAIR PRIDEMORE: And the sponsor is
17 paying \$21 a month because the cost of the program
18 is \$28 a month?

19 WITNESS MALLARD: You got it.

20 MADAM CHAIR PRIDEMORE: All right. The
21 customer is expected to save \$15 a month?

22 WITNESS MALLARD: That's on average. They're
23 going to get the output of one kilowatt of solar.
24 And so it varies through seasons of the year,
25 through month by month. But, on average, we expect

1 that block to produce approximately a \$15 net
2 savings for each participant over the course of a
3 year.

4 MADAM CHAIR PRIDEMORE: Can I further this into
5 just some obvious basic math?

6 WITNESS MALLARD: Uh-huh.

7 MADAM CHAIR PRIDEMORE: It's a program that
8 costs \$28 a month. The customer is saving 15.

9 WITNESS MALLARD: Uh-huh.

10 MADAM CHAIR PRIDEMORE: Where are the other net
11 benefits?

12 WITNESS MALLARD: So the benefits come from the
13 participating corporate sponsor, who has amongst
14 their corporate goals to try to help benefit the
15 communities in which their businesses are located.
16 That aligns with Georgia Power's goals, as well.

17 We really look forward to offering a program
18 that can help income qualified customers
19 participate, enjoy the benefits of solar, and see a
20 lower bill. But the program is designed such that
21 nonparticipating customers won't see any bill
22 impacts. They will all be covered by that corporate
23 sponsor.

24 COMMISSIONER MCDONALD: Does the corporate
25 sponsor get a REC?

1 WITNESS MALLARD: They do. They get the RECs.
2 That's the trade-off.

3 So the customers that are participating will
4 not get the renewable energy credit, Commissioner
5 McDonald. The corporate sponsor will have the RECs
6 retired on their behalf.

7 BY MS. KYSOR:

8 Q. Two follow-up questions on what the Chairwoman
9 was saying. So you noted that the savings is built off
10 the average expected production of the block. And in one
11 of the data responses you've listed that as 165 kilowatts
12 per block per month.

13 I'm just curious, do you know whether that
14 number is based off of the actual data on your Community
15 Solar Program production or if it's based on --

16 A. (Witness Mallard) NREL load shape. I don't,
17 but we can find that out subject to check.

18 Q. Thank you.

19 And then I'm looking at your testimony,
20 page 48, lines 26 through 28.

21 A. (Witness Mallard) I'm sorry. Say it one more
22 time.

23 Q. Page 48. Actually, lines 27 and 28.

24 A. (Witness Mallard) Okay. I'm there.

25 Q. And I just want to make sure I understand who

1 is paying for what. So there there's a sentence that
2 starts: All other program costs will be recovered from
3 the participating sponsor.

4 And I just want to confirm, does the
5 participating sponsor pay 75 percent of the monthly fee
6 or more?

7 A. (Witness Mallard) They pay the fee buy-down,
8 then they're also responsible for the program costs
9 related to the Income Qualified Community Solar Program.
10 So if there's Community Solar costs to run the program
11 overall, and we've talked about those, we designed those
12 and bank that amount into the overall price.

13 Additional costs, as we've talked about, the
14 customer acquisition could be a little more complicated.
15 It could be a little more costly to qualify these
16 customers to make sure we're targeting the right
17 customers. Any additional costs that are attributed
18 specifically to Income Qualified Community Solar will
19 also recover those costs from the participating sponsor.

20 Q. Do you have any idea, ballpark, how much those
21 additional costs might be?

22 A. (Witness Mallard) I think we do. I do not have
23 that off the top of my head. I think that exists in the
24 model where we develop the pricing.

25 Q. Could I make a hearing request for the

1 information about what a corporate sponsor might pay in?

2 A. (Witness Mallard) Sure.

3 MS. KYSOR: Chairman, could I make that hearing
4 request?

5 MADAM CHAIR PRIDEMORE: Certainly. Lines 24
6 and 25 of that page you say: The company will seek
7 corporate sponsorships.

8 Does the company have a corporate sponsor
9 that's signed up contingent upon this agreement?

10 WITNESS MALLARD: They're not signed up, but
11 they've indicated strong interest, assuming the
12 program is approved similarly to what we've
13 designed, Commissioner.

14 MADAM CHAIR PRIDEMORE: Line 25 makes that
15 plural, sponsorships. You have one or many?

16 WITNESS MALLARD: So, interestingly enough, we
17 had one that was the most interested. Since that
18 same as we've shared some of the program designs in
19 the IRP, we have received interest from other
20 similar customers. And so I would say their
21 interest is not as confirmed, but we do have other
22 customers who are interested.

23 BY MS. KYSOR:

24 Q. Now, I want to go back to one question. I
25 don't think I got a yes-or-no answer from you on where I

1 asked if Georgia Power would be open to having some kind
2 of bill savings assurance built into the program for
3 income qualified customers. I think you said you haven't
4 done that yet.

5 I'm curious, yes or no, whether you're open to
6 having that?

7 A. (Witness Mallard) So in this current design as
8 put forth in this pilot, I would say we're not. The
9 pilot design is as it is, but certainly we would consider
10 alternative designs as we go forward.

11 That's one of the great things about a pilot is
12 we've got to roll it out there, we're going to see what
13 the results are, and then we can certainly make --
14 consider different enhancements and improvements.

15 Q. And on page 48, line 17, you note that 5,000 of
16 the existing 8,000 blocks would be available for the
17 income qualified pilot?

18 A. (Witness Mallard) Correct.

19 Q. I'm curious -- I know you're changing the
20 Community Solar Program generally to open it up to
21 commercial customers, as well. If the 8,000 block
22 program gets eaten up quite quickly, I know you have also
23 asked to expand your Community Solar. I'm curious if you
24 intend to still keep 5,000 blocks available?

25 A. (Witness Mallard) No, no. I would say it would

1 be our intent to sell as many blocks as we can. The
2 5,000 block target here for income qualified, should we
3 sell more of standard Community Solar blocks, I think we
4 would work with Commission and staff to modify that. I
5 wouldn't want to turn anybody away to sell these blocks
6 that we have to reserve them for a particular program.

7 Q. I'm shifting now to the top of page 52,
8 running through the middle of page 53, where your
9 testimony talks about the DER local reliability
10 constraints pilot program.

11 A. Okay.

12 Q. You're off the hot seat for now, Mr. Mallard.

13 Okay. So I just -- a simple question. So your
14 testimony addresses the DER local reliability and
15 constraints pilot and then the DSM panel talks about the
16 DER customer program. I want to confirm those are
17 separate programs.

18 A. (Witness Robinson) That's correct.

19 Q. And are they unrelated?

20 A. (Witness Robinson) They are unrelated.

21 Q. Okay. And then I want to understand a little
22 bit more about the pilot program. Will these DERs
23 provide backup power to the customers when the grid power
24 is unavailable wherever the sites are?

25 A. (Witness Robinson) Yes. Correct. For the

1 seven sites that we have specified and mentioned, the
2 three buckets of use cases, capacity, resilience and
3 reliability. The reliability and resilience would be
4 targeting the use case of which you speak.

5 Q. And then would Georgia Power be able to call on
6 those DERs to operate at other times for reliability
7 purposes or any other reason?

8 A. (Witness Robinson) Initially it would be for
9 those three use cases. If we saw a value in dispatching
10 those for capacity needs in the future, of course, we
11 would work with Commission and Commission staff how we
12 would make that happen. But the important thing is those
13 resources need to be available when those contingencies
14 occur.

15 So we would need to make sure that those
16 battery systems and those generators that they're paired
17 with are available and online when that reliability need
18 or that resilience need or that capacity need happens.

19 Q. And so when the DER is operating, would it take
20 some of that customer's load offline or reduce that
21 customer's demands during those times?

22 A. (Witness Robinson) It would not anticipate
23 reducing demand, but it would take those customers off of
24 those distribution feeders. So say you had a car hit a
25 pole on one of these feeders and you had a thousand

1 customers that were behind or in the scheme of one of
2 these LRC pilots. That pilot would come online and feed
3 those thousand customers until the system were restored
4 and those customers could come back online.

5 Q. Will the participating customers or sites pay
6 anything to have the DER cited there?

7 A. (Witness Robinson) No, they will not.

8 Q. And would Georgia Power pay, I guess, through
9 the pilot for the capital costs of these units in this
10 program?

11 A. (Witness Robinson) Yes. That's correct.

12 Q. Has Georgia Power already selected the sites in
13 these six cities?

14 A. No, we have not. There are six locations -- or
15 seven locations that have been proposed geographically
16 disbursed throughout the state looking at attainment
17 areas, non-attainment areas, different types of customer
18 base, rural, metro. So we look to see the benefit of
19 locating these on the system and where we could do more.

20 And so we have not specifically identified on
21 those feeders where we would put these. Five of those
22 feeders have solar on them currently today. We'd look to
23 site these as close to the solar as possible to see if we
24 can pair these systems with the solar, as well.

25 Q. And shifting now to some questions about the

1 reserve margin. Mr. Weathers, I think it was you that
2 mentioned that your reserve margin study looked at a
3 58-year period from 1962 to 2019; is that correct?

4 A. (Witness Weathers) That's right.

5 Q. And so subject to check, in at least the last
6 four IRPs, 2013 through this one, the reserve margin
7 study was based on data that started in 1962 and then
8 went to the most current year available?

9 A. (Witness Weathers) That's correct. We've just
10 appended to the data as the actuals have occurred.

11 Q. So there's a different number of years --
12 weather years studied each cycle when you update the
13 study?

14 A. (Witness Weathers) There is. I mean, again, as
15 additional years occur that data is added -- I mean, the
16 purpose of the weather years is to model weather
17 volatility, the impacts of that on the reserve margin.
18 So as more years pass, that's just additional data
19 points. So the more data points, the more robust the
20 analysis is, in terms of the weather volatility.

21 Q. Have you identified any trends in weather over
22 the years, how weather might change in more recent
23 decades?

24 A. (Witness Weathers) No, not specifically. I
25 mean, there are cold temperatures and hot temperatures no

1 matter which decade that you look at.

2 But we're really not trying to identify trends
3 in the data. We're trying to capture volatility around
4 the data. So we're not projecting load to the reserve
5 margin study.

6 We take the company's actual forecast and load
7 forecast. We're modeling the volatility around that.
8 Because the planning reserves are there to compensate for
9 volatility, whether that be in the load itself or on the
10 resource side.

11 Q. The weather years analyzing the reserve margin
12 study, those are just looking at the temperatures for
13 each year; right?

14 A. (Witness Weathers) It is the temperature for
15 those years. For every hour of the year.

16 Q. And in the -- I know it's the next panel that
17 talks about the load and energy forecasts, but they look
18 at a different set of weather impacts over time; right?

19 A. (Witness Weathers) They do. I mean, they're
20 looking at a different set of weather years. And they're
21 looking at -- you can ask them about that.

22 But probably different variables. Again,
23 they're trying to project the company's load forecast
24 going forward. So there's a lot of inputs to that, in
25 terms of customer demand, growth, technology, things like

1 that.

2 That's not what the reserve margin study is
3 trying to do. We're only interested in weather
4 volatility because that's what the planning reserves are,
5 in part, there to cover.

6 Q. Gotcha. So the reserve margin weather years
7 are just looking at weather volatility during a certain
8 set of years?

9 A. (Witness Weathers) Yeah. It's the temperature
10 volatility because that's the part of the weather that's
11 most impactful to the analysis that we do.

12 Q. But you haven't looked at how the temperature
13 volatility may change over time?

14 A. (Witness Weathers) Not specifically. I mean,
15 we -- any changes over time will be captured in the
16 analysis. You know, for example, if there are more
17 frequent occurrences in recent year of a particular
18 temperature, the way that we -- we consider all the
19 weather years to be equally probable. So more frequent
20 occurrences of a temperature means in the analysis it
21 occurs more frequently. So there's a little bit heavier
22 weighting towards that temperature.

23 Q. Shifting gears, a couple of questions about the
24 natural gas PPAs. Looking at page 24, line 21, roughly.
25 I just want to confirm the natural gas PPAs that you're

1 proposing for certification, they don't have fixed fuel
2 prices included in them; right?

3 A. (Witness Grubb) They don't have fixed fuel
4 prices from a commodity standpoint. We do have firm
5 transportation for delivering that gas that are fixed,
6 but they would be based on daily gas prices just like our
7 company-owned units.

8 Q. So customers would pay for any variability in
9 the gas price over the term?

10 A. (Witness Grubb) They would.

11 A. (Witness Weathers) They would. Go ahead.

12 A. (Witness Grubb) The capacity prices are set and
13 the firm transportation prices are set. But, yes, they
14 would.

15 Of course, that's taken into account in our
16 dispatch; all right? So if gas prices go up or down,
17 that's factored into how we dispatch the fleet.

18 A. (Witness Weathers) Yeah. And in the analysis,
19 as well, it took into account a range of fuel prices.

20 Q. And did the 2022 to 2028 capacity RFP that
21 resulted in those PPAs -- did it prioritize proximity to
22 north Georgia load and any ability to address the
23 problems raised in the north Georgia reliability and
24 resilience action plan?

25 A. (Witness Grubb) It did not target those. These

1 were all existing facilities. And so we were able to
2 capture the impacts of that in the transmission studies.

3 Some of them are in the north part of the
4 state. And so we could take that into account when we
5 did our unit retirement studies and transmission studies.
6 We captured those. But, again, it wasn't specifically
7 targeted, but we do capture it in all of our analyses.

8 Q. And just a question about the renewable
9 integration study and the RCP and the relationship
10 between the two. So it seems like the renewable
11 integration study is going to feed into the renewable
12 cost benefit study; correct?

13 A. (Witness Weathers) That's correct.

14 Q. Is there any -- will they continue operating
15 a -- separate studies in parallel or are they then into
16 one analysis?

17 A. (Witness Weathers) Well, I think it needs to be
18 separate because the renewable integration study, that's
19 an actual study. So that's the product of running a
20 model, looking at penetrations of solar and what's the
21 cost to integrate that. The renewable cost benefit
22 framework is just a compilation of benefits and costs.

23 And so it pulls the renewable integration costs
24 from that study. It pulls the avoided energy costs from
25 the company's planning models. The capacity benefit

1 transmission losses, they're pulled in from different
2 places and compiled in one framework, the RCB framework,
3 to be applied.

4 Q. Thank you. Just one last clarifying question
5 on page 15, lines 17 to 19.

6 A. (Witness Grubb) Yes. You said 15, lines 17 to
7 19?

8 Q. Lines 17 to 19 where you mention that the
9 company added a CO2 intensity scenario that drives CO2
10 emissions down to 10 percent of current levels by 2050.

11 I'm curious if that's -- is that scenario
12 intended to address possible carbon pricing, Southern
13 Company's load and no carbon goal, or both?

14 A. (Witness Weathers) It's neither one. It's
15 technically a different method of applying carbon
16 pressure. As we've looked across the current landscape
17 of proposals, there are different ways -- and a lot of
18 them are aimed towards getting to net zero, which is
19 consistent with the Southern goal.

20 But, really, that's to model a declining ton
21 limit on fleet emissions. Not applied by price pressure,
22 but just applied as limits on an annual basis.

23 They both get to a net zero level of carbon
24 emissions. It was just to apply -- to examine through
25 analysis what if there's a different approach, other than

1 price, to get there, what impact does that have on the
2 build-out of the fleet.

3 MS. KISER: Thank you, panelists. That's all
4 the questions I have.

5 Chairman, could we, please -- I would ask that
6 GIPL PSC Exhibit 1 and 2 be moved into evidence.

7 (The documents referred to as GIPL PSC Exhibits
8 1 and 2 were received into evidence.)

9 MADAM CHAIR PRIDEMORE: Most certainly,
10 Ms. Kysor. Thank you.

11 Georgia Large Scale Solar Association and
12 Advanced Power Alliance.

13 MR. CARVER: Madam Chair, fellow Commissioners,
14 Brad Carver on behalf of the Georgia Large Scale
15 Solar Association and Advanced Power Alliance.

16 CROSS-EXAMINATION

17 BY MR. CARVER:

18 Q. Good afternoon, Panel. Good to see y'all
19 again.

20 A. (Witness Robinson) Good afternoon.

21 Q. Let me start off by asking y'all -- and, again,
22 these will be directed to the panel and whoever is most
23 appropriate to answer.

24 To date, how much solar generation does the
25 company have under contract?

1 A. (Witness Mallard) Online right now, it's about
2 2,400 megawatts. Under contract on top of that would be
3 another 1,100 megawatts or so.

4 Q. And then up to this point with the RFPs that
5 are out now, prior to this IRP, how much would you have
6 online?

7 A. (Witness Mallard) So we're committed to
8 renewables total of about 5,400 megawatts before the ask
9 in this IRP. Now, some of that is biomass and wind, but
10 the lion's share is solar.

11 Q. So in -- through your history, 2013, 2016,
12 2019, Georgia Power has used a variety of programs to
13 grow that solar portfolio; is that correct?

14 A. (Witness Mallard) Yes.

15 Q. Is it the company's view that the use of
16 competition to procure solar has resulted in better value
17 for the customers?

18 A. (Witness Mallard) Yes. One of our renewable
19 principles that I talked about earlier is using
20 competitive solicitations to procure the best value for
21 customers. So absolutely we feel really good about the
22 results that have come from our utility scale and our
23 distributed generation solicitations.

24 MADAM CHAIR PRIDEMORE: Mr. Mallard, did I just
25 hear you say biomass? Is there biomass in this

1 proposal? Because I haven't seen any.

2 WITNESS MALLARD: No. Mr. Carver asked for the
3 total amount of solar on the system. The number I
4 have in mind includes biomass and wind, which is
5 5,400. Could back that out and solar is going to
6 end up being 46 or 700 without the wind and biomass.

7 MADAM CHAIR PRIDEMORE: Okay.

8 WITNESS GRUBB: And, Commissioner, that's
9 biomass from 2010 and beyond --

10 MADAM CHAIR PRIDEMORE: Early biomass.

11 WITNESS GRUBB: Yeah.

12 MADAM CHAIR PRIDEMORE: Okay. Thank you.

13 WITNESS GRUBB: Yes, ma'am.

14 BY MR. CARVER:

15 Q. Does the CARES program build on the experience
16 the company has gained through these competitive
17 solicitations?

18 A. (Witness Mallard) Yes, it does. And just to be
19 clear, the CARES program really refers specifically to
20 the subscription program element of these procurements.
21 We really identified the procurements themselves by the
22 years in which the resources are expected to come online.

23 So the utility scale, RFP, for example, for --
24 right now it's on the street is for 2022, 2023. We call
25 them by that name. The CARES actually refers to the

1 subscription element of those procurements.

2 Q. Gotcha. Is it your opinion that the utility
3 scale solar market is willing and has been able to
4 deliver cost effective solar to Georgia Power's customers
5 at a price that is below avoided cost?

6 A. (Witness Mallard) Yes. It's impressive the
7 prices that the Georgia market has produced. In my
8 opinion, the Georgia competitive solar market is one of
9 the premier markets for renewable energy in the whole
10 country.

11 Q. The Astrape solar penetration study seems to
12 suggest that the existing solar included in the Georgia
13 Power generation mix is providing value to the ratepayer
14 and has been a beneficial addition to the utility's
15 overall generation fleet.

16 Would that be correct?

17 A. (Witness Weathers) Well, the Astrape -- you say
18 the renewable integration study? It doesn't directly
19 address the benefits of the solar that has been added.
20 It just includes that solar that has been added and then
21 examines the impacts of it on operations and then the
22 impacts of additional solar. So it's not doing it --
23 it's not producing a cost benefit of that solar. It just
24 assumes it happens.

25 Q. This Commission has opted to increase the total

1 number of megawatts of solar megawatts proposed by
2 Georgia Power in the previous two -- actually, in the
3 last three IRPs, 2013, 2016, and 2019; is that correct?

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

5 Q. The Commission decided to expand the utility
6 scale solar megawatts. The fact that the Commission
7 decided to expand those megawatts can be validated by the
8 Astrape solar penetration study; is that correct?

9 A. (Witness Weathers) Again, Mr. Carver, I think
10 that it's two different things. I mean, the value and
11 benefit to customers of that capacity is -- is examined
12 when the RFP is evaluated. The Astrape study assumes
13 that it's built and is there on the system. And then
14 it's evaluating the impact on realtime operations of that
15 generation.

16 So it's not -- it's -- that study itself is not
17 calculating value. The value had already been calculated
18 at the time the RFPs were evaluated and certified.

19 Q. So in -- several of you may recall that in the
20 2019 IRP we talked a lot about fuel price volatility, the
21 situation in Europe, liquified natural gas exports to
22 Europe, and the effect of the Russian pressure on western
23 Europe.

24 In light of that, when the solar industry talks
25 about fuel price volatility, is it correct to say that

1 that is bad for the ratepayers?

2 A. (Witness Weathers) Is fuel price volatility bad
3 for ratepayers? Not necessarily. Because volatility
4 goes up and it goes down.

5 I mean, we are certainly seeing a recent
6 increase in natural gas prices. We saw that before the
7 Russian/Ukraine conflict related to the pandemic and the
8 decreased demand during the pandemic. And then as the
9 demand came back, production was slower to respond.
10 We've seen that with the situation in Europe and the
11 value of exports to Europe.

12 However, if we look at the forward natural gas
13 price curve, we expect that those impacts will be
14 relatively short-term. The long-term fundamentals
15 continue to support gas prices consistent with what's in
16 our filing. In fact, the Energy Information Association,
17 the governmental agency that produces the forecast that
18 we use, the latest forecast that they produced just last
19 month continues to show long-term natural gas prices
20 similar to what we have in our filing.

21 So we think it's important to consider a range
22 of gas prices because within that range you expect there
23 to be volatility. But if you're considering a range,
24 then you're making sure you're making the best decision
25 for customers, not just on a single price, but on the

1 range of prices.

2 Q. When Georgia Power invests in utility scale
3 solar, does that act as a hedge against fuel price
4 volatility?

5 A. (Witness Weathers) Well, it doesn't impact the
6 volatility of fuels, but it does provide energy that is
7 not subject to volatility itself.

8 Q. These are fixed-price contracts for 30 years
9 plus, right, so there's not volatility with a procurement
10 that happens with a utility scale procurement that's set
11 at a fixed-price contract?

12 A. (Witness Weathers) That's correct. There's no
13 volatility in the price of the PPAs, if you're -- if
14 that's what you're talking about.

15 Q. So wouldn't that act as a hedge against
16 volatility you see with other fuel sources, including
17 natural gas?

18 A. (Witness Weathers) Well, I think it's
19 definitely part of a diverse portfolio. So any diversity
20 in the portfolio helps with fuel price volatility, as you
21 can shift from one generation source to another.

22 So there is -- there's benefit from having
23 solar. The company has recognized that. We are planning
24 for that. It's reflected in our models. And so -- so it
25 is a benefit to having a resource that's -- that doesn't

1 have the same volatility.

2 Q. That has no volatility?

3 A. (Witness Weathers) That's -- not in price.

4 Q. In price?

5 A. (Witness Weathers) In output it does. And so
6 there's different types of volatility. So it's important
7 to consider those different outputs in a robust planning
8 analysis.

9 Q. Could you explain the concept of best cost
10 solar projects?

11 Could you also explain how and under what
12 circumstances this evaluation could be used?

13 A. (Witness Mallard) Yeah, I'll be happy to. And,
14 really, Commissioners, what we're proposing here with the
15 best cost analysis, the fundamental change is to stop
16 using that Mg0 avoided cost number as an automatic
17 disqualifier, as we have in the past.

18 As we've talked about earlier, we have some
19 improvements in our modeling. We're now able to
20 preselect renewable resources through that model and that
21 show that those resources will provide economic benefits
22 to customers long term.

23 And so in the past the model hasn't been able
24 to select those resources. And so that avoided cost
25 ceiling, if you will, has been used to ensure that we're

1 procuring those resources that will benefit customers.

2 Now, with the new enhancements in the model and
3 the ability to choose renewable resources, our plan has
4 identified this renewable need. And so it's in that way
5 that our evaluation process will be modified.

6 Really, the steps will be more of the same.
7 We're going to continue to choose the resources that
8 provide the most value to customers, including both their
9 costs, their operational characteristics, their
10 interconnection costs, and the benefits they provide
11 customers. But the primary change is that we'll no
12 longer propose to use that Mg0 avoided cost bogey as an
13 eliminator of proposals.

14 Q. So in this IRP, for the first time, Georgia
15 Power has proposed a regional RFP north Georgia --
16 focusing on north Georgia. Would you agree that when
17 evaluating solar projects participating in this north
18 Georgia RFP that it is appropriate that the RFP bid
19 evaluation reflect the value of the targeted region,
20 i.e., north Georgia, and not a statewide avoided cost?

21 A. (Witness Mallard) So, no, I don't think that's
22 right at all. What will happen is each of these projects
23 are going to get evaluated based on where they choose to
24 locate and a project-specific transmission evaluation.
25 It's in that way that each project will be assessed the

1 proper cost for integrating into the system.

2 The energy itself is -- should be valued on a
3 statewide basis. And that's what we'll propose to do.
4 It's the integration cost, the impact to interconnect to
5 the transmission system where projects that locate in
6 north Georgia will see a benefit.

7 A. (Witness Robinson) And, Commissioners, it's
8 important that the future RFPs that look at -- if you
9 look at south Georgia talked about the -- the constraints
10 that we're already seeing. I mean, we're getting very
11 full as it relates to south Georgia. We saw that in the
12 last RFP. I think the RFP that's being evaluated right
13 now will show that, as well.

14 And I think the costs associated with
15 transmission will be reflected if we continue in south
16 Georgia and not target north Georgia. But we need time,
17 as I mentioned before, to build the transmission, those
18 highways, to get the megawatts from south Georgia to
19 north Georgia so that we can continue development in
20 south Georgia. But I think as we go forward, we're going
21 to see more and more constraints as it relates to
22 transmission and transmission costs imputed against
23 future bids in south Georgia in RFPs.

24 A. (Witness Grubb) And that geo- -- from a
25 generation standpoint, there's value in geographic

1 diversity, as well.

2 Q. Georgia Power has -- I'm sorry?

3 A. (Witness Robinson) I'm sorry. What Mr. Grubb
4 was talking about there is if you've got solar and -- all
5 of it in south Georgia and you have a thunderstorm come
6 across or you have a hurricane that comes and clips the
7 southern part of the state and you lose all of that solar
8 you don't have the benefit of having the additional solar
9 in north Georgia at that time.

10 Q. Georgia Power has proposed a significant amount
11 of BESS, battery energy storage systems, in this 2022
12 IRP. And certainly GLSSA and APA applaud this step to
13 modernize the grid.

14 Do you think it is prudent and appropriate to
15 articulate all the storage use cases that the BESS
16 procurement will address for the utility?

17 A. (Witness Grubb) Could you repeat the question?
18 I'll make sure I --

19 Q. Yeah. So --

20 A. (Witness Grubb) -- answer the last part.

21 Q. So do you think it's appropriate to articulate
22 all of the storage use cases that the BESS procurement
23 will address for the utility?

24 A. (Witness Weathers) I don't know, Mr. Carver,
25 sitting right here, we can identify all of the storage

1 use cases that the BESS could procure? What we've done
2 is we have examined costs and benefits associated with
3 the uses of storage determined by our modeling.

4 So primarily we're looking at the storage being
5 able to replace operating reserves on the system to serve
6 that function, instead of the steam units. But it also
7 provides other energy benefits and there's also capacity.

8 So we have considered the ones we've been able
9 to identify and quantify, but there may be others --
10 other uses of it, because it's a very flexible resource,
11 that we just can't anticipate right now.

12 Q. So we've established earlier that the
13 competitive bid procurement process has worked well for
14 both utility scale and distributed generation
15 procurement. Isn't it safe to assume that such
16 competitive procurement would also ensure that the free
17 market delivers the best value for storage?

18 A. (Witness Mallard) Yes. And that's actually
19 what we're proposing is the same way that we went to the
20 market for a competitive RFP for our EPC vendor for the
21 Mossy Branch project, the 65 megawatt project that we
22 talked about that was approved last August, it's our plan
23 and our intention that for the proposed McGrau Ford
24 project, and for other projects going forward, that the
25 company would procure those EPC services through a

1 competitive RFP. It's really just the ultimate ownership
2 and control and operation that Georgia Power is
3 requesting to own and operate. And, again, it's because
4 of the importance of those reliability services and that
5 responsibility to provide that reliability is why we
6 think that's critical that Georgia Power own those
7 resources.

8 Q. Witness Mallard mentioned earlier that Georgia
9 Power will accept solar plus storage bids for the RFPs in
10 upcoming procurements. If the bid storage use cases are
11 not valued appropriately, Georgia Power would end up with
12 an inaccurate market response; is that correct?

13 A. (Witness Mallard) I would say that's true in
14 every RFP the company has ever run or will run.

15 Q. So back in January the issue came up for the
16 second RFP from the CRSP program. And we had a
17 discussion around the level playing field between storage
18 and storage -- or, excuse me, solar -- solar only and
19 solar plus storage bids.

20 What is Georgia Power going to do going forward
21 that we'll have a level playing field between storage --
22 or excuse me, solar only and solar plus storage bids?

23 A. (Witness Mallard) So I will confirm to you and
24 commit to the Commission that as part of the RFP
25 evaluation process, the company works very closely with

1 the staff and the independent evaluator to make sure that
2 we are evaluating all of the bids and all the different
3 technologies and use cases appropriately. So we'll
4 absolutely strive and make sure that we do properly value
5 solar only, solar that's required to be on automatic
6 generation control now, and compare that to appropriately
7 other resources, like wind or other sources that might be
8 bid in, but also solar and the storage use cases,
9 including solar -- there's new ones. There's firming and
10 shifting and there's smoothing -- smoothing and firming
11 and scheduled use case are the three use cases now in the
12 RFP.

13 A. (Witness Weathers) And just to add to that, the
14 mechanism by which we do what Mr. Mallard is describing
15 is the renewable cost benefit framework. And so
16 specifically if you think of the example of smoothing
17 solar -- and so smoothing solar has the benefit of not
18 incurring the support capacity costs related to impacting
19 regulating reserves.

20 And so when we give it that credit in the RFP
21 evaluation, another way to accomplish that is with -- is
22 with AGC on the solar itself. And so they're both
23 avoiding the same cost. And so they're both getting the
24 same credit in the current way that we do the evaluation.

25 But I think as long as we're consistently

1 applying the renewable cost benefit framework in an
2 appropriate way to give the assigned costs where those
3 are due and to give credits where those -- and benefits
4 where those are due also, that's the way that we can
5 ensure fairness across different technology types.

6 Q. Now, Georgia Large Scale Solar Association and
7 Advanced Power Alliance, we have a lot of renewable
8 energy advocates in this room, but we are the group in
9 this case, in this IRP, and have been in the past two
10 IRPs, to be a voice for the utility scale market segment.
11 We also bring expertise of the other 49 states, as well.

12 Is Georgia Power open for our input on how to
13 best create those use cases based on the experience we've
14 had in other markets?

15 A. (Witness Mallard) Yeah. Certainly. We're open
16 to that and we absolutely depend on your members and all
17 the bidders in our RFPs to provide us that -- that
18 intelligence and that information for -- from their
19 experience and their participation in other markets.

20 In fact, some of the recommendations that GLSSA
21 has made in the last IRP, including take-or-pay
22 contracts, including AGC, which wasn't recommended last
23 time, including considering scenarios of -- of carbon and
24 gas, we've taken a lot of those into account and have --
25 we've leveraged those. Those are now parts of our

1 program. So we absolutely appreciate that.

2 I'll also point out to the Commission that it's
3 appropriate to receive that feedback. It's also
4 appropriate to make sure that the Commission, staff,
5 Georgia Power and the IE continue to run an RFP that
6 provides the most benefits to our customers.

7 And so while it's important to receive feedback
8 from the market participants, they're motivated to make
9 sure that they can provide the most successful bids they
10 can and do the best for their commercial enterprises.
11 And so we want to make sure that we take that into
12 account, as well, as receive that feedback and then fold
13 it into our RFPs and PPAs.

14 Q. And I think that's fair and I appreciate that.

15 But -- but you would also say, and you've said
16 before, that the more robust the competition, the better
17 value that we create for the ratepayers; correct?

18 A. (Witness Mallard) Yeah. So having a robust
19 response to our RFPs absolutely ensures really good
20 competition and produces good results for customers.

21 Q. So we're all familiar with the renewable cost
22 benefit framework. Is it possible for us to get a
23 storage cost benefit framework?

24 A. (Witness Weathers) Well, it -- what we've done
25 is we've -- is the value that storage brings is related

1 to it. And I think if you look at the renewable
2 integration study, which is the basis for the integration
3 cost of the renewable cost benefit framework, to the
4 extent storage can mitigate that integration cost, it
5 receives that benefit. So that in the battery storage
6 analysis that we've done in this IRP, it includes that as
7 a benefit for it.

8 So stor- -- the renewable cost benefit
9 framework is there to identify the unique benefits and
10 costs associated with variable energy resources that are
11 in addition to the normal cost and benefits for fully
12 dispatchable resources. So battery storage is a fully
13 dispatchable resource. It doesn't have the same
14 intermittency impacts. But we do make sure we consider
15 the unique values that it brings, such as the mitigation
16 costs or the flexibility costs that we included in the
17 battery storage analysis.

18 Q. Shifting to the issue of transmission upgrades,
19 does the ten-year transmission plan that Georgia Power
20 has -- does it include the north Georgia action plan?

21 A. (Witness Robinson) It does not include -- it
22 does include controls on Bowen 3 and 4. So that
23 assumption is in the ten-year plan. It does not include
24 the proposed RFP in north Georgia.

25 The transmission that's being developed

1 currently with ITS participants is not in this. That is
2 a transmission plan that's looking, Commissioners,
3 towards that 2035 date of future retirement of Bowen 3
4 and 4, 6,000 megawatts of renewables on the system, add
5 some for the EMCs and municipalities. We've got to plan
6 the system as a whole.

7 So you won't find those in the ten-year plan,
8 but there are some aspects of the north Georgia
9 reliability and resilience plan that are in the ten-year
10 plan that I laid out.

11 Q. Was renewables integration modeled separately
12 from the coal retirement -- the Plant Bowen coal
13 retirements in north Georgia transmission planning?

14 A. (Witness Grubb) So the -- are you asking about
15 the renewable integration study? It -- ask the question
16 again. Sorry about that.

17 Q. Well, yeah. So -- and, again, we're talking
18 about transmission upgrades. So was transmission
19 upgrades to facilitate renewables integration modeled
20 separately from transmission upgrades necessary for the
21 coal retirements?

22 A. (Witness Robinson) The last solar that was
23 added to the ten-year plan is the last RFP that was
24 certified. So those solar units are in the study moving
25 forward.

1 But any anticipated solar that would be
2 approved in the future is not in the ten-year plan, but
3 is being anticipated in the studies that are ongoing with
4 the ITS participants.

5 Q. So going now to, again, BESS, battery energy
6 storage system integration, what -- you did a 15 percent
7 storage. What other levels of storage were modeled?

8 A. (Witness Weathers) Really the other level that
9 was modeled is really zero. And so the comparison we
10 made was a system that had renewables that only could
11 rely on existing resources on the system, the fossil
12 resources for operating reserves, versus one at roughly a
13 15 percent level, which was proved to be a lower
14 production cost.

15 So we didn't -- we talked about earlier we did
16 some integration in the model to decide on the
17 15 percent. But once that was decided on being the
18 appropriate amount to mitigate the cost, that was the
19 amount that was studied and compared to having no storage
20 on the system.

21 A. (Witness Grubb) And, again, another that we've
22 talked about on that, it was done to maintain the
23 reliability at the same level. So it wasn't testing all
24 the different levels of storage. It was what level of
25 storage at that renewable penetration maintains my

1 reliability in the same manner and now I can compare it
2 to the cost of the existing system.

3 Q. Thank you.

4 So turning to page 14 of your testimony, this
5 is dealing with renewable integration study, you state:
6 The 1,000 megawatts being proposed represents a
7 sufficient amount of storage resources to improve the
8 cost-effectiveness of solar integration and improve solar
9 reliability.

10 When you say improve cost-effectiveness of
11 solar integration, does that mean optimize?

12 A. (Witness Weathers) Well, it's not necessarily
13 optimized, but it is -- it is an improvement. So what we
14 talked about here is that as you increase renewables, you
15 don't have to add batteries at the levels that we're
16 looking at. It's just going to cost more if you don't
17 have the batteries.

18 And so the level of batteries that we modeled,
19 as Mr. Grubb just said, it was a sufficient amount to
20 restore the intra-hour reliability back to the pre-solar
21 levels, back to the current levels, and to do that in a
22 more cost-effective way.

23 It's not necessarily an optimized amount. It
24 may be 15 percent, it may be 15 and a half, it may be 14,
25 but it is an amount that was determined to be adequate

1 and sufficient to get back to those pre-mitigation
2 levels.

3 Q. So does the amount of storage needed to reduce
4 integration costs depends on the volume of solar?

5 A. (Witness Grubb) Yes. And that's what the
6 renewable integration study is showing is as you continue
7 to add it, you have to add more operating reserves. So
8 how --

9 A. (Witness Weathers) But the 15 percent --

10 A. (Witness Grubb) -- best to add those.

11 A. (Witness Weathers) Sorry.

12 A. (Witness Grubb) No. You're fine.

13 A. (Witness Weathers) But the 15 percent was
14 pretty consistent across the range that we studied. So
15 whatever level you studied, it -- as you get into higher
16 levels of solar penetration, it's a little bit less. But
17 across the range for the foreseeable future, 15 percent
18 was pretty consistent.

19 Q. Could it mean that if more solar were added
20 that more storage should be added?

21 A. (Witness Weathers) In terms of megawatts, yes.
22 And so if there's additional solar beyond what's
23 contemplated by 2030, then the 1,000 megawatts would
24 ideally be a little bit higher to accommodate that.

25 Q. So on page 18 now of your testimony, lines 14

1 and 15, you say: Transmission projects are necessary to
2 accommodate replacement capacity.

3 Is the replacement capacity renewable or
4 nonrenewable?

5 A. (Witness Grubb) One second, Mr. Carver. Let me
6 read that entire paragraph.

7 A. (Witness Weathers) What line is that on,
8 Mr. Carver?

9 Q. That's on lines 14 and 15.

10 A. (Witness Weathers) I think it says that the
11 projects that are necessary to accommodate the combined
12 retirements and the procurement replacement capacity.

13 A. (Witness Grubb) Right. That replacement
14 capacity we're speaking about here are the six gas PPAs
15 from existing facilities. And so when we made that final
16 determination of recommending the certification of those
17 six PPAs, it was reflected in our transmission models.

18 And, as Mr. Robinson said earlier, any plan in
19 committed renewables on the system are included in those
20 evaluations.

21 A. (Witness Robinson) That's right.

22 Q. Okay. Turning to page 29. This is, again, on
23 the north Georgia plan. Page 29, lines 4 through 6, you
24 state: The existing transmission system is strained by
25 the geographic distance separating south Georgia and load

1 in north Georgia. The long-term planned retirement of
2 Plant Bowen units 3 and 4 will exacerbate this geographic
3 constraint.

4 So the system is strained by a separation of
5 generation in the south and load in north -- south
6 Georgia and load in north Georgia; is that correct?

7 A. (Witness Robinson) Generally, yes.

8 Q. Did you evaluate transmission improvements in
9 the north-south interface to address that strain?

10 A. (Witness Robinson) Can you repeat the question?

11 Q. Did you evaluate transmission improvements in
12 the north-south interface to address that strain?

13 A. (Witness Robinson) When you speak of the
14 north-south interface, the north-south interface in the
15 state of Georgia?

16 Q. Yes.

17 A. (Witness Robinson) The transmission system
18 generally connecting the load in north Georgia to the
19 south Georgia?

20 Q. Correct.

21 A. (Witness Robinson) There were evaluations
22 looking at many different scenarios of retirements and
23 looking at Bowen 3 and 4. There were significantly more
24 overloads and constraints that were identified when you
25 retired Bowen 3 and 4 at a future date. What it did not

1 anticipate is additional solar in the south Georgia area
2 or offset by additional solar in the north Georgia and
3 successful in siting there.

4 Those studies that I mentioned that are ongoing
5 with the ITS participants anticipate those needs
6 looking -- as I said, looking at that date in 2035,
7 understanding that strategic projects will take time to
8 build, six and a half, seven, eight years, as I mentioned
9 before. We've got to get ahead of that curve, look
10 beyond the ten-year plan, and anticipate that date out in
11 2035.

12 A. (Witness Grubb) And so, Mr. Carver, and
13 Commissioners, what -- and Mr. Robinson can correct me
14 here if I'm wrong. But right now we're able to serve the
15 system, obviously.

16 A. (Witness Robinson) Right.

17 A. (Witness Grubb) So what we're talking about on
18 this is future changes. So Bowen 1 and 2, you retire
19 because we've identified those projects. The long-term
20 retirement of Plant Bowen 3 and 4 is what we're talking
21 about.

22 So it's not everything solved at this point.
23 That north Georgia plan says as we continue to transition
24 the fleet, we need to identify what generation resources
25 take the place of Bowen 3 and 4 upon its retirement and

1 what transmission. And both of those interact.

2 A. (Witness Robinson) That's correct.

3 Q. So back to storage again. On page 31, this
4 would be lines 4 through 7. The question was: Why is
5 the company's plan to have company-owned storage?

6 You state: The company must maintain a
7 sufficient portion of the energy storage resources on the
8 system under its ownership and control to reliably serve
9 its customers in a cost-effective manner.

10 So my question is: Georgia Power must maintain
11 a sufficient portion of ESS under its ownership and
12 control to reliably serve in a cost-effective manner; is
13 that true?

14 A. (Witness Grubb) Yes. And this is speaking,
15 again, to the renewable integration study and the
16 operating reserves and the 1,000 megawatts of storage.
17 As you said earlier this morning, storage will still be
18 able to bid into renewable RFPs. It will absolutely
19 still be able to bid into future capacity RFPs. This is
20 speaking specifically about that 1,000 megawatts in the
21 renewable integration study and those storage resources,
22 not the entire system. Those specific ones.

23 Q. Gotcha.

24 A. (Witness Weathers) And the point is the company
25 doesn't have to own all storage resources, but the ones

1 that we are either committing to serve the operating
2 reserve function. So one of the critical operations
3 functions in the system, those need the flexibility that
4 ownership provides.

5 Q. But there are two elements, right, ownership
6 and control?

7 Those are two -- those are two separate
8 elements; right?

9 A. (Witness Weathers) They can be. But ownership
10 ensures a -- definitely ensures a robust control across a
11 variety -- we talked about use cases earlier. A variety
12 of the use cases, some of which we don't even know what
13 they will be today, but ownership provides the ultimate
14 control over the maintenance and over the operating
15 procedures and over the performance of the devices.

16 A. (Witness Grubb) Yeah. And I think what
17 Mr. Weathers just said is spot on. It's not talking
18 about control in terms of automatic control. It's
19 control over all those different aspects.

20 Q. Along this same line, lines 31 and 32, same
21 page: To ensure the best cost, the company will issue
22 competitive solicitations to supply EPC, engineering
23 procurement construction, services in support of this
24 effort.

25 A. (Witness Grubb) Mr. Carver, we only go through

1 line 26. So are -- you said lines 31 and 32 or do you
2 mean pages?

3 A. (Witness Weathers) You mean pages?

4 A. (Witness Grubb) Pages 31 --

5 Q. I'm sorry. I'm sorry. Yeah, yeah. Pages 31
6 and 32.

7 A. (Witness Grubb) No. That's fine.

8 Q. Sorry about that.

9 A. (Witness Grubb) Just want to make sure we're
10 looking at the right spot.

11 Q. Yep. It continues on to page 32.

12 A. (Witness Grubb) Right.

13 Q. So, again, the company will issue competitive
14 solicitations for EPC services; correct?

15 A. (Witness Mallard) That's right.

16 Q. So Georgia Power will have competitive
17 solicitation for that, but not allow competitive
18 solicitation for third-party EPC at sites not owned by
19 the company?

20 A. (Witness Mallard) Well, the ownership of the
21 site could be different. There's some different
22 arrangements there. But ultimately this is an RFP for
23 these EPC services for a battery energy storage system
24 that the company will ultimately own and control.

25 Q. Are y'all aware that a large industry has

1 arisen bidding into competitive ESS procurements,
2 including not just EPC, but siting and operating such
3 facilities?

4 A. (Witness Mallard) Yeah. I've studied some of
5 those. A lot of them in California where they use PPA
6 agreements to source their storage.

7 Q. All right. Going to pages 34 and 35, this is
8 dealing with the renewable expansion plan.

9 A. (Witness Grubb) Yes.

10 Q. You state: Greater amounts of solar or
11 renewable energy are deemed economically optimal in
12 scenarios -- this is line -- excuse me -- lines 26 and
13 then continuing onto the next page -- scenarios with
14 higher fuel emissions cost or lower-cost renewable
15 procurements.

16 The model selects higher levels of renewables
17 as optimal with higher fuel and emissions costs; is that
18 correct?

19 A. (Witness Weathers) Yes.

20 Q. So this is kind of like what we were talking
21 about earlier, price volatility?

22 A. (Witness Grubb) Well, this -- yeah. This is
23 specifically aiming towards the evaluations that we did
24 in the scenarios. So the ability of our models to pick
25 across different scenarios.

1 So, obviously, in a high gas, carbon-type case,
2 you're going to see a higher prediction of renewables
3 that benefit customers. And so we use that range to come
4 up with that 6,000 megawatt guidance.

5 Q. Have gas prices risen since you ran the model?

6 A. (Witness Weathers) Long-term natural gas prices
7 have not risen, in terms of our forecast. Short-term
8 have, but we're looking here about bulk procurement and
9 an evaluation period of multiple years. And those have
10 not changed over the long term.

11 A. (Witness Grubb) And these are resources that
12 we're requesting in this IRP that will come online in '28
13 and '29. And so as we continue go through these RFPs, we
14 mention that as we come back in IRPs we are going to
15 continue to upgrade that.

16 Our models can now pick renewables. And so
17 we're going to have that guidance from every IRP cycle
18 here forward and we can adjust those accordingly.

19 Q. And on that short-term increase that you're
20 talking about, is that because of events like the
21 invasion of Ukraine and the increased demand for LNG in
22 Europe and the United States?

23 A. (Witness Weathers) It is. And I talked to that
24 earlier. That -- it's in part due to that, but we were
25 already seeing some rises in short-term natural gas

1 prices due to the pandemic and due to the production --
2 response to production as demand increases -- increased
3 coming out of the pandemic. It is putting upward
4 pressure because production didn't respond as quickly as
5 demand did. And then, as you mentioned, the increase for
6 demand of exports to Europe.

7 Those things we do think are short-term. The
8 market thinks they're short-term. The long-term
9 forecasts we looked at, as well, also considers those to
10 be short-term dynamics.

11 Q. Okay. So going now to, again, the best cost
12 evaluation we talked about before. On page 37, which
13 deals with evaluation of criteria, you state that the
14 company will determine the exact -- excuse me -- yeah.
15 The company, working with the Commission, staff and IE,
16 will determine the exact criteria and methods of
17 evaluation, ranking, and selection as part of the
18 Commission-approved RFP process; correct?

19 A. (Witness Mallard) Correct.

20 Q. How will the public and stakeholders be
21 involved in reviewing criteria and methods for evaluating
22 in the upcoming RFPs?

23 A. (Witness Mallard) So as with all of our RFPs,
24 there's a period where we accept comments from interested
25 parties, from bidders. It's usually a two- or three-week

1 period. And all of our evaluation methodologies, our
2 PPAs, the RFP, all of that thing is -- all of those
3 things are there for comment by, again, bidders and other
4 interested parties.

5 And we do take that -- that feedback very
6 seriously. We plow those comments, those suggestions, as
7 appropriate, into the design of the RFP. And we expect
8 that to continue in much the same way.

9 Ultimately, the decisions around how to
10 evaluate these resources so they provide the most benefit
11 for Georgia Power customers are the responsibility of the
12 company, the Commission, staff, and the independent
13 evaluator.

14 Q. Prior to the independent evaluator and the bid
15 wall going up, are y'all open to input from stakeholders,
16 like the Georgia Large Scale Solar Association, Advanced
17 Power Alliance?

18 A. (Witness Mallard) Yes. Definitely. And some
19 of these improvements, the flexibility, the adaptability
20 that we're proposing in these RFPs will absolutely allow
21 for that. And it's going to be critical.

22 We're really seeing a dynamic time in the solar
23 and storage market right now. We're going to need to be
24 as flexible as we can be based on those market conditions
25 to receive that feedback. One of the improvements that

1 we're making that's probably not highlighted in here
2 specifically is that we're going to propose to use two
3 separate bid teams.

4 I know some of the market has expressed
5 frustration in the limited amount of time where the
6 parties can speak freely without being constrained by the
7 RFP evaluation and communication guidelines. So we'll --
8 one of the proposals we have going forward internally is
9 we'll have two separate teams. And so we'll have a
10 separate team running RFP 1, a separate team running
11 RFP 2. RFP 2 team would be available to have those
12 direct conversations with bidders in the marketplace.

13 Q. Thank you.

14 So on page 38 now, next page, you say: The
15 evaluation team will take additional factors into
16 consideration.

17 What factors, other than generation and
18 transmission costs, will be considered?

19 A. (Witness Mallard) Well, those are the primary
20 ones. And, again, just to reiterate, the value that can
21 be delivered from these projects to our customers is the
22 primary factor that we will choose these. But, as we've
23 talked about a good bit now, interconnection to the
24 transmission system is becoming more challenging. The
25 ability to select the portfolio of projects that can

1 maximize value to customers.

2 What we're seeing is in some of our portfolio
3 analyses, Commissioners, these projects interact with
4 each other. And so picking a portfolio of these four
5 projects that are lowest cost may not produce the best
6 net benefit as opposed to these two and two more that
7 were further down the list because of the impacts of
8 those projects on the entirety of the transmission
9 system, the ability to take that into account and to be
10 responsive to these market conditions that we're talking
11 about.

12 We're hearing from solar bidders in the
13 marketplace that the volatility that we've been talking
14 about is absolutely there for the ability to be able to
15 procure the solar equipment, battery energy storage
16 equipment. We want to make sure that we are able to be
17 responsive to that and can run the most efficient RFPs
18 that can procure these resources for the benefit of
19 customers.

20 Q. So turning to the next page, page 39, this is
21 dealing with the cadence of the RFPs. So with adding --
22 you know, beyond this time horizon, adding 6,000 more
23 megawatts, has the company considered parallel RFPs, one
24 for the north and one for the south, to provide
25 redundancy in case one of the RFPs does not yield an

1 acceptable volume of solar?

2 A. (Witness Mallard) So that's not what we're --
3 what we're proposing. We considered a lot of different
4 cadences and timelines for the RFP.

5 What we think makes the most sense is the most
6 efficient for the market, for Georgia Power, for the
7 staff to be able to administer is for the first RFP to be
8 issued, starting subsequent to this IRP, if approved.
9 And it will seek resources that will be COD in 2026 and
10 '27.

11 And then we'll start a second RFP and there
12 will actually be a little bit more time in between there.
13 We're adding some time for the more complex transmission
14 analysis. So it's a little bit longer timeline, but then
15 the second RFP will solicit resources.

16 We're not sure yet if the first RFP is
17 successful in procuring north Georgia resources, the
18 second RFP could be statewide again. It could be
19 geographically steered to another location. All of those
20 things will be dependent on the results of the first RFP.

21 And so it's that feedback loop, that ability to
22 get that realtime information from the market and then
23 craft that into updated RFP timelines and CODs. That's
24 exactly the flexibility that we're proposing that we
25 think makes the most sense, given the current conditions.

1 A. (Witness Robinson) And I think timing is going
2 to be very important, Commissioners, when you look at
3 particularly south Georgia. We've got to have that time
4 to build that transmission.

5 If we're unsuccessful in the north Georgia and
6 we have to procure all in south Georgia, we're going to
7 need to spread that out. We can't just take that all in
8 one chunk. We've got to strategically build the
9 transmission.

10 And we don't have the time from an operational
11 perspective to go onesey, twosey, doing upgrades here and
12 there throughout the system. We just don't have the --
13 our outage windows are becoming more and more
14 constrained. Resources are constrained.

15 And what that's going to do is put pressure on
16 the market to drive out CODs. We're not going to be able
17 to get those solar and renewable facilities online in
18 time because of the need to build that longer-term
19 strategic transmission from south to north.

20 Q. So speaking of that, if the north Georgia
21 procurement does not yield 1,050 megawatts, can those
22 megawatts roll over to the statewide or other -- the next
23 regional RFP?

24 I think right now you're saying statewide.

25 A. (Witness Mallard) Yeah. Certainly that would

1 be the expectation.

2 Q. Okay. All right. We are --

3 A. (Witness Robinson) And, again, timing would
4 have to be considered in that, as well, as it relates to
5 transmission.

6 Q. We're on the stretch run here. Four more
7 questions.

8 Why is the CARES program limited to 2,100
9 megawatts? The company testified that there's 2,000
10 additional megawatts of REC demand beyond what is shown
11 in the updated R3 program.

12 A. (Witness Mallard) So I think I'm following your
13 question, Mr. Carver. What the company proposed is to
14 make all of the resources procured through the utility
15 scale procurements available for subscription. So that's
16 2,000 megawatts.

17 And then what we've also proposed through the
18 retail REC retirement program is to make renewable energy
19 credits procured through prior solicitations, both the
20 ready solicitation and the current ongoing solicitations
21 approved in 2019, to make 2,000 more megawatts available
22 for subscription there. So those numbers are based on
23 the available megawatts and also the demonstrated
24 customer demand that we've seen from customers.

25 Q. Will the first subscription option have a

1 portfolio price made up of elements similar to the CRSP
2 portfolio price, i.e. supply costs, net present value of
3 net benefits?

4 A. (Witness Mallard) Ask the question one more
5 time, please.

6 Q. Will the first subscription option have a
7 portfolio price made up of elements similar to the CRSP
8 portfolio price, supply costs, net present value of net
9 benefits?

10 A. (Witness Mallard) So the methodology -- what
11 we're proposing is actually two different subscription
12 price calculation methodologies, the first of which is
13 consistent and similar with the way that the CRSP price
14 is calculated. The second of which is a fixed price.

15 We've gotten some feedback from some of these
16 large customers that the volatility, the unknown of the
17 credit that they're going to get back is a barrier for
18 their participation. So we're proposing a second
19 subscription methodology so that we can fix the price for
20 those customers over the term of their subscription.

21 Q. If new load is being procured outside of the
22 2,100 megawatt cap, as in economic development programs,
23 can customers come to Georgia Power with recourses they
24 would like the company to procure, as is the case with
25 Portland General Electric's VRET program or Duke

1 Energy's, in the state of North Carolina, GSA program?

2 A. (Witness Mallard) So Georgia Power is going to
3 be guided by those principles that we've talked about a
4 good bit already. We're going to procure renewable
5 resources that benefit all of our customers. A
6 particular resource chosen by a particular customer that
7 didn't align with -- with the needs of all Georgia Power
8 customers would not be appropriate.

9 I think -- we talked about this a minute ago,
10 as well. I think Georgia Power's competitive RFPs are
11 some of the best in the country. I think we get some of
12 the best pricing, some of the best projects. I think
13 that is the premier vehicle to procure renewable
14 resources is through Georgia Power's competitive RFPs.

15 Q. Why is the MUSH program participation limited
16 to customers under 3 megawatts of aggregate annual peak
17 demand?

18 A. (Witness Mallard) So it's a carve-out. MUSH
19 customers have been unable to participate in the CRSP
20 program prior because of the 3 megawatt participation
21 limit. And so we've got some MUSH customers smaller than
22 that. And so what we tried to do with the program design
23 here is carve out a specific amount of that CARES
24 capacity just for those smaller municipal, university,
25 school, and hospital customers.

1 Q. Gentlemen, thank you very much.

2 A. (Witness Grubb) Thank you.

3 A. (Witness Weathers) Thank you.

4 MR. CARVER: That concludes my questions.

5 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
6 Industries Association, Solar Energy Association,
7 and Vote Solar.

8 MS. OTTENWELLER: Thank you.

9 Good evening, Madam Chair, Commissioners, and
10 to the panel.

11 MADAM CHAIR PRIDEMORE: Do you go by Ms. Chiles
12 Ottenweller or --

13 MS. OTTENWELLER: Ottenweller is fine.

14 MADAM CHAIR PRIDEMORE: -- Ms. Ottenweller?
15 Ottenweller, okay.

16 MS. OTTENWELLER: That's great. Thank you.

17 MADAM CHAIR PRIDEMORE: Thank you.

18 MS. OTTENWELLER: So just to give you a roadmap
19 for your brief time with me, counsel for Georgia
20 Power has agreed to allow my co-counsel and I to
21 split up the questions. So my questions are going
22 to be limited to the Aurora modeling and monthly
23 netting and then I'm going to hand it over to Scott
24 Thomasson. Thank you.

25 CROSS-EXAMINATION

1 BY MS. OTTENWELLER:

2 Q. So I want to start with the Aurora modeling.
3 For the renewable energy expansion plan, did Georgia
4 Power model both fixed and tracking solar?

5 A. (Witness Weathers) No. I mean, it was really
6 based on a tracking solar-type profile that we modeled.

7 Q. And the standalone solar additions in the
8 Aurora model, those were assumed to have zero capacity
9 value; right?

10 A. (Witness Weathers) The standalone solar
11 additions? Yes.

12 Q. The solar that you --

13 A. (Witness Weathers) So the incremental solar,
14 yes, it was assumed to have zero capacity value, that's
15 correct.

16 Q. Does solar have capacity value in the RCB
17 framework?

18 A. (Witness Weathers) Yes. Whenever -- when we
19 actually evaluate real projects, then the capacity value
20 is assessed at that time. And so previous projects that
21 we've added through the RCB framework, the capacity value
22 is assigned.

23 But on a going-forward basis, we didn't include
24 capacity value. The reason is because, you know, the
25 capacity value of solar is trending toward zero. So the

1 more that we add, the less incremental capacity value you
2 have with each additional megawatt.

3 And then we wanted to really evaluate the
4 energy savings. So when the model selects them, they
5 select them for energy savings, not for any capacity
6 value.

7 Q. Thank you.

8 Does solar have capacity value in the ELCC
9 study that y'all did?

10 A. (Witness Weathers) Yes, it does. I mean,
11 there's -- it depends on the season, but, yes, there's
12 capacity value.

13 Q. Okay. And are y'all counting future solar PPAs
14 towards the 70/30 allocation that you're looking at?

15 A. (Witness Grubb) So the 70/30 is only what's
16 committed to and planned. And so, again, we talked this
17 morning around -- we used the capacity equivalence as
18 part of it, not nameplate. But it's just what we have
19 committed and planned.

20 Q. But the plan would include that 2,400 or the
21 2,300?

22 A. (Witness Grubb) No. I think it's -- I'd have
23 to -- subject to check, but I don't think it included our
24 IRP request.

25 Well, I'd have to check. I'd have to go back

1 and look.

2 Q. Okay.

3 A. (Witness Grubb) It's pretty small, though,
4 because the capacity equivalence -- as a matter of fact,
5 I just answered my own question.

6 We wouldn't have them in there because we're
7 giving them that zero capacity. So we would have
8 existing gas, PPAs, all the company-owned resources, and
9 any plan and committed solar that we've truly procured
10 that we have a capacity equivalence on.

11 Q. Okay. Thank you.

12 A. (Witness Weathers) Yeah. And just to -- just
13 to clarify, just to make sure, you know, all the existing
14 projects and projects that we have procured that are real
15 projects, we identified the capacity value.

16 And so whether that's the -- what we call the
17 ICE factor in the existing renewable cost benefit
18 framework, or the ELCC, which is just a different way of
19 doing it, they have capacity value.

20 From on a going-forward basis for incremental
21 solar, we've assumed that the capacity value will be zero
22 because it is trending towards zero. And we don't want
23 -- and, really, our primary capacity value is in the
24 winter.

25 So we don't want to give a false assumption of

1 future capacity value that may or may not materialize.
2 When those products come online or they're procured, we
3 evaluate the capacity value at that time to assign to it.

4 Q. Okay. And did the renewable expansion model
5 allow for solar paired with battery storage to be
6 selected?

7 A. (Witness Weathers) It was looking at just
8 solar. So we looked at what standalone solar, what would
9 be economic for customers across a range of scenarios.

10 Q. Okay. And Georgia Power considered six
11 different scenarios in its renewable expansion modeling,
12 right, and three of those had a carbon price?

13 A. (Witness Mallard) That's correct.

14 A. (Witness Weathers) Yes.

15 Q. Okay. And these scenarios form the basis for
16 the company's proposed renewable procurement strategy in
17 this proceeding?

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

19 Q. And I -- you may want to refer to your IRP
20 filing Attachment F at F160 for this.

21 A. (Witness Grubb) Yes.

22 A. (Witness Weathers) I just turned there.

23 Q. Okay. Georgia Power essentially averages out
24 the outcomes of those scenarios to get to the 2,400
25 megawatts by 2029; right?

1 A. (Witness Grubb) So which number -- did you
2 reference the -- you said 20- --

3 Q. At F160, the 2,400 megawatts by 2029. That's
4 an average of what was selected from those six
5 portfolios, right, or the six scenarios?

6 A. (Witness Grubb) Yeah. We -- it was really the
7 six is a long-term guidance. And I think we just looked
8 at the 2,300 as something that we felt like kept us on
9 that path, but we also could physically do from a
10 transmission and the ability to build the solar facility.
11 So I didn't even realize that the 24 hit right there on
12 that, but really that 2,300 is the step towards the six.

13 Q. Okay.

14 A. (Witness Grubb) 335.

15 Q. So would you say that the carbon price does
16 impact the company's renewable energy procurement target?

17 A. (Witness Weathers) It --

18 A. (Witness Grubb) It does.

19 A. (Witness Weathers) It does, yes.

20 A. (Witness Grubb) And so that's why we've stated
21 that, you know, the guidance that we're getting in this
22 IRP is looking at these scenarios. We have that ability
23 now. We will adjust that over time based on fuel prices,
24 carbon prices, and those other things. So it does impact
25 it.

1 Q. Okay. And I just want to follow up with
2 something that I think Mr. Mallard said earlier to
3 Mr. Jones. He was talking about redefining avoided
4 costs.

5 I just want to clarify that that's something
6 that y'all are doing for planning purposes, but it's not
7 actually impacting the RCB avoided cost number that's
8 used for compensation purposes; right?

9 A. (Witness Grubb) When you say -- just to be
10 clear, when you say compensation purposes, you mean
11 through kind of the 4822 or the RNR?

12 Q. Yes.

13 A. (Witness Grubb) Yeah. So that's a great
14 clarification. So when we look at pricing something in
15 that manner, then we do use the Mg0 because that's a
16 price we're paying. There's not an avoided cost to
17 carbon yet.

18 So we pay RNR QS under 4822 on -- based on a --
19 well, QFs are a day ahead, but we base it on a non-carbon
20 price. As carbon becomes an impact and a real true cost,
21 we would reflect it there.

22 So here we're looking at the range of resources
23 to procure. We'll actually pay them what they bid in.
24 So it's just a different procurement.

25 Q. Just to clarify, so you're -- there are carbon

1 price assumptions built into your long-term planning, but
2 when you're looking at the long-term avoided costs say
3 for a utility scale RFP, that number will not include a
4 carbon price?

5 A. (Witness Grubb) We haven't traditionally. I'll
6 let Mr. Mallard speak to what we might do going forward.

7 I know on some other solicitations the capacity
8 RFP we look at a range. And so it's just going to depend
9 on how that develops over time. Right now we have not.
10 We've looked at just that non-carbon case.

11 Q. Okay. The Mg0?

12 A. (Witness Grubb) That's right.

13 A. (Witness Weathers) And there -- there's two
14 ways to look at it. You could look at a range of avoided
15 costs in your evaluation process, or you could look at a
16 range of scenarios when you -- including the avoided
17 costs when you determine how much you are going to
18 procure.

19 So the latter is what we've done. We've done
20 the avoided cost analysis on the front-end across a range
21 of scenarios. Because, again, we're looking at
22 procurements for projects that will be 30 years. And so
23 we want to consider potential carbon impacts in that.
24 And that sets the amount.

25 And then when we do the evaluation, we can

1 continue using the renewable cost benefit framework that
2 has a single set of avoided costs. That's why
3 Mr. Mallard described it's not appropriate to consider
4 that Mg0 as the only -- the only determinate or that it
5 is a price ceiling because you've considered a more
6 robust range when you selected the renewable procurement
7 amount.

8 Q. Okay. My next question is about the scenarios
9 that were modeled in the IRP mix study. And those
10 scenarios are listed in the IRP mix study at page 18, if
11 that would be helpful.

12 So Georgia Power modeled 11 scenarios for this
13 study; right?

14 A. (Witness Weathers) Yes.

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

16 A. (Witness Weathers) That's correct.

17 Q. Okay. I realize that the costs themselves are
18 trade secret and so I don't want to stray into that, but
19 are you able to say without revealing trade secret
20 information which scenario was the lowest system cost?

21 A. (Witness Grubb) So which -- I'm sorry. Which
22 are -- which study were you referring to in looking at
23 the economics?

24 Q. It's the IRP mix study. And the numbers
25 themselves are in trade secret capacity expansion plan

1 spreadsheet.

2 A. (Witness Weathers) I don't -- I don't have that
3 in my -- I'm guessing it would be the low gas, zero
4 dollar carbon. That's typically the lowest cost. When
5 gas prices are low and when there's no carbon prices.

6 Q. If I showed it to you, could that reflect --

7 A. (Witness Grubb) Yeah. Which particular part of
8 the filing? It's -- there's -- it's in a few places. I
9 just want to make sure --

10 Q. Yes. No, it's -- it's tricky to find.

11 MADAM CHAIR PRIDEMORE: You may approach.

12 MS. OTTENWELLER: Sorry.

13 Thank you. Sorry about that, Madam Chair.

14 BY MS. OTTENWELLER:

15 Q. So are you able to say which scenario was the
16 lowest system cost?

17 A. (Witness Weathers) Yes. It was the low load
18 scenario.

19 Q. Okay.

20 A. (Witness Weathers) And if I could explain what
21 that -- what that one is.

22 Q. Yes. That would be great. That was my next
23 question.

24 A. (Witness Weathers) That's the -- of the 11
25 scenarios, that's the one where we looked at increasing

1 levels of electrification, increasing customer and
2 end-use efficiency, and resources -- behind the meter
3 resources for customers.

4 And so what -- effectively what that meant is
5 there's less load for Georgia Power to serve from Georgia
6 Power's resources. So that's why, in terms of system
7 production costs, it was a lower amount.

8 Q. Okay. I want to turn now to monthly netting.
9 And I'm going to try to avoid handing out exhibits. So I
10 think we can do this without it.

11 But there -- and I think this question is for
12 you, Mr. Mallard. But do you recall a data response that
13 was asking you about the Cogen Act?

14 A. (Witness Mallard) Yes.

15 Q. Okay. Would it help -- be helpful to have a
16 copy of that to refresh your recollection?

17 A. (Witness Mallard) Sure. That probably would be
18 best.

19 MS. OTTENWELLER: Okay. May I approach?

20 MADAM CHAIR PRIDEMORE: You may approach.

21 MS. OTTENWELLER: Thank you.

22 BY MS. OTTENWELLER:

23 Q. Does Georgia Power Company count the 5,000
24 customer monthly netting pilot towards the .2 percent cap
25 in the Cogeneration and Distributed Generation Act of

1 2001?

2 A. (Witness Mallard) No, we don't. And as is
3 referenced in this response, we really are only counting
4 behind-the-meter RNR customers that are outside of the
5 monthly netting pilot program approved by the PSC in the
6 '19 IRP.

7 Q. Okay. And are there any other programs,
8 besides instantaneous netting, that y'all count towards
9 the .2 percent cap?

10 A. (Witness Mallard) No. There's energy offset
11 customers. Some customers choose to install that don't
12 meet the -- either the size requirements or don't choose
13 to participate.

14 Additionally, there is some that are so large
15 that they're qualifying facilities. So we actually have
16 some rooftop solar qualifying facilities on top of some
17 large rooftops. But the RNR instantaneous netting is the
18 only one that we count towards as our compliance vehicle
19 for the Cogen Act.

20 Q. Okay. Thank you.

21 Do you know what the average annual kilowatt
22 hour usage is for residential customers of Georgia Power?

23 A. (Witness Mallard) I don't know the average. I
24 know we typically say a 1,000 kilowatt hours a month, but
25 I think the average is probably a little more than that.

1 Q. Okay. So subject to check, around a 1,000
2 kilowatt hours?

3 A. (Witness Mallard) (Nods head.)

4 A. (Witness Grubb) Per month, right.

5 MS. OTTENWELLER: May I approach?

6 MADAM CHAIR PRIDEMORE: Yes, you may approach.

7 MS. OTTENWELLER: I am going to hand out an
8 exhibit that I have premarked as GSEIA/SEA/Vote
9 Solar Exhibit 1.

10 (The document referred to was marked for
11 identification as GSEIA/SEA/Vote Solar Exhibit
12 No. 1.)

13 BY MS. OTTENWELLER:

14 Q. Now, this is a data response that Georgia Power
15 filed concerning customers on the RNR pilot program;
16 correct?

17 A. (Witness Grubb) Yes.

18 Q. And I specifically want to look at the number
19 that's at the bottom of the second page.

20 A. (Witness Mallard) Well, just to clarify, it's
21 generally about RNR, not specifically about monthly
22 netting.

23 Q. Okay. So that was one of my first questions is
24 whether this was RNR generally including instantaneous
25 netting program, okay. Thank you for that.

1 So customers on the RNR tariff have used, on
2 average, 1,100 to 1,900 kilowatt hours a month over the
3 last several years; right?

4 A. (Witness Mallard) Are we looking at the table
5 under D on page 2?

6 Q. Yes.

7 A. (Witness Mallard) Yes.

8 Q. And the numbers at the bottom.

9 A. (Witness Mallard) Yes.

10 Q. And we talked about how the average residential
11 customer uses around a 1,000 kilowatt hours.

12 A. (Witness Mallard) Uh-huh.

13 Q. So the numbers here are -- is that how much
14 energy they consumed after they installed solar?

15 A. (Witness Mallard) Yes. These numbers are going
16 to be --

17 Q. Okay.

18 A. (Witness Mallard) -- net of the solar that's
19 consumed behind the meter. We just don't have a way to
20 track that. So really what we see is what's metered,
21 which is the customer's usage net of the solar consumed
22 on-site.

23 Q. Okay. So these customers with rooftop solar
24 are still using more electricity on average after going
25 solar than the average residential customer is in

1 Georgia?

2 A. (Witness Mallard) Yes. And so -- and that
3 would stand to reason, a lot of customers that are most
4 interested in rooftop solar, customers with large houses,
5 relatively large monthly electric bills, relatively large
6 rooftops where they can fit a significant amount of
7 solar. So, yes, that stands to reason.

8 Q. And I know you mentioned to Ms. Kysor that you
9 haven't conducted a cost of service study specifically on
10 solar customers. So is there a chance that these
11 customers who are installing rooftop solar are cheaper to
12 serve than the average residential customer?

13 A. (Witness Mallard) There's a chance but I don't
14 think that's going to be the case. Introducing
15 intermittent solar behind the meter is going to
16 absolutely add volatility to the customer's load shape.
17 It's going to -- it's going to reduce their overall load
18 factor, and so that makes them more expensive to serve.
19 We end up with a higher peak demand.

20 Solar does almost nothing to reduce total net
21 demand on a customer's premise. But then we have a lot
22 less kilowatt-hours to recover cost from. So my
23 hypothesis would be, generally speaking, customers with
24 behind-the-meter rooftop solar are generally more
25 expensive to serve than other similarly sized customers.

1 Q. And you mentioned earlier that you had looked
2 at some studies and analyses that had been done in other
3 places. Are you familiar with a study by Duke Energy
4 that demonstrated that solar customers are, in fact,
5 cheaper to serve than similarly situated residential
6 customers?

7 A. (Witness Mallard) I'm not familiar with that
8 study.

9 Q. Okay. Thank you.

10 So -- and just so you know where I'm going with
11 this, because I didn't raise it initially. So your
12 testimony at page 49, you identified four concerns with
13 the monthly netting pilot; right? And so one of them was
14 cost shifting, which we just touched on. The second
15 concern was an increase in unplanned, variable energy
16 resources.

17 A. (Witness Mallard) Right.

18 Q. So Georgia Power has about 2.6 million
19 customers; right?

20 A. (Witness Mallard) That sounds right.

21 Q. And about 3,400 of those are on the RNR tariff?

22 A. (Witness Mallard) Yes.

23 Q. Subject to check, that's about .13 percent of
24 your customer base?

25 A. (Witness Mallard) Subject to check. I can't do

1 that math in my head.

2 Q. Okay. I couldn't either.

3 So in your testimony you say this is unplanned.
4 But Georgia Power does estimate behind-the- meter solar
5 adoption in its load forecast; right?

6 A. (Witness Grubb) We do.

7 Q. And qualifying facilities are variable, too;
8 right? And generally larger in size than rooftop solar
9 customers?

10 A. (Witness Mallard) That's right.

11 Q. You would also call those unplanned?

12 A. (Witness Mallard) That's right.

13 Q. Would Georgia Power have the same concern with
14 respect to electric vehicles?

15 A. (Witness Mallard) So electric vehicles is a
16 little bit different. We're talking the difference
17 between load that Georgia Power is obligated by statute
18 and moral obligation to serve, and distributed
19 generation, which can be valuable to the system, but
20 absent being part of one of our IRP-approved programs,
21 really is generation that Georgia Power makes sure that
22 we have fair programs, that we compensate them
23 accurately, but that we maintain the reliability and the
24 safety of the system while we comply with PURPA, with the
25 Cogen Act, and with other requirements for us to purchase

1 this energy from these generators.

2 Q. So the third concern that you identified was
3 the infiltration of solar marketers misinforming
4 customers; right?

5 A. (Witness Mallard) That's right.

6 Q. What does the company do with a complaint that
7 they receive from a customer with respect to, you know,
8 misinformation?

9 A. (Witness Mallard) Well, at the very highest
10 level, we try to solve it. And we have absolutely been
11 inundated. One of the things that's been challenging
12 with the monthly netting rollout is just the high volume
13 of applications, and then the high volume of players that
14 are new to our market that don't understand the rules of
15 our programs, don't understand Georgia Power's programs
16 and processes. And so we've been doing a whole lot of
17 education and helping these new participants in the
18 marketplace.

19 Ultimately, Commissioners, and I know you are
20 aware of some of these complaints from customers as well,
21 satisfying our customers is our number one objective.
22 And so we do everything we can to help our customers get
23 the best outcome that they can. But a lot of times we
24 find that they've been talked into a deal that is just --
25 is just not the way that the program works. The paybacks

1 they've been promised are never going to be realized.

2 And so we do everything we can to help them
3 maximize their investment, get on the program that makes
4 the most sense for them. And then for some of these more
5 egregious cases, we have actually referred the offending
6 party to the State attorney general's office for
7 investigation.

8 Q. Okay. Do you also inform the Commission of
9 those --

10 MS. OTTENWELLER: Oh, sorry, Madam Chair.

11 MADAM CHAIR PRIDEMORE: Go ahead. It's a fine
12 question. Go ahead.

13 BY MS. OTTENWELLER:

14 Q. I was also -- in addition to contacting the AG,
15 do you also inform the Commission about instances?

16 A. (Witness Mallard) I would say any that arise to
17 that level, we do. We generally work pretty closely with
18 staff and Commissioners on some of these complaints. I
19 can't say that they're aware of every complaint that we
20 get and every issue that we try to resolve.

21 MADAM CHAIR PRIDEMORE: Has the company sent a
22 cease and desist letter to the solar companies out
23 there that are using your likeness, logo, and name
24 to market their products?

25 WITNESS MALLARD: We have sent several of

1 those. I don't know how many exactly. And I'm also
2 not sure of the effectiveness of those. But, yes,
3 Chair Pridemore, we've sent several cease and desist
4 letters.

5 MADAM CHAIR PRIDEMORE: Thank you. I'd like a
6 data request. I like those. Thank you.

7 MS. OTTENWELLER: Can I have that too?

8 WITNESS MALLARD: A hearing request.

9 BY MS. OTTENWELLER:

10 Q. Are you aware of consumer protection bills that
11 have been filed at the Georgia legislature?

12 A. (Witness Mallard) Generally, but not the
13 specifics.

14 Q. Okay. So has Georgia Power taken a position on
15 any of those bills?

16 A. (Witness Mallard) No. And I'm only generally
17 aware. As I understand them, they would require Georgia
18 Power and/or the Commission staff to provide some
19 education and support for behind-the-meter solar in these
20 solar installers. But I'm just not familiar with the
21 details.

22 Q. Okay.

23 MADAM CHAIR PRIDEMORE: They also include the
24 EMCs, as well as the municipalities.

25

1 BY MS. OTTENWELLER:

2 Q. Is it your position that the Commission has
3 some discretion to implement consumer protections as part
4 of any program that they might approve?

5 A. (Witness Mallard) Yes.

6 Q. Okay. Thank you.

7 The fourth concern you cited in your testimony
8 was noncompliance with interconnection rules. Has
9 Georgia Power changed its interconnection requirements
10 since the monthly netting pilot was approved?

11 A. (Witness Mallard) No. The last change we had
12 was subsequent to the 2019 rate case when section G was
13 added to the rules and regs. That created some
14 additional requirements.

15 But our RNR program and other distributed
16 generation programs have their own set of interconnection
17 requirements that are part and parcel of the agreement
18 that the customers sign. So what happens is for the most
19 part, the customers don't fill out these agreements,
20 they're filled out by the installer.

21 And, again, probably owing to the newness of a
22 lot of these outfits to our state and to our processes,
23 we really have seen a lot of mistakes made, a lot of
24 corners cut, both on the application itself and then the
25 actual installation of the system and how it's

1 interconnected to the customer and then to the grid.

2 Q. Okay. Do you know how long it takes Georgia
3 Power to process an interconnection application so a
4 solar system can be connected to the grid?

5 A. (Witness Mallard) I don't know exactly. I can
6 tell you that we've been working really hard to get our
7 backlog taken care of as the monthly netting pilot caused
8 our average monthly interconnection requests to go from
9 the 30 to 50 a month range to 6- and 800 a month, and so
10 we've been playing catch-up for a while.

11 I'm really happy to say we processed over 550
12 just in February alone, so we've made a lot of
13 improvements there and how we can process those and move
14 those along as quickly as possible. But I don't have off
15 the top of my head an average amount of time it takes.

16 A. (Witness Robinson) For transmission
17 interconnect that followed the LGIP process, it's 36 to
18 48 months.

19 Q. Okay.

20 A. (Witness Robinson) From application to COD.

21 Q. For the smaller scale residential commercial,
22 could I do a hearing request on that to find out --

23 A. (Witness Mallard) Yeah. So say the -- say your
24 actual question.

25 Q. Sure. How long it's taking Georgia Power to

1 process interconnection applications for solar systems
2 that are in the queue for RNR. Thank you.

3 A. (Witness Mallard) Yes.

4 Q. Just a few more questions from me.

5 In the IRP filing it talks about how the
6 company's planning to introduce in the rate case a new
7 requirement for all customers installing solar behind the
8 meter to pay a set application fee based on the system
9 size. Do you recall that?

10 A. (Witness Mallard) Yes. That's in the plans.

11 Q. Have you determined yet how much that fee will
12 be?

13 A. (Witness Mallard) We haven't. We're evaluating
14 that and evaluating what those costs look like based on
15 the higher volume that we're seeing these days, which is
16 adding cost, but actually we're gaining efficiencies in
17 how we process those, and so still doing that analysis.

18 Q. Okay. And can you talk about what the
19 justification for that application fee based on system
20 size is?

21 A. (Witness Mallard) Yeah. It would really just
22 be the general cost causation. We want to make sure that
23 we're recovering costs from those that are causing them,
24 the time and effort that it takes to process the
25 applications, and then also to -- for our billing

1 department, for our metering departments, for all of
2 those folks that work on those projects. And so the cost
3 would really be based on the actual cost that the company
4 realizes to process the applications.

5 MS. OTTENWELLER: Okay. I want to hand out
6 what I premarked as Exhibit 2 of GSEIA, SEA and Vote
7 Solar, if I may approach?

8 (The documents referred to were marked for
9 identification as GSEIA, SEA and Vote Solar,
10 Exhibit No. 2.)

11 MADAM CHAIR PRIDEMORE: You may approach.

12 MS. OTTENWELLER: Okay.

13 MADAM CHAIR PRIDEMORE: We're after 6:00.

14 Thank you to the faithful.

15 BY MS. OTTENWELLER:

16 Q. So this is a survey that Georgia Power included
17 in data response STF-DEA-22, Attachment A. And I want to
18 refer you to page 12, if I may. The page numbers are a
19 little bit hard to read.

20 A. (Witness Mallard) I don't see page numbers.
21 Can you tell me what the title is going to be?

22 Q. Starts with "Most would prefer to work with pay
23 utility."

24 So this survey was conducted in November 2021,
25 titled "Marketing Research Solar Behind the Meter";

1 correct?

2 A. (Witness Mallard) Correct.

3 Q. And as part of the questions about kind of
4 rooftop solar and Community Solar, Georgia Power asked
5 customers whether they would prefer to work with or pay
6 their utility to install and maintain a solar system or
7 work with and pay a solar installer; correct?

8 A. (Witness Mallard) Correct.

9 Q. And this shows 82 percent would prefer to work
10 with pay utility, 18 percent work with or pay a solar
11 installer; right?

12 A. (Witness Mallard) I see that.

13 Q. Okay. And then on the next page it talks about
14 how more specifically customers were asked whether they'd
15 be interested in allowing the utility to lease rooftop
16 space to install a solar system.

17 A. (Witness Mallard) Yes.

18 Q. Does Georgia Power have a plan to offer rooftop
19 solar products in competition with solar installers?

20 A. (Witness Mallard) No, not at this time, but
21 we're -- as part of what we kind of continuously do,
22 Commissioners, which is to evaluate the marketplace,
23 evaluate customer needs, look at our program offerings,
24 this research right here is part and parcel to that. By
25 polling these customer, by asking them what their wants

1 and needs are, it does help inform us and help us come up
2 with future programs and potential designs.

3 Q. Okay. Four questions left for me.

4 So one product that Georgia Power does offer
5 today is the Community Solar subscription program; right?

6 A. (Witness Mallard) Yes.

7 Q. And when a customer signs up for that program,
8 they get a credit based on the electricity that's
9 generated from their block of capacity?

10 A. (Witness Mallard) Correct.

11 Q. Does Georgia Power net that solar generation
12 against the subscribing customer's consumption on a
13 one-to-one basis?

14 A. (Witness Mallard) Yes.

15 Q. And then my last question. There was some talk
16 earlier about net metering in the Florida legislation.
17 Are you familiar with the legislation --

18 A. (Witness Mallard) Generally.

19 Q. -- that was passed?

20 A. (Witness Mallard) Uh-huh.

21 Q. So do you know if the bill that was passed,
22 you're aware it creates a policy over the next six years
23 sort of known as the GlidePath?

24 A. (Witness Mallard) Yes. Step down, yes.

25 Q. Do you know if that GlidePath is more or less

1 generous than Georgia Power's monthly netting pilot
2 program?

3 A. (Witness Mallard) More or less generous?

4 Q. In terms of compensation for rooftop solar
5 customers?

6 A. (Witness Mallard) Well, so I'm assuming that
7 they're starting at retail compensation now and the glide
8 path is going to glide them down to a compensation rate
9 that's going to be less than that. I think the exact
10 details of that are still, assuming the bill gets signed,
11 are going to be in the hands of the Florida PSC to
12 develop the actual details there.

13 But the compensation's going to go from retail
14 credit, which is what they have now, which is what
15 monthly netting offers, down to something less than that.
16 And I can only assume it's going to be something based on
17 an avoided cost methodology similar to what we use in
18 Georgia.

19 Q. Okay. So right now in Georgia under monthly
20 netting pilot, it's -- that policy is not what we would
21 call annual netting; right? It's monthly netting?

22 A. (Witness Mallard) That's right.

23 Q. And you're aware Florida currently today has
24 annual retail net metering?

25 A. (Witness Mallard) So they'll bank all those

1 kilowatt-hours for the entire year. And so you can --

2 Q. Right.

3 A. (Witness Mallard) -- roll them from month to
4 month, yes.

5 Q. And you're aware that the legislation, if
6 passed, would move that down to monthly netting between
7 now and 2028?

8 A. (Witness Mallard) I'm not familiar, but subject
9 to check, yes.

10 Q. Okay. And that the export rate would actually
11 be higher than avoided cost. It would be a percentage of
12 the retail rate, from 75 down to 50 percent?

13 A. (Witness Mallard) So -- and that's just part of
14 the glide path until the PSC can come up with a new
15 valuation. I think all that made sense to me.

16 Commissioners, what I would comment there is
17 they're doing the best they can to unwind the policy that
18 has created a huge subsidy. They've got a lot of
19 customers who have made their solar decision based on
20 expected paybacks based on retail compensation, and
21 they're doing the best they can to glide them down so
22 that the economic impact to those customers is not as
23 significant.

24 That's something that I hope we can avoid here
25 in Georgia and avoid creating a program and a policy that

1 eventually one day puts us in the same place as a state
2 like Florida where we're really trying hard to unwind the
3 policy to bring it back and compensate that solar energy
4 at the more appropriate price.

5 Q. But would you agree that between now and 2029,
6 those customers will actually have a more beneficial
7 policy than is offered in the Georgia Power monthly
8 netting program?

9 A. (Witness Mallard) Yeah, I can't say that for
10 sure. I can tell you that I don't think that the monthly
11 rollover accounts for very much. If we think about the
12 100 percent of the output of solar over the course of a
13 year, I can't imagine that the monthly rollover amount is
14 more than 5 percent or so of those total kilowatt-hours.

15 You're really talking about energy that's
16 produced in addition to more energy that's produced than
17 the home or business uses in the course of a month. And
18 so that part being compensated at a higher rate, I'm not
19 sure if that offsets the glide path pricing that they've
20 proposed. So I can't say for sure without studying it
21 more.

22 MS. OTTENWELLER: Okay. No further questions
23 from me. I'm going to hand it over to Scott
24 Thomasson. Thank you.

25 MADAM CHAIR PRIDEMORE: Hello, Mr. Thomasson.

1 MR. THOMASSON: Madam Chair, gentlemen, good
2 evening. I appreciate your endurance. The good
3 news is I have a lot to cover, but I have been
4 crossing off questions as they were asked as
5 instructed and my bingo card is getting very full,
6 so I've got a lot less than I originally did.

7 CROSS-EXAMINATION

8 BY MR. THOMASSON:

9 Q. Just as Mr. Carver covered the utility-scale
10 procurement, I'm going to start by covering the DG side
11 of the procurement and some of the improvements that
12 y'all are proposing. But first I want to make some
13 clarifications about the leftover capacity from the 2019
14 IRP DG programs.

15 So is it accurate that of the 210 megawatts
16 planned and approved in the 2019 IRP, that not all those
17 210 megawatts have been procured since then?

18 A. (Witness Mallard) Yes, that's accurate.

19 Q. And do you have a rough number for how much has
20 been procured?

21 A. (Witness Mallard) So I can tell you the amount
22 procured in the Customer-Connected program, which is 1
23 megawatt out of the 25 megawatt target. I can give you a
24 rough number on the REDI II, which is seven projects and
25 in the neighborhood of 14 megawatts or so.

1 What I can't talk about are the results of the
2 ongoing DG RFP, which is on the homestretch but not
3 finished yet. All of that information is confidential
4 and protected as part of the RFP.

5 Q. But so far that hasn't been brought to the
6 Commission for certification?

7 A. (Witness Mallard) That's correct.

8 Q. The total number would be well below 50 percent
9 of what's been brought here; is that --

10 A. (Witness Mallard) I just -- I just can't
11 comment on the results of --

12 Q. No, that's fine.

13 A. (Witness Mallard) -- that RFP at all.

14 Q. No, it's -- the number is not as important as
15 the clarification that in the IRP on 1172, the company
16 says that that 210 megawatts is part of the supply side
17 plan, but is it your testimony that that leftover
18 capacity is not being rolled over into the proposed
19 200 megawatts that's part of the new proposals in this
20 IRP. Those are separate; right?

21 A. (Witness Mallard) So leftover capacity has not
22 yet been proposed to be rolled over. I believe there's
23 language in the order approving the DG RFP that does call
24 for the capacity to be rolled over, but I think the
25 Commission would need to -- would need to act on that and

1 approve the exact form that that would take.

2 Q. But the 200 megawatts you propose is
3 independent of that for now?

4 A. (Witness Mallard) That's correct.

5 Q. Okay. And just to clarify why we're talking on
6 the numbers. How does the company determine that
7 allocation of how much is going to be planned for
8 distributed generation as part of the overall procurement
9 so that that 200 number out of 2,300?

10 A. (Witness Mallard) Yeah. It's based on our
11 experience with the prior DG solicitations, based on the
12 amount of the interest that we've gotten, based on this
13 Commission's longstanding support of distributed
14 generation, and the company's recognition of the value
15 that these distributed generation resources bring to the
16 system.

17 And so as we think about the improvements that
18 we're planning to make, hosting capacity probably being
19 the most impactful that will help these projects locate
20 in areas to minimize their interconnection costs. We're
21 confident looking at sort of the landscape of bids that
22 we've received in distributed generation solicitations
23 over the last few years, that 200 megawatts is an amount
24 that the market can compete and can produce that amount
25 of resources for the company to procure.

1 Q. Did the company consider levels other --
2 allocations other than 200, higher or lower than 200
3 megawatts and why were those not selected? I mean --

4 A. (Witness Mallard) Yeah. Again, it's based on
5 our judgment, our experience, our look at the response to
6 our prior RFPs, what the pricing looked like, what the
7 reasons were that projects didn't go forward, our
8 interpretation of the impact that our proposed
9 improvements are going to make. And so it's for all
10 those reasons, we synthesized all that data and
11 determined that 200 megawatts was a reasonable amount and
12 in customers' best interest.

13 Q. And when I asked earlier, you mentioned the
14 customer side of the programs, both the REDI II and the
15 Customer-Connected Solar Program.

16 A. (Witness Mallard) Yes.

17 Q. The company is not proposing any additional
18 customer-sided capacity in this procurement --

19 A. (Witness Mallard) That's --

20 Q. -- beyond those two programs?

21 A. (Witness Mallard) That's correct. The
22 Customer-Connected Program was recently extended by
23 Commission action. As I mentioned, 25 megawatts
24 allocated. We just have one customer signed up right
25 now, but -- and I think we answered this in the DR. We

1 really do have lots of customers that are interested, and
2 what we've learned through recruiting these customers to
3 participate is a lot of them have really long timelines
4 to make decisions like this. It's got to go through lots
5 of different approval processes internally. And so what
6 we determined made the most sense for customers was to
7 leave the Customer-Connected program open, to maintain
8 the ability for these customers to continue to apply. I
9 think we've got close to 20 customers who have indicated
10 pretty strong interest at this point. So we don't need
11 to add any additional capacity there; we just are
12 proposing to continue the Customer-Connected program with
13 the expectation that some of these customers who have
14 expressed interest will sign up to participate soon.

15 Q. And for those reasons, is it also your
16 testimony that the company is not proposing to roll that
17 25 megawatts into anything else because you want to keep
18 it open?

19 A. (Witness Mallard) That 25 megawatts will remain
20 with the Customer-Connected program.

21 Q. Is that also true for the REDI II capacity
22 that's under --

23 A. (Witness Mallard) The REDI II capacity is not
24 going to -- is not going to remain available. And I
25 apologize, but I cannot remember what the language is in

1 the order as it relates to rolling the capacity forward.

2 Obviously, it's always Commission decision as
3 to what the dispensation is of unused megawatts would be,
4 and so I think that would be a Commission decision when
5 the time came.

6 Q. And just generally on that last point. I mean,
7 it's still the company's position that the size of that
8 allocation within the overall procurement and the overall
9 size of the procurement are a policy decision for the
10 Commission to make; right?

11 A. (Witness Mallard) Absolutely.

12 Q. I want to talk about the feedback that you
13 received and the improvements that you're proposing for
14 the procurement process. On page 35 of your testimony,
15 on line 11, you mentioned that the company has considered
16 feedback from market participants. How did the company
17 receive this feedback? Did you solicit from market
18 participants? Was it part of the RFP process? What
19 channels did you use?

20 A. (Witness Mallard) Yes, definitely it's part of
21 the RFP process and we received lots of feedback through
22 the independent monitors' website. Additionally, we've
23 received feedback through the Public Service Commission
24 staff and the Commission directly from the participants
25 in the market. And so that feedback is really important

1 to Georgia Power.

2 We designed lots of elements of this program to
3 procure resources that provided the most value for our
4 customers, but along the way, we identify elements of the
5 procurement processes that can be improved, and so that's
6 exactly the case this time. That feedback from the
7 market participants is invaluable. I'm taking that into
8 consideration and are planning some improvements to our
9 processes going forward.

10 Q. Could you summarize or mention any highlights
11 that you may remember from the bidder comments
12 specifically in some of the RFP feedback about maybe why
13 those procurements were not filled --

14 A. (Witness Mallard) I'm not comfortable speaking
15 about that in detail. That is still an ongoing RFP. The
16 details and the information about that RFP is still
17 protected information and governed by our standards of
18 conduct and communication. I can summarize at a high
19 level that bidders -- that the process as we designed it
20 allowed for bidders to bid and also have an
21 interconnection cost assumption that would modify their
22 pricing and added some complexity.

23 Additionally, the actual cost and requirements
24 to interconnect proved problematic for a lot of these
25 projects to move forward. So it's taking into account

1 the process, the feedback on how that went and how we
2 could make that a more efficient process for bidders
3 going forward. That really is the basis for the
4 improvements that we're considering.

5 Q. So interconnection was a major theme of those
6 comments, and were there other themes, timing, or design
7 of the program or, you know, allowance of third-party
8 ownership?

9 A. (Witness Mallard) Yeah, I'm just not willing to
10 comment details of the DG RFP.

11 Q. Understood.

12 Okay. So let's talk about the improvements
13 that you're proposing from the feedback. Since
14 interconnection was a theme, without getting into the
15 details of the comments, what's the company proposing as
16 an improvement with regard to interconnection for DG?

17 A. (Witness Mallard) Well, I would say, first and
18 foremost -- and, again, I will only be able to speak
19 about these at a high level, as well, Commissioner. The
20 ongoing RFP is not over. We haven't formalized and
21 synthesized all of those comments, and we don't have all
22 of the proposals finalized as to what we might do, but
23 we're certainly considering a few things.

24 I would sum it up as this: We want the process
25 to be more efficient for these bidders. We want bidders

1 to -- we really want to follow the utility scale
2 procurement process a little bit more. We're going to
3 receive the bids. We're going to evaluate them based on
4 the value that they provide to customers based on their
5 pricing and output, and then we're going to
6 chronologically go down evaluating the interconnection
7 costs for each of those bids and then selecting bids that
8 provide the most value for customers.

9 The primary improvement is going to be an
10 enhancement to our interconnection guidance process. So
11 we already offer interconnection guidance to these
12 bidders. It's available so they can understand the cost
13 to interconnect, but the hosting capacity map is the
14 primary improvement that's going to make process more
15 efficient. It's going to allow these bidders to select
16 sites that minimize interconnection costs, and we're
17 hopeful it's going to produce a much more efficient and
18 successful RFP.

19 Q. And with regard to the hosting capacity
20 mapping, what criteria is the Company going to use to
21 determine where the interconnection is more favorable in
22 that mapping?

23 A. (Witness Robinson) So the company is currently
24 discussing with a consultant building the models
25 necessary for all 2,356 feeders that we have throughout

1 the state, using a tool called CYMEDist, which is an
2 Eaton product, that has an EPRI 2.0 drive process, ICA
3 capability as far as looking at hosting capacity
4 availability.

5 So those -- there will be a rollout over
6 several years because 2,300 feeders is a lot of feeders
7 to build models, and we've got to staff up for that. But
8 those are the primary tools that we'll be using is
9 CYMEDist software and the modules available, particularly
10 the EPRI 2.0 Drive -- EPRI Drive 2.0 Module.

11 Q. So what's the information that going to be
12 provided from that software? I mean, what kind of
13 details is a developer going to see when they go into
14 this on-line?

15 A. (Witness Robinson) So it's still under
16 development, but what we envision is a GIS-based model
17 that would give kind of a red light, green light, maybe
18 yellow light based on feeder location throughout the
19 state, available capacity that we calculate using this
20 process that we're developing currently.

21 Q. And let's assume that we're sort of a red
22 light, green light, yellow light process, are those going
23 to be indicative of expected interconnection costs or is
24 that purely just a reflection of congestion?

25 A. (Witness Robinson) It will really be more

1 indicative of the amount of capacity that's available on
2 the feeder. We will still need to follow our
3 interconnection process looking at interconnection costs
4 and insuring safe, reliable interconnection of those
5 facilities in the future.

6 Q. Is the company considering offering any
7 additional information about interconnection costs which
8 is standardized costs for equipment and components that
9 go into an interconnection study and interconnection
10 costs?

11 A. (Witness Mallard) So what we are offering is a
12 year-round interconnection guidance process, and there's
13 three different levels, Commissioners, and they each have
14 a fee associated with them. \$1,300 for the basics; 3,500
15 for the mid level; \$9,500 that really tells you all the
16 information down to a feeder level that you need to
17 interconnect your facility.

18 That enhanced guidance is being used right now
19 by bidders to evaluate potential future sites. We're
20 optimistic that by using that additional enhanced
21 interconnection guidance, plus the hosting capacity map,
22 is going to allow these bidders to find sites that really
23 do minimize the interconnection costs on the system.

24 Q. Does the information that you're describing
25 include, for example, standardized costs or estimates of,

1 you know, particular physical components of
2 interconnection that a developer might roughly estimate
3 their own project?

4 A. (Witness Mallard) Yeah. I think at the high
5 level -- I don't know about standardized costs. Each
6 interconnection is different, but I think at the enhanced
7 level of interconnection guidance provides a pretty good
8 level of details that can help a bidder understand
9 exactly what those interconnection costs are going to be.

10 Q. Does the company provide that information to
11 staff as well for review?

12 A. (Witness Mallard) Yes, if staff asks for it for
13 review, absolutely.

14 Q. Okay. Has the company received feedback
15 whether it was in the RFP process or not from bidders
16 asking to be able to review interconnection studies and
17 the particulars of interconnection studies when those
18 bidders did not execute PPA?

19 A. (Witness Mallard) Again, I'm just not going to
20 be able to talk about specifics of the ongoing DG RFP.

21 Q. Going forward for future procurements, would
22 the company be willing to work with local installers and
23 other stakeholders to talk about access to that kind of
24 information or giving that information to staff?

25 A. (Witness Mallard) We're absolutely willing to

1 talk with them and work with them. And I personally have
2 talked with and worked with more than I can count over
3 the last six months or so.

4 Q. That's fair.

5 Does the company provide any detailed breakouts
6 of interconnection costs, whether they're specifically
7 studies or observe illustrative interconnection costs to
8 staff that it doesn't provide to installers?

9 A. (Witness Mallard) So staff is part and parcel
10 of the development of our distributed generation RFP
11 along with the independent evaluator and independent
12 monitor. And so they work closely with the company as we
13 develop the overall parameters of the RFP, and certainly
14 the interconnection processes. So staff has got full
15 insight into how the RFP is developed and what that
16 information looks like and what's provided.

17 A. (Witness Robinson) And I also believe there
18 was a data request to provide some of that information as
19 well.

20 Q. Does staff also play a role, along with the
21 company and independent evaluator in resolving some of
22 those comments that come up during the RFP process?

23 A. (Witness Mallard) Oh, yes. It's a
24 collaborative process. The comments that are received
25 through the RFP process first come to the company, then

1 feedback from staff. Ultimately, the IE or IM evaluates
2 them as well, and then once there's a consensus on the
3 response, the responses are posted through the IE
4 website.

5 MADAM CHAIR PRIDEMORE: Mr. Thomasson, how more
6 questions do you have?

7 MR. THOMASSON: I would say I probably have 10
8 to 15 more minutes.

9 MADAM CHAIR PRIDEMORE: 10 to 15 more minutes?
10 Okay. So for the purposes of housekeeping, it is
11 coming up on 6:30. We have present, let's see,
12 one -- is Mr. Carver still here?

13 MR. CARVER: Yes.

14 MADAM CHAIR PRIDEMORE: Okay. Two.

15 Mr. Jones, is he still here? Three.

16 Sierra Club, are they still here? Four.

17 MR. STEVEN JONES: I'm the other Mr. Jones.

18 MADAM CHAIR PRIDEMORE: Oh, sorry. Mr. Steven
19 Jones, yes. I saw him wave.

20 Okay. Sierra Club is still here.

21 SACE and the all American ABCs of -- they're
22 still here. And Mr. Mahan, are you still here?

23 MR. MAHAN: Yes, ma'am. I'm still here.

24 MADAM CHAIR PRIDEMORE: At 8:00, the AC in this
25 building goes away, and there's nothing that we can

1 do about it. We have tried.

2 COMMISSIONER SHAW: We could leave.

3 MADAM CHAIR PRIDEMORE: I like the way that
4 Commissioner Shaw thinks; however, with this number
5 of intervenors, we still have to get through this
6 and allow Georgia Power to do redirect, if they have
7 any.

8 So let me ask you: If you've answered it, I
9 appreciate the sounds of your voices, be brief, just
10 answer the question. We don't need the background
11 on every question. And then if you and all of the
12 other questioners and attorneys would just pick up
13 the pace a little bit. Let's act like we've had
14 some caffeine. And if you need some, we'll send
15 somebody out to get us some. But it's about to get
16 hot in here, so let's just pick up the pace. Thank
17 you, Thomasson.

18 BY MR. THOMASSON:

19 Q. I will wrap up that line of questioning with
20 just a general thing that I think you got at before, but
21 the company is still willing to talk about other
22 improvements to the DG procurement process in addition to
23 just the locational guidance?

24 A. (Witness Mallard) Yes.

25 Q. There were a lot of the questions about best

1 cost procurement and how that -- I don't want to go back
2 over any of that, but along with this theme, is the
3 company going to offer additional guidance and
4 information in future procurements about how best cost is
5 going to be applied?

6 A. (Witness Mallard) Sure. Well, as we roll out
7 the RFP, the evaluation methodologies will be made
8 available, and so all that information will be proposed
9 in the RFP and PPA documents as the RFPs development.

10 Q. So that will also include how best cost might
11 relate to RCB evaluations as part of procurement and
12 maybe REC treatment?

13 A. (Witness Mallard) So the RECs are assumed to
14 be conveyed to the company on behalf of all customers.

15 Q. This is where I skip through a lot. I only
16 have a couple questions that I didn't get to on Community
17 Solar. Does the company have data on how many customers
18 have left the Community Solar Program?

19 A. (Witness Mallard) I'm sure we do. There's a
20 fairly significant amount of turn. I don't have that
21 information available.

22 Q. Has there been any effort to understand what
23 drives the churn or why customers are leaving?

24 A. (Witness Mallard) Oh, yeah. We absolutely
25 study that and understand from customers what their

1 motivations are. I'll be honest, I think the primary
2 driver is customers would are moving locations have
3 Community Solar move locations, final their account, and
4 don't restart at their new location.

5 Q. And you mentioned with the exception of the
6 income qualified scenario that the customers retire the
7 RECs as part of the Community Solar Program?

8 A. (Witness Mallard) Yes, RECs are retired on the
9 customer's --

10 Q. Is there a value associated with those RECs and
11 the price the customers pay for that subscription?

12 A. (Witness Mallard) so there's not. We don't
13 assume a value for RECs that are bundled with energy that
14 the company generates or purchases.

15 Q. And a clarification from some of the other
16 questions earlier. Has the company evaluated whether
17 benefits accrue to all customers from the Community Solar
18 Program as a whole?

19 A. (Witness Mallard) Yes, I would say when the
20 Commission approved the development of the Community
21 Solar facilities that were built below the company's
22 projected avoided cost at the time, they were, in effect,
23 making the decision that those resources do benefit all
24 Georgia Power customers.

25 Q. How does the company recover costs for solar

1 capacity that's not fully subscribed as part of that
2 program?

3 A. (Witness Mallard) So the cost of the Community
4 Solar facilities are recovered through base rates.

5 Q. Okay. Does the company follow the normal RFP
6 process for procurement when choosing developers for the
7 Community Solar projects?

8 A. (Witness Mallard) So those were all done a few
9 years back. I don't know that we had an established
10 process. Going forward, if we were going to develop more
11 self-built, Community Solar facilities, we would
12 certainly envision a competitive RFP for the EPC. I
13 think there was a competitive RFP, but I just can't say
14 for sure.

15 Q. A strong presumption that it would be
16 competitive going forward?

17 A. (Witness Mallard) Yes.

18 Q. That's fair. Couple of other clarifications on
19 RECs. There were some questions earlier about the
20 revenue coming from RECs. Do any of those revenues go
21 toward compensating solar developers of PPA
22 counter-parties from previous solicitations that may not
23 have received much compensation at the time, but I think
24 the question is more cut and dry, would you say, any of
25 the revenue from selling off RECs go to counter-parties

1 for existence --

2 A. (Witness Mallard) Yes, so a couple of things.
3 The company doesn't sell RECs. We'll retire RECs on
4 behalf of participating customers for our programs but we
5 don't sale RECs. Additionally, we don't purchase RECs
6 other than unbundled RECs for the simple solar program.
7 RECs are all conveyed to the company as part of the
8 agreements and the purchase power agreements.

9 The RECs are assumed to be conveyed to the
10 company along with the energy. That's been true for
11 every procurement all the way back to ASI Prime, I
12 believe, which was approved in the 2013 IRP.

13 Q. And Mr. Walsh had asked you some questions
14 about whether the benefits of RECs would be distributed
15 unevenly when the company is retiring RECs for specific
16 customers that were previously allocated to all
17 customers. Do you remember that earlier?

18 A. (Witness Mallard) I remember.

19 Q. Do you recall as part of your answer that you
20 mentioned that the customers that are receiving the RECs
21 for retirement could use those RECs for compliance
22 purposes as part of the value for them?

23 A. (Witness Mallard) That's right.

24 Q. Is there a value -- is there a negative value
25 for all customers who are having those RECs transferred

1 from them to not having that compliant value, or is there
2 sort of an avoided compliance cost from customers being
3 able to hedge against -- or the company being able to
4 hedge on behalf of customers?

5 A. (Witness Mallard) So I don't think so. There's
6 no compliance value today, and we also anticipate
7 including language in these agreements that would make it
8 clear that should the company need any of these RECs for
9 any sort of compliance with federal, state, or other sort
10 of carbon or renewable requirement that we could reclaim
11 those RECs. There will be a clause in the contract that
12 will make sure the customer is protected should any of
13 those RECs be needed for any future compliance case.

14 Q. Is it accurate that the company tracks RECs
15 associated with the simple solar program through the
16 North American Renewables Registry, NAR?

17 A. (Witness Mallard) Yes.

18 Q. Does the company keep a REC inventory through
19 that NAR for its other REC programs?

20 A. (Witness Mallard) No. The only the unbundled
21 RECs purchased for simple solar to provide that program
22 is tracked through NAR. RECs that we received that are
23 bundled with renewable energy through purchase power
24 agreements are self-built are just tracked on internal
25 company spreadsheets.

1 Q. So is that the reason because you know the
2 source that you can account for it yourself?

3 A. (Witness Mallard) That's right. We get the
4 meter readings, so that's going right to the source for
5 the amount of renewable generation.

6 Q. All right. Just a couple more questions about
7 battery storage.

8 A. (Witness Mallard) Sure.

9 Q. I know there were a lot of the questions about
10 the 15 percent and the 1,000 megawatts and how you reach
11 that. I'm not going to cover that again. But
12 independent of the reasons that you settled on the
13 15 percent and the 1,000 megawatts, hypothetically, if a
14 higher level of storage were selected, higher than
15 15 percent, or higher than the 1,000 megawatts for the
16 existing capacity, would that make integration costs for
17 solar higher or lower? I mean, independent of what the
18 ultimate balancing decision is, if it were higher would
19 integration costs for solar be lower necessarily or does
20 it depend?

21 A. (Witness Weathers) When you say "integration
22 costs for solar," are you referring to the renewable cost
23 benefit framework or are you referring to actual costs on
24 the system.

25 Q. More the latter, but I'll take an answer for

1 either one.

2 A. (Witness Weathers) okay. So if it's the
3 latter -- and your question is would additional batteries
4 make it less costly to integrate solar?

5 Q. Yeah. And a different way of asking is, how
6 does the level of, you know, the optimal battery
7 percentage affect the integration cost for solar?

8 A. (Witness Weathers) Sure. Yeah. I mean, I
9 think batteries are -- they always provide benefits.
10 They're very flexible. They can provide a range of
11 benefits. The reason why the level of batteries that we
12 chose was consistent with the amount that's needed to
13 mitigate the impacts of solar, you know, from the levels
14 we saw in the study to current levels.

15 And so if you have additional batteries you can
16 either further increase intra-hour reliability or you can
17 use those batteries for other purposes. Either way,
18 there's value there. There's value to having batteries
19 on the system.

20 Q. But they may be values that don't necessarily
21 reduce the integration cost for solar at some point?

22 A. (Witness Weathers) They reduce it -- they
23 increase reliability, but it's more than the amount of
24 the study. So we studied the current system reliability
25 as being the target. And so I would imagine that the

1 incremental benefits of each additional battery may be
2 diminished a little bit versus what we studied.

3 Q. All right. And a quick clarification about the
4 comparison of company-owned BESS to baseload facilities
5 historically. I think you contrasted sort of economic
6 considerations against reliability, and the reliability
7 was the key criteria for wanting to own -- to control it
8 for reliability purposes, not to control results in
9 better economic outcomes; is that accurate?

10 A. (Witness Grubb) Let me make sure I'm following
11 what you're asking. I think I'm with you, but I want to
12 make sure I'm following you.

13 Q. Yes. So the primary concern for the company
14 wanting to own BESS is reliability and control, not
15 comparing the economics to third party -- or not the best
16 cost or least cost like we talked about in other
17 procurements?

18 A. (Witness Grubb) So, yes, the reliability is the
19 drive for the ownership. As far as a cost comparison
20 between if you did company ownership versus the market, I
21 don't know that we can speak to that because it goes back
22 to all those use cases; right? So it depends on how
23 robust, how stringent, how restrictive, how much
24 performance you would put in one of those PPAs, and we
25 don't know all those answers. So I don't know that it

1 would be cost competitive.

2 But to your point, the real request for company
3 ownership is about the need to have that ownership so we
4 can invest in it, everything we spoke about this morning
5 and earlier today. That's the main driver.

6 Q. Okay. I'll take that.

7 MADAM CHAIR PRIDEMORE: Reliability being the
8 driver for BESS has been asked and answered multiple
9 times.

10 MR. THOMASSON: The clarification was more
11 about the cost effectiveness, but I'll move on.

12 BY MR. THOMASSON:

13 Q. The last question on BESS is you talked about
14 using a competitive procurement for EPC for a
15 company-owned BESS. Would be it possible to include in
16 that same competitive solicitation or RFP process also
17 allow the market to bid in PPA or third-party-owned
18 contracted BESS without, you know, fundamentally changing
19 the RFP process? Doesn't the current RFP process allow
20 for that?

21 A. (Witness Mallard) No, the current RFP for EPC
22 would not allow for that. We would have to modify it.
23 And, again, it's our position that the company needs to
24 own those resources to maintain the reliability our
25 customers expect. So we wouldn't want to entertain

1 allowing third-party ownership in that EPC RFP.

2 Q. Okay. So you can't consider EPC and what we'll
3 call PPAs in the same RFP process?

4 MADAM CHAIR PRIDEMORE: Talk in the mic for me,
5 Mr. Thomasson.

6 MR. THOMASSON: Oh, sorry about that.

7 MADAM CHAIR PRIDEMORE: Talk quick and in that
8 mic. There you go.

9 A. (Witness Grubb) We would not for this, for this
10 application.

11 BY MR. THOMASSON:

12 Q. Okay. Is the company considering any
13 competitive solicitations for the DER reliability and
14 constraints pilot?

15 A. (Witness Grubb) That's more a panel two
16 question, but what we've filed is for company ownership,
17 but Mr. Evans can speak more to that tomorrow.

18 WITNESS ROBINSON: Actually, Mr. Grubb --

19 WITNESS GRUBB: I'm sorry.

20 A. (Witness Robinson) Local reliability
21 constraints -- for these pilots they would be
22 company-owned facilities. We would not --

23 Q. Could it be similar to BESS? I mean, could you
24 do an EPC RFP for that as well?

25 A. (Witness Robinson) We will through our

1 generation development team.

2 Q. Okay.

3 A. (Witness Robinson) We will run an EPC. And,
4 you know, we would consider third-party ownership in the
5 future, depending on the results of these pilots and how
6 we -- like I mentioned, five of the seven feeders that
7 we've identified have existing solar on those feeders,
8 and how do we interact with those and develop those into
9 these schemes?

10 Q. But the company is not open to considering
11 third-party owned resources for that DER pilot?

12 A. (Witness Robinson) Not at this time for this
13 purpose for these pilots until we get more comfort with
14 how we deploy, how we interact, how we engineer, how we
15 operate these in real-time.

16 MR. THOMASSON: All right. That's all I have,
17 Madam Chair.

18 MADAM CHAIR PRIDEMORE: Thank you,
19 Mr. Thomasson.

20 MR. THOMASSON: I would ask that
21 Ms. Ottenweller's two exhibits be entered into the
22 record into GSEIA 1 and 2.

23 MADAM CHAIR PRIDEMORE: So moved.

24 (The documents referred to as GSEIA
25 Exhibits 1 and 2 were received into evidence.)

1 MADAM CHAIR PRIDEMORE: Mr. Moreland, are you
2 present? No.
3 Ms. Coyle, Georgia Watch.
4 CROSS-EXAMINATION
5 BY MS. COYLE:
6 Q. Good evening. I'll try to keep mine short, and
7 I think you referred to it, Chair Pridemore, as spicy or
8 something along those lines?
9 MADAM CHAIR PRIDEMORE: That's right. Sweet
10 and spicy.
11 BY MS. COYLE:
12 Q. Sweet and spicy. So, good afternoon, evening?
13 A. (Witness Grubb) Evening.
14 Q. I think mine is relatively short compared to
15 some of the previous intervenors. I had one follow-up
16 question to a conversation you were having earlier.
17 Ms. Kysor and Chairman Pridemore were asking you
18 questions about the income-qualified Community Solar, and
19 I heard you say that the customer on average, you expect,
20 would save \$15?
21 A. (Witness Mallard) That's right.
22 Q. And the cost of the program is \$28, 21 of that
23 is paid by the company, and 7 of that is by the customer.
24 Is the \$15 savings net of that \$7?
25 A. (Witness Mallard) Yes. Yes. So the customer

1 would pay the \$7. We would estimate their savings to be
2 approximately \$22. Again, those are just averages, so
3 yes.

4 Q. Great. Thank you.

5 And then going back and just, you know, briefly
6 referring to your testimony, starting on page 7, that
7 first, you know, paragraph summarizing the testimony of
8 your panel.

9 A. (Witness Grubb) Yes, ma'am.

10 Q. And in your testimony there you state that the
11 plan is a balanced portfolio of resources for my
12 customers in a clean, safe, reliable and affordable
13 electricity, and then you end that same paragraph again
14 talking about continuing to insure reliability to serve
15 its customers across the state in a clean, safe, and
16 affordable answer. So my questions -- few questions
17 relate to that.

18 Would you agree that having electricity be
19 affordable is of importance to all of your customers?

20 A. (Witness Mallard) (Nods head.)

21 Q. And particularly your residential customers
22 especially those of low to moderate income?

23 A. (Witness Grubb) Yes, I would agree with that.

24 Q. And as you acknowledged earlier today with
25 Mr. Walsh and others, this IRP will be followed by a rate

1 case; is that right?

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

3 Q. And ultimately, then, do you expect that your
4 customers will have to pay for the plan that is approved
5 in this IRP?

6 A. (Witness Grubb) Yes. Some parts of this plan
7 are not in the next rate case, because this is a
8 long-term plan, but eventually, yes. The IRP results
9 impacts to the rate case.

10 Q. So everything in the IRP has a cost associated
11 with it, whether it's in this next rate case or in a
12 future rate case?

13 A. (Witness Grubb) And benefits, you know, it does
14 have associated benefits, but yes.

15 Q. And so, again, going back to your testimony
16 that the plan is affordable, how do you know that the
17 plan is going to be affordable for your customers,
18 especially those residential customers in the low to
19 moderate income category?

20 A. (Witness Grubb) So when we speak about
21 affordable here, what we're saying is when we look at our
22 30-year studies and we look at our evaluations here that
23 we are picking what is in the best interest of customers
24 from a cost standpoint. So when we say affordable, we're
25 looking at that long-term interest of customers and

1 what's the most cost-effective decision on those
2 resources.

3 Q. But you made decisions about what to include in
4 this plan that's before us now based on some assumption
5 that it is affordable?

6 A. (Witness Grubb) Well -- and, again, that is
7 because what we're looking at is our cost in our models
8 whether it's the reserve margin study, unit retirement
9 study, we're looking at that cost to customers. It's the
10 entire customer base, not by class, or not by rate, but
11 we're looking at the overall customer cost.

12 Q. But is it fair to say you want all of your
13 customers to find electricity they purchased from you to
14 be affordable?

15 A. (Witness Grubb) Yes. And, again, that's what
16 we're looking at is customer costs in all of the
17 evaluations that we're doing.

18 Q. So in order for you to state and testify that
19 the plan is affordable, have you calculated the percent
20 increase in customer rates tied to this plan?

21 A. (Witness Grubb) Not in the IRP. Again, the IRP
22 is a 20-year plan. Some aspects of it are 30 years, and
23 so what we're looking at is that incremental cost. But
24 as you make that decision on incremental costs, the lower
25 incremental cost decision will have lower rate impacts

1 over the time than something that was more expensive. So
2 we don't do rate calculations. We're looking at
3 incremental costs on our side.

4 A. (Witness Weathers) One thing that's important
5 here to realize is when we say "affordable," the elements
6 of the plan are less cost to customers than whatever the
7 alternatives were. So to kind of go through the list of
8 things we're looking at, what's the least cost for
9 customers? That's attributes to the affordability of it.

10 Q. And that's actually my next line of
11 questioning, so thanks for getting us there.

12 A. (Witness Weathers) You're welcome. Trying to
13 speed it up.

14 Q. That's being a little spicy too.

15 A. (Witness Weathers) If only I was that good. I
16 can't take credit for that.

17 Q. So then would you say, then, that you've
18 applied certain methodologies to your proposals to
19 evaluate, you know, on page 35, and the whole section 35
20 through 37, you talk about, for example, best cost
21 procurement, moving into that as it relates to RFPs on
22 page 35, lines 16 to 18, you start talking about to
23 moving to best cost procurements. So you're trying to
24 fill more methodologies into this plan than maybe you
25 have in previous IRPs to help you evaluate whether or

1 not, in fact, you are going to have a lower cost option
2 that you're presenting?

3 A. (Witness Mallard) Yes. It's an enhancement to
4 our planning process. As we talked about the models can
5 select renewable resources, and that's what they've done.
6 Now we're going to modify our procurement processes to
7 make sure we can go procure those best cost resources.
8 And just to be clear, Commissioners, as Mr. Grubb talked
9 about, it can be less upward pressure on rates. It can
10 also be savings on rates. It could also be downward
11 pressure on the fuel-cost bucket based on some of the
12 decisions that come out of this IRP.

13 Q. And so those -- you mentioned procurement
14 costs. You're looking for avoided costs -- you're
15 looking in some scenarios. You always have an eye to --
16 you seem to express a lot of concern about things that
17 might put upward pressure on rates and you're looking for
18 other opportunities to put downward pressure on rates; is
19 that a fair --

20 A. (Witness Mallard) We're looking for the best
21 mix of cost and reliability for our customers.

22 Q. And so, for example, in your discussion with
23 Chairman Pridemore about your request for \$28 million,
24 just to apply for a license renewal for Plant Hatch 1 and
25 2, that could take five years before you actually find

1 out from the nuclear commission whether or not that \$28
2 million was well spent; is that right?

3 A. (Witness Grubb) That's correct, but that
4 \$28 million is really around the option for 2034 through
5 2054, and 2038 through 2058 and the value to customers of
6 maintaining Plant Hatch.

7 So, again, it comes back to that long-term IRP
8 nature, and that's what we're looking at is we feel like,
9 and our numbers show, that it will be advantageous to
10 customers to extend those licenses.

11 Q. And I believe you said to Chairman Pridemore
12 that it would be cheaper than building new?

13 A. (Witness Grubb) I think that may have been a
14 Commissioner comment.

15 MADAM CHAIR PRIDEMORE: That was a bench
16 comment.

17 A. (Witness Grubb) But I would agree with that.
18 That is a benefit of Plant Hatch.

19 A. (Witness Robinson) And, Commissioners, to that
20 point, one of the reasons we need to take it now in the
21 time we need to take it is, if we're not successful in
22 that renewal, we're going to need to build a lot of
23 transmission to replace those units down in the Baxley
24 area. So that's an important piece to insure reliability
25 in the future.

1 Q. Do you think that the comment from the beach
2 might have been related to Plant Vogtle 3 and 4?

3 A. (Witness Grubb) That would be my assumption,
4 but I will let the bench speak to that if they need to.

5 Q. Now, I didn't see, and could be in there and I
6 overlooked it, but I didn't see a reference to Plant
7 Vogtle 3 and 4 in your testimony.

8 A. (Witness Grubb) It's included in the plans.

9 Q. But not in your direct testimony?

10 A. (Witness Grubb) No, we aren't asking anything
11 in this IRP on Plant Vogtle. It's included in the plans.
12 It's included in our models, but there's no specific
13 request related to Plant Vogtle.

14 Q. Thank you. But this IRP covers the years 2023
15 to 2025; is that correct?

16 A. (Witness Grubb) That is correct.

17 Q. And so -- and this may, again, be in your -- in
18 the actual filing and not your testimony, but it struck
19 me, do you expect that Unit 3 and possibly Unit 4 might
20 actually begin adding capacity to the mix in that time
21 frame?

22 A. (Witness Grubb) I mean, that's the schedule
23 that we've incorporated is late '22, and then, I think,
24 mid '23, so whatever the latest schedules are, they're in
25 there.

1 Q. How significant is that? You talked about risk
2 and risk mitigation. If Unit 3 and/or 4 are not adding
3 capacity to the mix in that time frame, what does that
4 mean for your need to -- you know, you talked about just
5 a minute ago Plant Hatch and your long-range planning
6 about transmission. What happens if Vogtle 3 and 4
7 aren't online in this three-year period where you've got
8 this built into the plan for the capacity?

9 A. (Witness Grubb) Right. So it is -- if it were
10 three-year delay, are you asking -- yes, so you would
11 have to have some replacement capacity. So when you look
12 at our numbers, we're -- we have Vogtle coming online at
13 the end of 2022, Vogtle 3, and then Vogtle 4, coming on
14 the next line, so our needs reflect that. So if --

15 Q. Do you model what happens if they're not online
16 then?

17 A. (Witness Grubb) We do not, because the
18 expectation is that it will be the end of this year.
19 We're given that guidance, and so we're watching that,
20 but it's included in those dates right now.

21 Q. And just a moment ago we talked about your
22 concern about looking at capacity and the choices you
23 make about including source of the capacity in the plan,
24 and I wanted to look at whether or not that particular
25 item in the mix would put upward pressure on rates?

1 A. (Witness Grubb) Something along those lines. I
2 don't think I one hundred percent followed you.

3 Q. But what we talked about that one of the things
4 you look at in your modeling is to see whether or not
5 something you put in the model results in a sense that
6 it's going to put upward pressure on rates?

7 A. (Witness Weathers) In comparison to the
8 alternative; right? So the model is either optimizing
9 that, selecting the least cost, or in particular specific
10 evaluations often you're comparing something versus the
11 alternative. We pay the one with the least cost or best
12 value to customers.

13 Q. So something might put less upward pressure on
14 rates; correct?

15 A. (Witness Grubb) So, for example, if you have to
16 add a resource to meet a capacity need, then it's the
17 best cost resource that can meet that need, but it's
18 upward cost because you're trying to add a resource.

19 Q. And when Vogtle Units 3 and 4 go into service,
20 whether it's in the next few years or not, how much
21 upward pressure will that put on rates?

22 A. (Witness Grubb) So I can't speak to rate
23 pressures and everything on Vogtle. I know there's the
24 entire docket where that's addressed. I am not involved
25 in any of the rate impacts from Vogtle.

1 Q. None of you have looked, followed along with
2 all the Vogtle fun we have to -- subject to check, would
3 you think roughly 10 percent is what's been in --

4 A. (Witness Grubb) Subject to check, that's my
5 understanding. We didn't study that. That's a different
6 analysis.

7 Q. And as far as you know, because this is in your
8 area of expertise, is anything in that IRP, based on your
9 modeling, going to put that much upward pressure on
10 rates?

11 A. (Witness Grubb) That much reference into --

12 Q. Potentially 10 percent upward pressure? If
13 Vogtle is going to put -- 3 and 4 put 10 percent upward
14 pressure on rates, you're looking at --

15 A. (Witness Grubb) You haven't put --

16 MADAM CHAIR PRIDEMORE: Can I ask a question?
17 Where did we get this 10 percent upward pressure on
18 rate number for Vogtle 3 and 4? Where is that
19 coming from?

20 MS. COYLE: From previous VCM testimony.

21 MADAM CHAIR PRIDEMORE: By whom? When?

22 MS. COYLE: Filed by the company.

23 MADAM CHAIR PRIDEMORE: Filed by the company
24 when? I mean, which VCM?

25 MS. COYLE: I think the last two, but I would

1 be happy to -- I can provide that information. I
2 said subject to check, so...

3 MADAM CHAIR PRIDEMORE: Okay. I would very
4 much like that, because that does not track with
5 what this Commission has -- what we've supported in
6 the past. That's new.

7 BY MS. COYLE:

8 Q. Let me rephrase that. Is there anything in
9 this IRP that's going to put as much pressure -- upward
10 pressure on rate as much as is expected from Plant Vogtle
11 3 and 4?

12 A. (Witness Grubb) Wouldn't expect that, but I
13 think, again, from a Vogtle standpoint, you're looking at
14 a 60- and 80-year resource that over the life delivers
15 benefits, but, again, what we're looking at is that
16 incremental cost --

17 Q. So whether it's on the supply side or the
18 demand side, whether it's for behind-the-meter solar on
19 affordable housing as we discussed earlier or programs to
20 help income qualified customers install energy efficiency
21 measures, you're not talking about percentages in upward
22 pressure on rates? You're talking about, I think you
23 used the word incremental?

24 A. Depending on if there's a need to add a
25 resource then you are, but we're doing it in the best

1 cost way. But in terms of that magnitude, I don't expect
2 anything in here to be of that nature. Again, back to
3 the Vogtle, that's a 60-, 80-year evaluation that's done
4 in the VCM docket and evaluated twice a year.

5 Q. But generally your goal is to have a plan for
6 capacity, adding capacity and retiring the coal plants,
7 for example, that is economic and that mitigates rate
8 impact; is that correct?

9 A. (Witness Grubb) Yes. We're looking at the
10 cost and benefits. So, again, there can be benefits that
11 outweigh those costs, but each decision is based on best
12 costs looking forward at customers.

13 A. (Witness Robinson) And, Commissioners,
14 reliability is a huge part of the plan as well. Not just
15 cost, but reliability of the system as well.

16 Q. And so I would like to ask you some questions,
17 the last line of the questioning. I would like to ask
18 you some questions about your proposed early retirements
19 of coal plants, and the coal ash cleanup that's included
20 in the IRP. Did you consider how to handle those aspects
21 of your proposal in the most economic manner?

22 A. (Witness Grubb) In terms of -- you mentioned
23 two. The coal ash is a different panel's testimony. So
24 I can't speak to that.

25 Q. Okay. Let's just focus on the early retirement

1 of the coal plants.

2 A. (Witness Grubb) Okay. So the question being,
3 did we look at costs when we evaluated it?

4 Q. Did you consider how to handle the early
5 retirement of coal plants in the most economic manner,
6 the way we were just talking about in terms of your
7 modeling things and you're looking at best cost and best
8 option for ratepayers?

9 A. First, I wouldn't -- we don't have a set
10 retirement date on coal units. I wouldn't determine
11 it as -- I wouldn't define it as an early retirement.
12 It's just the retirement of them. But, yes, our
13 evaluation on the coal units is based on do I -- is it
14 best for customers to continue to invest in that coal
15 unit, or do I retire it and replace it? So it is an
16 economics evaluation at that standpoint.

17 Q. Do -- well, you used the term early. I think
18 it's fairly standard in the industry when you have a coal
19 plant that's retiring while it still has what's
20 considered some useful life.

21 A. (Witness Grubb) Well, you mean as far as like
22 depreciable lives? I mean, that's sometimes used. We've
23 never really set a retirement date in terms of planning.

24 Q. Okay. So speaking, then, of retirement of coal
25 plants -- and there were a number of questions from

1 Mr. Walsh and from Mr. Jones about these -- did you
2 consider, again, in the recommendation to retire certain
3 coal plants, the cheapest cost option for handling your
4 recovery of those costs, the remaining net book value?

5 A. (Witness Grubb) So we have not proposed the
6 treatment of that.

7 Q. Are you aware that some states, including North
8 Carolina and Florida, have lowered the cost impact of
9 coal plant retirement by recovering those costs through
10 securitized bonds, you know, at a lower financing cost
11 than traditional rate base?

12 A. (Witness Grubb) I'm not an expert on
13 securitization. I don't know what other states have
14 done, but that's --

15 MADAM CHAIR PRIDEMORE: Yeah, can step in here?
16 These are rate case questions, and I know we are
17 looking forward to seeing you back for the rate case
18 this fall. But when we're talking about the
19 financing and costs of projects, it's different if
20 it's in a Vogtle capacity. That's a VCM. But we're
21 talking about a 20-year strategic plan.

22 MS. COYLE: Yes, ma'am.

23 MADAM CHAIR PRIDEMORE: So securitization is a
24 bonding mechanism.

25 MS. COYLE: I'm just trying to get as much

1 information as I can to see how much this plan is
2 going to be reflected in the rate case, but thank
3 you.

4 MADAM CHAIR PRIDEMORE: Thank you, Ms. Coyle.
5 Mr. Carver, Interstate Gas Supply?

6 MR. CARVER: No questions, Madam Chair.

7 MADAM CHAIR PRIDEMORE: I love the sound of
8 that phrase.

9 Mr. Clarkson, have we seen you yet?

10 (No response.)

11 I know he's writing something pithy, I'm sure.

12 Restore Chattooga Gorge Coalition, Mr. Jones,
13 Mr. S. Jones.

14 MR. STEVEN JONES: Madam Chair, Commissioners,
15 thank you for the opportunity to appear before you.
16 My name is Steven Jones with the law firm of Taylor
17 English Duma. I'm here today on behalf of Restore
18 Chattooga Gorge Coalition. I know it's late. I'll
19 try to keep it brief.

20 CROSS-EXAMINATION

21 BY MR. STEVEN JONES:

22 Q. Panel, I represent a coalition of entities that
23 have one principal interest in this proceeding and that
24 is to restore the gorge underlying the lake upstream of
25 your facility known as Tugalo. My questions will relate

1 solely to that purpose and I will address them to you as
2 a panel, whoever feels that they are the best suited to
3 answer the question, please do so.

4 On page 27 of the prefiled direct testimony you
5 address the hydro fleet of the company. What is the size
6 of the hydro fleet?

7 A. (Witness Grubb) It's about 1,100 megawatts.

8 Q. Okay. And what is the capacity of Tugalo?

9 A. (Witness Grubb) I've got to check. Tugalo is
10 what is -- there's a lot of plants, one second, it is 52
11 or so.

12 Q. So 1,152, that would put Tugalo at
13 approximately 4 or 5 percent of the entire hydro fleet;
14 is that right?

15 A. (Witness Grubb) Subject to check, yes.

16 Q. Okay. And what is the capacity of the entire
17 Georgia Power system?

18 A. (Witness Grubb) So 16 -- well, I'd have to
19 look -- 19,000 or so, it depends on -- it changes by
20 year.

21 Q. Okay. I showed in the territorial base
22 caseload spreadsheet for 2022 just over 20,000 megawatts.

23 A. (Witness Grubb) Depending on which year you're
24 looking at, yeah.

25 Q. So with those numbers that we've agreed to,

1 that puts Tugaloo's capacity at .2 percent of the entire
2 Georgia Power fleet; is that right?

3 A. (Witness Grubb) That sounds correct. Again,
4 just because it's .2 percent doesn't mean it doesn't
5 bring value, though.

6 Q. Absolutely. Just talking numbers now.

7 A. (Witness Grubb) I understand.

8 Q. And Georgia Power's long -- or has excess
9 capacity through the year 2029; is that right?

10 A. (Witness Grubb) I would say it's above target.
11 We don't refer to it as access until you get value from
12 it, but yes.

13 Q. You don't show a shortage in capacity until the
14 year 2030; is that correct?

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

16 Q. And that is in 2022, your long on capacity,
17 companies long on capacity about 800 megawatts; is that
18 right?

19 A. Yes. I don't have in right in front of me, but
20 yes.

21 Q. Subject to check?

22 A. Yes.

23 Q. How old is Tugaloo?

24 A. (Witness Grubb) It's -- I think it's in the
25 '20s. I think it's a Vintage 1920s type of facility.

1 Q. Subject to check, can we say a hundred years, a
2 hundred-plus years?

3 A. (Witness Grubb) Sure.

4 Q. What's the average life of a dam?

5 A. (Witness Weathers) Well, so, I think it depends
6 on components. All right. So what we're talking about
7 in the modernization is the turbines and the generators.
8 And so they're well beyond their lives, which is exactly
9 why in the 2019 IRP we brought forward the need to invest
10 in those generators and those turbines to maintain those
11 facilities.

12 Q. What about the structure itself?

13 A. (Witness Grubb) The structure itself, I don't
14 deal with that as much, but I think we do everything we
15 need to, and those structures are sound and in good
16 shape. So the hydro modernization is really around the
17 generation aspects of the dams. The dams themselves meet
18 all the standards that they need and we invest in those
19 as we need to.

20 Q. Has the company done any analysis of how long
21 the physical structures, what's their useful life? At
22 what point do you -- in other words, at what point do you
23 consider decommissioning the entire structure?

24 A. And you're referring to the dam?

25 Q. The dam itself, the bricks mortar.

1 A. (Witness Grubb) I don't know what that is, what
2 the record of or the pattern of reviewing those are.
3 Again, I think what we've noted is that the risk of and
4 the cost of decommissioning those dams would be very high
5 in terms of remediating those dams and removing those
6 dams.

7 Q. Are you aware that there's federal resources
8 and/or grants available to help decommission each dam?

9 A. (Witness Grubb) I was not aware of that.

10 Q. Okay. What's upstream of Tugalo Dam?

11 A. (Witness Grubb) So there's four other dams
12 upstream from Tugalo.

13 Q. And there's a lake upstream?

14 A. (Witness Grubb) Yeah, above each one of those
15 dams.

16 Q. And there's two rivers; correct?

17 A. (Witness Grubb) That's my understanding.

18 Q. Are you aware that the Chattooga River is a
19 wild and scenic river?

20 A. (Witness Grubb) I'm sure it is.

21 A. (Witness Mallard) Yeah, I'm aware. I've rafted
22 down it.

23 Q. That, Mr. Mallard, is my next question.

24 A. (Witness Grubb) I've never rafted down it, if
25 that's your next question.

1 Q. Would you like to?

2 A. (Witness Grubb) One of these days.

3 Q. Are you aware that underneath Lake Tugalo there
4 is, in fact, two more falls in addition to the five
5 upstream on the Chattooga?

6 A. (Witness Grubb) Was not aware of it.

7 A. (Witness Mallard) No.

8 Q. I guess now you are.

9 A. (Witness Grubb) Yes, I am.

10 Q. Do you know how deep the lake is?

11 A. (Witness Grubb) I do not.

12 Q. Has the company done any studies as to
13 sedimentation of the lake in the past hundred years?

14 A. (Witness Grubb) I can't say that we have or
15 have not. I've been focused on the generation aspects of
16 it.

17 Q. Okay. So as part of your study as to
18 modernization in the 19 IRP and this IRP, did you do any
19 studies as to the specifics, circumstances related to
20 each lake and whether each lake has suffered from unique
21 components that might add to the capital cost to operate
22 the dam in the future?

23 A. (Witness Grubb) You need to ask that -- when
24 you say suffering, I'm not sure I follow.

25 Q. Yeah. When the company looks at the cost to

1 operate a dam in the future, does it look only at the dam
2 and the generating resources itself, or does it look to
3 the costs associated with things such as sedimentation
4 removal?

5 A. (Witness Grubb) I don't know what we do on the
6 side of looking at sedimentation. Again, what we brought
7 forth to the Commission and what we're moving forward
8 with is these are older plants. As they start to have
9 outages, the FERC license to generate from those dams is
10 based on their ability to operate.

11 Q. Okay.

12 A. (Witness Grubb) We need that FERC license to
13 be able to maintain those dams, because, in our opinion,
14 the cost of retiring those dams is going to be quite
15 substantial, from our understanding.

16 Q. Understood. So you're not aware of any
17 sedimentation in the lake outside of your knowledge base?

18 A. (Witness Grubb) I personally am not, no?

19 Q. Any other panel?

20 A. (Witness Mallard) No. What I would say,
21 Commission, is it's interesting to me as we look forward,
22 looking at renewable resources, looking at storage
23 resources, these dams and these generators that we have
24 in north Georgia are both of those things. They're a
25 hundred years old and they've been providing renewable

1 resources and energy storage all at the same time.

2 I think it just makes sense for hydro
3 modernization for us to go forward with that and keep
4 these resources as valuable resources on our system.

5 Q. Mr. Mallard, to staff's question during its
6 cross-examination, the company didn't do any analysis of
7 alternative resources?

8 A. (Witness Grubb) So we did not do an economic
9 evaluation. Again, like we said in 2019, if we were to
10 do it like a unit retirement study and look at retiring
11 the dam and replacing it, you would have to have the
12 estimates of that dam removal, and we do not have those
13 because it would take a lot of money to do those studies.
14 We think the cost would be prohibitive. So it makes
15 sense for customers to maintain those dams and invest in
16 them, the generation.

17 Q. And the company has yet to do an environmental
18 impact study?

19 A. (Witness Grubb) At which plant?

20 Q. All of them.

21 A. (Witness Grubb) I --

22 Q. Specifically Tugalo.

23 A. (Witness Grubb) I don't know. I would think
24 that the FERC license requirements that we have and when
25 we relicense them would have an environmental study to

1 it. I don't know if with the amendments we'd turn those
2 over or not.

3 COMMISSIONER MCDONALD: Mr. Jones, help me just
4 a minute. What is your objective with these
5 questions? In one statement, what is your
6 objective?

7 MR. STEVEN JONES: Ultimately, we want to see
8 the gorge restored so it becomes a navigable river
9 again. We think there's economic benefit to that,
10 to the --

11 COMMISSIONER SHAW: Wasn't the updates to the
12 Tugalo Dam part of the 2019 IRP?

13 WITNESS GRUBB: They were, Commissioner. And
14 so what -- as we've moved forward with that project,
15 we have to file an amendment to the license at FERC.
16 And so that process is going underway right now.
17 And as I understand it, the association that is
18 represented here today is taking part in that -- in
19 that permit, so that licensing amendment.

20 So it was and we were moving forward with it.
21 We've done the scoping and engineering, but before
22 we can replace the turbine and generator work, we
23 have to get an amendment from FERC. That process is
24 taking place and it's being contested.

25 COMMISSIONER SHAW: I gotcha. Makes sense.

1 MR. STEVEN JONES: I'm about halfway done, so
2 I'm hurrying.

3 BY MR. STEVEN JONES:

4 Q. Panel, around the lake, who owns the property
5 along the shoreline?

6 A. (Witness Grubb) As far as the entire lake, I'm
7 not sure. I mean, I think there's lakes where it's
8 private landowners. I think there's lakes where we own
9 it. I don't know around the lake above Tugalo.

10 Q. Okay. So you don't know if it's owned by
11 Georgia Power or the state of Georgia or the state of
12 South Carolina?

13 MR. HEWITSON: Madam Chair, I believe that
14 question has been asked and answered, but I also
15 think we're getting far afield from the
16 modernization project that is subject to the 2022
17 IRP.

18 MR. STEVEN JONES: I'm getting there, Madam
19 chair, I promise, if you don't mind.

20 MADAM CHAIR PRIDEMORE: Okay. Counsel
21 withdraws.

22 MR. STEVEN JONES: Thanks, Steve.

23 BY MR. STEVEN JONES:

24 Q. Panel, are you aware, are there any residential
25 or commercial structures fronting the dam or fronting the

1 lake?

2 A. (Witness Grubb) Our hydro team knows. I
3 personally don't know.

4 Q. Okay. But they hydro team hasn't presented any
5 testimony relevant to the modernization efforts in this
6 IRP docket; is that right?

7 A. Other than support of what they're doing with
8 us, but we didn't include landowners around the lake in
9 terms of the generation value of those resources.

10 Q. In the 2022 IRP, Georgia Power is proposing
11 solar components and battery components, that's been
12 covered?

13 A. (Witness Grubb) Yes. Correct.

14 Q. The FERC license is referred to as a mid-term
15 license; is that right?

16 A. (Witness Grubb) That's right. I think the next
17 license renewal is in the '30s, so it was an amendment
18 based on the modernization.

19 Q. Okay. And that would be 2036?

20 A. (Witness Grubb) Subject to check, I believe
21 that's correct.

22 Q. And as -- not to belabor the point, but to
23 staff's cross, there's no assurance that FERC will grant
24 that license?

25 A. (Witness Grubb) No. Our expectation is that

1 they will, based on a lot of discussions we've had with
2 all of the agencies that we had actually had discussions
3 with before we filed the amendment at FERC. And so we
4 didn't get any pushback from the agencies that we spoke
5 with, is my understanding.

6 Q. Okay. With respect to just Tugalo and the
7 modernization efforts and the cost reports that have been
8 filed to date in the '19 IRP, is that project -- is it on
9 budget, on forecasted budget?

10 A. (Witness Grubb) I don't have the report with
11 me. We obviously aren't finished with the project. So I
12 think right now it's just scoping and engineering work.
13 I think it's slightly higher, but I don't believe it's
14 that much more than what we did in the IRP. And so we do
15 have a review with staff that we filed with the
16 Commission bi-annually to keep them up to speed where we
17 are on those budgets.

18 Q. But it's your belief that it's, at this point,
19 slightly over budget?

20 A. I believe it's slightly under budget, but I
21 will say that Terrora, which is the first ones that we
22 completed, did come in under budget and the company feels
23 confident in our ability to move -- be successful on the
24 hydro modernization project, especially as we continue to
25 gain experience.

1 MR. STEVEN JONES: Okay. I'll have one
2 exhibit, and I'll mark this as RCG Exhibit 1.

3 Madam Chair, may I --

4 MADAM CHAIR PRIDEMORE: You may approach.

5 (The document referred to was marked for
6 identification as Exhibit No. RCG-1.)

7 BY MR. STEVEN JONES:

8 Q. Gentlemen, this is what I've labeled as RCG-1,
9 is the bi-annual hydro modernization report for the
10 period ending December 31, 2021, filed in Docket 42310.
11 If you would, please flip to the spreadsheet attached
12 labeled Plant Tugalo at the very top.

13 Panel, would you please identify for me, if you
14 read it, there's a note section at the very bottom below
15 the table.

16 A. (Witness Grubb) You're on the specific plant
17 Tugalo spreadsheet; correct?

18 Q. That's correct.

19 A. Let me review it real quickly before I jump
20 down there. Notes at the very bottom?

21 Q. Correct. It's a little tough to read.

22 A. Yeah. So there's one asterisk that notes the
23 project forecast is updated, and we filled that out once
24 it's updated and approved. And the final project
25 forecast was developed in the quarter 3, 2021, and then

1 we note that we measure against the 2019 IRP budget.

2 Again, that 2019 IRP budget isn't necessarily
3 approved in terms of a cost approval, but it's guidance
4 for the Commission. But we are providing that comparison
5 back to there. And those are the two notes below the
6 table.

7 Q. And the current estimate of completion on the
8 right-hand column, third to the left, projected forecast,
9 the current estimate, what is the total?

10 A. (Witness Grubb) That is 115, so it's around
11 600 million over the --

12 Q. So construction hasn't started and we're
13 already projecting over budget, the company is already
14 projecting over budget. Is that a fair reading?

15 A. (Witness Grubb) It's a projection. I think
16 when you look at the grand scheme of things, that's still
17 within reason that we could result in something lower
18 than that.

19 Again, the one that we have completed, Terrora,
20 did come in under budget, and these are estimates that
21 will change as we continue to get RFP results on turbines
22 and generators, but, yeah, so slightly over budget.

23 Q. Okay. And last question, I fibbed, though, I
24 do have two exhibits.

25 A. (Witness Grubb) Okay.

1 Q. So I'm going to mark this exhibit as RCG
2 Exhibit 2. Madam Chair?

3 MADAM CHAIR PRIDEMORE: You may approach.

4 (The document referred to was marked for
5 identification as Exhibit No. RCG-2.)

6 BY MR. STEVEN JONES:

7 Q. Gentlemen, are you familiar with this document?

8 A. (Witness Grubb) Not very familiar. I know this
9 appears to be the filing of the amendment at FERC, and so
10 I was aware that we did it, but I'm not -- I wasn't
11 involved in drafting or anything. Our hydro services
12 team took care of this. So I know we filed it, but I
13 haven't spent a lot of time reading it or reviewing it.

14 Q. Are you aware in this document that the company
15 takes the position that any expenditures not made prior
16 to any 2022 IRP are not available?

17 MR. HEWITSON: Madam Chair, I believe the
18 witness already said he's not familiar with the
19 document.

20 BY MR. STEVEN JONES:

21 Q. Okay. Could I have you, then, flip to what is
22 the physical page 10?

23 MADAM CHAIR PRIDEMORE: Mr. Jones, what's the
24 first couple of words on the page that you're
25 referring to?

1 COMMISSIONER MCDONALD: Hold it up and show it
2 to us (indicating.)

3 BY MR. STEVEN JONES:

4 Q. The first -- it's Items 3, 4, Roman numeral 2.
5 There's a foot note number 4 at the bottom.

6 MADAM CHAIR PRIDEMORE: Got it.

7 A. (Witness Grubb) I'm sorry. You said it's on
8 the page with Items 2, 3 and 4?

9 Q. Footnote 4 is at the bottom, yes, sir.

10 MADAM CHAIR PRIDEMORE: First words on the page
11 are waived it's 401 authority to the State of
12 Georgia.

13 A. (Witness Grubb) okay. I miscounted. I counted
14 the letter, not just the file. I'm sorry.

15 So on the page, so what was the question?

16 Q. Would you please just read the third -- the
17 second and third sentence.

18 MR. HEWITSON: Madam Chair, the document hasn't
19 been put into evidence. The witnesses have
20 testified they're not familiar with the document. I
21 don't think it's appropriate to have them read it
22 into evidence in this proceeding. This is not --
23 this is not a document that was filed with the
24 Georgia Public Service Commission. It was filed
25 with FERC. The FERC relicensing amendment is not at

1 issue before this Commission.

2 MR. STEVEN JONES: Madam Chair, it goes to the
3 fact of whether or not this Commission has the
4 authority to make a decision on the Tugalo Dam going
5 forward in this 2020 IRP, and this is a party
6 admission or representation made to a federal agency
7 about that issue, which is the only issue that the
8 coalition is here on.

9 MADAM CHAIR PRIDEMORE: Is this an open item
10 that Southern Company has before FERC?

11 (No response.)

12 MADAM CHAIR PRIDEMORE: Sustained.

13 MR. STEVEN JONES: Okay. No further questions.

14 MADAM CHAIR PRIDEMORE: Thank you, Mr. Jones.
15 Sierra Club?

16 MR. HEWITSON: Madam Chair, the witnesses have
17 been going for about three hours straight, might we
18 give them a five-minute break to stretch their legs?

19 MADAM CHAIR PRIDEMORE: Absolutely. Let's --
20 yes, we'll admit your two exhibits into the record.
21 Thank you, Mr. Jones.

22 MR. STEVEN JONES: Thank you, Madam Chair.

23 MADAM CHAIR PRIDEMORE: Yes. The witnesses
24 will take a five-minute break and come back at 7:30.

25 (Whereupon a break was taken.)

1 MADAM CHAIR PRIDEMORE: Mr. Fabish, okay. All
2 right. We've got four witnesses. Let's begin.

3 CROSS-EXAMINATION

4 BY MR. FABISH:

5 Q. Absolutely. So think I can go pretty quickly
6 here. I hope folks will appreciate that. You guys have
7 had a long day already.

8 So with regard to the coal plants for sure,
9 Units 1 and 2, the Company is pursuing the voluntary
10 incentives program.

11 COMMISSIONER MCDONALD: You're going to have to
12 speak up.

13 MR. FABISH: Is this on? Is that any better?

14 MADAM CHAIR PRIDEMORE: Yes.

15 MR. FABISH: Good. Excellent. We shoot for
16 better.

17 BY MR. FABISH:

18 Q. Pursuing to voluntary incentives program,
19 compliance pathway (inaudible) guidelines; right?

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

21 Q. And that gives you an extra three years to
22 comply with that; right?

23 A. (Witness Grubb) Right. We're going down the
24 parallel paths of both, but that's what we filed as the
25 not what we're focused on.

1 Q. But what you mean by that parallel paths is
2 that it preserves that flexibility to make a decision
3 later as to whether or not to install the controls, if
4 that looks like the best option, or to retire the unit if
5 that looks like the best option; right?

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

7 Q. But you're not doing that with Bowen 3 and 4?

8 A. (Witness Grubb) That is correct. And my
9 understanding, panel three would have to elaborate on it,
10 is that's not option at Bowen 3 and 4, the VIP option.

11 Q. Punt that question for panel three then.

12 But if it were the option, would that also
13 provide a similar sort of flexibility for Bowen 3 and 4?

14 A. (Witness Grubb) It would, but my understanding
15 is it's not one. So we had to look at Phys Chem Bio 3
16 and 4.

17 Q. As part of the IRP -- there's a little bit of
18 factoring in some load growth due to vehicle
19 electrification; is that right?

20 A. (Witness Grubb) There is. Again, not the
21 expert on the load forecast, but there is some electric
22 transportation assumptions in our load forecast.

23 A. (Witness Weathers) Panel two could probably
24 explain better.

25 Q. (Inaudible.) Okay. But given that, has the

1 company taken a look at what the charging needs will be
2 for the increased number of electric vehicles over the
3 20-year planning horizon?

4 A. (Witness Grubb) You mean in terms of loads?

5 Q. In terms of just the physical infrastructure,
6 the make-ready, the transmission, the chargers.

7 A. (Witness Grubb) I think that's -- those aspects
8 are often more in the rate case in terms of our tariffs
9 and our make-ready programs for electric vehicles. I
10 don't know if Mr. Robinson has anything to add from their
11 standpoint.

12 A. (Witness Robinson) A bill has to be brought
13 forward in the rate case.

14 Q. Okay. Perfect. Thank you.

15 And then there is a hydrogen demonstration
16 project in the IRP; is that right?

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

18 Q. Yeah.

19 A. (Witness Grubb) Again, more specific details
20 in panel three, but we are proposing that for several
21 reasons.

22 Q. Okay. And this may be a question for panel
23 three, but what's the source of the hydrogen for that
24 project?

25 A. (Witness Grubb) It would be electrolysis. I do

1 know that part. As far as, you know, the source of the
2 actual creating the hydrogen, I don't know. But it would
3 be through electrolysis.

4 Q. Great.

5 Turning back to some of the unit retirements, I
6 think someone testified -- I'm over in the corner so it's
7 hard for me to see who was speaking -- testified earlier
8 that the unit retirement study looks at existing
9 environmental compliance requirements but not potential
10 risks that may be forthcoming; is that right?

11 A. (Witness Grubb) So in terms of coal rules, you
12 know, if there were revisiting of the MATS rule or the
13 ELG, that's correct. Until we have a proposed rule, we
14 don't include that in there. So other than carbon in the
15 scenarios, we don't capture anything beyond ELG.

16 Q. Okay. So, like you said, not like a stricter
17 potential MATS rule or a stricter effluent limitation
18 guidelines rule or potential new requirements for a
19 start-up/shutdown malfunction, or a tightened national
20 air quality standards for particulate matter or ozone,
21 that whole list of things wasn't part of the unit
22 retirement study?

23 A. (Witness Grubb) That is correct.

24 Q. Okay. Would the company agree that those are
25 potential risks --

1 A. (Witness Grubb) We would.

2 Q. -- in terms of compliance?

3 A. (Witness Grubb) We would.

4 Q. And so by retiring those units, those risks are
5 not something that ratepayers are confronted with for
6 those units?

7 A. (Witness Grubb) Right. To our point from this
8 morning, it's not just the carbon risk that we're looking
9 at, it's those future risks.

10 Q. Great. So just a couple more questions.

11 Southern Company has a 2050 -- and I think this
12 was alluded to earlier today -- has a 2050 carbon
13 neutrality target that's enunciated; right?

14 A. (Witness Weathers) That's correct.

15 Q. But the planning that's being done in this
16 process is essentially least-cost planning. It's not
17 based on trying to hit that target; correct?

18 A. (Witness Grubb) That's right. I mean, things
19 are trending in a very similar way because the cost of
20 resources, technology developments, and those things are
21 moving that way. But just as we've said in '19, we still
22 are using the state regulatory processes and our models
23 and processes to view it so we definitely take carbon
24 risk into account through our scenarios.

25 A. (Witness Weathers) And the target -- the

1 Southern Company goal is not driving the planning in
2 terms of objective function, not all of our scenarios
3 plan to that. But the planning process drives the
4 Southern Company goal. And so the goal was developed as
5 a result of the planning process and in coordination and
6 using the vehicle of the planning process to achieve it.

7 Q. Okay. Well, that sort of anticipates my last
8 question, which was going to be: If that goal didn't
9 exist, would there be anything different about the
10 retirements, procurements that are in this IRP?

11 A. (Witness Grubb) I would say no because we're
12 looking at carbon risks, not just that goal driving,
13 driving our decisions.

14 MR. FABISH: I think that's everything I have.

15 MADAM CHAIR PRIDEMORE: Thank you, Mr. Fabish.

16 Southern Alliance for Clean Energy and

17 Southface Energy Institute.

18 Good evening, Mr. Baker.

19 CROSS-EXAMINATION

20 BY MR. BAKER:

21 Q. Good evening, Madam Chairman, Commissioners,
22 Panel. Thank you for hanging in there. I'm going to try
23 to -- I have a lot of material -- cut it back, and we're
24 going to get going right now.

25 First question: Did Georgia Power work with

1 Southern Power on development of the Garland Solar
2 Facility battery storage project in California? This is
3 the 88-megawatt, 352-megawatt-hour energy storage
4 project.

5 A. (Witness Grubb) Did you ask if Georgia Power
6 worked with them on that?

7 Q. Yeah.

8 A. (Witness Grubb) Not that I'm aware of, no.

9 Q. Are you aware of it?

10 A. (Witness Grubb) No. I don't think we worked on
11 that. That was a Southern Power -- Southern Power
12 project.

13 A. (Witness Mallard) I'm generally aware of the
14 project but none of the specifics.

15 Q. Really? Okay.

16 All right. Well, then, you wouldn't know if
17 it's true that Southern Power Energy storage, the project
18 is co-owned in partnership with KKR and AIP management, I
19 assume; right?

20 MR. HEWITSON: I think they've already answered
21 that; no, they're not aware of it.

22 MADAM CHAIR PRIDEMORE: Sustained.

23 BY MR. BAKER:

24 Q. Now that you know about the existence of the
25 Southern Power storage project in California, it's

1 88 megawatts, do you think anybody at Georgia Power might
2 be in communication with them to maybe learn a little bit
3 about --

4 MADAM CHAIR PRIDEMORE: Sustained.

5 Mr. Baker, we have a plan that's been put
6 forward that's been filed with this Commission that
7 we've all spent a lot of time marking through.
8 That's a project in California. It's not a part of
9 the plan. Let's just try to keep us in the rails.

10 MR. BAKER: Well, they're proposing a 1,000
11 megawatts of storage development and they've got
12 a --

13 MADAM CHAIR PRIDEMORE: But it's by a
14 subsidiary of the holding company, not the operating
15 company. The holding company is not regulated by
16 this body, the operating company is.

17 MR. BAKER: I understand that, but they can
18 pick up the phone and talk to each other. I mean,
19 it's one big family; right?

20 MADAM CHAIR PRIDEMORE: This --

21 MR. BAKER: All right.

22 MADAM CHAIR PRIDEMORE: This is a process under
23 the Georgia Power 2022 Integrated Resource Plan.

24 BY MR. BAKER:

25 Q. All right. Well, because Georgia Power has no

1 experience operating large-scale solar storage, wouldn't
2 it be more economical for an experienced third-party
3 company to manage and operate the storage?

4 A. (Witness Grubb) As we've spoken to this
5 morning, there aren't -- there is nobody who has
6 experience with a large battery operating on our system.
7 And again, the request for ownership is all around
8 reliability and our need to own and control operating
9 reserves, and that's what we've talked about several
10 times today.

11 Q. All right. I'm going to refer to page 32 of
12 your prefiled testimony: Will the McGrau Ford battery
13 facility be operational by 2026?

14 A. (Witness Grubb) You said page 32?

15 Q. 32, line 19.

16 A. (Witness Grubb) McGrau Ford?

17 Q. Yes, sir.

18 A. (Witness Mallard) Yes. Yes. We're there.

19 Q. Will the facility be operational by 2026?

20 A. (Witness Mallard) Yes, that's the plan.

21 Q. Okay. Page 32, line 19, you state -- okay.

22 And what is the status of construction of the
23 McGrau Ford battery facility?

24 A. (Witness Mallard) So there's no construction.
25 The project is conceptual in nature. We're generally

1 following the battery storage action plan as listed in
2 the IRP. So the site has been identified, engineering,
3 design work is underway, interconnection studies are
4 underway. We're now to the point where we're asking for
5 Commission approval.

6 At that point, once Commission does approve, we
7 would go forward with that competitive RFP for EPC
8 vendors. At that point, we can finalize the cost benefit
9 analysis and present that to the Commission for final
10 approval.

11 Q. What is the projected operation date for the
12 65-megawatt, four-hour lithium ion battery energy storage
13 system located at Mossy Branch?

14 A. (Witness Mallard) October of 2023.

15 Q. And when will the 2-megawatt standalone battery
16 system be operational?

17 A. (Witness Mallard) We only have a rough timeline
18 for that yet. That project is not as far along on the
19 development cycle.

20 Q. Okay. Do you have a location, a proposed
21 location for it?

22 A. (Witness Mallard) We've identified a location
23 of Jekyll Island, Georgia, but final engineering, but a
24 final engineering design and drawings is not complete.

25 Q. Is the 2-megawatt standalone battery system

1 related to any of the seven local reliability constraint
2 pilots you were proposing?

3 A. (Witness Robinson) No, it is not.

4 Q. Is the Fort Stewart project the one Form Energy
5 is collaborating with Georgia Power to develop?

6 A. (Witness Mallard) No, that's a -- that's a
7 separate project. The Fort Stewart project is going to
8 use traditional lithium-ion battery storage technology.

9 Q. Okay. It was reported in February, Utility
10 Dive, that Form Energy announced a partnership with
11 Georgia Power to test a 100-hour ion battery -- iron
12 battery -- iron-air battery. Where is that project going
13 to be located?

14 A. (Witness Grubb) So we -- as we put in the
15 filing, we're still studying that. We aren't
16 specifically requesting that, so that determination has
17 not been made.

18 Q. Has Georgia Power Company had a NERC citation
19 or violation in the last five years because they did not
20 have enough reserves?

21 A. (Witness Weathers) What kind of reserves,
22 Mr. Baker?

23 Q. Backup reserves? Adequacy reserves for -- have
24 you had a NERC citation in the last five years?

25 A. (Witness Weathers) In terms of resource

1 adequacy --

2 Q. Yes.

3 A. (Witness Weathers) -- you said?

4 Q. Yes?

5 A. (Witness Weathers) No.

6 Q. What about sufficient reserves to meet the

7 generation load?

8 A. (Witness Weathers) Operating reserves?

9 Q. Yes.

10 A. (Witness Grubb) So we haven't had any loss of

11 load events. We haven't had any shed load events or any

12 of those types of things. So we have --

13 Q. Okay.

14 A. (Witness Grubb) I'm unaware of any reliability

15 issues that we've had from that stand point.

16 A. (Witness Robinson) What was the time frame?

17 A. (Witness Grubb) The last five years.

18 A. (Witness Mallard) Last five years.

19 A. (Witness Robinson) We did have -- we did have a

20 NERC alert in October of 2017. I believe that falls

21 within the five years, but that's not a violation.

22 Q. Okay. All right. Were generating reserves

23 used during the winter of 2021, 2022?

24 A. (Witness Weathers) When you say "generating

25 reserves," that's a term we haven't used. What do you

1 mean by that?

2 Q. Well, did you have to call upon reserve
3 generating resources to meet load demand during the
4 winter of 2021, 2022?

5 A. (Witness Grubb) The only way to meet demand is
6 with resources. And so we would have supplied those from
7 the fleet. I'm not sure what you're asking about in
8 terms of, like, winter reserves, but --

9 A. (Witness Weathers) Are you talking about
10 operating reserves?

11 Q. Yes.

12 A. (Witness Weathers) I mean, operating reserves
13 are used every minute of the day in terms of regulating
14 reserves.

15 Q. Okay. Were any -- were any generating assets
16 lost during the winter of 2022 -- '21/2022?

17 A. (Witness Grubb) Whether we had any forced
18 outages, I'm not -- I'm not sure. I'm not saying we
19 didn't, but I'm not --

20 A. (Witness Weathers) Are you asking about
21 specifically due to cold weather or any --

22 Q. Yes.

23 A. (Witness Weathers) -- any reasons?

24 Q. Any reasons, and then specifically cold
25 weather?

1 A. (Witness Weathers) Well, any reasons, yeah,
2 there's -- there's always -- I think most every hour of
3 the year forced outages on the system. Specifically due
4 to cold weather this past winter, I'm not aware.

5 A. (Witness Grubb) But I think we had to DR on
6 something, but I'd -- subject to check on some recent
7 outages, but I can't recall the details.

8 Q. When Georgia Power testifies that it
9 continuously evaluates resource adequacy, is -- how do
10 you define continuously? Is it daily? Quarterly?
11 Monthly?

12 A. (Witness Weathers) Through the annual planning
13 process.

14 Q. The annual planning process. Okay.

15 Have any major reliability events occurred in
16 Georgia since 2019?

17 A. (Witness Grubb) No, not from a loss of load
18 standpoint.

19 Q. Is there a NERC criterion that requires
20 balancing of generation and load within a five-minute
21 time interval?

22 A. (Witness Robinson) I'm not familiar with the
23 interval, but there is -- there are BAL requirements,
24 balancing requirements that require a certain equation to
25 be met to ensure frequency stays within certain tolerance

1 on the system.

2 Q. Is it a five-minute standard?

3 A. (Witness Weathers) It's not a five-minute
4 standard, but the modeling was performed at a five-minute
5 level to approximate that. So we can't go down to the
6 six-second level or instantaneous level, so we used
7 five-minute to -- to capture intra-hour volatility, and
8 it did reveal some volatility concerns.

9 Q. Well, the next question is, why would you use a
10 five-minute standard when the NERC standard actually uses
11 a 30-minute interval for system balancing?

12 A. (Witness Weathers) Well, so, yeah, 30-minute
13 refers -- yeah, so the standard does include 30-minute,
14 but it's measuring the frequency on the system and it --
15 in terms of staying within certain bounds. And so the
16 five-minute interval that we modeled indicates that
17 there's pressure on the ability of the system to meet
18 those requirements for the BAL standard. Doesn't
19 indicate that there's going to be a violation, but
20 there's pressure on the realtime balancing, and
21 five-minute was the -- the level of granularity we were
22 able to get to in the study.

23 Q. Okay. But NERC doesn't require -- that was
24 your standard, that wasn't NERC's standard; is that
25 correct?

1 A. (Witness Weathers) The five-minute's not a
2 standard. It's the modeling approach in order to
3 identify the intermittency issues and identify the best
4 way to alleviate those.

5 Q. So was that Georgia Power's modeling standard,
6 not NERC's?

7 A. (Witness Weathers) That was our modeling
8 approach.

9 A. (Witness Grubb) But, again, you've got to be
10 able to study that to understand how you're going to
11 perform in a 30-minute interval. So that's what we're
12 trying to get down to is that realtime operation.
13 Because we have the requirement in realtime to balance
14 load and generation, so that's what we were studying.

15 Q. By using that five-minute modeling standard,
16 doesn't that artificially inflate the integration charge
17 you're proposing for the RCB framework?

18 A. (Witness Weathers) No.

19 Q. Does the reserve margin study enable
20 calculation of the sensitivity and/or profit proportion
21 of each of these risk factors?

22 A. (Witness Weathers) Will you repeat that one
23 more time?

24 Q. Okay.

25 A. (Witness Weathers) Make sure I get that --

1 A. (Witness Grubb) And you switched to the reserve
2 margin study was your question; correct?

3 Q. Yes. Yes, sir. Yes, I have.

4 A. (Witness Grubb) Okay.

5 Q. Does the reserve margin study enable
6 calculation of the sensitivity and/or proportion of each
7 of these risk factors?

8 A. (Witness Weathers) When you say "these risk
9 factors," which are you referring to?

10 Q. The ones identified in the reserve margin
11 study.

12 A. (Witness Weathers) Oh. Quantifying the drivers
13 for seasonal planning, is --

14 Q. Yes, sir.

15 A. (Witness Weathers) -- that what you mean?

16 Q. Yes, sir.

17 A. (Witness Weathers) Yeah, so they're not
18 quantified directly, but the combination of the six
19 drivers for seasonal planning are the reasons why the
20 Commission approved the company moving to seasonal
21 planning three years ago.

22 Q. All right. Is the energy sales forecast
23 impacted by the assumption that technologies such as
24 motor vehicles currently fueled by oil or natural gas
25 will convert to electricity in the future?

1 A. (Witness Grubb) So we just spoke to that, that
2 that's more of a panel two load forecast question on the
3 details, but we do include assumptions on EVs.

4 MADAM CHAIR PRIDEMORE: How many more you got,
5 Mr. Baker.

6 MR. BAKER: I got quite a few.

7 MADAM CHAIR PRIDEMORE: All right. Clip it up,
8 then. Come on.

9 MR. BAKER: I am. I'm clipping it up.

10 BY MR. BAKER:

11 Q. All right. Quick question: Are you aware
12 that -- turning to the target reserve margin, are you
13 aware that in other cold weather areas of the country,
14 that their winter reserve margins are much less than the
15 ones that are being proposed by the company?

16 A. (Witness Weathers) I'm aware that there are
17 some. You have to also look at are they summer or winter
18 peaking. There's a lot of dynamics that go into it.

19 Q. Do you have any -- any information or knowledge
20 about the Kansas that -- Kansas uses a 12 percent reserve
21 margin in the winter?

22 A. (Witness Weathers) I do not.

23 Q. Okay.

24 A. (Witness Grubb) And some of the other things we
25 don't know, Commissioners, is what all Kansas does around

1 their units. I mean, if you have a unit in Minnesota,
2 you probably do it a little definitely than you do in
3 Atlanta. So that's why it's got to be specific to our
4 system.

5 Q. Well, there was a series of questions before --
6 I can't remember if it was Mr. Jones or Mr. -- or
7 Mr. Jones asked them. But based on the investment made
8 in winterization of the system and facilities, is there a
9 correlation between the winterization and the ability to
10 lower your winter reserve margin?

11 A. (Witness Weathers) Not if you base it on
12 economics, which is what we do. So winterization does
13 help with the reliability and provides benefits to
14 customers. But our target reserve margin, the primary
15 basis is economics. So the 26 percent winter target
16 reserve margin continues to be economic for customers.

17 Q. Okay. Turning to demand response resources,
18 why are demand response resources not considered a
19 dispatchable resource within the reserve margin studies
20 dispatchable resource load stat?

21 A. (Witness Weathers) They are.

22 Q. They are?

23 A. (Witness Weathers) Yeah. They're a resource
24 that reserve margins study. Optimization can call on
25 those to serve load.

1 Q. Has the company evaluated any potential cost
2 deficiencies and system reliability benefits that could
3 be gained by improving reserve sharing agreements -- by
4 improving reserve sharing agreements in the Southeastern
5 Electric Reliability Council planning region?

6 A. (Witness Grubb) So could you ask it one
7 more time. You're asking --

8 Q. Sure.

9 A. (Witness Grubb) -- if we've studied sharing
10 reserves with other entities within the Southeast?

11 Q. Yes. In the SERC region, has that ever been
12 considered?

13 A. (Witness Grubb) No. I mean, I think from a
14 reserve margin standard, we don't operate with those
15 other systems. We obviously are neighbors with them, we
16 can, you know, have reliability aspects of being able to
17 call on them. We do have some assumptions in the reserve
18 margin study by being able to purchase from those other
19 areas, but we don't operate our system with those other
20 systems. We don't dispatch with those systems. And so
21 we study Southern Company's system that serves our
22 customers, and we do have assumptions around purchases we
23 can get from surrounding areas.

24 A. (Witness Weathers) And to Mr. Grubb's point, we
25 don't have formal reserve sharing arrangements with those

1 entities, but we do consider that there is interface
2 capability between our area and other areas and that,
3 when economic, there's the ability to purchase across
4 that interface. And that affects the target reserve
5 margin. That helps put downward pressure on them.

6 Q. So you buy -- you can buy excess power that
7 they have when the -- when you have a need for it, but
8 there is no formal agreement as to that purchase and --
9 or sale agreement relationship?

10 A. (Witness Weathers) That's right. Because if we
11 look at weather diversity across a larger region, there
12 will be opportunities when Southern Company can be a
13 seller and times when it can be a buyer. And those
14 interchange -- the economic interchange of powers is
15 taken into account in the reserve sharing, in the reserve
16 margin study.

17 Q. Has there been an estimate done by Georgia
18 Power Company regarding the rate impacts from the
19 Southeast Energy Exchange Market by any chance?

20 A. (Witness Grubb) So you said SEEM? The
21 Southeast --

22 Q. The Southeast --

23 A. (Witness Grubb) SEEM, yes.

24 A. (Witness Weathers) I am not aware of any study
25 about the rate impacts of it.

1 Q. Would the cost or benefits of SEEM be reflected
2 in Georgia Power ratepayer rates, by any chance?

3 A. (Witness Weathers) Current rates?

4 Q. Or future rates?

5 MADAM CHAIR PRIDEMORE: Can I ask, that's a
6 question for the rate case. There's a rate --
7 that's a rate case-related question because SEEM is
8 a -- let's stick to planning, strategic planning.

9 BY MR. BAKER:

10 Q. All right. Turning to winter peak demands. Do
11 you know or can you identify the causes of the higher
12 volatility of winter peak demands relative to summer peak
13 demands?

14 A. (Witness Weathers) Well, weather. Weather is
15 going to be the primary driver of that. So in the
16 wintertime, temperatures can drop pretty low. A normal
17 winter low may be something around 19, 20 degrees. They
18 can get as low as 5 degrees, as low as zero degrees, even
19 negative.

20 In the summer, your temperatures in relation to
21 your weather normal, the gap is much smaller. So you may
22 be looking at weather normal in the upper 90s. You're
23 not going to get usually to 115 in the system. Maybe
24 more like 100. And so it's just the impact of cold
25 weather on the system demand is greater in the winter

1 than it is in summer.

2 Q. Okay. Is a higher penetration of heat pumps in
3 the market causing this higher volatility in the winter,
4 or contributing to it?

5 A. (Witness Weathers) It certainly does contribute
6 to the growth in winter loads as compared to summer
7 loads, and there could be some volatility associated with
8 that in terms of strip heating coming on.

9 Q. Has the company taken into consideration local
10 greenhouse gas laws and local clean energy policies in
11 its carbon pricing forecast?

12 A. (Witness Grubb) You said local?

13 Q. Yes, local greenhouse gas laws and local clean
14 energy policies.

15 A. (Witness Grubb) Which kind of greenhouse gas
16 laws do you -- are you referring to in terms of local
17 ones? I'm not aware of local ones.

18 Q. I would say some municipalities in the state of
19 Georgia may have local greenhouse gas laws.

20 A. (Witness Grubb) They have goals, as we heard
21 from earlier. But, no, our CO2 scenarios are based on
22 what a federal legislative or regulatory approach would
23 be.

24 Q. When Georgia Power changed its resource mix
25 study for the 2022 IRP by including the first time, for

1 the first time solar battery energy storage and wind
2 resources, did the company consider including other
3 resources such as demand response, energy efficiency,
4 dispatchable and distributed energy resources, and DER
5 aggregations in the expansion planning model?

6 A. (Witness Weathers) So in terms of energy
7 efficiency, so there was the DSM study that I believe the
8 second panel can speak to that. Distributed energy
9 resources, not specifically. I think we model really
10 generic, repeatable utility-scale projects in terms of
11 candidate units. And so as you mentioned, we have a new
12 model that allowed us to do that.

13 There's a screening process to help determine
14 which ones would be most economical for customers and
15 repeatable on a commercial basis, and those are the ones
16 that we included in our model.

17 Q. Regarding the effluent limitations guidelines,
18 has the company included consideration of public policy
19 requirements such as current and forthcoming
20 environmental regulations into their system planning
21 process over the last decade?

22 A. (Witness Grubb) So you're asking around -- I
23 think that's the question that Mr. Fabish just asked us
24 around the unit retirement studies. We have the current
25 ELG rule, but not any other future considerations. So if

1 that -- if that was your question around future possible
2 rules, then that's what we answered earlier from Sierra
3 Club's counsel.

4 Q. Well, it was really a -- dealing with the
5 broader public policy requirements, other public policy
6 requirements for ELG compliance guidelines.

7 MR. HEWITSON: I think that question's been
8 asked and answered.

9 MADAM CHAIR PRIDEMORE: It has.

10 BY MR. BAKER:

11 Q. Okay. Referring to page 19 of your prefiled
12 testimony, when examining the flexibility of gas units in
13 the context of intermittent solar resources, in what ways
14 did the company consider the flexibility of wind, hydro
15 power, and energy efficiency as alternative solutions?

16 A. (Witness Grubb) Well, so we're not saying that
17 there aren't other resources that have flexibility. We
18 were just using that as an example of the start and stop
19 times on gas units and minimum up and downtimes are a lot
20 shorter than coal units. We're not saying there aren't
21 other flexibility. It was just an example more to point
22 to the lack of flexibility of coal units. It wasn't an
23 exhaustive list.

24 A. (Witness Weathers) We also didn't include solar
25 with storage as replacement resources after the

1 expiration of the power -- of the gas power purchase
2 agreements when we did the unit retirement study.

3 Q. Mr. Weathers, just a clarification question to
4 a prior testimony. You said this morning that Southern
5 Company plans and operates the entire system as a whole;
6 is that correct? Is that a correct statement of your
7 prior testimony?

8 A. (Witness Weathers) Yes. Yes. Through the
9 agreement between the operating companies, they pool
10 their resources and loads together, and it's operated
11 from one centralized dispatch.

12 Q. Okay. And Southern Company reported a
13 significant increase in coal generation megawatt hours in
14 2021. It went from 17 percent in 2020 to 21 percent in
15 2021. Would that increase also be representative of the
16 2021 coal generation for Georgia Power?

17 A. (Witness Weathers) I don't have the Georgia
18 Power data, but that's really due to the increased loads,
19 you know, versus a pandemic year. And also the higher
20 gas prices, as we talked about, the short-term run up in
21 gas prices a little bit earlier.

22 Q. And Georgia Power is predicting a significant
23 drop in coal generation to 16 percent this year; correct?

24 A. (Witness Grubb) I'd have to -- subject to
25 check, I don't know what we were last year.

1 Q. Well, you have at the IRP document, page 424,
2 Figure 3; is that accurate?

3 A. (Witness Grubb) Yeah. So for --

4 Q. Okay.

5 A. (Witness Grubb) -- 2022, from an energy
6 standpoint, that would be correct.

7 Q. All right.

8 A. (Witness Grubb) I just needed to confirm that
9 number.

10 Q. Okay. Other -- is that reduction in coal
11 generation due to the retirement of the Wansley units?

12 A. (Witness Grubb) That would -- that would
13 contribute. I don't know which number you're comparing
14 it to before. Did you compare it to 2021?

15 Q. 21 percent.

16 A. (Witness Grubb) Yeah, so it would be. And then
17 also, these are weather normal projections; whereas, '21
18 would have actual generation in there.

19 Q. Referring to pages 23 and 24 of your prefiled
20 testimony, you discuss the 2022, 2028 capacity RFPs and
21 the comments and feedback received from bidders and
22 interested parties. Do you know how many commentators
23 are anticipated in the process of the RFP?

24 A. (Witness Grubb) So which -- you're on page 23?

25 Q. 23 -- the bottom of 23, top of 24.

1 A. (Witness Weathers) You're asking if we know how
2 many individual people or entities commented?

3 Q. Approximately?

4 A. (Witness Grubb) No.

5 Q. Dozens? Hundreds? Thousands? Probably do you
6 know?

7 A. (Witness Grubb) I mean, the IE report has those
8 details. But, I mean, there were several from interested
9 bidders, just like we see in all of our RFPs. I don't
10 remember exactly the numbers, but I think it was 60- or
11 70-something comments, somewhere along those lines.

12 Q. Okay.

13 A. (Witness Grubb) Subject to check.

14 Q. Were third-party owned and operated demand
15 response resources and programs evaluated in the RFP?

16 A. (Witness Grubb) You said third-party owned
17 demand response?

18 Q. Yeah. Owned and operated demand response
19 resources and programs?

20 A. (Witness Grubb) No, they were not. The
21 capacity RFP was looking at supply side resources in
22 terms of existing gas, new gas, standalone storage,
23 storage paired with renewables.

24 Q. Do the winning bids for the natural gas PPAs
25 represent the lowest bids in the RFP?

1 A. (Witness Grubb) They do.

2 Q. Are each of the natural gas PPA winning bids
3 below the company's equated cost?

4 A. (Witness Grubb) So for capacity RFP, there is
5 no avoided cost hurdle. The avoided cost in the RFP is
6 the RFP itself. And so what you're looking at is what
7 are the best resources we can add. So there is no
8 hurdle. They compete with themselves.

9 Q. Okay. Turning to page 25 of your prefiled
10 testimony, you list the additional sums that are being
11 requested for the various PPAs. Can you explain how the
12 additional sums were determined or calculated for each of
13 these units since they vary between each unit?

14 A. (Witness Grubb) Sure. What we did,
15 Commissioners, is we looked at the PPAs that we're
16 seeking certification for and compared them across their
17 terms on their annual evaluation compared to the company
18 on proposal -- proposed in the capacity RFP, and then the
19 additional sum is based on 20 percent of that difference.

20 Q. Georgia Power sought 1,000 to 3,000 megawatts
21 of capacity from facilities sized between 100 and 1,200
22 megawatts. Why wasn't a lower-sized facility such as a
23 50-megawatt facility allowed to bid in the RFP?

24 A. (Witness Grubb) So that's really around
25 storage. And when we look at retiring what we're

1 retiring here, 3,500 megawatts of coal units, it's just
2 not in the best interest of the company to have a lot of
3 small storage bids put in, A, from the standpoint that
4 they probably aren't as economical as the larger ones.
5 B, how do you operate it? And then, C, just from a
6 standpoint of evaluating all those bids. So 100
7 megawatts was a -- was a level that we felt would result
8 in good storage bids that we worked with the staff and
9 the IE on getting approval for that.

10 Q. Do you consider the long-duration storage and
11 tall-wind technologies mature technologies?

12 A. (Witness Grubb) So I'll speak to the
13 long-duration storage. We don't, in terms of -- that's
14 why our request isn't for a specific project. What we've
15 noted in the IRP is that that's a very promising and
16 interesting technology, but the reason that we aren't
17 asking for a specific project at that point is it does
18 need to develop, and we will study that.

19 From a wind standpoint, I think wind itself is,
20 but I think Mr. Mallard's alluded to our demonstration
21 project really is around the construction getting to the
22 tall-wind level.

23 A. (Witness Mallard) Agree.

24 Q. Okay. Does the company have any experience
25 with the long-duration storage?

1 MADAM CHAIR PRIDEMORE: You've asked that,
2 Mr. Baker. You've asked that very question: Does
3 the company have experience with long-duration
4 storage?

5 These pauses are taking up the time. We're
6 running out of air in terms of cool air. I'm going
7 to give you, Mr. Baker, until -- it's 8:08, so I'm
8 going to give you until 8:11.

9 BY MR. BAKER:

10 Q. All right. Referring to the latest
11 interconnection queue, is the 600-megawatt battery energy
12 storage project in Fulton County affiliated with Southern
13 Company or any of its subsidiaries?

14 A. (Witness Grubb) That's on the -- no, that's not
15 associated with us.

16 A. (Witness Mallard) I'm not aware.

17 A. (Witness Grubb) No.

18 A. (Witness Robinson) Not that I'm aware.

19 Q. You state at page 42, lines 20 through 23: The
20 addition of renewable resources on the system creates
21 additional fuel diversity, environmental benefits, and
22 projects to create long-term cost savings for all
23 customers.

24 Would you agree that statement applies to
25 customer -- customer-owned renewal resources as well?

1 A. (Witness Mallard) Yes, all renewable resources.

2 Q. Is the company aware that public interest
3 organization stakeholders submitted requests to Southern
4 Company transmission planners and in the SERTP process to
5 study transmission needs driven by public policy
6 requirements, including coal combustion residuals and
7 other EPA rules that impact coal plant retirements
8 included in the 2022 IRP?

9 A. (Witness Robinson) I am not aware.

10 Q. These were submitted in 2015, 2016 and 2017.
11 Not aware?

12 A. (Witness Robinson) No.

13 Q. Referring to the IRP plan, in the IRP you
14 mentioned significant increases in interest in
15 behind-the-meter programs. Is there a significant
16 increase in interest in the RNR monthly netting program?

17 A. (Witness Mallard) Yeah, so -- so there was.
18 The RNR monthly netting pilot definitely generated
19 significant interest in the program.

20 Q. Okay. Was it a successful program?

21 A. (Witness Mallard) So we learned a lot. And
22 from that aspect, it has generated benefits. We've been
23 able to see what a high volume of applications does, been
24 able to improve our processes, and we're gathering data,
25 as we've already referenced earlier, that will be the

1 basis for more robust analysis on the cost shift and
2 increase cost from monthly netting.

3 Q. Okay. And what specific distributed energy
4 resource technologies will be eligible to be installed in
5 the seven locations that you're proposing?

6 A. (Witness Robinson) The seven locations are a
7 combination of traditional recip engines. They could be
8 either diesel, natural gas, and then battery energy
9 storage. But as I mentioned before, we are looking to
10 pair those with solar that's existing features.

11 MADAM CHAIR PRIDEMORE: My clock shows it's
12 8:11.

13 MR. BAKER: Well, for the record, I have more
14 questions. I request the opportunity to complete my
15 cross. I've cut it back. I've cut it back.

16 MADAM CHAIR PRIDEMORE: I recommend that
17 counsel go through his questions ahead of time and,
18 therefore, it's these long pauses and this long,
19 drawn-out process, Mr. Baker, that it's adding to
20 the time.

21 MR. BAKER: I'm going through the questions,
22 trying to -- I cut -- I was cutting through those
23 pauses, Madam Chairman. I wasn't delaying --

24 MADAM CHAIR PRIDEMORE: How much more time do
25 you need?

1 MR. BAKER: It's going to be more than you want
2 to give me. Let me just -- could we let Mr. Mahan
3 go and let me just check and see if there's
4 anything, remaining questions that I really need to
5 ask for my clients?

6 MADAM CHAIR PRIDEMORE: Does counsel have an
7 objection to that, either staff or Georgia Power?

8 MR. HEWITSON: No objection.

9 MADAM CHAIR PRIDEMORE: Okay. Work on that
10 list, check it twice, find out who's naughty or
11 nice.

12 Mr. Mahan, Southern Renewable Energy
13 Association. He's been with us today on video.
14 He's ill.

15 MR. MAHAN: Hi, can you-all hear me?

16 MADAM CHAIR PRIDEMORE: Yes. Hi, Mr. Mahan.
17 Go ahead.

18 MR. MAHAN: Hi. Sorry, I was --

19 MADAM CHAIR PRIDEMORE: The panel is yours.

20 MR. MAHAN: I appreciate it.

21 CROSS-EXAMINATION

22 BY MR. MAHAN:

23 Q. Good evening. Just starting at the top here,
24 across the integrated resource plan, has the Southeastern
25 Energy Exchange Market been modeled (inaudible) --

1 A. (Witness Grubb) I couldn't hear.

2 A. (Witness Robinson) We can't hear.

3 MADAM CHAIR PRIDEMORE: Please, repeat your
4 question, Mr. Mahan.

5 BY MR. MAHAN:

6 Q. Yes. Across the Integrated Resource Plan, has
7 the Southeastern Energy Exchange Market been modeled?

8 MADAM CHAIR PRIDEMORE: We can't understand,
9 and the court reporter can't understand. Can you
10 pick up the receiver?

11 MR. MAHAN: Yes. I have picked it up. I
12 actually tried to call in on my phone, because I
13 think I have better reception over there, but it's
14 not piping through that way.

15 MADAM CHAIR PRIDEMORE: That's a little better.
16 Speak clearly into your microphone, Mr. Mahan.

17 Mr. Mahan, are you still here?

18 MR. MAHAN: I apologize. Can you hear me now?

19 MADAM CHAIR PRIDEMORE: Let's get moving.

20 Speak clearly into your mic.

21 MR. MAHAN: Yes, ma'am.

22 BY MR. MAHAN:

23 Q. Across the IRP, was the Southeastern Energy
24 Exchange Market modeled or not?

25 A. (Witness Weathers) It was not modeled. The IRP

1 is primarily a capacity planning tool, and the
2 Southeastern Energy Exchange Market does not offer
3 capacity. It is an energy exchange method as an
4 intra-hour energy.

5 Q. And SEEM doesn't include any transmission
6 planning either, does it?

7 A. (Witness Weathers) It does not. The SEEM is
8 designed to use a new form of transmission. It's the
9 lowest non-firm transmission available, so it doesn't
10 impact transmission planning at all.

11 Q. Let's move on to the transmission plan. Y'all
12 provide some locational guidance in transmission Appendix
13 E4, and you call it the optimal ITS substation. Is that
14 the extent of the locational guidance you-all plan on
15 providing?

16 A. (Witness Robinson) For the purpose of
17 transmission, that is correct. That's a study that we
18 did looking at a comprehensive look throughout the state
19 of buses throughout the state of Georgia, substation
20 buses injecting up to 300 megawatts, and those are the
21 sites that did not cause any constraints. They just
22 happened to all be in north Georgia.

23 Q. When I read that, I took it to mean that
24 southern Georgia was excluded from the study, not that it
25 just so happened to be that way; is that right?

1 A. (Witness Robinson) No, there were tranches,
2 injections done at 100 megawatts, 200 megawatts, 300 and
3 400. We picked 300 because it matched very closely the
4 latest RFPs that we've had bid in and there were no buses
5 in south Georgia that could accept 300 megawatts without
6 transmission constraints.

7 Q. Thank you.

8 And also in the transmission plan in
9 Appendix D1, this is the ten-year transmission plan for
10 the IRP; correct?

11 A. (Witness Grubb) We're flipping to it,
12 Mr. Mahan. Just one moment or two. It's a big binder.

13 Q. Sure.

14 A. (Witness Grubb) You said D1?

15 Q. Yeah, I believe so. It's technical appendix
16 Volume 3.

17 A. (Witness Robinson) Okay. So ask your question
18 again.

19 Q. Are you seeking approval of the ten-year
20 site -- the ten-year transmission plan in this IRP?

21 A. (Witness Robinson) No. This is a transmission
22 plan that we developed with the ITS participants as part
23 of the SERTP process as well. We bring this to show our
24 prudence as it relates to planning the system and meeting
25 the transmission plan associated with the resource plan

1 to make sure that we deliver the megawatts from the
2 generation to the load.

3 Q. So the Commission is not going to approve this
4 ten-year transmission plan in this IRP?

5 A. (Witness Robinson) It's part of the IRP. We're
6 not asking for explicit approval of the transmission
7 plan. This is a work product of the ITS that also feeds
8 into the SERTP process on an annual basis.

9 Q. So -- and I was going to ask this question, but
10 I think you just answered it. How often does the
11 ten-year transmission plan get updated?

12 A. (Witness Robinson) Annually.

13 Q. Okay. And the transmission upgrades that are
14 identified in the plan, not all of them are associated
15 with the north Georgia reliability and resilience action
16 plan; is that correct?

17 A. (Witness Robinson) None of them are associated
18 with the north Georgia reliability and resiliency plan.
19 I think I answered that earlier.

20 Q. I apologize.

21 So when are the north Georgia transmission
22 upgrades going to be put into the ten-year plan?

23 A. (Witness Robinson) Those are currently being
24 studied by the ITS participants, and we are looking at,
25 as I mentioned before, that time frame in 2035 where you

1 anticipate the retirement of Bowen 3 and 4, additional
2 renewables, whatever's approved out of this IRP in south
3 Georgia, on top of what the EMC's and municipalities'
4 needs are. And we are working through that process right
5 now. Hope to have the plan solidified by this summer,
6 and then we will bring that forward in SERTP process as
7 it relates to future ten-year plans and the next IRP
8 cycle as it relates to the ten-year plan that we filed in
9 the IRP.

10 Q. With regards to SERTP, I think we're on
11 Appendix E1 here, because you keep referencing it, y'all
12 state the SERTP process did not produce any
13 stakeholder-proposed alternatives that were included in
14 the ITS ten-year transmission and expansion plan for '22
15 to '31.

16 A. (Witness Robinson) That's correct.

17 Q. How are the stakeholder alternatives proposed
18 in SERTP?

19 A. (Witness Robinson) So there is a process that's
20 detailed on the SERTP website that allows for stakeholder
21 input into that process on an annual basis for bringing
22 projects for consideration for cost allocation.

23 Q. Is that also through -- is that through the
24 regional planning stakeholder group at SERTP?

25 A. (Witness Robinson) Subject to check, I believe

1 that's correct.

2 Q. And are you aware that there was a SERTP
3 meeting in March?

4 A. (Witness Robinson) There is a second quarter
5 meeting that -- or a first quarter meeting that's
6 scheduled in March, typically, on an annual basis, that's
7 correct.

8 Q. And are you aware that no Georgia Power nor any
9 Southern Company participants agreed to participate in
10 the regional planning stakeholder group at that meeting?

11 A. (Witness Robinson) I am not aware of that.

12 Q. Okay. Let's move on to the capacity power
13 purchase agreements. Can you describe to me how the
14 capacity benefit is determined in the capacity PPAs
15 additional sum methodology? I think it might have
16 something to do maybe with a new combustion turbine or
17 perhaps a value of lost load. If you could explain that,
18 I'd appreciate that.

19 A. (Witness Grubb) I'm not sure I quite followed
20 your question. You're asking around the -- you started
21 on the capacity benefit in the RFP, but then you switched
22 to additional sum. Are you asking --

23 Q. So --

24 A. (Witness Grubb) -- additional sum question, how
25 that was determined?

1 Q. Well, my understanding is with the additional
2 sum is the additional sum is based, in part, off of the
3 capacity benefit value, and the company gets a certain
4 percentage of the total capacity benefit value in a
5 dollar-per-KW basis. And so I'm --

6 A. (Witness Grubb) Yeah, it -- I just wanted to
7 make sure I was following your question right.

8 It's like I just said just a little while ago,
9 what we've done for the additional sum was we have the
10 evaluation by year for the PPAs that we're seeking
11 certification, and we have the evaluation valued by year
12 of the company-owned proposal, and we took 20 percent of
13 the difference in those years. So it's not just capacity
14 benefit, it's the entire valuation in the RFP.

15 A. (Witness Weathers) Right. And to add to that,
16 Mr. Mahan, it is the difference between the net cost of
17 the PPA and of the company-owned proposal. They both
18 received the capacity benefit, so we're just looking at
19 the difference of those two.

20 Q. Okay. On the -- in the main IRP document, and
21 I think this is Chapter 11, Page 79, you state that
22 there's a capacity need in 2029. Is that with or without
23 the proposed capacity PPAs in this IRP?

24 A. (Witness Grubb) That includes those. So that
25 reflects the coal retirements we're requesting and the

1 six PPAs we're seeking certification for.

2 Q. Okay. And also on that same page you state
3 that the company may monitor and consider issuing a,
4 quote, all-source RFP to address the capacity needs in
5 the future.

6 Is that all-source RFP similar to the capacity
7 RFP that we just went through or is it something
8 different?

9 A. (Witness Grubb) So I lost the page reference
10 but I can speak to it. So, again, it would definitely at
11 least be what we've done in the 2022 to 2028 capacity RFP
12 to allow standalone storage and storage plus renewables.
13 We haven't really thought through much more beyond that.
14 In a lot of respects, that is an all-resource RFP. So
15 it's not yet determined but we will continue to think
16 through that and other options that we would allow bids
17 for.

18 Q. Okay. And the previous capacity RFP that's
19 lead to the power purchase agreements that are being
20 proposed in this IRP, why did the company choose power
21 purchase agreements instead of acquisitions or new-build
22 options?

23 A. (Witness Grubb) They were more economic for
24 customers.

25 Q. But you-all are able to get the flexibility and

1 the firm enough commitments necessary out of those PPAs
2 to serve reliability needs?

3 A. (Witness Grubb) Yes, from the proforma PPAs for
4 combined cycles and combustion turbines, yes.

5 Q. Okay.

6 A. (Witness Grubb) For capacity and energy needs,
7 correct.

8 Q. Okay. With regards to the reserve margin and
9 target reserve margin, the wintertime reserve margin
10 target is higher than the summertime reserve margin
11 target. And is that, in part, to take into account that
12 natural gases, the generators have lower capacity
13 accreditation during wintertime?

14 A. (Witness Weathers) No. They don't have lower
15 capacity credit in the wintertime. But it is due --
16 there are several reasons for that. One of the reasons
17 is that they are exposed to cold weather outages at
18 extreme temperatures, but there are other reasons as
19 well.

20 Q. Okay. So, effectively, in the models, natural
21 gas resources don't have a different capacity value from
22 summertime to wintertime?

23 A. (Witness Weathers) That is correct. And our --
24 the way that we do capacity value is what we call the ice
25 factor and it's actually comparing against a combustion

1 turbine, a gas-fired unit, and other resources are
2 compared to that. So that's the standard that we compare
3 against.

4 Q. Thank you.

5 A. (Witness Grubb) We do show higher winter
6 megawatts than summer megawatts from a rating standpoint.
7 So Mr. Weathers answered capacity value, but the capacity
8 amounts are seasonal based on winter and summer.

9 Q. Thank you.

10 In the IRP, the company is requesting a 1,000
11 megawatts of company-owned energy storage. Is that
12 inclusive of the McGrau Ford site or is the McGrau Ford
13 site in addition to that 1,000 megawatts?

14 A. (Witness Grubb) Yeah, the McGrau Ford would be
15 the -- the initial project in that thousand. So it would
16 count towards that thousand megawatts.

17 Q. And so I think the number, then, is
18 735 megawatts. What is the anticipated duration of those
19 battery resources, the new battery resources? Is it one
20 hour? Two hours? Four hours?

21 A. (Witness Grubb) So McGrau is a -- is a two-hour
22 facility. I think we studied that. We would make sure
23 that as we continued to deploy those, that we would -- we
24 would evaluate if a longer duration storage worked. But
25 McGrau is two hours and our thought is the first few

1 would be two hours.

2 Q. Okay. And is that all that energy storage that
3 the company is planning for expected to be built in north
4 Georgia?

5 A. (Witness Mallard) Not necessarily. So the
6 company would site those resources based on our
7 evaluation of potential generation sites and site those
8 around the state where, really, they could create the
9 most benefits for customers.

10 Q. Okay. I'd like to move on to the CARES RFP
11 program. Can you help me understand -- I understand
12 CARES is meant to be a full-subscription program this
13 go-round, but what happens if there are no subscribers?
14 Does the full 2,100 megawatts of utility-scale solar and
15 the associated DG solar, does all that still get built?

16 A. (Witness Mallard) Yeah, so -- so the -- really,
17 the way this procurement is designed, Mr. Mahan, is that
18 the company is requesting these resources because of the
19 benefits they provide to all Georgia Power customers.
20 Really, the subscription option is an add-on or
21 underneath that procurement. And so if approved by the
22 Commission, the company would plan to procure all 2,300
23 megawatts regardless if they are subscribed to or not.

24 Q. That's great news. Appreciate that.

25 The proposed 2023 CARES RFP is intended to

1 focus on north Georgia. Have you-all checked the
2 generation and interconnection queue lately for north
3 Georgia and the possibility that there's probably not
4 enough facilities to bid into that 2023 RFP?

5 A. (Witness Mallard) Yes. So I haven't checked it
6 lately. I do believe there are facilities in the queue,
7 and then it's our expectation that we've got a really
8 resilient renewable market here in Georgia. It would be
9 our expectation that the market will be able to deliver
10 projects in north Georgia to meet those capacity targets.

11 Q. How long does it take to go from first filing
12 in the generation interconnection queue to having a
13 signed generation interconnection agreement?

14 A. (Witness Mallard) It's 36 to 48 months, that
15 general time frame.

16 A. (Witness Robinson) Well, that's the COVs,
17 that's the construction of facilities. But to go through
18 the process is -- I'm sorry. I don't have that
19 information in front of me. The information I do know is
20 that from submission of request to COD is 36 to 48
21 months. So if you take two years off of construction for
22 that, subject to check, it's somewhere in the
23 neighborhood of a year to go through that process to then
24 begin design and construction of those facilities. Those
25 facilities would be -- will be done in the 36- to

1 48-month time frame.

2 Q. Let's move on to the generation resource mix
3 study in the Aurora modeling specifically.

4 MADAM CHAIR PRIDEMORE: Mr. Mahan, before you
5 go any further, I'm going to ask you, how much more
6 time do you need? I'm being mindful of the fact
7 that the room that we're in doesn't have HVAC
8 service anymore, and these witnesses have been on
9 the stand now for 11 hours.

10 MR. MAHAN: Yes, ma'am. Ten minutes?

11 MADAM CHAIR PRIDEMORE: Can we make it eight?

12 MR. MAHAN: Yes, ma'am.

13 MADAM CHAIR PRIDEMORE: Thank you.

14 BY MR. MAHAN:

15 Q. How were federal tax credits for renewables and
16 energy storage accounted for in the modeling?

17 A. (Witness Weathers) Mr. Mahan, are you referring
18 to the mix study for the IRP or are you referring to the
19 renewal expansion study?

20 Q. Yes, the generation resource mix, I believe
21 that's the one that used the Aurora model.

22 A. (Witness Weathers) Okay. And you asked about
23 how the tax credits are factored in?

24 Q. Yes.

25 A. (Witness Weathers) Yeah. So the company has in

1 the resource mix study a couple of different pricing for
2 solar. And so one of them really assumes that a
3 continuation of the existing investment tax credits, and
4 one of them looks at what the price of solar would be if
5 those tax credits expired, so we look at both of them.

6 Q. And when you ran the Aurora model, did you all
7 place a cap on the amount of solar generation that could
8 be added on an annual basis?

9 A. (Witness Weathers) We did. We had a limit of
10 1,500 megawatts of solar on an annual basis, but we also
11 looked at a sensitivity without that. And, really, over
12 the course of the planning horizon, it doesn't matter.
13 It's just a timing of the solar. Either you're going
14 to -- if you have the cap, you'll add it more evenly over
15 time. If you remove the cap, you'll still add about the
16 same amount of solar over a 35-year period, but it'll
17 just be concentrated in a few years.

18 Q. And did you allow renewable energy resources be
19 selected by the model prior to 2025?

20 A. (Witness Weathers) No, 2025 was the first
21 year.

22 Q. Okay. And when you ran the Aurora model, did
23 you include the 2.3 gigawatts of natural gas PPAs?

24 A. (Witness Weathers) Yes.

25 Q. Those were hard-wired, hard-coded into the

1 model?

2 A. (Witness Weathers) Yes. Yes. Those were, as
3 well as the coal retirements.

4 Q. Okay. Finally, here on the integration
5 analysis, did the integration cost analysis account for
6 integration cost of the inflexibility of fossil and
7 nuclear plants because they don't follow load, they --
8 and they're hard to ramp?

9 A. (Witness Weathers) Essentially, yes. I mean,
10 that's what -- that's where the value is attributed to
11 battery storage is derived from is because they --
12 because the existing fossil fleet is less flexible in
13 that battery storages are very flexible. So they can
14 provide the same operating reserve services to manage
15 additional solar generation more economically than the
16 existing fleet can.

17 MR. MAHAN: That'll do it for me. I appreciate
18 it. Thank you.

19 WITNESS GRUBB: Thank you.

20 MADAM CHAIR PRIDEMORE: Thank you, Mr. Mahan.
21 That's the best eight minutes I've ever heard.

22 Coming in at three.

23 Hello, Mr. Baker.

24 MR. BAKER: I have a proposition to make.

25 Could I submit my remaining handful of questions to

1 Georgia Power for a written response?

2 MADAM CHAIR PRIDEMORE: No.

3 MR. BAKER: All right.

4 MADAM CHAIR PRIDEMORE: How many do you -- how
5 much time do you need?

6 MR. BAKER: Ten minutes if I talk fast.

7 MADAM CHAIR PRIDEMORE: You're going to get
8 eight.

9 MR. BAKER: All right. Here we go.

10 (CONTINUED) CROSS-EXAMINATION

11 BY MR. BAKER:

12 Q. For the qualified Community Solar Program, the
13 sponsors buy down the credits --

14 A. (Witness Mallard) Yes.

15 Q. -- and get the RECs. Is this really a solar
16 program for low-income customers or just a way to reduce
17 utility bills?

18 A. (Witness Mallard) So it's a -- it's definitely
19 a solar program. One of the results, we expect to have
20 reduced utility bills, but we're going to educate those
21 customers and they're going to get to participate in
22 solar by subscribing to a block of that Community Solar
23 output.

24 Q. Does the company make it a practice to provide
25 a description of the transmission system need underlying

1 each project, as well as economic analysis for each
2 transmission project included in its ten-year
3 transmission expansion plan for public comment and
4 feedback?

5 A. (Witness Robinson) Can you repeat your
6 question? That was pretty long.

7 Q. Okay. Does the company make it a practice to
8 provide a description of the transmission system need
9 underlying each project, as well as economic analysis for
10 each transmission project included in its transmission --
11 ten-year transmission plan for public comment or
12 feedback?

13 A. (Witness Robinson) We do file that in this IRP.
14 We do file that documentation. It is in the ten-year
15 plan, all the documentation that you mentioned. And then
16 the ten-year plan, as I mentioned before, is also part of
17 the SERTP process.

18 Q. If the costs of the proposed transmission
19 projects are not reported publicly, how does the company
20 and its integrated transmission system partners solicit
21 and develop cost-effective solutions and alternatives?

22 A. (Witness Robinson) As I mentioned before, that
23 information is available through the IRP process. It --
24 much of it is trade secret but it is available, the cost,
25 alternatives looked at for the ten-year plan. And it, I

1 do believe, is available for public review and comment.

2 Q. Do third-party-owned solutions get proposed in
3 the process?

4 A. (Witness Robinson) There is an opportunity
5 through the SERTP process, as I mentioned before, to
6 bring projects forward for cost allocation and that is
7 all explained on the SERTP website.

8 Q. And could you describe the cost benefit
9 analysis the company uses to evaluate transmission and
10 distribution solutions and alternatives?

11 A. (Witness Robinson) So that's listed in the --
12 that's also filed in Volume 3 --

13 Q. Volume 3?

14 A. (Witness Robinson) -- In Section A; correct.

15 Q. Thank you.

16 Referring to the CARES program, the carbon-free
17 energy around the clock, how much battery energy storage
18 is allocated to the program?

19 A. (Witness Mallard) So what's contemplated is
20 enough battery energy storage to match with 650 megawatts
21 of renewable energy in order to be able to produce a
22 100-megawatts block around the clock. I think we modeled
23 close to 200 megawatts of batteries to be able to make
24 that happen.

25 Q. Will battery energy storage have to be

1 operational before the program is offered?

2 A. (Witness Mallard) Yes. In order to produce the
3 energy around the clock, the battery energy storage would
4 have to be operational.

5 Q. Will the battery energy storage count towards
6 the 1,000 megawatts by 2030?

7 A. (Witness Mallard) It would not. It's a
8 different use case, so we wouldn't count it towards the
9 1,000.

10 Q. Has the pricing for this carbon-free energy
11 around the clock been established?

12 A. (Witness Mallard) So preliminary pricing
13 analysis has been done, but what we're looking to do here
14 is to go to the market, solicit the solar resources, and
15 be able to produce final executable pricing and PPAs to
16 offer to interested customers.

17 Q. Okay. Turning to the retail -- resource retail
18 REC retirement program.

19 A. (Witness Mallard) Yes.

20 Q. If the company originally told the commission
21 these RECs were going to be retired on behalf of all
22 customers, shouldn't that commitment be honored?

23 A. (Witness Mallard) So the certification
24 language, as I remember it, Mr. Baker, says that the RECs
25 should be used for the benefit of all customers. If the

1 company decides to do something else with those RECs,
2 other than retire them on behalf of all customers, we
3 would need Commission permission, and so that's exactly
4 what we're requesting here.

5 Q. How will the corresponding greenhouse gas
6 accounting work for this?

7 A. (Witness Mallard) So really what we're talking
8 about here is just retiring these RECs on behalf of
9 specific customers rather than all Georgia Power
10 customers. And so, you know, we keep track of the RECs
11 and who they're retired on behalf. It really doesn't
12 impact the company's overall carbon emissions as measured
13 at the stack. The ownership of the REC does not impact
14 that.

15 Q. And are you familiar with the greenhouse gas
16 protocol and the difference between the location-based
17 method and the market-based method for scope two
18 emissions count?

19 A. (Witness Mallard) No.

20 Q. All right. Mr. Mallard, your response to
21 cross-examination by Mr. Walsh seemed to indicate that
22 the company does not consider the REC transaction to also
23 convey any emission reduction to subscribers; is that
24 correct?

25 A. (Witness Mallard) Ask that question again,

1 please.

2 Q. Okay. I'll slow it down.

3 Your response at cross-examination to
4 Ms. Walsh's question seemed to indicate that the company
5 does not consider the REC transaction to also convey any
6 emission reduction to the subscribers; is that correct?

7 A. (Witness Mallard) No, I don't think that is
8 correct. The -- a customer, a subscriber who wishes to
9 use that renewable energy to help them meet a carbon
10 reduction or a renewable energy goal does need the
11 renewable energy credit retired on their behalf. That's
12 what gives them ownership or title to the renewable
13 energy attribute.

14 Q. Thank you.

15 And final question: Does the ITS planning
16 process apply a consistent cost benefit methodology or
17 have a threshold cost benefit ratio that it employs to
18 select projects for inclusion in the plan?

19 A. (Witness Robinson) We don't have a specific
20 ratio. We do have a process through the joint planning
21 process where we all, as four participants in the ITS,
22 review projects. We're able to bring other projects,
23 alternates for consideration. But, ultimately, we're
24 making the most economic decision for all customers in
25 the state of Georgia, and we're incentive to do that

1 through the parity structure that exists in the ITS.

2 MR. BAKER: Thank you, gentlemen, for your
3 time. Thank you, Madam Chairman. Thank you,
4 Commissioners.

5 MADAM CHAIR PRIDEMORE: Thank you very much,
6 Mr. Baker.

7 Mr. Hewitson, do you have redirect?

8 MR. HEWITSON: I do, Madam Chair.

9 MADAM CHAIR PRIDEMORE: How much?

10 MR. HEWITSON: I am going to attempt to do it
11 in five minutes or under.

12 MADAM CHAIR PRIDEMORE: You got it. Go.

13 REDIRECT EXAMINATION

14 BY MR. HEWITSON:

15 Q. Gentleman, I know it's been a long day and I'll
16 try not to speak too quickly, but I think you'll be happy
17 if we get through this quickly.

18 Mr. Grubb, you were asked several questions
19 about keeping Bowen 1 and 2 available for use in
20 emergencies. Just to be clear, are Bowen Units 1 and 2
21 being proposed for retirement only because of ELG
22 compliance costs?

23 A. (Witness Grubb) No, not just because of ELG.

24 Q. Okay. Does the company have a unique
25 opportunity now with the capacity RFP results?

1 A. (Witness Grubb) Yes, we do.

2 Q. Okay. And what are the benefits of that, and
3 acting quickly?

4 A. (Witness Grubb) So the benefits of that are
5 we -- the pricing that we've got is 40 to 33 percent
6 lower than contracts we have on hand now. And so the
7 value of those capacity recourses is great, and we do not
8 feel like we would be able to get comparable deals later
9 down the road.

10 Q. Okay. Mr. Walsh asked, way back when this
11 morning, whether the company could wait until 2025 to
12 make a decision on Bowen 1 and 2. If Bowen 1 and 2 were
13 to be retained as a generation source, these units would
14 have to comply with the ELG rule; is that your
15 understanding?

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

17 Q. Okay. And would that take time to hook those
18 units into the ELG system at Plant Bowen?

19 A. (Witness Grubb) My understanding is yes.

20 Q. Okay. Do you know by when that decision would
21 have to be made or that work would have to be done?

22 A. (Witness Grubb) The work, is my understanding,
23 is that that needs to begin the latter half of this year
24 for compliance by 2025.

25 Q. To retain Bowen 1 and 2, in addition to the ELG

1 compliance, would other investments need to be made in
2 these units?

3 A. (Witness Grubb) I think there is some in terms
4 of a piping. As we talked about this morning, it's not
5 massive, but there is work that has to be done to include
6 Bowen 1 and 2.

7 Q. Do you know if the cost of those investments
8 would exceed the spending limits placed on Bowen 1 and 2
9 in the 2019 IRP?

10 A. (Witness Grubb) So non-ELG expenses would in
11 terms of normal capital investment in the units to keep
12 them longer than O&M would, yes.

13 Q. Thank you.

14 I have some questions on the renewable
15 integration study. Mr. Walsh asked questions regarding
16 the flexibility violations and how they are not actual
17 outages. Is it true, though, that not addressing the
18 flexibility violations and the pressure that they create
19 on operators may lead to actual outages?

20 A. (Witness Weathers) Yes.

21 A. (Witness Robinson) As well as compliance
22 violations potentially.

23 Q. Okay. Regarding battery storage ownership,
24 you've been asked by a number of people, if developers
25 could build storage at a lower cost than the company

1 could. But to be clear, Georgia Power is still planning
2 to issue an RFP for actually building the battery
3 storage; is that correct?

4 A. (Witness Robinson) Correct.

5 Q. And while it is possible to draft a contract
6 that includes lots of different contingencies, can you be
7 sure that you know about every issue that could arise
8 even to include it in a contract for operating battery
9 systems?

10 A. (Witness Grubb) No.

11 A. (Witness Mallard) We do not.

12 Q. Okay. Mr. Walsh asked you a couple of
13 questions about accounting deferrals, and while the
14 timing of recovery is decided in the rate case, is it
15 your understanding that the Commission needs to grant the
16 deferral of the remaining net book value of retiring
17 units in the IRP to preserve the treat- --

18 MR. WALSH: I'm going to object on the leading
19 nature of this question.

20 MR. HEWITSON: Just trying to move it along,
21 Madam Chair.

22 MADAM CHAIR PRIDEMORE: It's okay. Rephrase.

23 MR. HEWITSON: Okay.

24 BY MR. HEWITSON:

25 Q. While the timing of recovery is decided in the

1 rate case, what is your understanding of when the
2 decision has to be made in terms of making the decision
3 on the -- when the accounting treatment will be decided?

4 A. (Witness Grubb) So the request to move to a
5 regulatory asset has been asked in the IRP for prior
6 retirement decisions.

7 Q. Mr. Mallard, you were asked several questions
8 regarding behind-the-meter solar --

9 A. (Witness Mallard) Right.

10 Q. -- specifically rooftop solar, of course. One
11 of your comments was that Georgia Power is committed to
12 growing rooftop solar in Georgia. Can you expand a
13 little bit on the company's philosophy regarding growing
14 rooftop solar in Georgia?

15 A. (Witness Mallard) Yes, sure. The company is
16 committed to growing rooftop solar in Georgia, but doing
17 so in a way where cost and benefits are accurately
18 allocated and where nonparticipating customers are
19 protected from any cost shifts or cost increases.

20 Q. Gentleman, the Exhibit GAM-2 that Mr. Jones,
21 Clay Jones put in front of you earlier today looked at
22 the -- looked at the Mg0 scenario in terms of renewable
23 development. Do you remember that exhibit?

24 A. (Witness Weathers) Yes.

25 Q. Okay. If there was any price of carbon in

1 another scenario, that makes the net benefit numbers more
2 negative when you're looking at the exhibit that he put
3 in front of you; is that correct?

4 A. (Witness Weathers) Yes, that's right. The coal
5 units -- the economics of coal units would look worse if
6 there's carbon prices in the scenario.

7 Q. Okay. Do you think it is appropriate for the
8 company to base retirement decisions only on one
9 scenario, for instance, only on the Mg0 scenario?

10 A. (Witness Weathers) No, it's not. To do that
11 would ignore risks to customers that aren't considered in
12 that scenario. The better approach would be to consider
13 a range in the scenarios that captures those risks.

14 A. (Witness Robinson) And, Commissioners, we have
15 to anticipate the build-out of the transmission system
16 and make sure that the transmission is there to
17 accommodate those future retirements and those risks that
18 Mr. Weathers lays out.

19 A. (Witness Grubb) And then, again, as we've
20 mentioned, those great value of these capacity RFPs that
21 we've brought forth and the pricing and to take advantage
22 of those is a timing decision now.

23 MR. HEWITSON: Thank you, gentleman. That's
24 all the redirect I have for you.

25 Thank you, Madam Chair.

1 MADAM CHAIR PRIDEMORE: Care to move any
2 evidence into the record?

3 MR. HEWITSON: The only exhibits we have
4 were -- I did at the beginning, which were GPC-1,
5 the trade secret version, as well as the public
6 disclosure version.

7 MADAM CHAIR PRIDEMORE: Okay. They're in.
8 I'll ask the court reporter at this time to make all
9 exhibits part of the record.

10 (The documents referred to were received
11 into evidence.)

12 Thank you to the witnesses. You've been great
13 for the last 11 -- almost 11 and a half hours.

14 A couple of housekeeping matters. Tomorrow,
15 Mr. Hewitson, I believe we're going to start with
16 the Valle, Phillips, Smith, and Evans panel;
17 correct?

18 MR. HEWITSON: That is correct.

19 MADAM CHAIR PRIDEMORE: Okay. We're going to
20 do so at 9:30 a.m. immediately upon the conclusion
21 of the administrative hearing, upon that
22 adjournment.

23 So thank you very much. We stand adjourned.

24 (Hearing adjourned at 8:45 p.m.)

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C E R T I F I C A T E

I, Brenda P. Elwell, Kelley Marie Nadotti, and
Debbie A. Eickhoff, Certified Court Reporters, do hereby
certify that the foregoing transcript is an accurate record
of the proceedings had in the above-entitled matter at the
time and place therein set forth.



Brenda P. Elwell, RPR, CCR, B-2023



Kelley Marie Nadotti, RPR, CRR
CCR 6256-8388-8026-4192



Debbie A. Eickhoff, RPR,
CCR 5090-9084-2699-3664

GEORGIA POWER Ex. 1

2022 Amended IRP

Public Disclosure and Trade Secret Version

Both are too large to attach to the
transcript. They are filed with the GPSC.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-JKA Data Request Set Number 3



STF-JKA-3-2

Question:

Please confirm the Company did not account for the “additional sum” on the Capacity RFP PPA units in the URS evaluation? If it did, please explain how it did. If it did not, please explain why it did not?

Response:

The “additional sum” was not included in the costs of the RFP portfolio within the Unit Retirement Study (“URS”). Please see the workpaper “TS_2022IRP_URS Portfolio Costs.xlsx” for the cost components of the modeled RFP units within the URS, which was previously provided to Commission Staff in accordance with the Commission’s final order in the 2019 IRP in Docket No. 42310. The Company does not believe additional sum should alter a decision to retire or certify resources in the best interest of customers.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-JKA Data Request Set Number 1



STF-JKA-1-1

Question:

Since the 2014 Polar Vortex, but before the winter weather event that significantly impacted Texas in February 2021, please identify each measure that the Company has undertaken to reduce the risk of generator outages due to extreme cold weather. For each measure, provide the following:

- a. Name of plant
- b. Description of measure
- c. Date when measure was initiated
- d. Date when measure was completed
- e. Capital cost incurred, or expected to be incurred in the case of on-going measures
- f. Expense incurred, or expected to be incurred in the case of on-going measures

Response:

NERC published a report in September 2014 entitled Polar Vortex Review, which recommended that utilities review and update power plant weatherization programs as a result of lessons learned from the 2014 Polar Vortex and limit planned outages during possible winter peak periods, among other things. The report noted that SERC's main driver of outages and derates related to the event was cold weather, with the clear majority of outages and derates related to equipment issues. The actions listed below were taken by the Company in response to the NERC report related to the recommendations associated with winter preparedness.

- Implemented the Southern Company Standard of Excellence ("SOE") – 033 Freeze Protection Program for Southern Company non-nuclear* generating plants, which includes the following: 1) identification of a freeze protection owner at each site; 2) freeze protection training; 3) freeze protection assessment; 4) freeze protection maintenance strategy; 5) operational procedures; and 6) process for communicating relevant matters and issues.

*The Freeze Protection Program is not applicable to the nuclear plants because they follow guidelines prescribed by the Nuclear Regulatory Commission.

- Southern Company Generation-Fleet Operations conducts regular meetings with the plants to prepare and confirm winter readiness. As potential cold weather events approach, there are additional meetings with the plants to verify unit readiness and share best practices.
- Incorporated extreme weather scenarios into the Winter Operational Readiness assessments. For winter assessment, forced outages of generation resources and gas

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-JKA Data Request Set Number 1

pipeline operational flow orders are assumed to be correlated with low system weighted temperatures. Sensitivities for reserves are developed at various temperature points that include these assumptions.

- Significantly reduced planned maintenance in January and February.

Please see STF-JKA-1-1 Attachment for a list of measures that were taken at each plant.

Staff Ex. 3

Response to STF-JKA-4-12

(TRADE SECRET)

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 1

STF-LA-1-44

Question:

Plant Held for Future Use.

- a. Identify the amount of PHFFU by item as of 12/31/2021.
- b. For each item of PHFFU, indicate whether it represents rights of way.
- c. For each item of PHFFU, indicate whether it represents land owned by the Company.
- d. For each item of PHFFU, identify and explain the intended use and when the item is anticipated to become utility plant in service.
- e. For each item of PHFFU, identify when the Company originally recorded the amount in the PHFFU account.
- f. Identify where each item of PHFFU is addressed in the Company's 2022 IRP. If an item of PHFFU is not addressed in the Company's 2022 IRP, explain why.

Response:

Please see STF-LA-1-44 Attachment. The Company is complying with the agreed upon timeframes and forums for review of Plant Held for Future Use ("PHFFU") as provided in Paragraph 16 of the Stipulation approved by the Commission in the Company's 2019 Rate Case in Docket No. 42516:

With the exception of easements and right of ways, Generation and Transmission property in PHFFU that has been held in PHFFU account for 15 consecutive years will undergo review during the first IRP proceeding following the 15th year that such property has been held in PHFFU. Distribution property in PHFFU that has been held in PHFFU account for 15 consecutive years will undergo review during the first base rate proceeding following the 15th year that such property has been held in PHFFU. In the respective proceeding, the Company will be required to present the specific plan for the property(s) that has exceeded 15 consecutive years in PHFFU, the Commission will decide the matter in that proceeding.

Contact: Jeff Grubb



Plant Held for Future Use

Description	a	b	c	d	e	f
	Balance As of Dec-2021	Right-of-Way / Easement ?	Land Owned by GPC?	Year of Anticipated Use in Providing Electric Service	Originally Recorded to PHFFU Account	2022 IRP Reference
Dawson Crossing - South Dahlonega 500kV Transmission Line Site	\$10,977,832	Yes	No	>2040	12/1/2008	Note (A)
New Hampstead Substation Site	53,836	No	Yes	>2040	6/30/2009	Note (B)
South Dahlonega - Clermont Jct 500kv Transmission Line Site	28,188,653	Yes	No	>2040	9/30/2009	Note (A)
South Dahlonega - Clermont Jct 230kv Transmission Line Site	17,268,413	Yes	No	>2040	9/30/2009	Note (A)
Bethabara-E. Walton 230kv Transmission Line Site	3,708,308	Yes	No	>2040	3/31/2011	Note (A)
Piedmont Substation Site	12,933,362	No	Yes	>2040	3/31/2011	Note (B)
Boyd Ave Substation Site	1,334,192	No	Yes	>2040	8/31/2012	Note (B)
St. Joe Timber Land / Stewart County	22,903,628	No	Yes	>2030	9/1/2012	Note (C)
McDonough - East Point 230 KV	89,188	Yes	No	>2040	9/1/2014	Note (A)
Utoy Springs Substation Site	594,185	No	Yes	>2040	9/1/2014	Note (B)
Wallace Dam - Klondike 500 KV	3,628,989	Yes	No	>2031	9/1/2014	Note (A)
South Hall - Winder Transmission Line Site	883,035	Yes	No	>2035	9/1/2014	Note (A)
Medical Arts Center Substation Site	1,236,066	No	Yes	2026	2/1/2017	Vol 3 [F]
Savannah Portside International- Old River Road Substation Site	30,266	No	Yes	>2040	8/1/2018	Note (B)
Northwest Region Operating HQ Site	529,886	No	Yes	2022	10/1/2019	Note (D)
Old Washington Road Substation Site	280,159	No	Yes	>2023	2/1/2020	Vol 3 [F]
Lewiston Road Substation Site	1,968,390	No	Yes	2024	3/1/2020	Vol 3 [F]
Total	\$106,608,387					

Note (A): Items are not addressed in the Company's 2022 IRP because plant held falls outside the 10-year Transmission planning horizon.

Note (B): Items are not addressed in the Company's 2022 IRP because plant held falls outside the 5-year Area planning horizon.

Note (C): Item does not appear in the Company's 2022 Integrated Resource Plan. However, Stewart County is included in PHFFU and remains a potential site for future generation resources.

Note (D): Item is not addressed in the 2022 IRP as it is not directly associated with any specific Transmission or Distribution line and substation projects nor affiliated with any Generation projects.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-DEA Data Request Set Number 2

STF-DEA-2-30

Question:

Regarding the Company's proposal for locational guidance to DG projects, pg. 14-99, please provide a list of what information the Company proposes to provide within the hosting capacity tool. Will this hosting capacity tool supplant the need for the Company's current Tier 1 interconnection guidance?

Response:

The hosting capacity tool will assist developers to identify where capacity may exist on the distribution system and is an enhancement to the existing Interconnection Guidance ("ICG") program. The hosting capacity tool will provide an annual snapshot of distribution circuit available capacity in a graphical GIS-based format

Per the IRP filing, the hosting capacity tool does not supplant the need for participants to leverage the Company's ICG program. Interconnection Guidance is available to assist DG participants with specific project siting and facility size decisions. The hosting capacity tool will be a complementary resource used in conjunction with the ICG program.



Staff Ex. 6
IRP FILING EXCERPT

(TRADE SECRET)

Transmission Retirement Projects

The 2022 Integrated Resource Plan (“IRP”) transmission system evaluations considered a portfolio of unit retirements that are likely to occur over many years, including impacts beyond the typical three-year IRP cycle. These assessments consider the overlapping, or simultaneous, retirements of many resources, including Plant Bowen Units 1-2, Plant Gaston Units 1-4, Plant Scherer Units 1-3, and Plant Wansley Units 1-2. This analysis also assumed Plant Scherer Unit 4 is retired. The projects needed to accommodate this group of retirements are summarized in the table below.

Project Name	Project Need Year	Lead Time (months)	Total Estimated Costs ¹	Facility Owner	Retired Units
BULL CREEK - VICTORY DRIVE 115 KV	2024	12	REDACTED	GPC	Wansley 1&2
KLONDIKE-NORCROSS 500KV (SWITCH REPLACEMENT)	2024	12	REDACTED	GPC	Wansley 1&2
ARKWRIGHT - LLOYD SHOALS 115 KV	2024	48	REDACTED	GPC	Wansley 1&2
TENASKA - HEARD CO 500 KV	2024	48	REDACTED	GTC	Wansley 1&2
BLAKELY PRIMARY - WEBB (APC) 115 KV	2026	12	REDACTED	GTC	Wansley 1&2
ARLINGTON PRIMARY - DAWSON PRIMARY 115KV	2028	18	REDACTED	GPC	Wansley 1&2
CORN CRIB - LAGRANGE 115 KV	2027	12	REDACTED	GPC	Wansley 1&2
LAGRANGE - NORTH OPELIKA 230 KV	2027	78	REDACTED	GTC/GPC/APC	Bowen 1&2
MORROW - YATES COMMON 115 KV	2028	12	REDACTED	GPC	Scherer 1-3
S COWETA BANK A	2028	12	REDACTED	GTC	Scherer 1-3
HOLLINGSWORTH FERRY - YELLOW DIRT 230 KV	2028	12	REDACTED	GTC	Scherer 1-3
DRESDEN - HOLLINGSWORTH FERRY 230 KV	2028	24	REDACTED	GTC	Scherer 1-3
GORDON - SANDERSVILLE #1 115 KV	2028	24	REDACTED	GPC	Scherer 1-3
BONAIRE PRIMARY - BUTLER 230 KV	2028	54	REDACTED	MEAG	Scherer 1-3
HAMMOND - WEISS DAM (APC) 115 KV	2030	48	REDACTED	APC/GPC	Scherer 1-3

As discussed in the 2022 IRP Main Document, the Company plans to continue working with ITS Participants to finalize a list of projects that can support the long-term retirement of Plant Scherer Units 1-4 while considering additional fleet transition needs. The list of projects summarized in the table are representative of the projects required to retire Plant Scherer Units 1-4 in addition to the resources requested for decertification in the 2022 IRP.

¹ Total planning grades estimates reflected. These costs represent the estimated total costs that will be incurred by all integrated transmission system (“ITS”) participants.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 4

STF-LA-4-4

Question:

In response to STF-L&A-5-11 in Docket Nos. 42310 & 42311, the Company explained that the evaluation of the method for ash pond closure and remediation to comply with federal and state CCR rules focuses on the ability to meet regulatory performance standards for the following two allowable closure options set forth in the federal and state CCR Rules: (1) Closure-in-Place (CIP), which involves closing the CCR unit in the existing location and dewatering, backfilling, and capping the impoundment; or (2) Closure-by-Removal (CBR), which involves dewatering the surface impoundment, excavating the CCR, and transporting and placing the ash material in an approved landfill or combining the ash with onsite ash ponds to be closed in place. For each ash pond, please explain in detail how the Company determined which method to use, show the cost of that chosen method, and show in detail how the Company evaluated the alternatives and determined that its chosen method had the lowest cost.

Response:

With STF-L&A-5-11 in Docket Nos. 42310 & 42311, the Company explained the process by which each ash pond was evaluated and how the Company determined the selected closure method. The Company's CCR strategy was approved in the 2019 IRP. This includes the closure of all 29 ash ponds currently being effectively implemented with significant progress made over the last three years. The Company will continue to evaluate opportunities to refine and optimize its closure plans as has been discussed in the 2022 ECS filed as part of Georgia Power's 2022 IRP.

Since the EPA published the CCR rule in 2015, the Company has worked to develop and implement closure plans in compliance with the rule for its 29 ash ponds across the state. The Company developed a compliance strategy that included ceasing placement of coal ash in ash ponds, which occurred in 2019, and putting necessary actions in motion to meet the rule's strict deadlines and requirements to close ash ponds. The Company's plans are based on long-standing rule interpretation held by both industry and environmental regulators. While the Company provides details to this Commission, Georgia EPD ultimately determines the closure and permit requirements, and the Company adjusts scope as necessary to ensure compliance.

The closure cost estimate and selected closure method for each CCR unit has been developed by Georgia Power with input from internal and external experts. The site-specific closure method is the most cost-effective to allow compliance with CCR rules, support permit requirements, and mitigate environmental risks. The Company has continued to update and report closure costs estimates with the Company's CCR Semi-Annual Status Reports in accordance with the Final

Contact: Aaron Mitchell



Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 4

Order of the 2019 Integrated Resource Plan proceeding in Docket No. 42310. Additionally, the Company will continue to periodically update these cost estimates as necessary. See the Company's response to STF-LA-1-8 for cost details of the chosen closure method for each of the individual CCR units.

Exhibit GAM-1

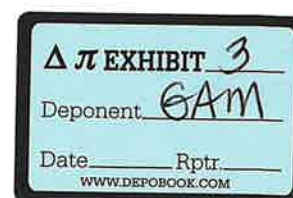
The Southern Company 2022 Long-Term Target Reserve Margin Study Metrics		
Metric	Winter	Summer
Loss of Load Expectation (LOLE)	20.00%	15.75%
Economic Optimum Reserve Margin (EORM)	24.25%	20.50%
Risk-Adjusted EORM (i.e., Value at Risk or VaR)	26.00%	23.25%
Source: Technical Appendix Volume I, An Economic and Reliability Study of the Target Reserve Margin for the Southern System, pages 60-62.		



Georgia Association of Manufacturers
GAM Ex. 2
Unit Retirement Study
(Trade Secret)

Exhibit GAM-3

Proposed Retirement Dates and Remaining Net Book Value at 12/31/21			
Plant	2017 Depreciation Study	Proposed	Remaining Net Book Value (\$000)
Wansley 1-2	2030	2022	\$472,173
Bowen 1-2	2030	2027	\$1,858,775
Scherer 3	2047	2028	\$809,031
Total			\$3,139,979
Sources: STF-LA-1-28 and 1-29.			



REG-ex 1



Bin 10230,
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374

PUBLIC DISCLOSURE

February 15, 2022

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

**RE: Georgia Power Company's Bi-Annual Hydro Modernization Report;
Docket No. 42310**

Dear Ms. Tanner:

In accordance with the Order Adopting Stipulation as Amended issued by the Georgia Public Service Commission (the "Commission") in the above styled docket, Georgia Power Company hereby files an original and fifteen (15) copies of its Bi-Annual Hydro Modernization Report for the period ending December 31, 2021.

This letter and the accompanying documents are submitted consistent with the Alternative Electronic Filing Procedures established by the Commission on March 17, 2020.

Please contact Cheryl Johnson at 404-506-6837 if you have any questions regarding this filing.

Sincerely,

/s/ Kelley Balkcom

Kelley Balkcom
Director, Regulatory Affairs
Georgia Power Company
mmcclosk@southernco.com

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NO. 42310**

**BASIS FOR THE ASSERTION THAT THE
INFORMATION SUBMITTED IS A TRADE SECRET**

In accordance with the Order Adopting Stipulation as Amended issued by the Georgia Public Service Commission ("Commission") in Docket No. 42310, Georgia Power Company ("Georgia Power" or the "Company") is providing to the Commission a Bi-Annual Hydro Modernization Report for the period ending December 31, 2021. The report contains proprietary cost data (the "Information") which constitutes trade secret information of Georgia Power, the Southern Company, and its affiliates, and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains confidential budgetary information related to projects at specific hydro generation facilities. Public dissemination of the Information would allow Georgia Power's potential suppliers and contractors access to such estimated costs, thereby bestowing insight into the Company's budgeted cost and timing of such expenditures. Such access would grant an unfair advantage to contractors and suppliers of the Company, who could use such information to artificially set bid and proposal prices during contract negotiations. This could lead to the Company having to pay a price higher than that which it would have paid on a level playing field.

The Information is subject to extensive efforts to maintain its confidentiality. Only select Georgia Power and Southern Company personnel and their legal counsel are granted access to the Information. Those personnel receive access only on a "need to know" basis. If a party outside of Georgia Power and Southern Company are granted access to the Information, the party is required to sign a confidentiality agreement with respect to the Information.

Signature Appears on the Following Page

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed the attached document and that the information included in such document is accurate to the best of his knowledge and that the specific information designated as trade secret constitute trade secrets pursuant to Article 27, Chapter 1, Title 10 of the Georgia Code.



Jeffrey R. Grubb
Resource Policy and Planning Director
Georgia Power Company

Subscribed and sworn to before me this 10th day of February 2022.



Notary Public

My Commission expires:



**Georgia Power Company's
Bi-Annual Hydro Modernization Update
For the Period Ending December 31, 2021**

This Hydro Modernization Update ("Update") is provided in accordance with the Order Adopting Stipulation as Amended (the "Order") issued by the Georgia Public Service Commission (the "Commission") in the matter of Georgia Power Company's 2019 Integrated Resource Plan ("IRP") under Docket No. 42310. As such, it provides information to allow the Commission to monitor Georgia Power Company's ("Georgia Power" or the "Company") modernization efforts at Plant Terrora, Plant Tugalo, Plant Bartletts Ferry, Plant Nacoochee, and Plant Oliver.

Summary of Work Performed by Site

Plant Terrora



Plant Terrora Units 1-2 are part of the North Georgia hydro group. These units began commercial operation in 1925.

Summary of Scope of Work: The scope of work for Plant Terrora Units 1-2 includes generator rewinds, turbine replacements, and the replacement of the Balance of Plant (BOP) systems such as lubricating oil, service water systems, 480V switchgear, and the plant control system.

Project Status: Major construction work at Plant Terrora is complete. Unit 2 began generating on 12/29/20, and Unit 1 began generating on 11/18/21. The remaining activities on site for early 2022 will include additional dual unit testing, close out of remaining punch list items, and demobilization of the temporary facilities that were used to support the modernization activities at site.

Plant Tugalo



Plant Tugalo Units 1-4 are part of the North Georgia hydro group. Plant Tugalo Units 1-2 began commercial operation in 1923. Plant Tugalo Units 3-4 began commercial operation in 1924.

Summary of Scope of Work: The scope of work for Plant Tugalo Units 1-4 includes generator replacements, turbine replacements, and replacement of the BOP systems such as lubricating oil, service water systems,

480V switchgear, and the plant control system.

Project Status: Site activities are picking up. Laydown areas, parking lots, and office spaces are being installed on site. Engineering design is roughly 62% complete and is scheduled for completion in the second quarter of 2022. Major BOP equipment procurement is complete. Removal of the old turbine and generator on Unit 1 is complete. The new cooling water piping loop has been installed. The field machining of the embedded components is in progress.

Plant Bartletts Ferry 1-4



Plant Bartletts Ferry Units 1-4 are part of the Chattahoochee hydro group. These units began commercial operation at varying times as shown below:

- Bartletts Ferry Units 1-2 in 1926
- Bartletts Ferry Unit 3 in 1928
- Bartletts Ferry Unit 4 in 1951

Summary of Scope of Work: The scope of work is limited to Plant Bartletts Ferry Units 1-4. The work on these units includes generator rewinds, turbine

replacements, and replacement of the BOP systems such as lubricating oil, service water systems, 480V switchgear, and the plant control system. Plant Bartletts Ferry Units 5-6 are not included in the scope of work at this time.

Project Status: Scope development is complete and detailed design work is underway. The procurement package for new turbines has been issued and awarded. The generator rewind procurement package is in development. Design work is currently focused on the headgate package, for which construction will commence in 2022. Unit 1 modernization work will follow with construction commencing in the first quarter of 2023.

Plant Nacoochee



Plant Nacoochee Units 1-2 are part of the North Georgia hydro group. These units began commercial operation in 1926.

Summary of Scope of Work: The scope of work expected for Plant Nacoochee Units 1-2 includes generator rewinds, turbine replacement on Unit 2, and replacement of the BOP systems such as lubricating oil, service water systems, 480V switchgear, and the plant control system.

Project Status: A scoping kickoff meeting has been completed and detailed design work has commenced. In alignment with the 2022 IRP, the Plant Nacoochee schedule has shifted to optimize the overall modernization project schedule and engineering teams. The procurement package for the new turbine is under development. The generator rewind procurement package will be issued upon award of the turbine package. Engineering, procurement, and construction has been pushed out a year due to turbine supplier issues and to allow the optimization of engineering design resources.

Plant Oliver



Plant Oliver Units 1-4 are part of the Chattahoochee hydro group. These units began commercial operation in 1959.

Summary of Scope of Work: The scope of work expected for Plant Oliver Units 1-4 includes turbine replacements and replacement of the BOP systems such as lubricating oil, service water systems, 480V switchgear, and the plant control system. Additionally, generator rewinds

will be performed on Units 3 and 4. Generator rewinds were previously completed for units 1 and 2 during their maintenance cycles in 2015 and 2016, respectively.

A scoping kickoff meeting has been completed and detailed design work has commenced. In alignment with the 2022 IRP, the Plant Oliver schedule has shifted to optimize the overall modernization project schedule and engineering teams. The procurement package for new turbines is in development. The generator procurement package for Units 3 and 4 will be issued once the turbine package has been awarded. Engineering, procurement, and construction has been pushed out a year due to turbine supplier issues and to allow the optimization of engineering design resources.

PUBLIC DISCLOSURE
Hydro Modernization Cost Report
Project Monitoring Report thru December 31, 2021
Total Project
(\$1,000s)

Year	Period Ending	Terrora Actuals	Terrora Project Forecast*	Tugalo Actuals	Tugalo Project Forecast*	Bartletts Ferry Actuals	Bartletts Ferry Project Forecast*	Nacoochee Actuals	Nacoochee Project Forecast*	Oliver Actuals	Oliver Project Forecast*	Total Actuals	Total Project Forecast*
2019	30-Jun	\$ 1,042	\$ 260	\$ -	\$ -	\$ -	\$ -	\$ -		\$ -		\$ 1,042	\$ 260
2019	31-Dec	\$ 3,430	\$ 1,848	\$ -	\$ -	\$ -	\$ -	\$ -		\$ -		\$ 3,430	\$ 1,848
2020	30-Jun	\$ 9,855	\$ 10,687	\$ 629	\$ 624	\$ 683	\$ 683	\$ 34		\$ 434		\$ 11,635	\$ 11,994
2020	31-Dec	\$ 15,498	\$ 18,624	\$ 5,508	\$ 5,443	\$ 1,734	\$ 1,734	\$ 6		\$ 3		\$ 22,749	\$ 25,801
2021	30-Jun	\$ 8,060	\$ 8,181	\$ 2,188	\$ 2,187	\$ 3,405	\$ 3,405	\$ 345		\$ 480		\$ 14,479	\$ 13,773
2021	31-Dec	\$ 8,450	\$ 7,694	\$ 18,030	\$ 17,473	\$ 11,287	\$ 11,315	\$ 1,352		\$ 521		\$ 39,640	\$ 36,482
2022	30-Jun	\$ -	\$ 750	\$ -	\$ 13,467	\$ -	\$ 4,672	\$ -		\$ -		\$ -	\$ 18,889
2022	31-Dec			\$ -	\$ 19,762	\$ -	\$ 14,461	\$ -		\$ -		\$ -	\$ 34,223
2023	30-Jun			\$ -	\$ 11,033	\$ -	\$ 18,096	\$ -		\$ -		\$ -	\$ 29,129
2023	31-Dec			\$ -	\$ 7,858	\$ -	\$ 14,532	\$ -		\$ -		\$ -	\$ 22,391
2024	30-Jun			\$ -	\$ 11,713	\$ -	\$ 12,224	\$ -		\$ -		\$ -	\$ 23,936
2024	31-Dec			\$ -	\$ 7,965	\$ -	\$ 13,242	\$ -		\$ -		\$ -	\$ 21,207
2025	30-Jun			\$ -	\$ 10,098	\$ -	\$ 11,815	\$ -		\$ -		\$ -	\$ 21,913
2025	31-Dec			\$ -	\$ 7,670	\$ -	\$ 12,996	\$ -		\$ -		\$ -	\$ 20,666
2026	30-Jun				\$ 3	\$ -	\$ 13,695			\$ -		\$ -	\$ 13,698
2026	31-Dec					\$ -	\$ 11,205			\$ -		\$ -	\$ 11,205
2027	30-Jun									\$ -		\$ -	\$ -
2027	31-Dec									\$ -		\$ -	\$ -
TOTAL		\$ 46,335	\$ 48,045	\$ 26,354	\$ 115,295	\$ 17,110	\$ 144,075	\$ 1,737	\$ -	\$ 1,439	\$ -	\$ 92,974	\$ 307,415

Sums and percentages may not add due to rounding.

Notes on Variances	
A	
B	
C	

*Added once Project Forecast estimates are updated and approved. Currently includes Plant Terrora Project Forecast that was developed 2/26/21, Plant Tugalo Q3 2021, Bartletts 1-4 Q4 2021, Measured against 2019 IRP Budget - \$446,618

PUBLIC DISCLOSURE
Hydro Modernization Cost Report
Project Monitoring Report - December 31, 2021
Plant Terrora

Actuals (\$1,000s)											
Year	Period Ending	Unit 1			Unit 2			Actuals	Project Forecast* (Developed 2/26/21)	% Variance (against Project Forecast)	Notes
		Turbine	Generator	BOP	Turbine	Generator	BOP				
2019	30-Jun	\$ -	\$ -	\$ -	\$ 594	\$ 31	\$ 417	\$ 1,042	\$ 260	300%	
2019	31-Dec	\$ -	\$ -	\$ -	\$ 1,678	\$ 303	\$ 1,449	\$ 3,430	\$ 1,848	86%	
2020	30-Jun	\$ 1,778	\$ -	\$ 12	\$ 3,949	\$ 1,582	\$ 2,534	\$ 9,855	\$ 10,687	-8%	
2020	31-Dec	\$ 972	\$ 1,551	\$ 802	\$ 4,512	\$ 2,648	\$ 5,012	\$ 15,498	\$ 18,624	-17%	
2021	30-Jun	\$ 3,222	\$ 1,277	\$ 2,666	\$ 498	\$ 3	\$ 395	\$ 8,060	\$ 8,181	-1%	
2021	31-Dec	\$ 4,970	\$ 921	\$ 2,070	\$ 129	\$ 0	\$ 360	\$ 8,450	\$ 7,694	10%	
2022	30-Jun							\$ -	\$ 750		
TOTAL		\$ 10,942	\$ 3,748	\$ 5,551	\$ 11,360	\$ 4,567	\$ 10,167	\$ 46,335	\$ 48,045	-3%	A
Current Estimate at Completion									\$ 46,521		

Sums and percentages may not add due to rounding.

Notes on Variances	
A	Projected final variance based on current estimate at completion.
B	
C	

Notes:
*Added once Project Forecast estimates are updated and approved. Final Project Forecast developed 2/26/21.
Measured against 2019 IRP Budget - \$58,160

Plant Tugalo

Actuals (\$1,000s)																	
Year	Period Ending	Unit 1			Unit 2			Unit 3			Unit 4			Actuals	Project Forecast*	% Variance (against Project Forecast)	Notes
		Turbine	Generator	BOP	Turbine	Generator	BOP	Turbine	Generator	BOP	Turbine	Generator	BOP				
2020	30-Jun	\$ 624		\$ 5										\$ 629	\$ 624	1%	
2020	31-Dec	\$ 1,871	\$ 54	\$ 91	\$ 1,165			\$ 1,165			\$ 1,161			\$ 5,508	\$ 5,443	1%	
2021	30-Jun	\$ 1,109	\$ 165	\$ 551	\$ 132		\$ 3	\$ 111		\$ 3	\$ 109		\$ 3	\$ 2,188	\$ 2,187	0%	
2021	31-Dec	\$ 4,497	\$ 1,727	\$ 7,002	\$ 1,231	\$ -	\$ 118	\$ 1,270	\$ -	\$ 731	\$ 1,330	\$ -	\$ 122	\$ 18,030	\$ 17,473	3%	
2022	30-Jun													\$ -	\$ 13,467		
2022	31-Dec													\$ -	\$ 19,762		
2023	30-Jun													\$ -	\$ 11,033		
2023	31-Dec													\$ -	\$ 7,858		
2024	30-Jun													\$ -	\$ 11,713		
2024	31-Dec													\$ -	\$ 7,965		
2025	30-Jun													\$ -	\$ 10,098		
2025	31-Dec													\$ -	\$ 7,670		
2026	30-Jun														\$ 3		
2026	31-Dec																
2027	30-Jun																
2027	31-Dec																
TOTAL		\$ 8,100	\$ 1,947	\$ 7,650	\$ 2,529	\$ -	\$ 121	\$ 2,546	\$ -	\$ 735	\$ 2,601	\$ -	\$ 125	\$ 26,354	\$ 115,295	0%	A
														Current Estimate at Completion		\$ 115,295	

Sums and percentages may not add due to rounding.

Notes on Variances	
A	Increase from 2019 IRP screening level estimate to current forecast driven by turbine, generator, GSU, and electrical equipment pricing.
B	
C	

Notes:
*Added once Project Forecast estimates are updated and approved. Final Project Forecast developed Q3 2021.
Measured against 2019 IRP Budget - \$109,736

PUBLIC DISCLOSURE
Hydro Modernization Cost Report
Project Monitoring Report - December 31, 2021
Bartlett's Ferry

Actuals (\$1,000s)																	
Year	Period Ending	Unit 1			Unit 2			Unit 3			Unit 4			Actuals	Project Forecast*	% Variance (against Project Forecast)	Notes
		Turbine	Generator	BOP	Turbine	Generator	BOP	Turbine	Generator	BOP	Turbine	Generator	BOP				
2020	30-Jun	\$ 683												\$ 683	\$ 683	0%	
2020	31-Dec	\$ 1,734												\$ 1,734	\$ 1,734	0%	
2021	30-Jun	\$ 2,405		\$ 1				\$ 539						\$ 2,405	\$ 2,405	0%	
2021	31-Dec	\$ 1,931	\$ 175	\$ 3,358	\$ 1,995	\$ 43	\$ 633	\$ 817	\$ -44	\$ 588	\$ 905	\$ 40	\$ 687	\$ 11,282	\$ 11,310	-0.25%	
2022	30-Jun													\$ -	\$ 4,872		
2022	31-Dec													\$ -	\$ 14,461		
2023	30-Jun													\$ -	\$ 18,098		
2023	31-Dec													\$ -	\$ 14,532		
2024	30-Jun													\$ -	\$ 12,324		
2024	31-Dec													\$ -	\$ 13,242		
2025	30-Jun													\$ -	\$ 11,818		
2025	31-Dec													\$ -	\$ 12,996		
2026	30-Jun													\$ -	\$ 13,695		
2026	31-Dec													\$ -	\$ 11,204		
2027	30-Jun																
2027	31-Dec																
TOTAL		\$ 7,234	\$ 176	\$ 3,358	\$ 1,995	\$ 43	\$ 633	\$ 1,304	\$ 44	\$ 588	\$ 905	\$ 60	\$ 687	\$ 17,110	\$ 144,075	67%	A
														Current Estimate at Completion	\$ 144,075		
Lums and non-lums may not add due to rounding																	

Sums and percentages may not add due to rounding.

Variances	
A	Increase from 2019 RFP screening level estimate to current forecast driven by turbine, generator, GSU, and electrical equipment pricing.
B	
C	

Notes:
*Added once Project Forecast estimates are updated and approved. Final Project Forecast developed Q4 2021.
Measured against 2019 RFP Budget = \$114,765

PUBLIC DISCLOSURE
Hydro Modernization Cost Report
Project Monitoring Report - December 31, 2021
Plant Nacoochee

Actuals (\$1,000s)											
Year	Period Ending	Unit 1			Unit 2			Actuals	Project Forecast*	% Variance (against Project Forecast)	Notes
		Turbine	Generator	BOP	Turbine	Generator	BOP				
2020	30-Jun				\$ 34			\$ 34	\$ -		
2020	31-Dec				\$ 6			\$ 6	\$ -		
2021	30-Jun				\$ 345			\$ 345	\$ -		
2021	31-Dec			\$ 628	\$ 724			\$ 1,352	\$ -		
2022	30-Jun							\$ -	\$ -		
2022	31-Dec							\$ -	\$ -		
2023	30-Jun							\$ -	\$ -		
2023	31-Dec							\$ -	\$ -		
2024	30-Jun							\$ -	\$ -		
2024	31-Dec							\$ -	\$ -		
2025	30-Jun							\$ -	\$ -		
2025	31-Dec							\$ -	\$ -		
2026	30-Jun										
2026	31-Dec										
2027	30-Jun										
2027	31-Dec										
TOTAL		\$ -	\$ -	\$ 628	\$ 1,109	\$ -	\$ -	\$ 1,737	\$ -		

Sum and percentages may not add due to rounding.

Notes on Variances	
A	
B	
C	

Notes:
*Added once Project Forecast estimates are updated and approved. Final Project Forecast expected Q1 2023.
2019 IRP Budget - \$44,117

PUBLIC DISCLOSURE
Hydro Brief Report
Project Monitoring Report - December 31, 2021
Plant Oliver

Year	Period Ending	Unit 1			Unit 2			Unit 3			Unit 4			Actuals	Project Forecast	% Variance (against Project Forecast)	Notes
		Turbine	Generator	BOP	Turbine	Generator	BOP	Turbine	Generator	BOP	Turbine	Generator	BOP				
2020	30-Jun	\$ 424											\$ 424	\$	-		
2020	31-Dec	\$ 2											\$ 2	\$	-		
2021	30-Jun	\$ 424											\$ 424	\$	-		
2021	31-Dec	\$ 521											\$ 521	\$	-		
2022	30-Jun												\$	-	\$		
2022	31-Dec												\$	-	\$		
2023	30-Jun												\$	-	\$		
2023	31-Dec												\$	-	\$		
2024	30-Jun												\$	-	\$		
2024	31-Dec												\$	-	\$		
2025	30-Jun												\$	-	\$		
2025	31-Dec												\$	-	\$		
2026	30-Jun												\$	-	\$		
2026	31-Dec												\$	-	\$		
2027	30-Jun												\$	-	\$		
2027	31-Dec												\$	-	\$		
	TOTAL	\$ 1,424	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	1,424	\$	-	

*Some and forecasted may not add due to rounding

Notes on Variance

A	
B	
C	

Notes:
 *Forecasted Project Financials, estimates are updated and approved. Final Project Forecast reported Q4 2023.
 *Actuals are reported as of 11/2021.

Major Standards	Type	PG ⁵	Estimated Student Enrollment	Need (100%)	Current (100%)	% Variation ⁶	Notes
SC.8.E.6.1-12 SC.8.E.6.1-12.1 SC.8.E.6.1-12.2 SC.8.E.6.1-12.3 SC.8.E.6.1-12.4 SC.8.E.6.1-12.5 SC.8.E.6.1-12.6 SC.8.E.6.1-12.7 SC.8.E.6.1-12.8 SC.8.E.6.1-12.9 SC.8.E.6.1-12.10 SC.8.E.6.1-12.11 SC.8.E.6.1-12.12 SC.8.E.6.1-12.13 SC.8.E.6.1-12.14 SC.8.E.6.1-12.15 SC.8.E.6.1-12.16 SC.8.E.6.1-12.17 SC.8.E.6.1-12.18 SC.8.E.6.1-12.19 SC.8.E.6.1-12.20 SC.8.E.6.1-12.21 SC.8.E.6.1-12.22 SC.8.E.6.1-12.23 SC.8.E.6.1-12.24 SC.8.E.6.1-12.25 SC.8.E.6.1-12.26 SC.8.E.6.1-12.27 SC.8.E.6.1-12.28 SC.8.E.6.1-12.29 SC.8.E.6.1-12.30 SC.8.E.6.1-12.31 SC.8.E.6.1-12.32 SC.8.E.6.1-12.33 SC.8.E.6.1-12.34 SC.8.E.6.1-12.35 SC.8.E.6.1-12.36 SC.8.E.6.1-12.37 SC.8.E.6.1-12.38 SC.8.E.6.1-12.39 SC.8.E.6.1-12.40 SC.8.E.6.1-12.41 SC.8.E.6.1-12.42 SC.8.E.6.1-12.43 SC.8.E.6.1-12.44 SC.8.E.6.1-12.45 SC.8.E.6.1-12.46 SC.8.E.6.1-12.47 SC.8.E.6.1-12.48 SC.8.E.6.1-12.49 SC.8.E.6.1-12.50 SC.8.E.6.1-12.51 SC.8.E.6.1-12.52 SC.8.E.6.1-12.53 SC.8.E.6.1-12.54 SC.8.E.6.1-12.55 SC.8.E.6.1-12.56 SC.8.E.6.1-12.57 SC.8.E.6.1-12.58 SC.8.E.6.1-12.59 SC.8.E.6.1-12.60 SC.8.E.6.1-12.61 SC.8.E.6.1-12.62 SC.8.E.6.1-12.63 SC.8.E.6.1-12.64 SC.8.E.6.1-12.65 SC.8.E.6.1-12.66 SC.8.E.6.1-12.67 SC.8.E.6.1-12.68 SC.8.E.6.1-12.69 SC.8.E.6.1-12.70 SC.8.E.6.1-12.71 SC.8.E.6.1-12.72 SC.8.E.6.1-12.73 SC.8.E.6.1-12.74 SC.8.E.6.1-12.75 SC.8.E.6.1-12.76 SC.8.E.6.1-12.77 SC.8.E.6.1-12.78 SC.8.E.6.1-12.79 SC.8.E.6.1-12.80 SC.8.E.6.1-12.81 SC.8.E.6.1-12.82 SC.8.E.6.1-12.83 SC.8.E.6.1-12.84 SC.8.E.6.1-12.85 SC.8.E.6.1-12.86 SC.8.E.6.1-12.87 SC.8.E.6.1-12.88 SC.8.E.6.1-12.89 SC.8.E.6.1-12.90 SC.8.E.6.1-12.91 SC.8.E.6.1-12.92 SC.8.E.6.1-12.93 SC.8.E.6.1-12.94 SC.8.E.6.1-12.95 SC.8.E.6.1-12.96 SC.8.E.6.1-12.97 SC.8.E.6.1-12.98 SC.8.E.6.1-12.99 SC.8.E.6.1-13.00 SC.8.E.6.1-13.01 SC.8.E.6.1-13.02 SC.8.E.6.1-13.03 SC.8.E.6.1-13.04 SC.8.E.6.1-13.05 SC.8.E.6.1-13.06 SC.8.E.6.1-13.07 SC.8.E.6.1-13.08 SC.8.E.6.1-13.09 SC.8.E.6.1-13.10 SC.8.E.6.1-13.11 SC.8.E.6.1-13.12 SC.8.E.6.1-13.13 SC.8.E.6.1-13.14 SC.8.E.6.1-13.15 SC.8.E.6.1-13.16 SC.8.E.6.1-13.17 SC.8.E.6.1-13.18 SC.8.E.6.1-13.19 SC.8.E.6.1-13.20 SC.8.E.6.1-13.21 SC.8.E.6.1-13.22 SC.8.E.6.1-13.23 SC.8.E.6.1-13.24 SC.8.E.6.1-13.25 SC.8.E.6.1-13.26 SC.8.E.6.1-13.27 SC.8.E.6.1-13.28 SC.8.E.6.1-13.29 SC.8.E.6.1-13.30 SC.8.E.6.1-13.31 SC.8.E.6.1-13.32 SC.8.E.6.1-13.33 SC.8.E.6.1-13.34 SC.8.E.6.1-13.35 SC.8.E.6.1-13.36 SC.8.E.6.1-13.37 SC.8.E.6.1-13.38 SC.8.E.6.1-13.39 SC.8.E.6.1-13.40 SC.8.E.6.1-13.41 SC.8.E.6.1-13.42 SC.8.E.6.1-13.43 SC.8.E.6.1-13.44 SC.8.E.6.1-13.45 SC.8.E.6.1-13.46 SC.8.E.6.1-13.47 SC.8.E.6.1-13.48 SC.8.E.6.1-13.49 SC.8.E.6.1-13.50 SC.8.E.6.1-13.51 SC.8.E.6.1-13.52 SC.8.E.6.1-13.53 SC.8.E.6.1-13.54 SC.8.E.6.1-13.55 SC.8.E.6.1-13.56 SC.8.E.6.1-13.57 SC.8.E.6.1-13.58 SC.8.E.6.1-13.59 SC.8.E.6.1-13.60 SC.8.E.6.1-13.61 SC.8.E.6.1-13.62 SC.8.E.6.1-13.63 SC.8.E.6.1-13.64 SC.8.E.6.1-13.65 SC.8.E.6.1-13.66 SC.8.E.6.1-13.67 SC.8.E.6.1-13.68 SC.8.E.6.1-13.69 SC.8.E.6.1-13.70 SC.8.E.6.1-13.71 SC.8.E.6.1-13.72 SC.8.E.6.1-13.73 SC.8.E.6.1-13.74 SC.8.E.6.1-13.75 SC.8.E.6.1-13.76 SC.8.E.6.1-13.77 SC.8.E.6.1-13.78 SC.8.E.6.1-13.79 SC.8.E.6.1-13.80 SC.8.E.6.1-13.81 SC.8.E.6.1-13.82 SC.8.E.6.1-13.83 SC.8.E.6.1-13.84 SC.8.E.6.1-13.85 SC.8.E.6.1-13.86 SC.8.E.6.1-13.87 SC.8.E.6.1-13.88 SC.8.E.6.1-13.89 SC.8.E.6.1-13.90 SC.8.E.6.1-13.91 SC.8.E.6.1-13.92 SC.8.E.6.1-13.93 SC.8.E.6.1-13.94 SC.8.E.6.1-13.95 SC.8.E.6.1-13.96 SC.8.E.6.1-13.97 SC.8.E.6.1-13.98 SC.8.E.6.1-13.99 SC.8.E.6.1-14.00 SC.8.E.6.1-14.01 SC.8.E.6.1-14.02 SC.8.E.6.1-14.03 SC.8.E.6.1-14.04 SC.8.E.6.1-14.05 SC.8.E.6.1-14.06 SC.8.E.6.1-14.07 SC.8.E.6.1-14.08 SC.8.E.6.1-14.09 SC.8.E.6.1-14.10 SC.8.E.6.1-14.11 SC.8.E.6.1-14.12 SC.8.E.6.1-14.13 SC.8.E.6.1-14.14 SC.8.E.6.1-14.15 SC.8.E.6.1-14.16 SC.8.E.6.1-14.17 SC.8.E.6.1-14.18 SC.8.E.6.1-14.19 SC.8.E.6.1-14.20 SC.8.E.6.1-14.21	1	10,242.5	12,152.3	12,152.3	100%		
SC.8.E.6.1-12 SC.8.E.6.1-12.1 SC.8.E.6.1-12.2 SC.8.E.6.1-12.3 SC.8.E.6.1-12.4 SC.8.E.6.1-12.5 SC.8.E.6.1-12.6 SC.8.E.6.1-12.7 SC.8.E.6.1-12.8 SC.8.E.6.1-12.9 SC.8.E.6.1-12.10 SC.8.E.6.1-12.11 SC.8.E.6.1-12.12 SC.8.E.6.1-12.13 SC.8.E.6.1-12.14 SC.8.E.6.1-12.15 SC.8.E.6.1-12.16 SC.8.E.6.1-12.17 SC.8.E.6.1-12.18 SC.8.E.6.1-12.19 SC.8.E.6.1-12.20 SC.8.E.6.1-12.21 SC.8.E.6.1-12.22 SC.8.E.6.1-12.23 SC.8.E.6.1-12.24 SC.8.E.6.1-12.25 SC.8.E.6.1-12.26 SC.8.E.6.1-12.27 SC.8.E.6.1-12.28 SC.8.E.6.1-12.29 SC.8.E.6.1-12.30 SC.8.E.6.1-12.31 SC.8.E.6.1-12.32 SC.8.E.6.1-12.33 SC.8.E.6.1-12.34 SC.8.E.6.1-12.35 SC.8.E.6.1-12.36 SC.8.E.6.1-12.37 SC.8.E.6.1-12.38 SC.8.E.6.1-12.39 SC.8.E.6.1-12.40 SC.8.E.6.1-12.41 SC.8.E.6.1-12.42 SC.8.E.6.1-12.43 SC.8.E.6.1-12.44 SC.8.E.6.1-12.45 SC.8.E.6.1-12.46 SC.8.E.6.1-12.47 SC.8.E.6.1-12.48 SC.8.E.6.1-12.49 SC.8.E.6.1-12.50 SC.8.E.6.1-12.51 SC.8.E.6.1-12.52 SC.8.E.6.1-12.53 SC.8.E.6.1-12.54 SC.8.E.6.1-12.55 SC.8.E.6.1-12.56 SC.8.E.6.1-12.57 SC.8.E.6.1-12.58 SC.8.E.6.1-12.59 SC.8.E.6.1-12.60 SC.8.E.6.1-12.61 SC.8.E.6.1-12.62 SC.8.E.6.1-12.63 SC.8.E.6.1-12.64 SC.8.E.6.1-12.65 SC.8.E.6.1-12.66 SC.8.E.6.1-12.67 SC.8.E.6.1-12.68 SC.8.E.6.1-12.69 SC.8.E.6.1-12.70 SC.8.E.6.1-12.71 SC.8.E.6.1-12.72 SC.8.E.6.1-12.73 SC.8.E.6.1-12.74 SC.8.E.6.1-12.75 SC.8.E.6.1-12.76 SC.8.E.6.1-12.77 SC.8.E.6.1-12.78 SC.8.E.6.1-12.79 SC.8.E.6.1-12.80 SC.8.E.6.1-12.81 SC.8.E.6.1-12.82 SC.8.E.6.1-12.83 SC.8.E.6.1-12.84 SC.8.E.6.1-12.85 SC.8.E.6.1-12.86 SC.8.E.6.1-12.87 SC.8.E.6.1-12.88 SC.8.E.6.1-12.89 SC.8.E.6.1-12.90 SC.8.E.6.1-12.91 SC.8.E.6.1-12.92 SC.8.E.6.1-12.93 SC.8.E.6.1-12.94 SC.8.E.6.1-12.95 SC.8.E.6.1-12.96 SC.8.E.6.1-12.97 SC.8.E.6.1-12.98 SC.8.E.6.1-12.99 SC.8.E.6.1-13.00 SC.8.E.6.1-13.01 SC.8.E.6.1-13.02 SC.8.E.6.1-13.03 SC.8.E.6.1-13.04 SC.8.E.6.1-13.05 SC.8.E.6.1-13.06 SC.8.E.6.1-13.07 SC.8.E.6.1-13.08 SC.8.E.6.1-13.09 SC.8.E.6.1-13.10 SC.8.E.6.1-13.11 SC.8.E.6.1-13.12 SC.8.E.6.1-13.13 SC.8.E.6.1-13.14 SC.8.E.6.1-13.15 SC.8.E.6.1-13.16 SC.8.E.6.1-13.17 SC.8.E.6.1-13.18 SC.8.E.6.1-13.19 SC.8.E.6.1-13.20 SC.8.E.6.1-13.21 SC.8.E.6.1-13.22 SC.8.E.6.1-13.23 SC.8.E.6.1-13.24 SC.8.E.6.1-13.25 SC.8.E.6.1-13.26 SC.8.E.6.1-13.27 SC.8.E.6.1-13.28 SC.8.E.6.1-13.29 SC.8.E.6.1-13.30 SC.8.E.6.1-13.31 SC.8.E.6.1-13.32 SC.8.E.6.1-13.33 SC.8.E.6.1-13.34 SC.8.E.6.1-13.35 SC.8.E.6.1-13.36 SC.8.E.6.1-13.37 SC.8.E.6.1-13.38 SC.8.E.6.1-13.39 SC.8.E.6.1-13.40 SC.8.E.6.1-13.41 SC.8.E.6.1-13.42 SC.8.E.6.1-13.43 SC.8.E.6.1-13.44 SC.8.E.6.1-13.45 SC.8.E.6.1-13.46 SC.8.E.6.1-13.47 SC.8.E.6.1-13.48 SC.8.E.6.1-13.49 SC.8.E.6.1-13.50 SC.8.E.6.1-13.51 SC.8.E.6.1-13.52 SC.8.E.6.1-13.53 SC.8.E.6.1-13.54 SC.8.E.6.1-13.55 SC.8.E.6.1-13.56 SC.8.E.6.1-13.57 SC.8.E.6.1-13.58 SC.8.E.6.1-13.59 SC.8.E.6.1-13.60 SC.8.E.6.1-13.61 SC.8.E.6.1-13.62 SC.8.E.6.1-13.63 SC.8.E.6.1-13.64 SC.8.E.6.1-13.65 SC.8.E.6.1-13.66 SC.8.E.6.1-13.67 SC.8.E.6.1-13.68 SC.8.E.6.1-13.69 SC.8.E.6.1-13.70 SC.8.E.6.1-13.71 SC.8.E.6.1-13.72 SC.8.E.6.1-13.73 SC.8.E.6.1-13.74 SC.8.E.6.1-13.75 SC.8.E.6.1-13.76 SC.8.E.6.1-13.77 SC.8.E.6.1-13.78 SC.8.E.6.1-13.79 SC.8.E.6.1-13.80 SC.8.E.6.1-13.81 SC.8.E.6.1-13.82 SC.8.E.6.1-13.83 SC.8.E.6.1-13.84 SC.8.E.6.1-13.85 SC.8.E.6.1-13.86 SC.8.E.6.1-13.87 SC.8.E.6.1-13.88 SC.8.E.6.1-13.89 SC.8.E.6.1-13.90 SC.8.E.6.1-13.91 SC.8.E.6.1-13.92 SC.8.E.6.1-13.93 SC.8.E.6.1-13.94 SC.8.E.6.1-13.95 SC.8.E.6.1-13.96 SC.8.E.6.1-13.97 SC.8.E.6.1-13.98 SC.8.E.6.1-13.99 SC.8.E.6.1-14.00 SC.8.E.6.1-14.01 SC.8.E.6.1-14.02 SC.8.E.6.1-14.03 SC.8.E.6.1-14.04 SC.8.E.6.1-14.05 SC.8.E.6.1-14.06 SC.8.E.6.1-14.07 SC.8.E.6.1-14.08 SC.8.E.6.1-14.09 SC.8.E.6.1-14.10 SC.8.E.6.1-14.11 SC.8.E.6.1-14.12 SC.8.E.6.1-14.13 SC.8.E.6.1-14.14 SC.8.E.6.1-14.15 SC.8.E.6.1-14.16 SC.8.E.6.1-14.17 SC.8.E.6.1-14.18 SC.8.E.6.1-14.19 SC.8.E.6.1-14.20 SC.8.E.6.1-14.21	1	10,242.5	12,152.3	12,152.3	100%		
SC.8.E.6.1-12 SC.8.E.6.1-12.1 SC.8.E.6.1-12.2 SC.8.E.6.1-12.3 SC.8.E.6.1-12.4 SC.8.E.6.1-12.5 SC.8.E.6.1-12.6 SC.8.E.6.1-12.7 SC.8.E.6.1-12.8 SC.8.E.6.1-12.9 SC.8.E.6.1-12.10 SC.8.E.6.1-12.11 SC.8.E.6.1-12.12 SC.8.E.6.1-12.13 SC.8.E.6.1-12.14 SC.8.E.6.1-12.15 SC.8.E.6.1-12.16 SC.8.E.6.1-12.17 SC.8.E.6.1-12.18 SC.8.E.6.1-12.19 SC.8.E.6.1-12.20 SC.8.E.6.1-12.21 SC.8.E.6.1-12.22 SC.8.E.6.1-12.23 SC.8.E.6.1-12.24 SC.8.E.6.1-12.25 SC.8.E.6.1-12.26 SC.8.E.6.1-12.27 SC.8.E.6.1-12.28 SC.8.E.6.1-12.29 SC.8.E.6.1-12.30 SC.8.E.6.1-12.31 SC.8.E.6.1-12.32 SC.8.E.6.1-12.33 SC.8.E.6.1-12.34 SC.8.E.6.1-12.35 SC.8.E.6.1-12.36 SC.8.E.6.1-12.37 SC.8.E.6.1-12.38 SC.8.E.6.1-12.39 SC.8.E.6.1-12.40 SC.8.E.6.1-12.41 SC.8.E.6.1-12.42 SC.8.E.6.1-12.43 SC.8.E.6.1-12.44 SC.8.E.6.1-12.45 SC.8.E.6.1-12.46 SC.8.E.6.1-12.47 SC.8.E.6.1-12.48 SC.8.E.6.1-12.49 SC.8.E.6.1-12.50 SC.8.E.6.1-12.51 SC.8.E.6.1-12.52 SC.8.E.6.1-12.53 SC.8.E.6.1-12.54 SC.8.E.6.1-12.55 SC.8.E.6.1-12.56 SC.8.E.6.1-12.57 SC.8.E.6.1-12.58 SC.8.E.6.1-12.59 SC.8.E.6.1-12.60 SC.8.E.6.1-12.61 SC.8.E.6.1-12.62 SC.8.E.6.1-12.63 SC.8.E.6.1-12.64 SC.8.E.6.1-12.65 SC.8.E.6.1-12.66 SC.8.E.6.1-12.67 SC.8.E.6.1-12.68 SC.8.E.6.1-12.69 SC.8.E.6.1-12.70 SC.8.E.6.1-12.71 SC.8.E.6.1-12.72 SC.8.E.6.1-12.73 SC.8.E.6.1-12.74 SC.8.E.6.1-12.75 SC.8.E.6.1-12.76 SC.8.E.6.1-12.77 SC.8.E.6.1-12.78 SC.8.E.6.1-12.79 SC.8.E.6.1-12.80 SC.8.E.6.1-12.81 SC.8.E.6.1-12.82 SC.8.E.6.1-12.83 SC.8.E.6.1-12.84 SC.8.E.6.1-12.85 SC.8.E.6.1-12.86 SC.8.E.6.1-12.87 SC.8.E.6.1-12.88 SC.8.E.6.1-12.89 SC.8.E.6.1-12.90 SC.8.E.6.1-12.91 SC.8.E.6.1-12.92 SC.8.E.6.1-12.93 SC.8.E.6.1-12.94 SC.8.E.6.1-12.95 SC.8.E.6.1-12.96 SC.8.E.6.1-12.97 SC.8.E.6.1-12.98 SC.8.E.6.1-12.99 SC.8.E.6.1-13.00 SC.8.E.6.1-13.01 SC.8.E.6.1-13.02 SC.8.E.6.1-13.03 SC.8.E.6.1-13.04 SC.8.E.6.1-13.05 SC.8.E.6.1-13.06 SC.8.E.6.1-13.07 SC.8.E.6.1-13.08 SC.8.E.6.1-13.09 SC.8.E.6.1-13.10 SC.8.E.6.1-13.11 SC.8.E.6.1-13.12 SC.8.E.6.1-13.13 SC.8.E.6.1-13.14 SC.8.E.6.1-13.15 SC.8.E.6.1-13.16 SC.8.E.6.1-13.17 SC.8.E.6.1-13.18 SC.8.E.6.1-13.19 SC.8.E.6.1-13.20 SC.8.E.6.1-13.21 SC.8.E.6.1-13.22 SC.8.E.6.1-13.23 SC.8.E.6.1-13.24 SC.8.E.6.1-13.25 SC.8.E.6.1-13.26 SC.8.E.6.1-13.27 SC.8.E.6.1-13.28 SC.8.E.6.1-13.29 SC.8.E.6.1-13.30 SC.8.E.6.1-13.31 SC.8.E.6.1-13.32 SC.8.E.6.1-13.33 SC.8.E.6.1-13.34 SC.8.E.6.1-13.35 SC.8.E.6.1-13.36 SC.8.E.6.1-13.37 SC.8.E.6.1-13.38 SC.8.E.6.1-13.39 SC.8.E.6.1-13.40 SC.8.E.6.1-13.41 SC.8.E.6.1-13.42 SC.8.E.6.1-13.43 SC.8.E.6.1-13.44 SC.8.E.6.1-13.45 SC.8.E.6.1-13.46 SC.8.E.6.1-13.47 SC.8.E.6.1-13.48 SC.8.E.6.1-13.49 SC.8.E.6.1-13.50 SC.8.E.6.1-13.51 SC.8.E.6.1-13.52 SC.8.E.6.1-13.53 SC.8.E.6.1-13.54 SC.8.E.6.1-13.55 SC.8.E.6.1-13.56 SC.8.E.6.1-13.57 SC.8.E.6.1-13.58 SC.8.E.6.1-13.59 SC.8.E.6.1-13.60 SC.8.E.6.1-13.61 SC.8.E.6.1-13.62 SC.8.E.6.1-13.63 SC.8.E.6.1-13.64 SC.8.E.6.1-13.65 SC.8.E.6.1-13.66 SC.8.E.6.1-13.67 SC.8.E.6.1-13.68 SC.8.E.6.1-13.69 SC.8.E.6.1-13.70 SC.8.E.6.1-13.71 SC.8.E.6.1-13.72 SC.8.E.6.1-13.73 SC.8.E.6.1-13.74 SC.8.E.6.1-13.75 SC.8.E.6.1-13.76 SC.8.E.6.1-13.77 SC.8.E.6.1-13.78 SC.8.E.6.1-13.79 SC.8.E.6.1-13.80 SC.8.E.6.1-13.81 SC.8.E.6.1-13.82 SC.8.E.6.1-13.83 SC.8.E.6.1-13.84 SC.8.E.6.1-13.85 SC.8.E.6.1-13.86 SC.8.E.6.1-13.87 SC.8.E.6.1-13.88 SC.8.E.6.1-13.89 SC.8.E.6.1-13.90 SC.8.E.6.1-13.91 SC.8.E.6.1-13.92 SC.8.E.6.1-13.93 SC.8.E.6.1-13.94 SC.8.E.6.1-13.95 SC.8.E.6.1-13.96 SC.8.E.6.1-13.97 SC.8.E.6.1-13.98 SC.8.E.6.1-13.99 SC.8.E.6.1-14.00 SC.8.E.6.1-14.01 SC.8.E.6.1-14.02 SC.8.E.6.1-14.03 SC.8.E.6.1-14.04 SC.8.E.6.1-14.05 SC.8.E.6.1-14.06 SC.8.E.6.1-14.07 SC.8.E.6.1-14.08 SC.8.E.6.1-14.09 SC.8.E.6.1-14.10 SC.8.E.6.1-14.11 SC.8.E.6.1-14.12 SC.8.E.6.1-14.13 SC.8.E.6.1-14.14 SC.8.E.6.1-14.15 SC.8.E.6.1-14.16 SC.8.E.6.1-14.17 SC.8.E.6.1-14.18 SC.8.E.6.1-14.19 SC.8.E.6.1-14.20 SC.8.E.6.1-14.21	1	10,242.5	12,152.3	12,152.3	100%		
SC.8.E.6.1-12 SC.8.E.6.1-12.1 SC.8.E.6.1-12.2 SC.8.E.6.1-12.3 SC.8.E.6.1-12.4 SC.8.E.6.1-12.5 SC.8.E.6.1-12.6 SC.8.E.6.1-12.7 SC.8.E.6.1-12.8 SC.8.E.6.1-12.9 SC.8.E.6.1-12.10 SC.8.E.6.1-12.11 SC.8.E.6.1-12.12 SC.8.E.6.1-12.13 SC.8.E.6.1-12.14 SC.8.E.6.1-12.15 SC.8.E.6.1-12.16 SC.8.E.6.1-12.17 SC.8.E.6.1-12.18 SC.8.E.6.1-12.19 SC.8.E.6.1-12.20 SC.8.E.6.1-12.21 SC.8.E.6.1-12.22 SC.8.E.6.1-12.23 SC.8.E.6.1-12.24 SC.8.E.6.1-12.25 SC.8.E.6.1-12.26 SC.8.E.6.1-12.27 SC.8.E.6.1-12.28 SC.8.E.6.1-12.29 SC.8.E.6.1-12.30 SC.8.E.6.1-12.31 SC.8.E.6.1-12.32 SC.8.E.6.1-12.33 SC.8.E.6.1-12.34 SC.8.E.6.1-12.35 SC.8.E.6.1-12.36 SC.8.E.6.1-12.37 SC.8.E.6.1-12.38 SC.8.E.6.1-12.39 SC.8.E.6.1-12.40 SC.8.E.6.1-12.41 SC.8.E.6.1-12.42 SC.8.E.6.1-12.43 SC.8.E.6.1-12.44 SC.8.E.6.1-12.45 SC.8.E.6.1-12.46 SC.8.E.6.1-12.47 SC.8.E.6.1-12.48 SC.8.E.6.1-12.49 SC.8.E.6.1-12.50 SC.8.E.6.1-12.51 SC.8.E.6.1-12.52 SC.8.E.6.1-12.53 SC.8.E.6.1-12.54 SC.8.E.6.1-12.55 SC.8.E.6.1-12.56 SC.8.E.6.1-12.57 SC.8.E.6.1-12.58 SC.8.E.6.1-12.59 SC.8.E.6.1-12.60 SC.8.E.6.1-12.61 SC.8.E.6.1-12.62 SC.8.E.6.1-12.63 SC.8.E.6.1-12.64 SC.8.E.6.1-12.65 SC.8.E.6.1-12.66 SC.8.E.6.1-12.67 SC.8.E.6.1-12.68 SC.8.E.6.1-12.69 SC.8.E.6.1-12.70 SC.8.E.6.1-12.71 SC.8.E.6.1-12.72 SC.8.E.6.1-12.73 SC.8.E.6.1-12.74 SC.8.E.6.1-12.75 SC.8.E.6.1-12.76 SC.8.E.6.1-12.77 SC.8.E.6.1-12.78 SC.8.E.6.1-12.79 SC.8.E.6.1-12.80 SC.8.E.6.1-12.81 SC.8.E.6.1-12.82 SC.8.E.6.1-12.83 SC.8.E.6.1-12.84 SC.8.E.6.1-12.85 SC.8.E.6.1-12.86 SC.8.E.6.1-12.87 SC.8.E.6.1-12.88 SC.8.E.6.1-12.89 SC.8.E.6.1-12.90 SC.8.E.6.1-12.91 SC.8.E.6.1-12.92 SC.8.E.6.1-12.93 SC.8.E.6.1-1							

^aValues are means ± SD.

POA included when contract value exceeds \$100K following award of contract and issuance of POA.

² PO's included when contract value exceeds \$100K (following award of contract and issuance of PO)

* This reflects change orders to the contract/purchase order

⁴ From Initial Contract Amount to Current Amount)

Figure 1. The study area and the location of the sampling stations.

[illegible]

1. The first 600,000 units sold are priced at \$100 each. The remaining 400,000 units are priced at \$90 each.	2.

PUBLIC DISCLOSURE
Project Change Orders
Project Monitoring Report - December 31, 2021
Material Change Orders (>\$100k)

Torrora			
Date CO Submitted	Description of Change Order Request	Dollar Amount Requested	Date Approved
1/30/2020	Controls	REDACTED	5/13/2020
1/30/2020	Penstock manholes/platforms, burkigen platform, air receiver tank, control room access	REDACTED	5/13/2020
5/14/2020	Unit 1/2 Turbine Increases	REDACTED	5/14/2020
5/14/2020	Night Shift Coordinator	REDACTED	5/16/2020
6/23/2020	Torrora Isolation Valves	REDACTED	10/2/2020
10/19/2020	Torrora Overhead Crane Upgrade	REDACTED	10/19/2020
11/10/2020	Equipment and Startup support	REDACTED	11/24/2020
11/24/2020	Operations Procedures	REDACTED	11/24/2020
3/29/2021	Emerson Phase 2 Startup Support	REDACTED	4/12/2021
9/9/2021	Torrora Unit 1 & 2- New Lower Generator Guide Bearing Oil Basin Cover Proposal for American Hydro	REDACTED	9/9/2021
9/9/2021	Torrora Unit 1- LQGB Housing and Bridge F4 Reconditioning for American Hydro	REDACTED	10/8/2021
	34 Other Change Orders (<\$100k)	\$ 936	Multiple
	Total	\$ 6,157	
Tugalo			
Date CO Submitted	Description of Change Order Request	Dollar Amount Requested	Date Approved
10/14/2021	Online Brush Removal, Vibration Sensors, Braking/Jack System, and Terminal Blocks	\$ 920	11/30/2021
Bartlett's Ferry Units 1-4			
Date CO Submitted	Description of Change Order Request	Dollar Amount Requested	Date Approved
8/31/2021	Additional Options and Engineering Studies	\$ 907	9/7/2021
Nacoochee			
Date CO Submitted	Description of Change Order Request	Dollar Amount Requested	Date Approved
Oliver			
Date CO Submitted	Description of Change Order Request	Dollar Amount Requested	Date Approved

[illegible]

Total Project Estimate	Unit	Purchase Order Date	Required Delivery Date	Scheduled Delivery Date
Turbine	1	Actual 12/28/2020	12/31/2020	7/2/2022
Turbine/Generator	3	Actual 3/18/2021	4/30/2021	6/30/2021
Turbine/Generator	3	Actual 3/18/2021	4/30/2021	6/29/2021
Turbine/Generator	4	Actual 3/18/2021	4/30/2021	6/30/2021
General Contractor	1-4			
Trash Rocks	1-4	Actual 1/11/2021	6/1/2022	3/14/2022
Governor I/PU Skids	1-4	Actual 3/27/2021	7/31/2022	7/11/2022
Station Service Transformers	1-4	Actual 4/21/2021	6/1/2022	8/20/2022
Switchgear	1-4	Actual 4/7/2021	3/14/2022	6/7/2022
Lube Oil Skids	NA	NA	NA	NA
Batteries	1-4	Actual 10-4/2021	8/10/2022	11/14/2022
Generator Step Up Transformer	1	Actual 8/24/2021	8/1/2022	11/17/2022
DGCS Unit 1	1	Actual 3/7/2021	12/31/2022	4/29/2023
Spillway Gates	1-4	Actual 1/31/2021	8/1/2022	5/6/2022

[illegible]

Delayed delivery time reflects unanticipated requirement for another day and delivery date required in most instances; all options



REG-EX2
Southern Company Generation
241 Ralph McGill Boulevard, NE
BIN 10193
Atlanta, GA 30308-3374
404 506 7219 tel

September 23, 2021

FERC Project No. 2354

North Georgia Project Non-Capacity Related License Amendment

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C.

Dear Secretary Bose:

Georgia Power Company (Georgia Power) is the Federal Energy Regulatory Commission (FERC) licensee for the North Georgia Project (FERC No. 2354). Pursuant to the requirements of 18 CFR Section 4.201, Southern Company on behalf of Georgia Power, files the attached Application for a Non-Capacity Related Amendment for the North Georgia Project (Project). The Project consists of six separate developments: Burton, Nacoochee, Mathis-Terrora, and Tallulah Falls on the Tallulah River; and Tugalo and Yonah on the Tugalo River.

Georgia Power's application for amendment includes a proposal to replace and upgrade four (4) generating units in the Tugalo powerhouse, including refurbishing the turbines, replacing the turbine runners, rewinding the generators, and replacing spillway gates and intake trash racks.

The proposal does not change any of the Project features or operations and will not impact water control capabilities of the Tugalo powerhouse. The unit modifications are expected to increase the rating for each unit by about 4.75 MW each and increase each unit's efficiency. The installed capacity would increase by 19 MW total. The existing nameplate rated capacity is 11.25 MW for each unit and following the upgrade, the units will be approximately 16 MW each (17 MW each at full gate).

The full gate discharge of each unit is expected to marginally increase from 1240 cubic feet per second (cfs) to approximately 1400 cfs (12.9 percent increase) below the 15 percent FERC criterion for a capacity related amendment. The increase in hydraulic capacity would have an insignificant effect on water quality, including dissolved oxygen and temperature. The proposed replacement of trash racks at the Terrora intake would also result in a decrease of approach velocities at both best and full gate settings.

The Project will continue to operate under the terms of its current FERC license and applicable Water Quality Certification. No environmental resources are adversely affected by the proposed upgrade and all existing protection, mitigation, and enhancement measures required by the Project license would not change.

Pursuant to the consultation requirements in 18 CFR 4.38(a)(7), Georgia Power consulted with the following entities on this non-capacity amendment during June and July 2021: U.S. Forest Service; U.S. Fish and Wildlife Service; Georgia Department of Natural Resources - Environmental Protection Division; Georgia Department of Natural Resources - Wildlife Resources Division; Georgia Historic Preservation Division; South Carolina Department of Natural Resources (SCDNR); South Carolina Department of Health and Environmental Control; South Carolina Department of Archives and History; and Indian tribes. Georgia Power provided the Draft Non-Capacity Related Amendment Application for agency review and comment

on August 6, 2021.

Following an initial consultation meeting, on July 30, 2021, SCDNR requested that Georgia Power provide a desktop entrainment study to evaluate potential adverse effects of increased cross-sectional area spacing of proposed new trash racks. Georgia Power conducted a desktop entrainment study and provided the analysis to the consulting agencies on September 14, 2021.

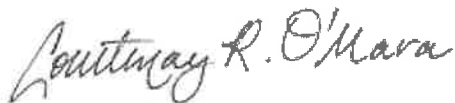
All comments from consultation have been included in the documents that are being submitted with this license amendment application. Georgia Power is submitting a revised Exhibit A and Exhibit F, as those are the only Exhibits that require adjustment due to this proposal. There are no proposed changes to operations (Exhibit B), environmental resources (Exhibit E), or the project boundary (Exhibit G).

Attachments submitted with this letter include the following:

Attachment A - Application for Non-Capacity Related Amendment of License
Attachment B - Consultation Record
Attachment C - Desktop Fish Entrainment Memo and Agency Consultation on the results of this analysis
Attachment D - Tracked Change Version of Revised Exhibit A
Attachment E - Clean Version of Revised Exhibit A
Attachment F - Draft Memorandum of Agreement
Attachment G - Proposed Revisions Needed for Exhibit F (Exhibit F, Sheet 14, FERC Drawing 2354-74) -
Submitted as CEII

Georgia Power respectfully requests that FERC conduct an expedited review and approval of the Tugalo upgrade application because there are no agency objections to the upgrade and it will not impact environmental resources. We have been in consultation with agencies already 60 days. If you have any questions about the Non-Capacity Related Amendment Application and/or revised license exhibits, or if you require additional information, please contact me on my cell phone at 404-797-9432 or by email at cromara@southernco.com.

Sincerely,



Courtenay R. O'Mara, P.E.
Hydro Licensing & Compliance Supervisor

cc: Wayne King - FERC, Atlanta Regional Office
Kelly Houff - FERC, DHAC
Jennifer Polardino - FERC, DHAC

Attachment A

Application for Non-Capacity Related Amendment of License

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Georgia Power Company

)

FERC Project No. 2354

**APPLICATION FOR NON-CAPACITY RELATED
AMENDMENT OF LICENSE**

Pursuant to Section 4.200 of the Federal Energy Regulatory Commission's (Commission or FERC) regulations,¹ Georgia Power Company (Georgia Power), hereby submits this Application for Non-Capacity Related Amendment of License (Application) for the North Georgia Project, FERC Project No. 2354 (Project). In filing this Application, Georgia Power seeks to amend the license² by upgrading and rehabilitating project turbines in the Tugalo powerhouse, rewinding and refurbishing the generators, replacing the control room panels, intake trash racks and spillway gates.

INITIAL STATEMENT

1. Georgia Power Company (Georgia Power) applies to the Federal Energy Regulatory Commission (FERC or Commission), under 18 CFR § 4.201, for a non-capacity amendment of the North Georgia Project (Project) license, a major existing waterpower project over 5 megawatts (MW), as described in the attached exhibit. This application is for a non-capacity amendment to upgrade and rehabilitate the four project turbines in the Tugalo powerhouse, rewinding and refurbishing the generators, replacing the control room panels, intake trash racks and spillway gates. The existing nameplate rated capacity³ is 11.25 MW each for units 1 through 4 and following the upgrade, the units will be approximately 16 MW each. Existing hydraulic capacity at nameplate rated capacity is approximately 1240 cubic feet per second (cfs) for each unit and refurbished units will be approximately 1400 cfs each.
2. The exact name and business address and telephone number of the applicant are:

Georgia Power Company
241 Ralph McGill Boulevard, NE
BIN 10193
Atlanta, Georgia 30308-3374

¹ 18 C.F.R. § 4.200.

² Accession Number 19961008-0044.

³ Nameplate rated capacity is "best gate".

Communication and correspondence pertaining to this application should be addressed to:

Courtenay O'Mara
241 Ralph McGill Boulevard, NE
BIN 10193
Atlanta, Georgia 30308-3374
404-506-7219

3. Georgia Power is a domestic corporation and is licensee for the waterpower project, designated as Project No. 2354 in the records of the Federal Energy Regulatory Commission, issued on the 3rd day of October 1996.
4. The amendments of license proposed and the reason(s) why the proposed changes are necessary, are:
 - a. CURRENT CONDITIONS

The Tugalo Development is the fifth of six hydroelectric developments that comprise the North Georgia Project and is located just downstream of the confluence of the Tallulah and Chattooga Rivers. The development consists of the Tugalo Dam and powerhouse and the impoundment, Lake Tugalo. The Tugalo Development is located in Oconee County in South Carolina and Rabun County in Georgia.

The Tugalo Dam is an 840-foot-long, 160-foot high concrete gravity dam with a 73-foot-long overflow section, a 357-foot-long gated spillway section, a 20-foot-long center non-overflow section, a 165-foot long intake section, and a 225-foot-long right non-overflow section. The crest elevation of the non-overflow sections is 905.0 feet above mean sea level; there is a bridge over the spillway at this same elevation. The spillway crest elevation is 885.0 feet.

Lake Tugalo is a 597-acre reservoir with a gross storage capacity of 43,000 acre-ft, and a useable storage capacity of 14,000 acre-feet at a full pond elevation of 891.5 ft msl. Lake Tugalo extends up the Chattooga River about three miles from the Tallulah/Chattooga confluence.

Four steel penstocks, each about 308 feet long and 13 feet in diameter, carry water from the intake section through the dam, then under a substation located between the dam and powerhouse, and finally into the generating units. The penstocks are encased in concrete.

The Tugalo powerhouse sits about 130 feet downstream of the toe of the dam; a substation is situated in the space between. The powerhouse is a steel, reinforced concrete, and masonry building 204'4" long and 64'4" wide, with a 40' by 37'10" control room extending out from the upstream side. The powerhouse is 109.5 feet high at its downstream face. It contains four generating units, a control room, and a machine shop.

Tugalo's four generating units are rated at 11.25 MW each, for a total capacity of 45 MW. Each unit has a vertical Francis-type turbine rated 22,850 horsepower at 143 feet of head, and a vertical, alternating current generator rated 18,293 KVA, 17,041 KW at 171.4 rpm.

The generating units supply power at 6600 volts. Voltage at the powerhouse is increased to 46-kilovolt (kV) via transformers located at the powerhouse. A short

line connects Tugalo powerhouse to the transmission substation located between the powerhouse and the dam.

The tailrace is 200-feet long and 150-feet-wide and is separated from the main channel on its left by a concrete wall about 70 feet long and on its right by a concrete wall about 200 feet long.

The plant is operated to help meet the demand of the Georgia Power system during peak periods of the day. Operation is modified run-of-river; Lake Tugalo stores inflow over short periods of time, which is utilized to provide generation from Tugalo powerhouse during peak power demand hours. The reservoir is kept at or near full pool elevation throughout the year. Tugalo powerhouse discharges directly into the downstream Lake Yonah.

b. PROPOSAL

Tugalo's electrical and mechanical systems need rehabilitation and refurbishment. Georgia Power is planning to modernize the electrical systems and provide refurbishment to extend the life of the Tugalo turbines, generating units, instrumentation, and controls, so that the plant can continue to meet the operational requirements of its existing license. Units 1 through 4 are driven by vertical, Francis type turbines. The turbines and runners have been in operation for approximately 95 years. There are four generating units in the Tugalo powerhouse; the units will be modernized in 2022-2025, one unit each year. The turbines must be completely disassembled to facilitate the upgrade.

The proposed scope of work for Tugalo includes the following.

- All turbine components will be removed and refurbished/upgraded.
- Replace the existing generators.
- Instrumentation and controls replacement to cover control systems for the units and the plant. It will also address communications systems local to the plant, river system or area and Corporate networks for remote connectivity.
- Electrical balance of plant systems including replacement of line breakers, generator breakers, excitation, protective relaying, station service transformers, cable bus, switchgear, and AC and DC panels. Demolition and removal of existing conduit tray and abandoned cable will be planned as necessary to accommodate new cable and equipment. Existing electrical components that are being replaced or abandoned will be demolished.
- Mechanical balance of plant systems including replacement of cooling water, service water bearing lube oil, thrust bearing high pressure oil lift, governor oil hydraulic pumping unit, service air, powerhouse HVAC, automatic grease system, unit drainage systems, new rotor jacking system.
- Demolition and removal of equipment and skid to be replaced or abandoned is planned, as necessary. Rehabilitation of surfaces in demolished areas will be implemented, as necessary.
- Civil infrastructure as applicable including trash racks and spillway gate replacements.

Table 1 shows the rated generating and maximum hydraulic capacities of the existing units with the expected performance of the upgraded units. Performance of the upgraded units may vary slightly based on final design, head conditions, and fabrication.

TABLE 1 – TUGALO EXISTING AND PROPOSED HYDRAULIC CAPACITIES AND RATED CAPACITY

UNIT	Existing Rated (Best Gate/Most Efficient) Capacity (MW)	Existing Rated (Best Gate /Most Efficient) Hydraulic Capacity (CFS)	Proposed Rated (Best Gate/Most Efficient) Capacity (MW)	Proposed Rated (Best Gate /Most Efficient) Hydraulic Capacity (CFS)	Proposed Full Gate/Max Capacity after Upgrade (MW)	Proposed Max Hydraulic Capacity (CFS) after Upgrade (Full Gate)
1	11.25	1240	16	1400	17	1500
2	11.25	1240	16	1400	17	1500
3	11.25	1240	16	1400	17	1500
4	11.25	1240	16	1400	17	1500

Each upgraded unit will increase rated capacity from 11.25 TO 16 MW (at best gate). Following the upgrade there will be an increase of approximately 1240 cfs to 1400 cfs at best gate hydraulic capacity for an increase of 12.9 percent at Tugalo. Georgia Power will operate the Tugalo powerhouse with no change to existing lake levels at Lake Tugalo.

5. (i) The statutory or regulatory requirements of the state(s) in which the project would be located that affect the project as proposed with respect to bed and banks and to the appropriation, diversion, and use of water for power purposes are as follows:
 - 1) Georgia Power is a public electric utility serving retail customers in the State of Georgia and as such, is required to operate and exist under the general laws of the State of Georgia regulating public utilities as codified in the Official Code of Georgia Annotated (O.C.G.A.) Title 46 Chapter 3A. Specifically, § 46-3A-2 which requires utilities to file an Integrated Resource Plan (IRP) with the Georgia Public Service Commission.
 - 2) Section 401(a) of the Clean Water Act (CWA) of 1977 requires that an applicant for a federal license to construct or operate facilities, which may result in any discharge into navigable waters, must provide the federal agency with a certificate from the state in which the discharge originates or from the appropriate interstate water pollution control agency. In Georgia, Water Quality Certifications (WQC) are issued by the Georgia Environmental Protection Division (Georgia EPD) as part of the Georgia Department of Natural Resources wetland regulatory program via O.C.G.A. Title 12 Chapter 5-21. The existing license for North Georgia includes a 401 Water Quality Certificate issued by Georgia Environmental Protection Division (EPD) on August 15, 1991. Although the Tugalo development is located partially in South Carolina, all discharges originate in Georgia. Therefore, only a water quality certification from Georgia is required by Section 401(a) of the CWA. South Carolina

waived its 401 authority to the state of Georgia during relicensing⁴. The proposed refurbishment does not affect lake levels, only the discharge, and the powerhouse is located in Georgia.

- 3) Section 7 of the Endangered Species Act requires consultation pertaining to the potential impact to threatened or endangered species. Georgia Power reviewed the U.S. Fish and Wildlife Service (USFWS) Environmental Conservation Online System (ECOS) Information for Planning and Consultation (IPaC) tool and also discussed the proposed upgrade with the USFWS, U.S. Forest Service (USFS), Georgia Department of Natural Resources (Georgia DNR), and South Carolina Department of Natural Resources (South Carolina DNR). Georgia DNR is authorized by O.C.G.A. Title 27 Chapter 3 Article 3 (§ 27-3-132) as well as Rule 391-4-10 and the Endangered Wildlife Act of 1973 to make decisions, approve permits and determine potential impacts to any resident species as endangered, threatened, rare or unusual species.
- 4) Section 106 of the National Historic Preservation Act (NHPA) requires FERC to consider any adverse effects to historic properties before issuing the Order approving a license amendment. Tugalo powerhouse is eligible for listing on the National Register of Historic Places (NRHP) and, therefore, a historic property per the NHPA. Georgia Power has consulted with the Georgia Department of Community Affairs, Historic Preservation Division (Georgia HPD), the South Carolina Department of Archives and History (SC DAH), and sent information packages to Indian tribes.

(ii) The steps which the Applicant has taken, or plans to take to comply with each of the laws cited above, are:

- 1) Per the Integrated Resource Plan (IRP) Act, the IRP must be filed every 3 years, with the most recent being submitted on January 31, 2019.

The January 2019 IRP included modifications and plans for modernization of the Terrora, Tugalo and Nacoochee plants in the North Georgia Project, including those upgrades to the Tugalo Development as discussed in this application. This IRP was approved by the Public Service Commission on July 29, 2019. Money approved by the Public Service Commission is only available in the years approved. Therefore, it is essential that FERC review this application in an expeditious manner to meet the schedule required by the Public Service Commission. The schedule outlined for the three North Georgia Projects are as follows:

- Terrora – Modernization work is in progress and will be completed in 2021
- Tugalo – First Unit in 2022, Second Unit in 2023, Third Unit in 2024, and Fourth Unit in 2025
- Nacoochee – Unit 2 in 2024

The year stated is the year for actual turbine runner replacement and generator rewinds. Detailed scoping and engineering for each project occurs in years prior to the installation. Once sufficient engineering work is complete for each unit, agency consultation can begin, and license amendments submitted to FERC. As noted, FERC issued the order approving the license amendment related to the Terrora project on

⁴ See Accession No 19961008-0044, footnote 12. FERC notes that “Although the dams for Yonah and Tugalo developments are located partially in South Carolina, all discharges originate in Georgia. Therefore, only a water quality certification from Georgia is required by Section 401(a) of the Clean Water Act.”

February 2, 2021. Additional license amendments will be submitted to FERC for the remaining projects as the information becomes available.

- 2) Georgia Power was issued a 401 Water Quality Certification (WQC) for the North Georgia Project on August 15, 1991 and has been operating in compliance with the WQC since the license order was granted. According to FERC's guidance for license amendments in the *Hydroelectric Project Handbook for Filings Other than Licenses and Exemptions* (Section 4.1), "Evidence of a new request for water quality certification is only required if the amendment would result in a material adverse effect on the water quality in the discharge from the project or proposed project." Georgia Power consulted with the Georgia EPD and received confirmation that the existing and proposed unit modifications would continue to meet water quality criteria. Although, South Carolina waived its 401 authority to the state of Georgia during relicensing in the early 1990s, as a courtesy Georgia Power reached out to the South Carolina Department of Health and Environmental Control (DHEC) on June 21 and July 12, 2021 via email and telephone, respectively. Georgia Power did not receive a response.

Based on the calculations provided and discussed with the Georgia EPD there will be no material adverse effect on the water quality; therefore, Georgia EPD stated that a new 401 water quality certification would not be necessary.

- 3) Section 7 of the Endangered Species Act requires consultation pertaining to potential impacts of proposed actions to federally threatened or endangered species. There may be listed species in the area of the Tugalo Development. Georgia Power reviewed the USFWS' IPaC tool in May 2021 and found that the Gray bat (*Myotis grisescens*), the Northern Long-eared bat (*Myotis septentrionalis*), and the Bog turtle (*Clemmys muhlenbergii*) may be present in the Tugalo Development area. The majority of the upgrade activities occur in the powerhouse and do not require any ground disturbance or cutting of trees; therefore, there would be no effect on the bats. The Bog turtle generally occupies open-canopy, herbaceous sedge meadows and fens bordered by wooded areas; Georgia Power does not anticipate any effect on this species. Finally, there are five federally-listed flowering plants and one federally-listed lichen, but no effect is anticipated because the proposed upgrade does not involve ground disturbing activities. The USFWS' IPaC tool also listed 6 migratory birds that may use the project vicinity; however, Georgia Power does not anticipate any effect on these species. In addition, Georgia Power consulted with the Georgia DNR and South Carolina DNR on state listed species. Three aquatic species are described for the greater facility area (Tallulah River HUC10 watershed [0306010201]) based on review of Georgia WRD's web-based Natural Heritage Inventory on May 18, 2020. Highscale Shiner (*Notropis hypsilepis*), primarily found in tributary streams, is State listed as Rare. Smokey Dace (*Clinostomus funduloides*) and Brassy Jumprock (*Moxostoma* sp. 4) are neither federal nor state listed. The facility upgrades are not expected to have any impact on current flow, lake levels, or aquatic life and agencies concurred.
- 4) The proposed replacement of the trash racks at the Tugalo intake would result in a decrease of approach velocities. The approach velocities expected with new trashracks are estimated to be 1.73 and 1.86 foot per second (ft/s) at best and full gate flows, respectively. This is a decrease of 0.02 and 0.55 ft/s from the estimated approach velocities at best and full gate flow with the existing trashracks and existing

units.

- 5) Per request on July 30, 2021 from South Carolina DNR, Georgia Power conducted a desktop entrainment study to evaluate potential adverse effects of the increased cross-sectional area of the proposed trash racks. Georgia Power provided the analysis to all consulting agencies on September 14, 2021. The agencies concurred with the results of the analysis and noted that decreased velocities may provide a beneficial effect.
- 6) The Tugalo upgrade proposal includes replacing the existing spillway gates and generators, and Georgia Power consulted with the Georgia HPD and SC DAH specifically for Section 106; all other agencies were also consulted on replacement of spillway gates. Georgia Power received edits on the Draft Memorandum of Agreement from Georgia HPD and SC DAH that were included in the initial consultation package mailed to these agencies. All comments received have been incorporated into the Draft Memorandum of Agreement (MOA) included in this license amendment application. Additionally, and with permission of FERC staff, Georgia Power sent an outreach package to the Eastern Band of Cherokee Indians, the Catawba Nation, the Cherokee Nation, and the United Keetoowah Band of Cherokee Indians. The Catawba Nation responded that they had no comments on the undertaking but want to be notified if artifacts or remains are found. The Draft MOA incorporates this request. No other of the aforementioned tribes provided any comments.
6. As the project is constructed and operating under the above described laws and rules as well as its existing FERC license and plans no changes in operation associated with the non-capacity license amendment, it will remain in compliance with the above cited rules and regulations. Future FERC license amendments will be submitted for the Nacoochee project separately once mechanical and electrical design work is further completed. In accordance with 18 CFR §4.201(c), only the following applicable exhibit(s) that require revision are made part of this Application:

Exhibits A, F, and G were incorporated into the License Order for Project No. 2354.

Georgia Power notes that the proposed upgrade will not change 1) project operations (Exhibit B), 2) the existing Project boundary (Exhibit G), or 3) the Recreation Plan; therefore, no revisions are needed for the other license exhibits and plans and therefore, not applicable to this amendment.

Exhibit A (Project Description) requires an update; therefore, Georgia Power is attaching a revised Exhibit A in track change and a fully accepted changed version.

Georgia Power will provide any updates to Exhibit F after the as-builts drawings are complete. A draft Exhibit F is provided includes edits for new dimensions for generators to show the proposed changes of this license amendment; spillway replacement does not affect existing Exhibit F drawings because replacement gates are same dimensions. The draft Exhibit F is filed under a Critical Energy Infrastructure Information (CEII) designation.

7. Commission regulations under 18 CFR § 4.38(a)(7) require Georgia Power to consult with resource agencies and Indian tribes, to the extent that the proposed amendment would affect their interests. Georgia Power has consulted and received input, which has been incorporated into this license amendment application with the following agencies/Tribes (Initial Meeting dates in parenthesis):

- U.S. Forest Service (June 24, 2021)
- U.S. Fish and Wildlife Service (June 25, 2021)
- Georgia Department of Natural Resources - Environmental Protection Division (June 14, 2021)
- Georgia Department of Natural Resources -Wildlife Resources Division (June 24, 2021)
- Georgia Department of Community Affairs, Historic Preservation Division (July 1, 2021)
- South Carolina Department of Natural Resources (July 15, 2021)
- South Carolina State Department of Archives and History (July 1, 2021)
- Catawba Nation (July 20, 2021)

Additional information on consultation with agencies and tribes is provided in 5 (ii) 2, 3, 5 and 6 above and documentation of consultation is provided in attachments.

Georgia Power submitted a summary of the upgrade to the aforementioned agencies and provided an opportunity to meet and discuss the proposed upgrade in June and July 2021. As follow-up to the June and July meetings, an information package was mailed to the agencies and feedback was incorporated into the Draft License Amendment Application. Georgia Power provided the draft Non-Capacity Related License Amendment Application for agency review and comment on August 6, 2021 and has incorporated input from agencies in this License Amendment application. As noted above in 5 (ii) 5), at the request of SC DNR in July 2021, Georgia Power conducted a desktop entrainment study and distributed the analysis memo to all the agencies in September 2021. Therefore, Georgia Power has been consulting for over 60 days with the applicable agencies and we are requesting a waiver of the 60-day review of the application and request expedited FERC review.

8. This application package also includes the following attachments to assist the Commission in their review:

Attachment B – Consultation Record

Attachment C – Desktop Fish Entrainment Memo and Agency Consultation on the results of this analysis

Attachment D – Tracked Change Version of Revised Exhibit A

Attachment E – Clean Version of Revised Exhibit A

Attachment F- Draft Memorandum of Agreement

Attachment G – Proposed Revisions Needed for Exhibit F (Exhibit F, Sheet 14, FERC

Drawing 2354-74) - *Submitted as CEII*

SUMMARY

This Non-Capacity Related License Amendment would allow for turbine upgrades and associated modernization efforts described herein at the Tugalo development for continued operation of the generating units. The Tugalo upgrade is the second plant in the North Georgia modernization projects for which Georgia Power is seeking FERC approval. Future project schedules will be affected by the Tugalo completion dates. Money approved by the Public Service Commission is only available in the years approved (see (ii)1).

Therefore, it is essential that FERC review this application in an expeditious manner to meet the schedule required by the Public Service Commission.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**GEORGIA POWER COMPANY
DOCKET NOS. 44160 & 44161****Data Request No. STF-DEA-3-37****BASIS FOR THE ASSERTION THAT THE
INFORMATION SUBMITTED IS A TRADE SECRET**

As part of Georgia Power Company's 2022 Integrated Resource Plan filed in Docket No. 44160 ("2022 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan filed in Docket No. 44161 ("2022 DSM Application"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-DEA-3-37 ("Response"). In the Response, the Company has provided specific customer information (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains specific customer account information that is confidential. The Information provides details about energy that has been pushed back to the grid from all participating RNR-Monthly Netting pilot customers. Customers trust Georgia Power to keep their data in confidence absent their permission to share it with third parties. If the Information were disclosed without customer permission, it would harm this trust relationship that Georgia Power maintains with its customers and the ability of Georgia Power to implement its rates and programs in the most efficient and economic manner for customers. Moreover, the disclosure of customer information could chill participation in the Company's programs in the future. Competitors are not required to disclose similar customer information and to require Georgia Power to do so would put it at an economic disadvantageous.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-DEA Data Request Set Number 3

STF-DEA-3-37

Question:

For the RNR Monthly Netting pilot, please provide all studies and analysis that have been performed by the Company or on its behalf to support that cost shifting and increases to non-participating customers have occurred (IRP Main Document, page 14-115).

Response:

As indicated in the IRP Main Document, Georgia Power has conducted a preliminary, high-level analysis of the impacts of the RNR-Monthly Netting pilot. However, the Company so far has only analyzed the increased costs based on the energy pushed back to the grid and has not yet performed the analysis to compare the revenue loss and any cost savings due to solar production consumed onsite. The analysis summarized in STF-DEA-3-37 Attachments A and B compares the difference in compensation for energy pushed back to the grid between RNR-Monthly Netting and RNR-Instantaneous and the resulting cost-shift that will ultimately be passed along to all Georgia Power customers. STF-DEA-3-37 Attachment A summarizes the results for all participating RNR customers in 2020 and STF-DEA-3-37 Attachment B summarizes results for 2021.

All supporting work papers are provided in TS STF-DEA-3-37 Attachments C through V.

Workpaper	Attachment Name
all RNR3 billing 2020 GS	TS STF-DEA-3-37 Attachment C
all RNR3 billing 2020 PLM	TS STF-DEA-3-37 Attachment D
all RNR3 billing 2020 PLS	TS STF-DEA-3-37 Attachment E
all RNR3 billing 2020 R	TS STF-DEA-3-37 Attachment F
all RNR3 billing 2020 SLM	TS STF-DEA-3-37 Attachment G
all RNR3 billing 2020 TOU-PEV	TS STF-DEA-3-37 Attachment H
all RNR3 billing 2020 TOU-RD	TS STF-DEA-3-37 Attachment I
all RNR3 billing 2020 TOU-REO	TS STF-DEA-3-37 Attachment J
all RNR3 billing 2021 FSTOU	TS STF-DEA-3-37 Attachment K
all RNR3 billing 2021 GS	TS STF-DEA-3-37 Attachment L
all RNR3 billing 2021 PLM	TS STF-DEA-3-37 Attachment M
all RNR3 billing 2021 PLS	TS STF-DEA-3-37 Attachment N
all RNR3 billing 2021 R	TS STF-DEA-3-37 Attachment O
all RNR3 billing 2021 R-M	TS STF-DEA-3-37 Attachment P
all RNR3 billing 2021 SLM	TS STF-DEA-3-37 Attachment Q
all RNR3 billing 2021 TOU-EO	TS STF-DEA-3-37 Attachment R
all RNR3 billing 2021 TOU-GSD	TS STF-DEA-3-37 Attachment S
all RNR3 billing 2021 TOU-PEV	TS STF-DEA-3-37 Attachment T
all RNR3 billing 2021 TOU-RD	TS STF-DEA-3-37 Attachment U
all RNR3 billing 2021 TOU-REO	TS STF-DEA-3-37 Attachment V

RNR3 Revenue Erosion for 2020

Rate	# Accts	# Billing Months	Generated kWh	Energy	ECCR	NCCR	DSM	FUEL	MFF	RNR Credit	Total Rev Diff	\$/kWh
ALL	1979	14724	5,689,939	\$294,052	\$60,044	\$27,817	\$7,045	\$120,810	\$12,123	-\$139,795	\$382,097	\$0.067153
PLS-C	62	490	612,591	\$40,396	\$8,249	\$3,821	\$1,163	\$11,984	\$1,800	-\$13,918	\$53,495	\$0.087327
PLS-I	1	2	2,400	\$259	\$53	\$25	\$0	\$59	\$12	-\$72	\$336	\$0.139867
PLM-C	94	486	804,686	\$43,619	\$8,907	\$4,126	\$1,256	\$17,821	\$1,931	-\$20,576	\$57,085	\$0.070940
PLM-I	13	129	681,245	\$6,192	\$1,264	\$586	\$0	\$10,133	\$413	-\$11,770	\$6,819	\$0.010009
SLM	7	44	90,720	\$3,216	\$657	\$304	\$93	\$2,185	\$197	-\$2,715	\$3,936	\$0.043386
GS-C	90	898	656,408	\$39,426	\$8,049	\$3,730	\$1,135	\$10,045	\$1,532	-\$11,676	\$52,240	\$0.079585
GS-I	1	12	1,865	\$0	\$0	\$0	\$0	\$2	\$0	-\$3	\$0	-\$0.000118
GS-R	2	24	4,413	\$430	\$88	\$41	\$8	\$113	\$21	-\$126	\$575	\$0.130190
R	1441	10226	2,294,499	\$129,453	\$26,435	\$12,246	\$2,443	\$54,652	\$4,914	-\$63,411	\$166,733	\$0.072666
TOU-REO	67	670	158,205	\$8,830	\$1,803	\$835	\$167	\$3,890	\$348	-\$4,402	\$11,471	\$0.072508
TOU-PEV	172	1559	337,861	\$21,549	\$4,400	\$2,039	\$767	\$8,804	\$903	-\$9,835	\$28,627	\$0.084731
TOU-RD	29	184	45,046	\$682	\$139	\$65	\$13	\$1,122	\$51	-\$1,290	\$780	\$0.017324
											\$764,194	

RNR3 Revenue Erosion for 2021

Rate	# Accts	# Billing Months	Generated kWh	Energy	ECCR	NCCR	DSM	FUEL	MFF	RNR Credit	Total Rev Diff	\$/kWh
ALL	3,615	29,717	14,109,842	\$760,240	\$150,750	\$44,446	\$13,669	\$300,648	\$29,365	-\$331,072	\$968,046	\$0.069
PLS-C	63	599	806,920	\$53,642	\$10,636	\$3,136	\$1,088	\$15,779	\$2,359	-\$17,361	\$69,279	\$0.086
PLS-I	1	12	19,960	\$1,943	\$385	\$114	\$0	\$493	\$90	-\$543	\$2,482	\$0.124
PLM-C	106	1,130	2,663,307	\$158,101	\$31,348	\$9,242	\$3,207	\$57,411	\$6,583	-\$63,166	\$202,727	\$0.076
PLM-I	16	170	982,313	\$19,557	\$3,878	\$1,143	\$0	\$16,614	\$804	-\$18,264	\$23,731	\$0.024
PLL-C	1	5	-	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
SLM	6	72	160,160	\$5,576	\$1,106	\$326	\$113	\$3,955	\$339	-\$4,305	\$7,109	\$0.044
GS-C	101	1,058	790,363	\$39,467	\$7,824	\$2,309	\$801	\$12,756	\$1,546	-\$14,027	\$50,676	\$0.064
GS-I	1	12	1,711	\$0	\$0	\$0	\$0	\$2	\$0	-\$2	\$0	\$0.000
GS-R	2	24	2,706	\$211	\$42	\$12	\$4	\$67	\$10	-\$74	\$273	\$0.101
TOUGSD-C	4	34	26,020	\$897	\$178	\$52	\$18	\$685	\$56	-\$708	\$1,178	\$0.045
TOUGSD-I	1	12	-	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
TOU-EO-C	24	247	437,605	\$18,426	\$3,654	\$1,077	\$374	\$8,184	\$813	-\$9,056	\$23,471	\$0.054
TOU-EO-I	2	24	12,720	\$533	\$106	\$31	\$0	\$316	\$30	-\$346	\$670	\$0.053
FSTOU	7	84	102,778	\$4,151	\$823	\$243	\$84	\$2,053	\$87	-\$2,304	\$5,137	\$0.050
R	2,922	22,656	7,136,845	\$404,517	\$80,216	\$23,649	\$7,051	\$159,513	\$14,588	-\$176,041	\$513,493	\$0.072
TOU-REO	87	901	245,419	\$13,574	\$2,693	\$794	\$237	\$5,694	\$509	-\$6,225	\$17,275	\$0.070
TOU-PEV	211	2,250	610,849	\$38,062	\$7,548	\$2,225	\$664	\$14,774	\$1,458	-\$16,068	\$48,662	\$0.080
TOU-RD	59	415	108,766	\$1,490	\$296	\$87	\$26	\$2,318	\$88	-\$2,543	\$1,762	\$0.016
R-M	1	12	1,400	\$92	\$18	\$5	\$2	\$35	\$5	-\$38	\$119	\$0.085

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 2



STF-LA-2-30

Question:

How does the Company identify and assign costs (other than the cost for RECs) to each of the following customer renewable energy programs, how much cost was assigned to each program in 2020 and 2021, and how much cost is anticipated for each program for each year, 2022 through 2028:

- A. CARES program
- B. R3 program
- C. Community Solar Program
- D. The Income-Qualified Community Solar Program
- E. The Flex REC Program

Response:

For all the renewable energy programs listed, program expenses are tracked through a unique workorder and/or project code. Program costs consist of labor, administrative, and other program expenses.

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 2

Cost assigned to each program in 2020 and 2021

	2020	2021
CARES Program	\$0	\$0
R3 Program	\$0	\$0
Community Solar	\$149,847	\$98,284
The Income-Qualified Community Solar Program	\$0	\$0
The Flex REC Program	\$0	\$0

Projected costs for each program for each year, 2022 through 2028

	2022	2023	2024	2025
CARES Program	\$90,250	\$256,300	\$255,800	\$260,503
R3 Program	\$90,250	\$278,300	\$277,800	\$282,503
Community Solar	\$126,433	\$137,076	\$148,784	\$161,663
The Income-Qualified Community Solar Program	\$83,041	\$750,000	\$500,000	\$500,000
The Flex REC Program	\$0	\$364,620	\$375,559	\$386,825

	2026	2027	2028
CARES Program	\$265,417	\$274,552	\$71,096,745
R3 Program	\$287,417	\$292,552	\$297,918
Community Solar	\$175,829	\$191,412	\$208,553
The Income-Qualified Community Solar Program	\$0	\$0	\$0
The Flex REC Program	\$398,430	\$410,383	\$422,695

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-DEA Data Request Set Number 1

STF-DEA-1-2

Question:

Please provide the following information regarding customers on the RNR tariff as of 1/1/2022:

- a) Total number of customers, by customer class, by year for the period of 2015-2021 for the monthly and instantaneous netting tariff options;
- b) Average installed system size (kW) by customer class for the period of 2015-2021;
- c) Aggregate capacity of interconnected solar PV facilities by customer class;
- d) Average per customer billed usage for residential RNR customers with solar PV installations for each month for the period of 2015-2021;
- e) Average per customer billed usage for commercial RNR customers with solar PV installations for each month for the period of 2015-2021;
- f) Average per-customer maximum demand (kW) (hourly) for residential RNR customers with solar PV installations for each month for the period of 2015-2021;
- And
- g) Projected number of RNR customers and capacity, by customer class, for the period of 2022-2026.

Response:

Please refer to the tables below for information regarding the Company's customers on the RNR tariff, based on currently active accounts and contracts.

- a. Total number of customers by customer class, by year for the period of 2015-2021 for the monthly and instantaneous netting tariff options:

RNR Instantaneous Netting				
Year	Residential	Commercial	Industrial	Total
2015	270	80	7	357
2016	383	104	8	495
2017	548	137	10	695
2018	659	160	13	832
2019	877	179	14	1,070
2020	38			38
2021	93	34	3	130

RNR Monthly Netting				
Year	Residential	Commercial	Industrial	Total
2015				-
2016				-
2017				-
2018				-
2019				-
2020	1,358	251	17	1,626
2021	3,022	257	19	3,298

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-DEA Data Request Set Number 1

b. Average installed system size (kW) by customer class:

Average System Size (kW)	
Residential	7
Commercial	42
Industrial	79

c. Aggregate capacity of interconnected solar PV facilities by customer class:

Aggregate Capacity kW AC	
Residential	20,962
Commercial	12,199
Industrial	1,738
Total	34,899

d. Average billed usage (kWh) for residential RNR customers for each month for the period of 2015-2021:

	Average Residential Billed kWh						
Month	2015	2016	2017	2018	2019	2020	2021
January	2,336	1,884	1,483	1,938	1,477	1,278	1,449
February	2,218	1,858	1,113	1,155	1,209	1,225	1,203
March	1,990	1,423	1,056	1,051	967	1,069	880
April	1,524	1,216	1,083	953	929	787	736
May	1,544	1,281	1,158	1,181	1,171	1,034	845
June	2,008	1,710	1,330	1,396	1,261	1,168	1,223
July	2,353	2,178	1,700	1,626	1,629	1,516	1,291
August	2,418	2,173	1,561	1,533	1,533	1,361	1,466
September	2,030	1,926	1,236	1,626	1,489	1,286	1,063
October	1,571	1,399	1,170	1,130	1,043	893	881
November	1,450	1,379	1,126	1,237	1,027	1,044	1,080
December	1,674	1,505	1,445	1,568	1,384	1,423	1,121
Overall Average	1,923	1,666	1,288	1,366	1,263	1,180	1,100

Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-DEA Data Request Set Number 1

- e. Average billed usage (kWh) for commercial RNR customers for each month for the period of 2015-2021:

Month	Average Commercial Billed kWh						
	2015	2016	2017	2018	2019	2020	2021
January	10,662	9,157	9,617	9,936	9,104	9,491	10,872
February	10,021	9,456	8,170	8,129	8,342	8,780	9,750
March	9,736	8,509	8,007	7,866	7,449	8,466	8,670
April	8,634	7,968	8,360	7,254	7,688	5,998	7,625
May	8,217	8,104	8,506	8,800	8,779	8,856	8,587
June	9,243	9,928	8,916	10,269	9,286	9,408	10,973
July	10,167	10,532	10,193	11,257	10,680	10,601	12,138
August	10,253	10,807	10,049	10,861	10,643	10,403	13,575
September	10,516	11,404	8,725	11,835	10,439	10,592	11,373
October	8,576	8,968	8,388	8,668	9,060	8,758	10,334
November	7,883	7,572	7,653	8,727	8,086	8,754	10,501
December	8,620	8,579	8,751	9,782	9,775	9,337	10,298
Overall Average	9,371	9,288	8,776	9,462	9,127	9,137	10,404

- f. Georgia Power does not record hourly demand for most residential customers and is therefore not able to provide this information.
- g. Georgia Power does not specifically project RNR customer participants nor capacity. Using historical data and current volume trends, Georgia Power produces linear estimates of potential capacity growth scenarios of aggregated behind the meter solar production used to adjust forecasted energy sales, but does not project RNR growth specifically.



Solar – Behind the Meter

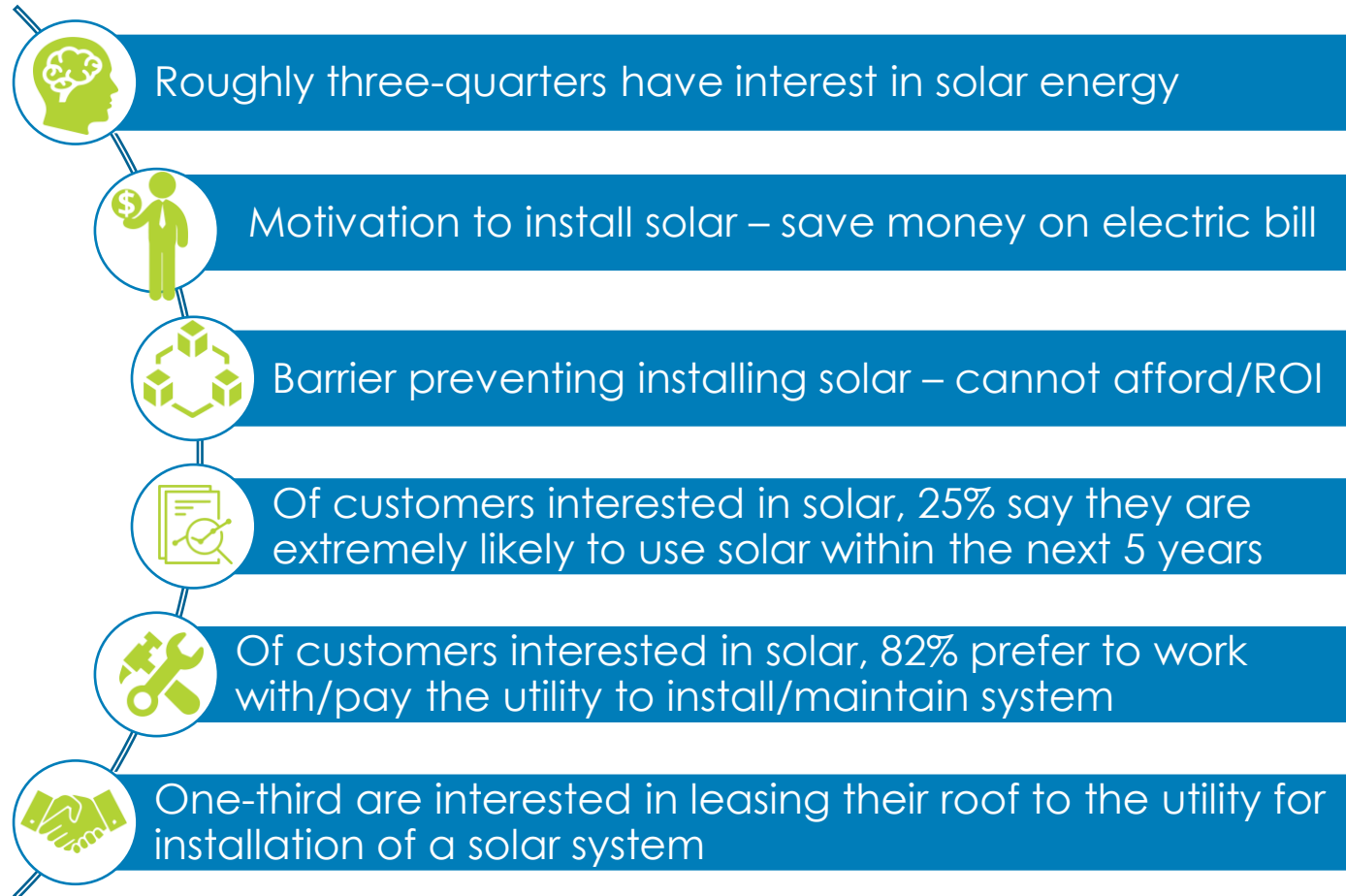
November 2021

Marketing Research

Methodology

Date	Market	Topic	Method
• Data collection October 21 – November 8, 2021	• Primarily Single-Family Homeowners • Across entire State	• Motivations • Barriers • Likelihood to install solar • Roof leasing • Awareness of: • Simple Solar • Community Solar	• Survey sent via email to 9865 customers • 600 completed surveys • Response rate 6 percent
			

Executive Summary



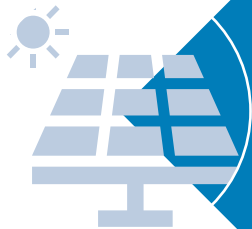
Recommendations



Educate/inform customers to help them make a decision about their own solar system, Community or Simple solar
Saving money on electric bill is the primary driver



Consider offering a program that will allow customers to work with/pay Georgia Power to install/maintain their solar system

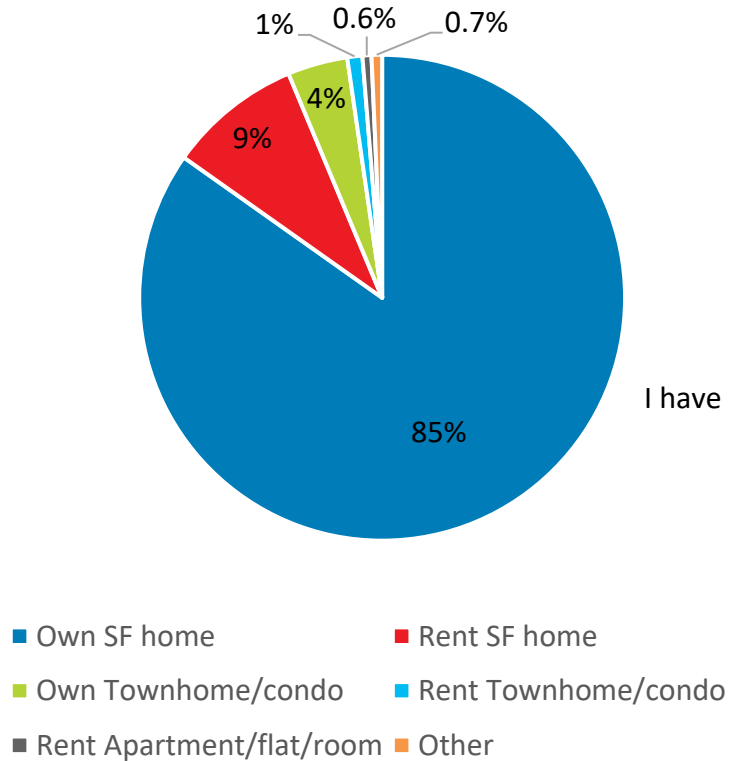


Evaluate a roof leasing program

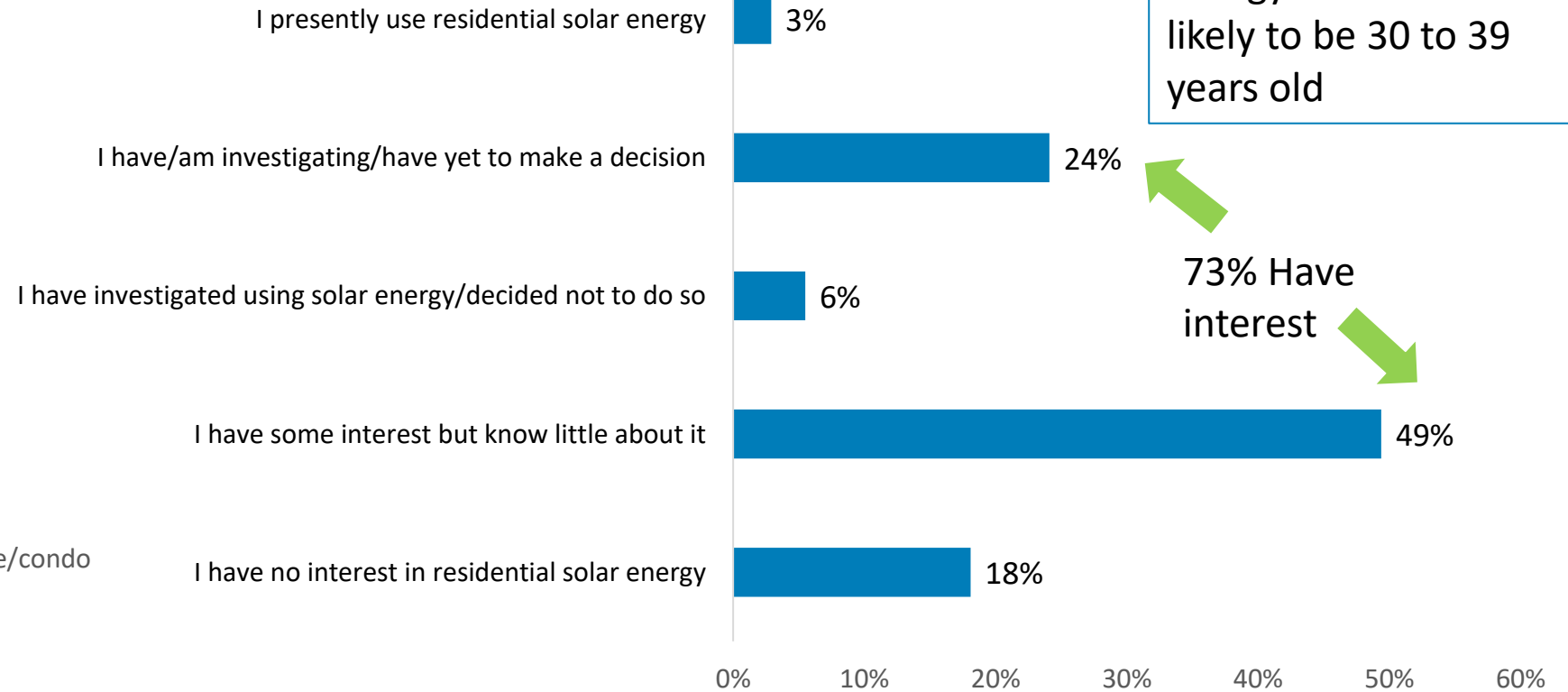
Detailed Findings **Single Family** **Home Residents**

Primary Residence & Residential Solar Energy Penetration/interest level

Primary Residence



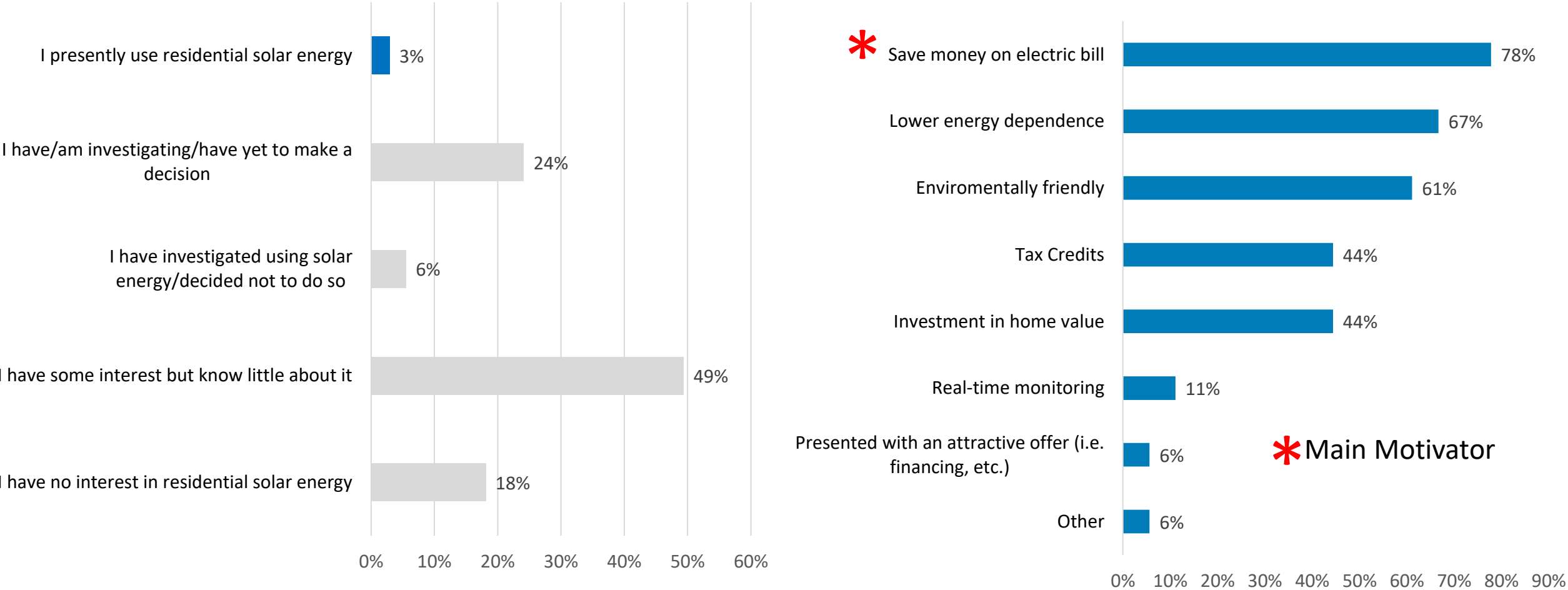
Solar Engagement



Which ONE of the following best describes your primary residence? (n=697)

Thinking specifically about residential solar energy, that being usage of solar energy by installing solar panels on your home or through participating in one of Georgia Power (GPC) solar programs, which ONE of the following best describes you? (n=652)

Presently use residential solar



Thinking specifically about residential solar energy, that being usage of solar energy by installing solar panels on your home or through participating in one of Georgia Power (GPC) solar programs, which ONE of the following best describes you? (n=652)

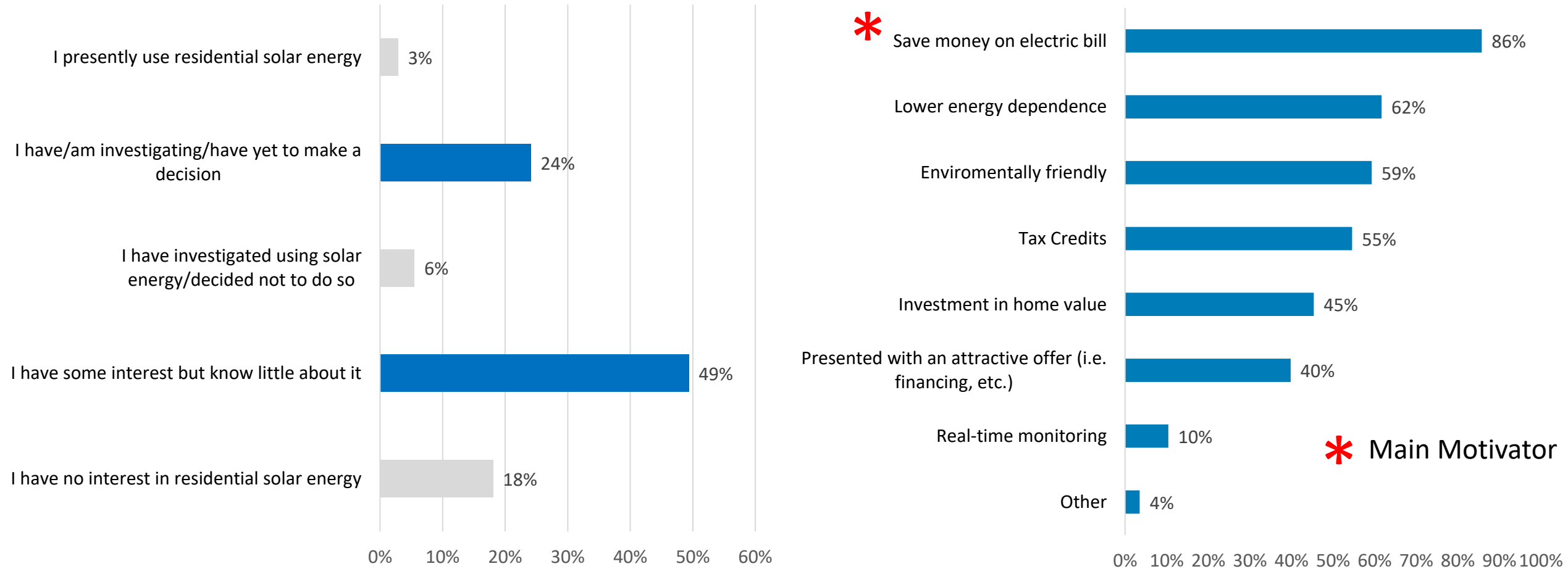
What was your motivation to install solar at your home? (Please select all that apply) (n=18)**

Of the factors that motivated you to install solar at your home, which one was the main motivator? (n=18)**

**Small sample size

060

Interested in solar-yet to make a decision/ know little about it

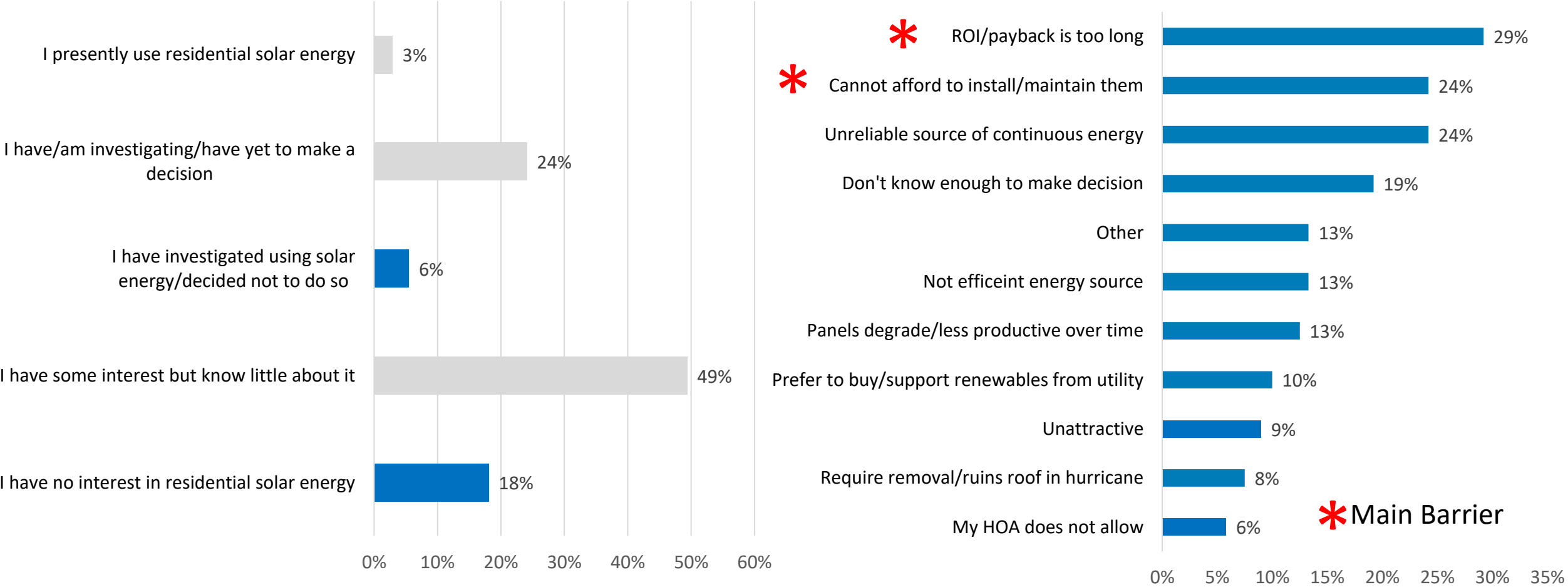


Thinking specifically about residential solar energy, that being usage of solar energy by installing solar panels on your home or through participating in one of Georgia Power (GPC) solar programs, which ONE of the following best describes you? (n=652)

What would be your motivation for installing solar at your home? (Please select all that apply) (n=452)

Of the factors that would motivate you to install solar at your home, which one is the main motivator? (n=443)

Decided not to use solar/not interested



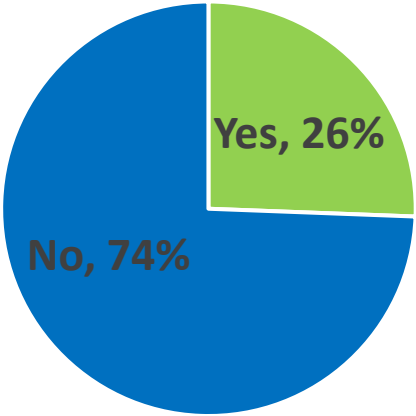
Thinking specifically about residential solar energy, that being usage of solar energy by installing solar panels on your home or through participating in one of Georgia Power (GPC) solar programs, which ONE of the following best describes you? (n=652)

Which of the following would you say are the main reasons you have not made the decision yet/are not interested in using residential solar energy? (Please select all that apply) (n=120)

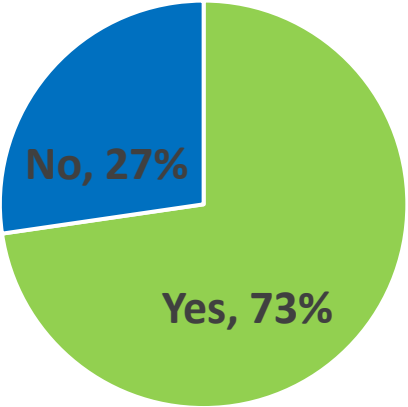
Of the reasons that prevented you from making a decision yet/deciding not to use solar energy, which one is the main reason? (n=120)

Additional Metrics

Approached by a 3rd-Party vendor?

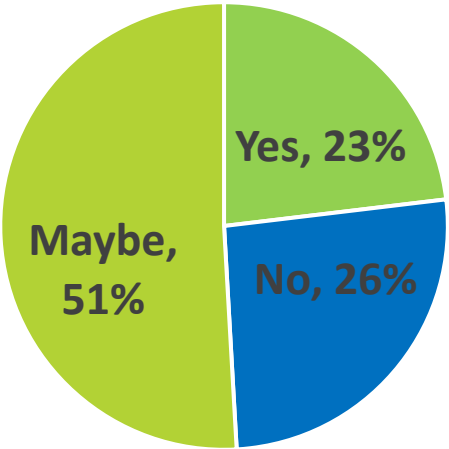


Did you/would you contact your electric utility before working with solar installer?



Installing solar/Impact to customers

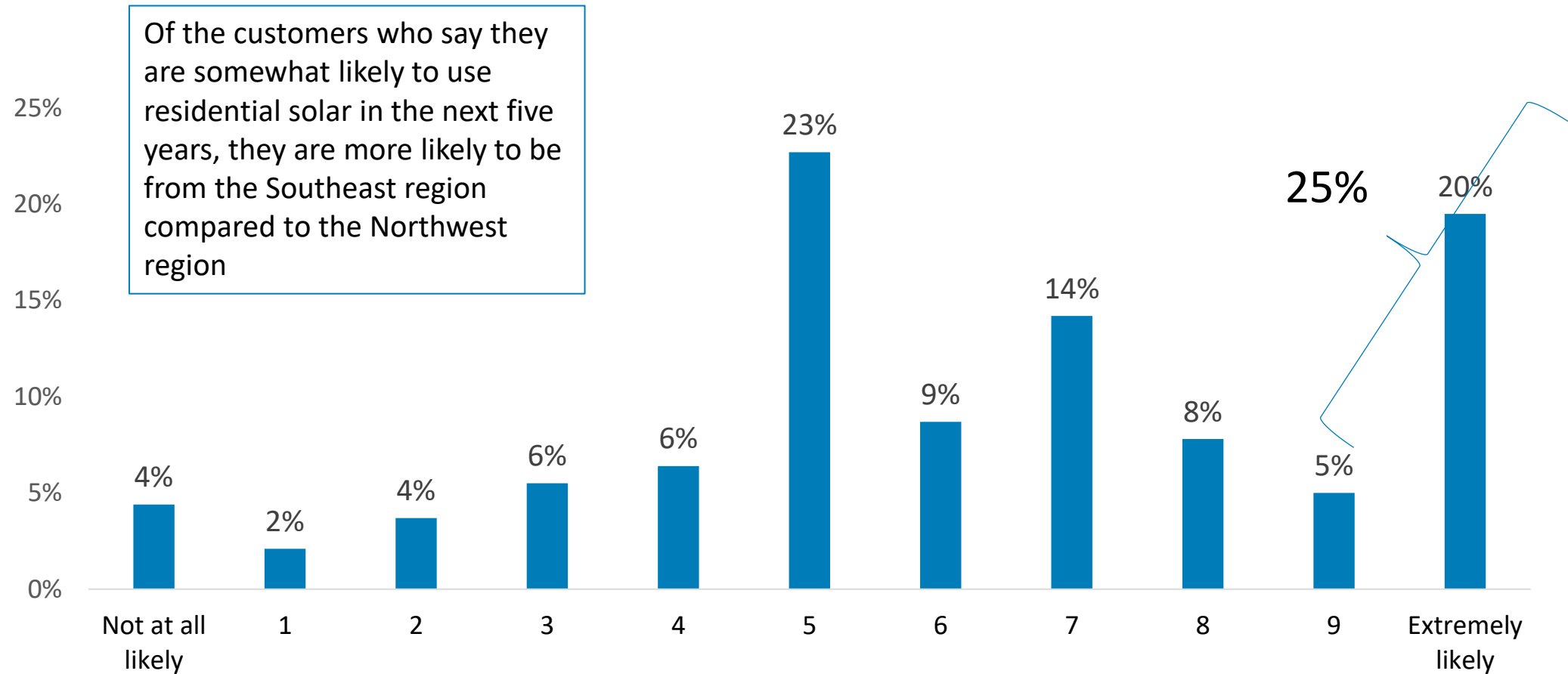
Customers who say **MAYBE** are more likely to say they are “**somewhat or very interested**” in leasing their roof to the utility for installation of a solar system.



Customers who say **NO** are more likely to say they are “**not at all interested**” in leasing their roof to the utility for installation of a solar system.

Have you ever been approached (i.e., called, emailed, someone knocked on your door) by a third-party solar vendor to install solar on your home? (n=583)
Did you/would you contact your electric utility before deciding to work with a third-party solar installer? (n=560)
If you were made aware that installing a solar system would negatively impact customers who do not have solar, would you still install solar? (n=554)

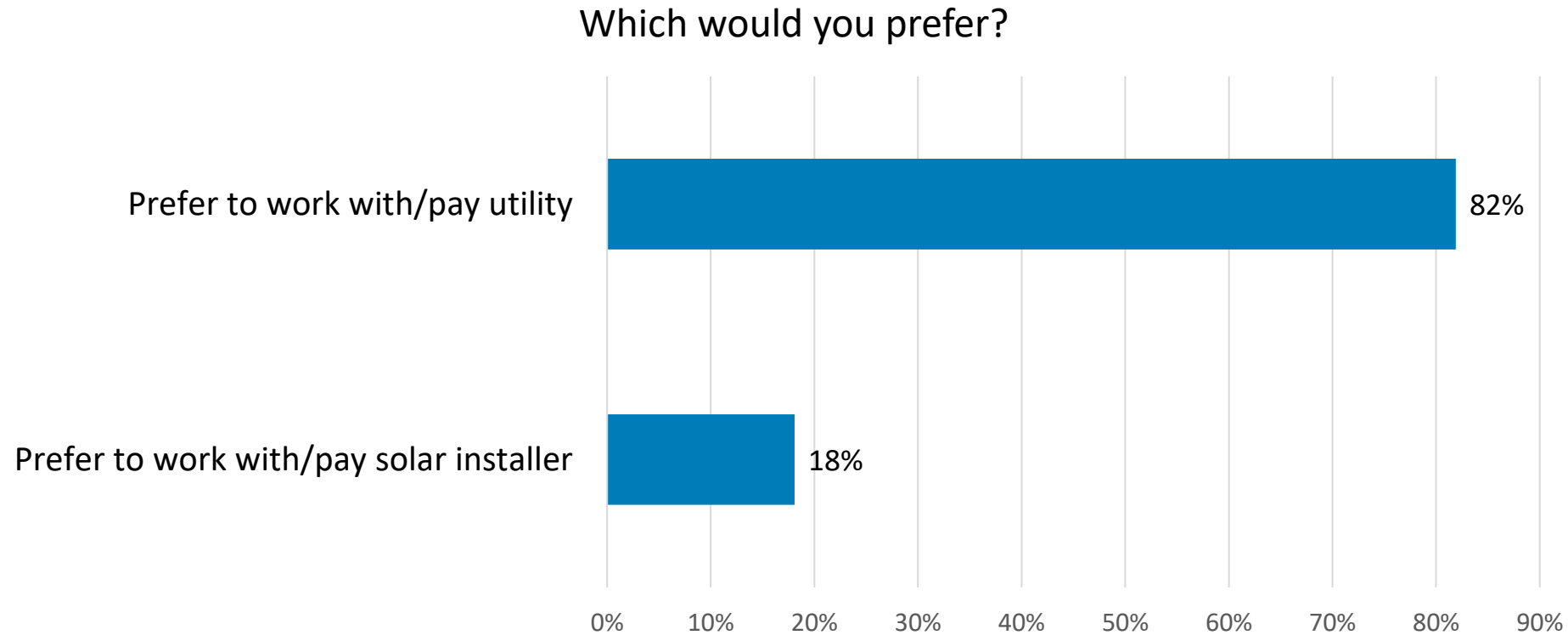
One-quarter say they are extremely likely to use residential solar energy within the next 5 years



Overall, based on everything you know and feel right now, how likely are you to use residential solar energy (either installing solar panels on your home or through one of GPC solar programs) within the next 5 years? (n=436)

Asked to those who have interest in solar energy but yet to make a decision or know little about it AND own/rent a single-family home

Most would prefer to work with/pay utility to install and maintain solar system

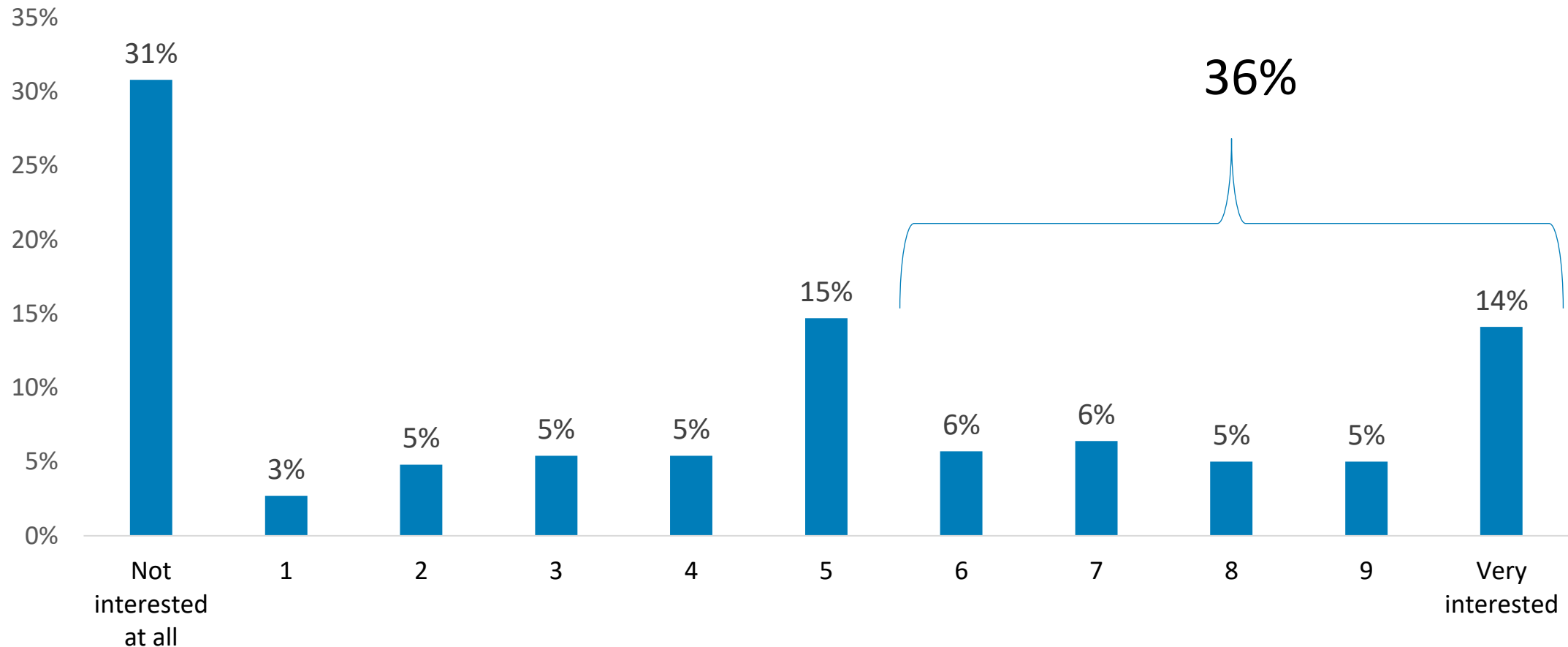


Which would you prefer? (n=315)

Asked to those who have interest in solar energy but yet to make a decision or know little about it AND are somewhat very likely to use solar in the next five years

Just over one-third are somewhat/very interested in allowing the utility to lease roof space to install a solar system

GASEIA SEIA Vote Solar Exhibit 2
Docket Nos. 44160 & 44161



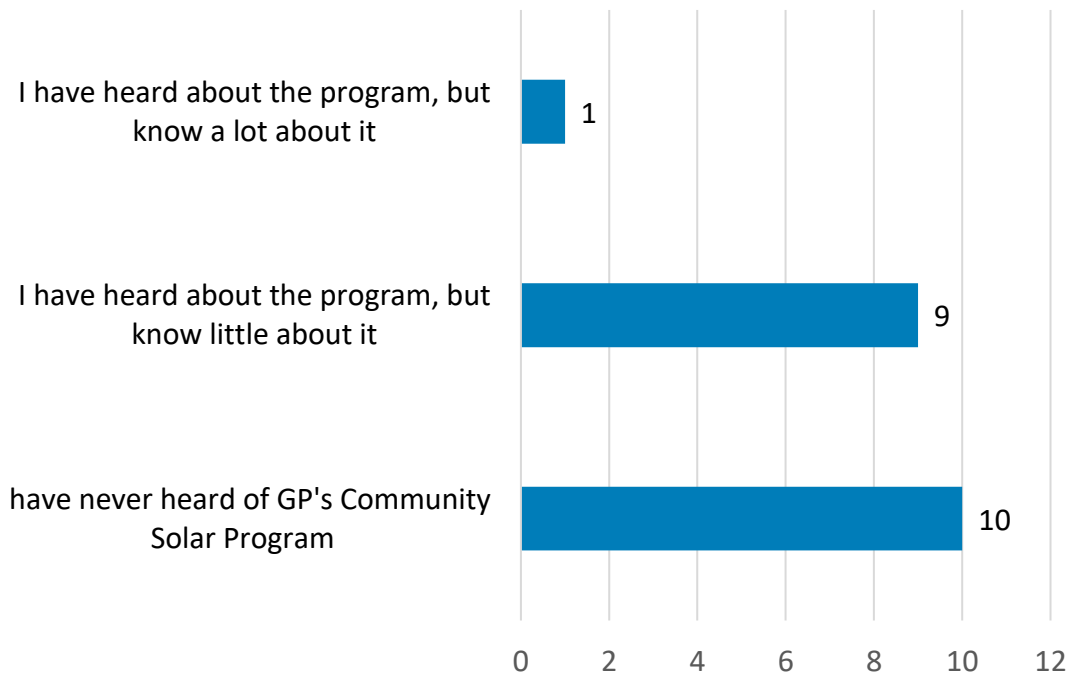
How interested would you be in allowing the utility company to lease your roof space to install a solar system? The energy produced from the solar system will go back to the grid and not offset your home's energy usage or lower your energy bill, however you would be compensated for leasing your roof. (n=559)

Detailed Findings **Non-Single** **Family Home** **Residents**

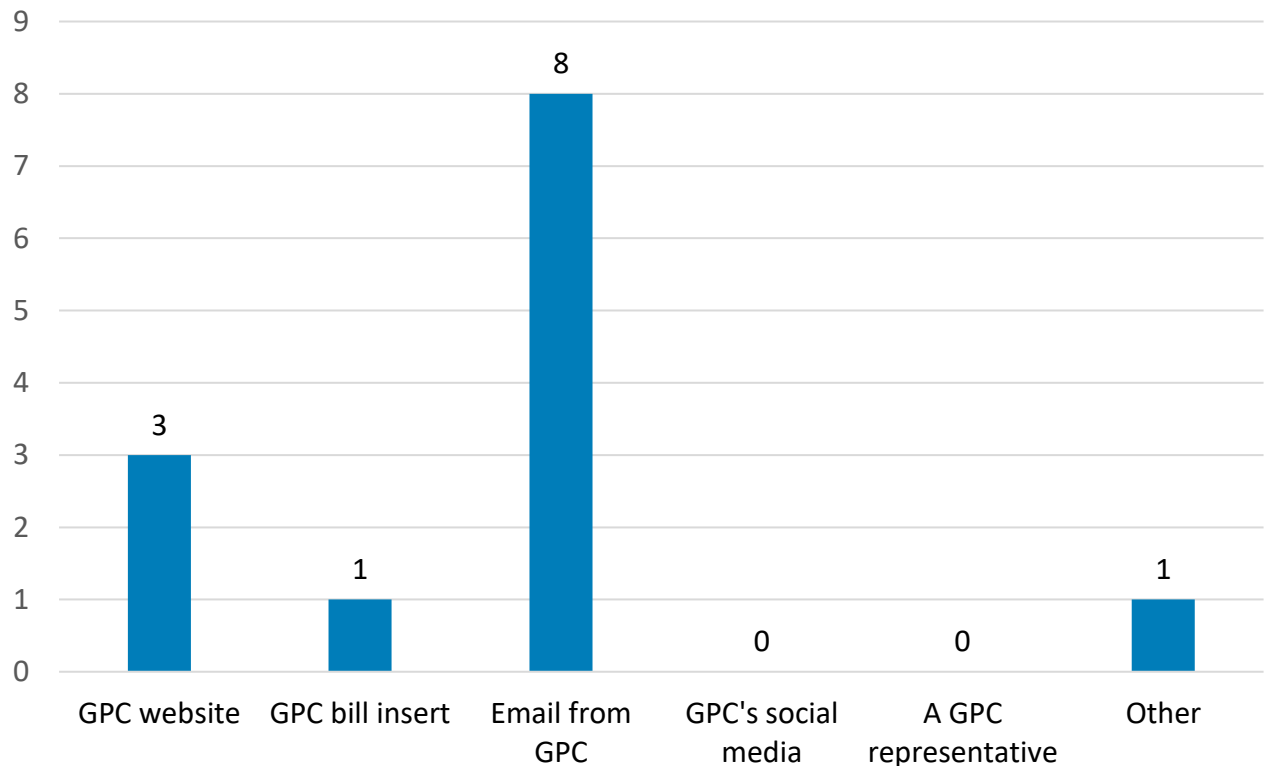
Community Solar

Due to the very small sample size, charts show actual customer numbers and not percentage of customers

Community Solar*



Communication Channel*



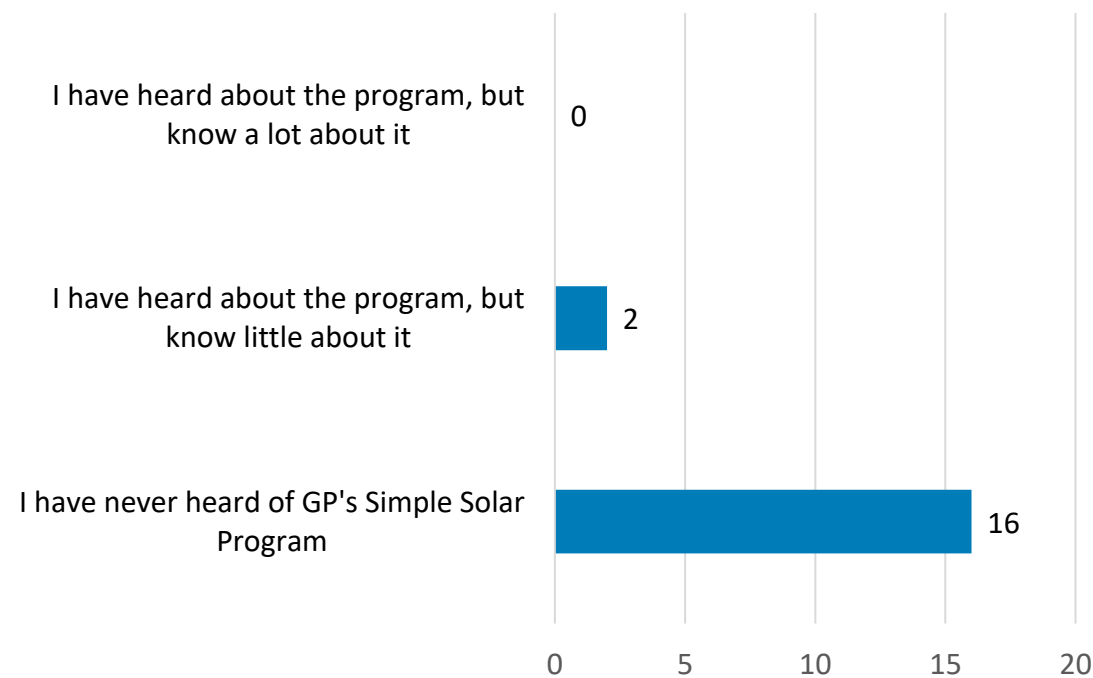
Have you ever heard of Georgia Power’s Community Solar Program? (n=20)*
Where have you heard about Georgia Power’s Community Solar Program? (Select all that apply) (n=9)*

*Small sample size

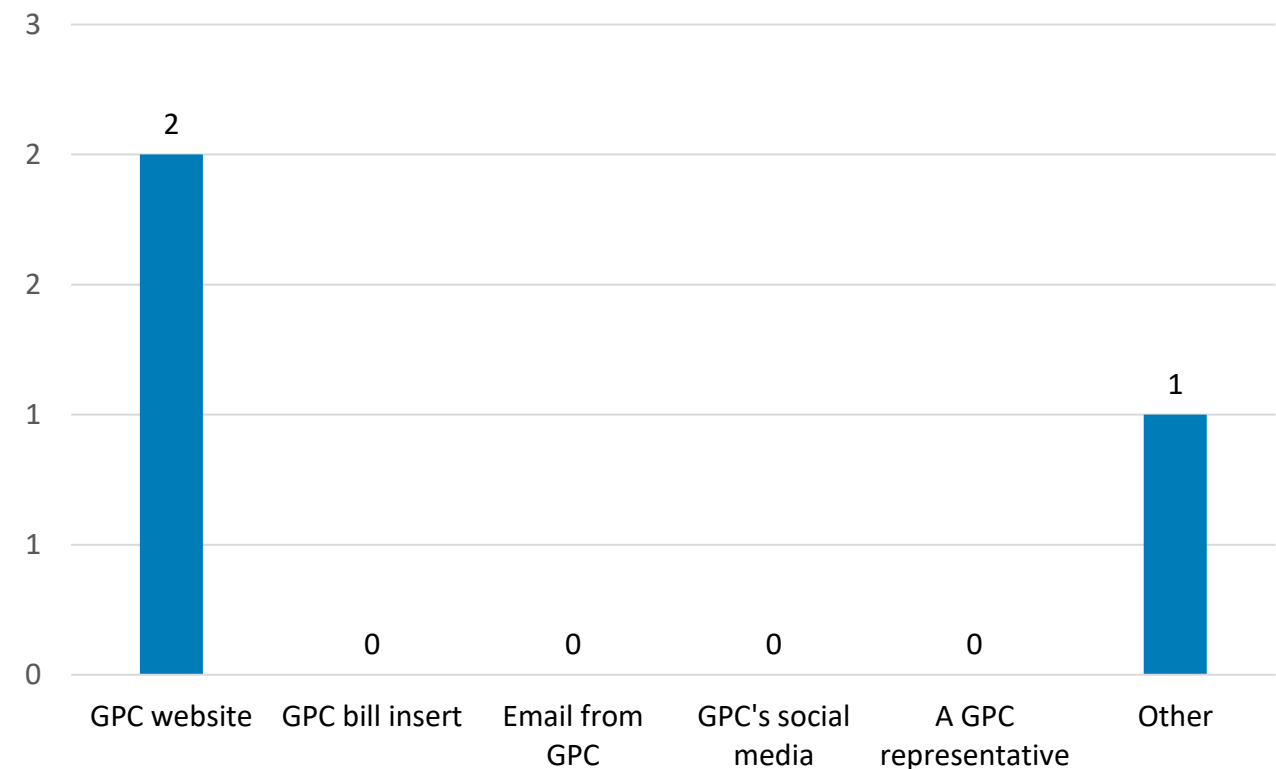
Simple Solar

Due to the very small sample size, charts show actual customer numbers and not percentage of customers

Simple Solar*



Communication Channel*

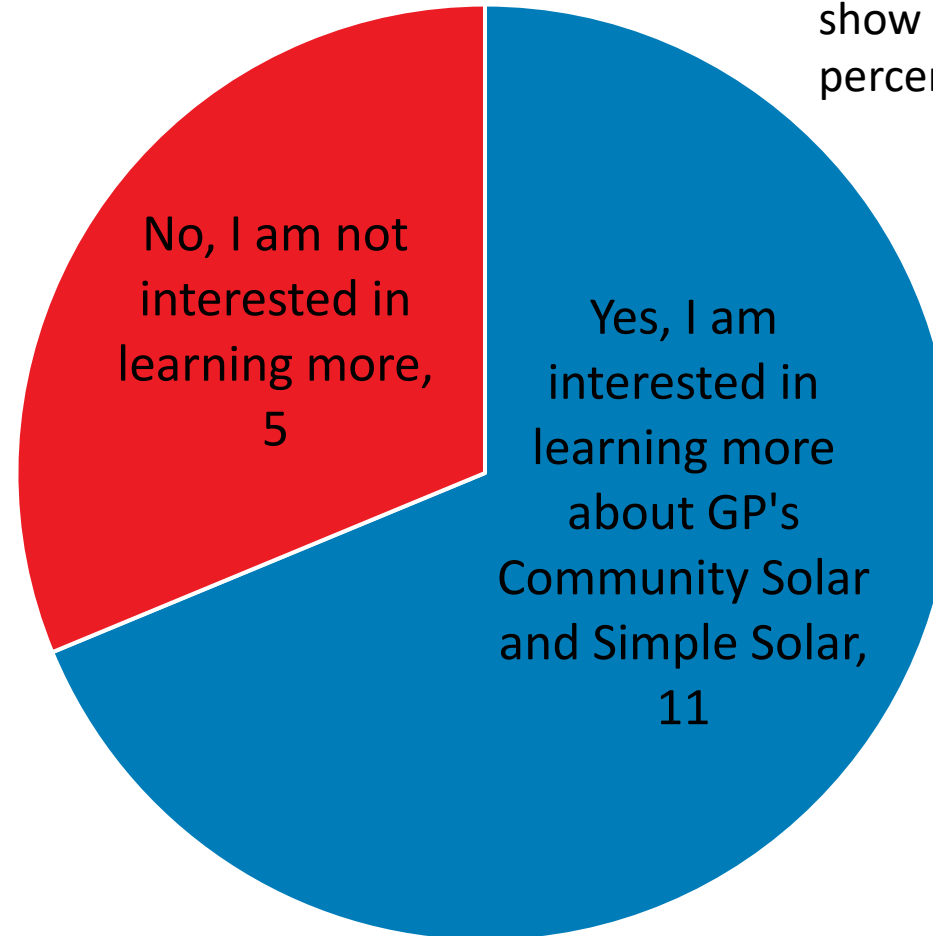


Have you ever heard of Georgia Power's Simple Solar Program? (n=18)*
Where have you heard about Georgia Power's Simple Solar Program? (Select all that apply) (n=2)*

*Small sample size

Interested in learning more...

Due to the very small sample size, charts show actual customer numbers and not percentage of customers



Would you be interested in learning more about Georgia Power's Community Solar and Simple Solar Program? (n=16)*

*Small sample size

Detailed Findings Comments

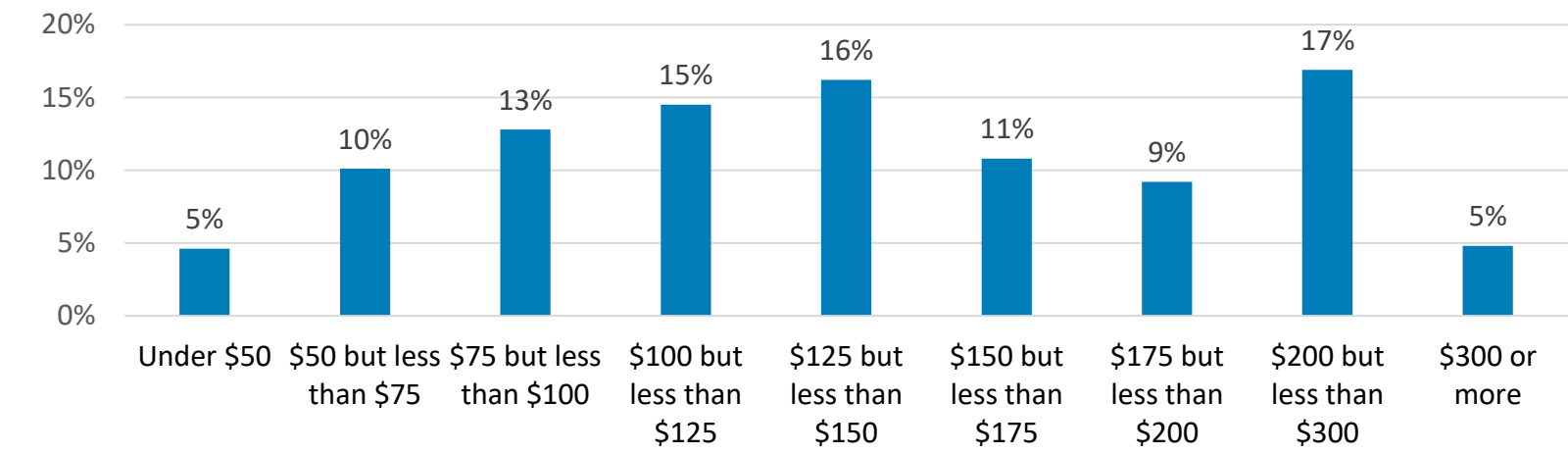
Comments

Any comments you would like to share with us? n=155	Count	Percent
Nothing	31	20%
Need more information	27	17%
Solar is moving in the right direction	18	12%
Interested in solar	16	10%
Too expensive/not cost effective	10	6%
HOA will not like/approve	9	6%
Solar not doable (i.e., tree coverage)	8	5%
Not interested in solar	7	5%
Prefer nuclear/hydro	6	4%
Renter	6	4%
Roof comment	4	3%
Distrust GPC	4	3%
Toxic/lifespan	4	3%
Currently use solar	3	2%
Solar not there yet	3	2%
Battery issues	2	1%
Condo	2	1%
Other	4	3%

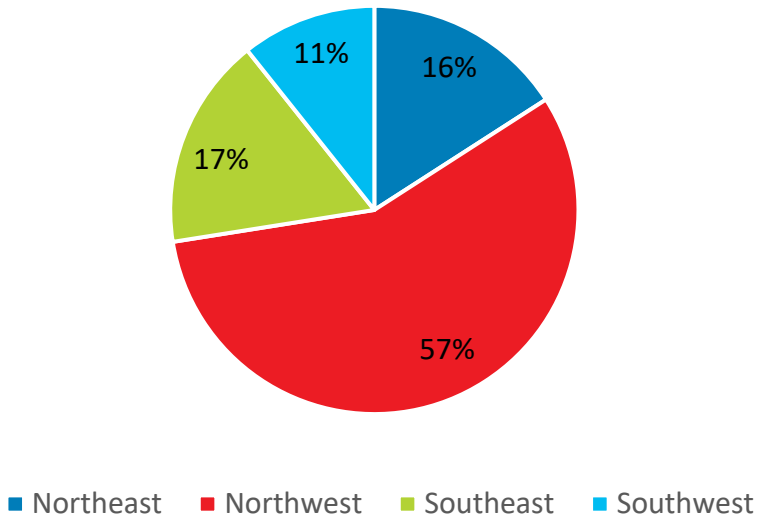
Detailed Findings Demographics

Demographics of Respondents

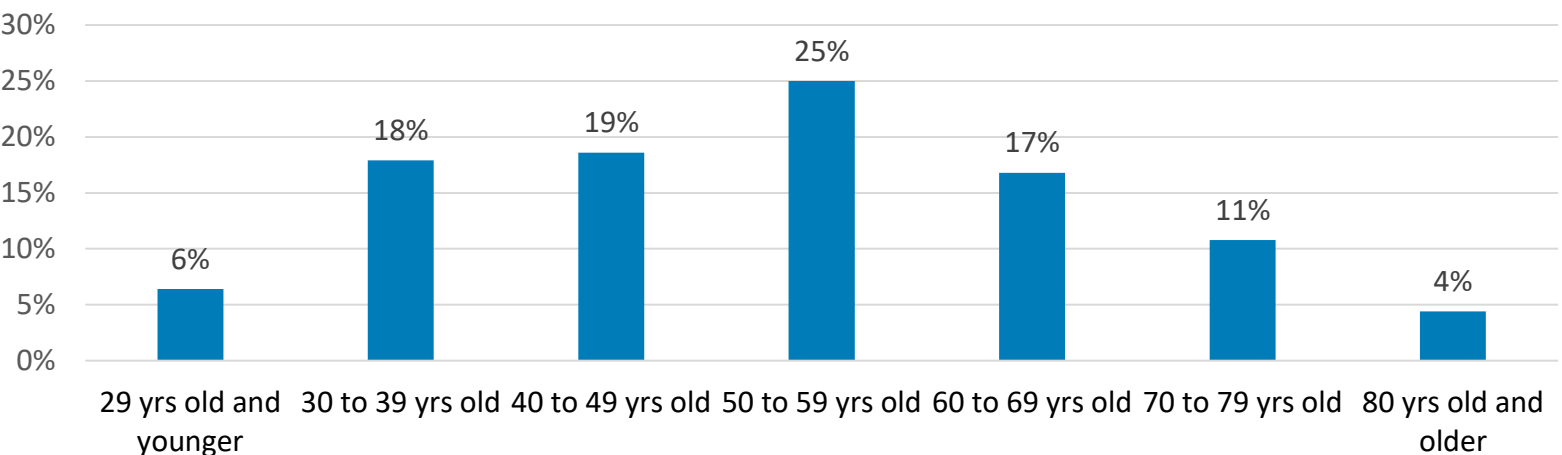
Average Annual Bill Amount



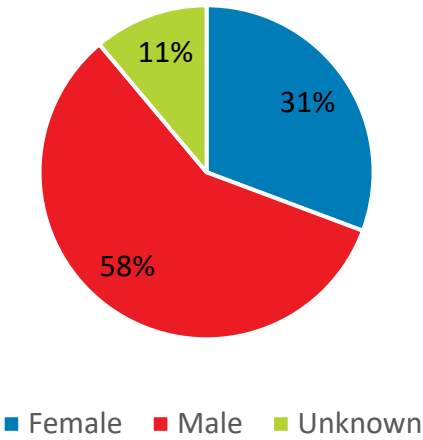
Region



Age

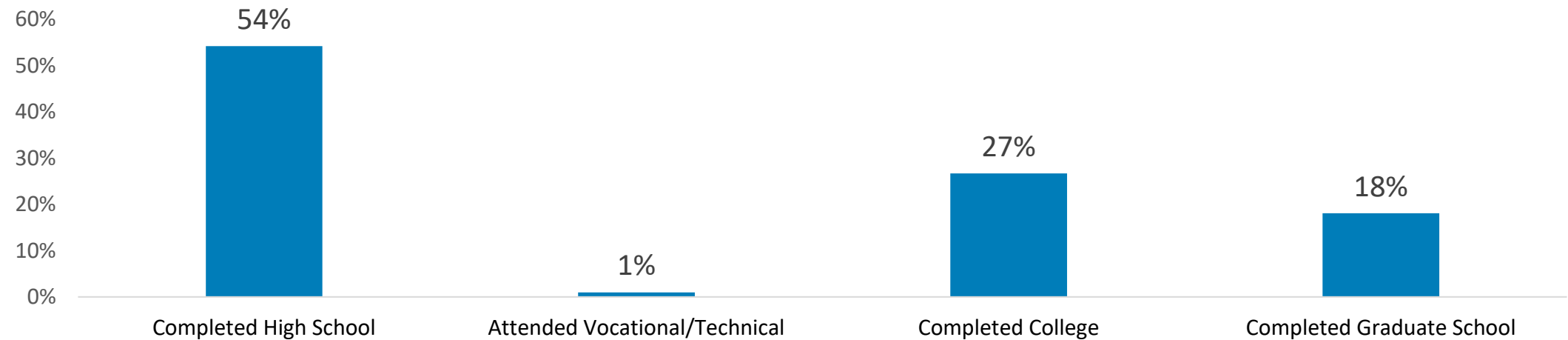


Gender

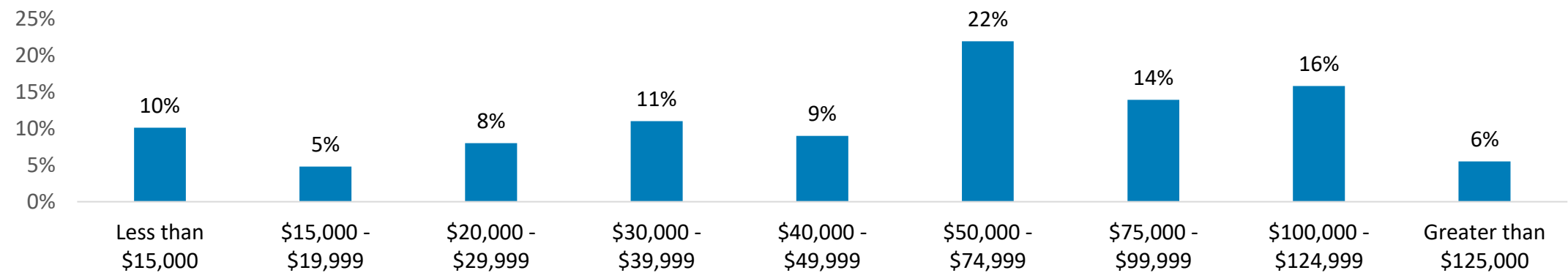


Demographics of Respondents

Education



Income



BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION
STATE OF GEORGIA

In Re:

Georgia Power Company's)
2022 Integrated Resource Plan) Docket No. 44160

Georgia Power Company's 2022)
Application for the Certification) Docket No. 44161
Decertification, and Amended)
Demand-Side Management Plan)

(VOLUME II)

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, April 5, 2022

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

PRESENT WERE :

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

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9 Atlanta, Georgia 30334

10 On behalf of Georgia Power Company:

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12 STEVEN HEWITSON, Esquire
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1	I N D E X				
2	WITNESSES:	DIRECT	CROSS	REDIRECT	RECROSS
3	Francisco Valle				
	Andy Phillips				
4	Jeffrey K. Smith				
	Lee Evans				
5	By Ms. Pryor	584	--	768	--
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6	By Mr. Davis	--	637	---	--
	By Mr. Galloway	--	--	---	--
7	By Mr. Prenovitz	--	--	---	--
	By Mr. Charles Jones	--	662	---	--
8	By Mr. Hubbard	--	--	---	--
	By Ms. Brown	--	666	---	--
9	By Ms. Kysor	--	680	---	--
	By Mr. Carver	--	--	---	--
10	By Mr. Thomasson	--	693	---	--
	By Ms. Coyle	--	698	---	--
11	By Mr. Carver	--	--	---	--
	By Mr. Fabish	--	725	---	--
12	By Mr. Baker	--	728	---	--
	By Mr. Jacob	--	--	---	--
13	By Mr. Mahan	--	--	---	--
14					
15	Mark S. Berry				
	Aaron D. Mitchell				
16	By Mr. Marzo	771	--	891	--
	By Mr. Thomas	--	816	---	--
17	By Mr. Davis	--	--	---	--
	By Mr. Galloway	--	--	---	--
18	By Mr. Prenovitz	--	--	---	--
	By Mr. Jones	--	--	---	--
19	By Mr. Hubbard	--	--	---	--
	By Ms. Brown	--	853	---	--
20	By Ms. Kysor	--	--	---	--
	By Mr. Carver	--	--	---	--
21	By Mr. Thomasson	--	--	---	--
	By Ms. Coyle	--	--	---	--
22	By Mr. Carver	--	--	---	--
	By Mr. Fabish	--	860	---	--
23	By Mr. Baker	--	874	---	--
	By Mr. Jacob	--	--	---	--
24	By Mr. Mahan	--	--	---	--
25					

1	EXHIBITS	FOR IDENTIFICATION	IN EVIDENCE
2	Georgia Power Company:		
3	2 - Amended 2022 application	586	586
4	for the certification,		
5	decertification, and amended		
6	demand-side management plan		
7	Staff:		
8	8 - STF-LA-4-4	844	852
9	Sierra Club:		
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P R O C E E D I N G S

MADAM CHAIR PRIDEMORE: Okay. Let's call to order Docket No. 44160 and Docket No. 44161: Georgia Power's 2022 application for approval of its integrated resource plan; Georgia Power's 2022 application for approval of its amended DSM plan and certification and decertification of certain DSM programs.

I have a long list of intervenors today. So let's call for appearances first.

Georgia Public Service Commission.

MR. THOMAS: Good morning. Preston Thomas, Alex Davis, and Dan Walsh with the Attorney General's Office on behalf of the Public Interest Advocacy Staff.

MADAM CHAIR PRIDEMORE: Georgia Power Company.

MS. PRYOR: Good morning. Allison Pryor, Steve Hewitson, and Brandon Marzo for Georgia Power Company.

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy.

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

MADAM CHAIR PRIDEMORE: Commercial Group.

(No response.)

1 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
2 for Georgia?

3 COMMISSIONER SHAW: It looks like he's not in
4 his chair.

5 MADAM CHAIR PRIDEMORE: I see. There you go.

6 COMMISSIONER SHAW: There he is.

7 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
8 for Georgia.

9 MR. PRENOVITZ: Steve Prenovitz, Concerned
10 Ratepayers for Georgia.

11 MADAM CHAIR PRIDEMORE: Thank you. You can
12 remute now, Mr. Prenovitz.

13 MR. PRENOVITZ: Yes, ma'am.

14 MADAM CHAIR PRIDEMORE: Cypress Creek
15 Renewables.

16 (No response.)

17 MR. GALLOWAY: Georgia Association of
18 Manufacturers.

19 MR. JONES: Clay Jones for GAM, Madam Chair.

20 MADAM CHAIR PRIDEMORE: Georgia Center for
21 Energy Solutions.

22 MR. HUBBARD: Madam Chair, Peter Hubbard for
23 GCES.

24 MR. GALLOWAY: Georgia Coalition of Local
25 Governments.

1 MS. BROWN: Alicia Brown for the Georgia
2 Coalition of Local Governments.

3 MADAM CHAIR PRIDEMORE: Georgia Interfaith
4 Power & Light and the Partnership for Southern
5 Equity.

6 MS. KYSOR: Good morning, Jill Kysor.

7 MADAM CHAIR PRIDEMORE: Georgia Large Scale
8 Solar Association and Advanced Power Alliance.

9 MR. CARVER: Good morning, Madam Chair. Brad
10 Carver on behalf of the APA and GLSSA. Thank you.

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

14 MR. THOMASSON: Madam Chair, Scott Thomasson
15 for Georgia SEIA, SEA, and Vote Solar.

16 MADAM CHAIR PRIDEMORE: Hello, Mr. Thomasson.
17 Okay. Georgia Solar Energy Association?
18 (No response.)

19 MADAM CHAIR PRIDEMORE: Georgia Watch.

20 MS. COYLE: Good morning. Liz Coyle on behalf
21 of Georgia Watch.

22 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

23 MR. CARVER: Brad Carver on behalf of
24 Interstate Gas Supply, along with Adam Wise.

25 MADAM CHAIR PRIDEMORE: Okay. Resource Supply

1 Management.

2 (No response.)

3 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
4 Coalition asked to be excused today.
5 Sierra Club.

6 MS. ARIZA: Good morning. Isabella Ariza and
7 Zach Fabish on behalf of Sierra Club.

8 MADAM CHAIR PRIDEMORE: Southern Alliance for
9 Clean Energy and Southface Energy Institute.

10 MR. BAKER: Good morning, Robert Baker.

11 MADAM CHAIR PRIDEMORE: Good morning,
12 Mr. Baker.
13 Southern Renewable Energy Association.

14 MR. MAHAN: Good morning. Simon Mahan for the
15 Southern Renewable Energy Association.

16 MADAM CHAIR PRIDEMORE: Okay. Do we have any
17 housekeeping matters to come before us before we get
18 started?

19 (No response.)

20 MADAM CHAIR PRIDEMORE: No.
21 Okay. Ms. Pryor, you want to swear in your
22 witnesses?

23 MS. PRYOR: Good morning. At this time I'd
24 like to call Georgia Power Company's next panel of
25 witnesses on direct; Mr. Valle, Mr. Phillips,

1 Mr. Smith, and Mr. Evans.

2 Gentlemen, please raise your right hands.

3 Thereupon,

4 Francisco Valle,
5 Andy Phillips,
6 Jeffrey K. Smith,
7 Lee Evans,
8 having been duly sworn, testified as follows:

9 DIRECT EXAMINATION

10 BY MS. PRYOR:

11 Q Mr. Valle, please start by stating your full
12 name, your employer, and your responsibilities for the
13 record.

14 A (Witness Valle) Sure. Good morning,
15 Commissioners. My name is Francisco Valle. I am the
16 director of market planning for Georgia Power. I'm
17 responsible for providing load forecast and economic
18 analysis.

19 Q And Mr. Phillips.

20 A (Witness Phillips) My name is Andy Phillips. I
21 manage the profitability and economic analysis team. My
22 team is responsible for the energy efficiency potential
23 study and calculating economics for the DSM portfolio.

24 Q Mr. Smith.

25 A (Witness Smith) Jeffrey Kyle Smith. I'm energy
efficiency -- excuse me, Commissioner. Energy efficiency
for Georgia Power. Our team is responsible for

1 designing, implementing, and evaluating energy efficiency
2 in residential demand response programs.

3 Q And Mr. Evans.

4 A (Witness Evans) Lee Evans. Costing and
5 demand-side support manager for Southern Company. I
6 provide economic and planning support for customer basic
7 programs.

8 Q Thank you.

9 Mr. Valle, on March 11th of this year, did you
10 file or cause to be prefiled 29 pages of direct testimony
11 in question-and-answer format in this case?

12 A (Witness Valle) Yes.

13 Q And are there any correction you need to make
14 to your prefiled testimony today?

15 A (Witness Valle) No, no corrections.

16 Q If I were to ask you the same questions today
17 under oath, would your answers be the same as are set
18 forth in your prefiled testimony?

19 A (Witness Valle) Yes.

20 MS. PRYOR: Chair Pridemore, at this time I
21 would like to identify for the record, Georgia Power
22 Company's application for the certification,
23 decertification, and amended demand-side management
24 plan as amended by errata filed on April 1st as
25 Exhibit GPC 2 and move Georgia Power Exhibit 2 into

1 the record, subject to cross-examination.

2 MADAM CHAIR PRIDEMORE: So moved.

3 The document referred to was marked for

4 identification as Exhibit GPC 2.)

5 MS. PRYOR: The court reporter has been

6 provided a copy of the prefiled direct testimony and

7 I now ask that the direct testimony of this panel be

8 copied into the record as if given here today.

9 MADAM CHAIR PRIDEMORE: So moved.

10 (Whereupon, the prefiled direct testimonies

11 of Mr. Valle, Mr. Phillips, Mr. Smith and Mr. Evans

12 follows:)

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STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	)	Docket No. 44160
2022 Integrated Resource Plan	)	

Georgia Power Company's	)	
2022 Application for the Certification,	)	Docket No. 44161
Decertification and Amended	)	
Demand-Side Management Plan	)	

DIRECT TESTIMONY OF
FRANCISCO VALLE, ANDY PHILLIPS, JEFFREY K. SMITH,
AND LEE EVANS

March 11, 2022

DIRECT TESTIMONY OF
FRANCISCO VALLE, ANDY PHILLIPS, JEFFREY K. SMITH,
AND LEE EVANS

IN SUPPORT OF GEORGIA POWER COMPANY’S

2022 INTEGRATED RESOURCE PLAN

GPSC DOCKET NO. 44160

AND

APPLICATION FOR THE CERTIFICATION, DECERTIFICATION AND
AMENDED DEMAND-SIDE MANAGEMENT PLAN

GPSC DOCKET NO. 44161

I. INTRODUCTION

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

2 A. My name is Francisco Valle. I am the Director of Market Planning for Georgia
3 Power Company (“Georgia Power” or the “Company”). My business address is 241
4 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

5 A. My name is Andy Phillips. I am the Profitability and Economic Analysis Manager
6 for Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E.,
7 Atlanta, Georgia 30308.

8 A. My name is Jeffrey K. Smith. I am the Manager of Energy Efficiency Strategy for
9 Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E.,
10 Atlanta, Georgia 30308.

Direct Testimony of Francisco Valle, Andy Phillips, Jeffrey K. Smith and Lee Evans
On Behalf of Georgia Power Company
Docket Nos. 44160 and 44161
Page 1 of 29

1 A. My name is Lee Evans. I am the Costing & Demand-side Support Manager for
2 Southern Company Services, Inc. ("SCS"). My business address is 241 Ralph
3 McGill Boulevard N.E., Atlanta, Georgia 30308.

4 **Q. MR. VALLE, PLEASE SUMMARIZE YOUR EDUCATION AND**
5 **PROFESSIONAL EXPERIENCE.**

6 A. I graduated from the Universidad Técnica Federico Santa María in Valparaíso,
7 Chile in 1997 with a degree in Electrical Civil Engineering. I also hold a Master of
8 Business Administration from Emory University's Goizueta Business School.

9 I joined Southern Company in 1997 as a planning analyst at Edelnor S.A., a
10 subsidiary of Southern Energy Inc., in Santiago, Chile. In 2001, I moved to Atlanta
11 to join Mirant Corporation where I held multiple roles of increasing responsibility
12 in system planning and market development and gained extensive experience
13 modeling power pools in the United States and valuing generation technologies and
14 demand response. Since then, I have worked at SouthStar Energy Services, a
15 subsidiary of Southern Company Gas, and served as the Manager of Risk Analysis
16 Services, a group hosted within the SCS Finance organization. In this role, I was
17 responsible for supporting the selection of optimal financing strategies for the
18 company's debt and equity portfolios and for providing business units with
19 quantitative analysis and risk mitigation strategies. I also supported Georgia Power
20 Market Planning by providing revenue, load forecasting, and risk analysis,
21 performed weather revenue variance analysis, reviewed features of load forecasting
22 models, and more.

23 I assumed my current position as Director of Market Planning in September of
24 2021. In this role, I am responsible for leading Georgia Power's Forecast and
25 Profitability & Economic Analysis teams. These teams produce, among other
26 things, our annual peak demand, energy, and revenue forecasts, as well as
27 profitability evaluations of demand side management programs.

1 **Q. MR. VALLE, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
2 **GEORGIA PUBLIC SERVICE COMMISSION?**

3 **A.** No. This is my first time testifying before the Georgia Public Service Commission
4 ("Commission").

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

7 **A.** I graduated in 1996 from the Georgia Institute of Technology with a Bachelor of
8 Science degree in Electrical Engineering. I also attended Emory University's
9 Goizueta Business School, where I graduated with a Master of Business
10 Administration in 2002. I began my career at Georgia Power in 1991 as part of the
11 Co-Operative Education Program. Since 1997, I have held several roles with
12 increasing responsibility in a variety of organizations including Distribution,
13 Customer Service, Sales, and Planning and Pricing. I managed the Company's
14 customer satisfaction programs from 2009 to 2012, served as a Key Accounts Team
15 Manager from 2012 to 2017, and managed four teams within the Sales Organization
16 as the Sales Support Manager from 2017 to 2018. In addition, I managed Georgia
17 Power's electrical transportation programs while serving as the Electrification
18 Manager from 2018 to 2019. I assumed my current role as the Profitability &
19 Economic Analysis Manager in 2019, where I am responsible for leading the
20 economic analysis in support of Georgia Power's energy efficiency programs.

21 **Q. MR. PHILLIPS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
22 **GEORGIA PUBLIC SERVICE COMMISSION?**

23 **A.** No. This is my first time testifying before the Commission.

1 **Q. MR. SMITH, PLEASE SUMMARIZE YOUR EDUCATION AND**
2 **PROFESSIONAL EXPERIENCE.**

3 A. I began my career with Georgia Power as a student intern in Customer Service and
4 Marketing in 1991. I attended Georgia State and Clayton State Universities,
5 graduating in 2001 with a Bachelor of Science degree focused on Environmental
6 Business and Geology. After joining the Company as a full-time employee in 1992,
7 I worked in various roles of increasing responsibility within the Marketing
8 Organization as a residential and small commercial energy auditor, energy
9 efficiency trainer, and eventually managing a group of energy experts. In 2006, I
10 transitioned to a team that worked with large commercial and industrial customers
11 performing advanced energy audits, process improvement audits, and detailed cost
12 comparisons.

13 In 2009, I worked as part of a team to develop the Energy Efficiency Organization
14 at Georgia Power, and served as Energy Efficiency Reporting, Development and
15 Evaluation Principal through 2013. From 2013 through 2016, I served as the
16 Residential Energy Efficiency Implementation Manager, leading the
17 implementation of Georgia Power's suite of residential energy efficiency and
18 demand response programs. In 2016, I assumed my current position of Manager of
19 Energy Efficiency Strategy for Georgia Power. I am a certified Business Energy
20 Professional, Demand Side Management Professional, Energy Auditor, Energy
21 Manager, and Sustainable Development Professional.

22 **Q. MR. SMITH, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
23 **GEORGIA PUBLIC SERVICE COMMISSION?**

24 A. No. I do, however, regularly engage with the Commission Staff and members of
25 the Demand Side Management Working Group ("DSMWG") during our quarterly
26 meetings.

1 **Q. MR. EVANS, PLEASE SUMMARIZE YOUR EDUCATION AND**
2 **PROFESSIONAL EXPERIENCE.**

3 A. I received a Bachelor of Science degree in Financial Management from Clemson
4 University in 2006 and a Master of Science degree in Finance from Georgia State
5 University in 2013. I have also served as an Adjunct Instructor of Finance for the
6 University of West Florida. I am a licensed Certified Public Accountant and a
7 member of the American Institute of Certified Public Accountants. I am also a
8 member and past chair of the Southeastern Electric Exchange's Rates and
9 Regulations committee and a member of the NERA Marginal Cost working group
10 and the Edison Electric Institute Rates and Regulatory Affairs committee.

11 I began my career with SCS in 2006 and worked in various roles within the
12 Accounting and Corporate Finance organizations. In 2011, I joined Gulf Power
13 Company ("Gulf Power") in revenue accounting. I later joined the Gulf Power
14 Regulatory and Cost Recovery organization, where I focused on rate design and
15 tracking for cost recovery clauses and the coordination of regulatory filings. In
16 2015, I became the Pricing, Costing & Load Research Supervisor, where I oversaw
17 the planning, implementation, and evaluation of retail electric prices. I also
18 supervised the planning and production of cost studies that serve as an input toward
19 pricing and the load research function. Prior to assuming my current role, I worked
20 as a Project Manager in Georgia Power's Pricing & Rates organization supporting
21 costing and pricing initiatives.

22 I assumed my current position as the SCS Costing & Demand-side Support
23 Manager in 2019. In my current role, I am responsible for planning and economic
24 analysis supporting demand-side initiatives and customer programs. I am also
25 responsible for developing and supporting marginal costing tools and regulated
26 cost-of-service studies.

1 **Q. MR. EVANS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
2 **GEORGIA PUBLIC SERVICE COMMISSION?**

3 A. No. This is my first time testifying before the Commission.

4 **Q. WHAT IS THE PURPOSE OF THIS PANEL’S TESTIMONY?**

5 A. The purpose of our testimony is to present additional information and support for
6 the Company’s 2022 Integrated Resource Plan (“IRP”) and 2022 Application for
7 the Certification, Decertification and Amended Demand Side Management Plan
8 (“DSM Application”) filed on January 31, 2022. We adopt the 2022 IRP and DSM
9 Application as part of our testimony.

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

11 A. The Company’s Budget 2022 Load and Energy Forecast (“Budget 2022”) provides
12 a twenty-year forecast of energy sales and peak demand to meet the planning needs
13 of Georgia Power. The major drivers of the load forecast, especially in the longer
14 term, are the economy and the penetration and efficiency trends in electric end uses.
15 Although the United States and Georgia both experienced solid economic growth
16 from 2013-2019, the onset of the COVID-19 pandemic in March 2020 caused a
17 short but deep recession that then sharply rebounded. The COVID-19 pandemic
18 significantly impacted Georgia Power’s retail sales as many individuals remained
19 at home in response to social distancing and isolation measures put in place during
20 the pandemic.

21 As Georgia continues to return to post-pandemic life, the state expects to return to
22 a period of healthy economic growth. As businesses continue to relocate and
23 expand in Georgia, employment growth and population growth will follow.
24 Georgia Power anticipates that total energy sales will grow at an average annual
25 rate of 0.8% from 2022 to 2041.

1 The continued implementation of demand-side programs remains an important
2 component of the 2022 IRP. In the 2022 DSM Application in Docket No. 44161,
3 the Company seeks certification of one new DSM program, a certificate
4 amendment for ten previously certified programs, decertification of two DSM
5 programs, a waiver of a Commission rule for one previously certified DSM
6 program, and Commission approval of certain other energy efficiency-related
7 activities. For all certified DSM programs, the Company is requesting an additional
8 sum equal to four cents for every kilowatt hour (“kWh”) saved using verified gross
9 energy savings in the first year of each certified program.

10 The proposed DSM programs were developed following a thorough evaluation
11 using the Commission’s approved processes and in collaboration with Commission
12 Staff and numerous interested parties. The Company projects that the proposed
13 DSM programs will result, on average, in approximately 113 megawatts (“MW”) of
14 demand reduction and 431 gigawatt hours (“GWh”) of energy reduction annually
15 for 2023-2025, based on the planned implementation levels. It is important to note
16 that due to lower avoided costs, many of the current DSM programs still appear
17 less favorable under the Total Resource Cost (“TRC”) and Rate Impact Measure
18 (“RIM”) tests when compared to the 2019 IRP. However, the Company believes
19 continuing these programs is beneficial in the current environment as customers are
20 responding favorably and market efficiencies can be achieved by maintaining a
21 presence in the marketplace.

22 In addition to addressing the aforementioned DSM programs, a key component of
23 this panel’s testimony pertains to dispatchable Distributed Energy Resources
24 (“DERs”). To leverage the resilience and reliability benefits that dispatchable
25 DERs can provide and meet a growing customer need, the Company seeks approval
26 in this IRP of its new tariff-based DER Customer Program. The DER Customer
27 Program will provide demand response value and corresponding System resilience
28 and reliability benefits for all customers and support commercial and industrial
29 customers with enhanced resiliency needs.

1 **II. LOAD AND ENERGY FORECASTS**

2 **Q. PLEASE SUMMARIZE GEORGIA POWER'S DEMAND AND ENERGY**
3 **FORECASTS THAT WERE FILED IN THE 2022 IRP.**

4 A. The Company developed a twenty-year forecast of energy sales and peak demand
5 to meet the planning needs of Georgia Power. Budget 2022 includes both a summer
6 and winter peak demand forecast for the retail classes of residential, commercial,
7 industrial, Metropolitan Atlanta Rapid Transit Authority (MARTA), and
8 governmental lighting. The energy and peak demand forecasts have been adjusted
9 for the effects of the DSM programs, cogeneration, behind-the-meter solar, and
10 electric vehicles. Additionally, the peak demand forecast is adjusted for the effects
11 of real time pricing customers' response to price signals.

12 **Q. WHAT ARE THE MAIN DRIVERS OF THE LOAD FORECAST?**

13 A. The main drivers of the load forecast are changes in the economy, including
14 customer growth and trends in electric end uses. Prior to the Great Recession of
15 2008, there was a closer relationship between economic growth and energy sales,
16 but this relationship has weakened in the last ten years due partly to improvements
17 in energy efficiency.

18 **Q. PLEASE DESCRIBE THE ECONOMIC GROWTH AND GEORGIA**
19 **POWER'S ENERGY SALES PRE-PANDEMIC.**

20 A. The United States and Georgia both experienced solid economic growth from 2013
21 through 2019. During this period, U.S. Gross Domestic Product growth averaged
22 2.5% per year, while Georgia's economy experienced growth of 3.3% per year. In
23 early 2020, the unemployment rate fell to 3.5% in the U.S. and 3.3% in Georgia.
24 However, the beginning of the Covid-19 pandemic in March of 2020 brought an
25 abrupt end to this period of economic growth, with a short but deep recession,
26 followed by a sharp rebound. Georgia lost more than 600,000 jobs from February
27 2020 through April 2020, and the unemployment rate jumped to 12.5%.

1 The COVID-19 pandemic significantly impacted Georgia Power's sales in 2020,
2 with April 2020's commercial and industrial sales falling approximately 13% and
3 18%, respectively, as compared to the prior year. Because social distancing and
4 isolation measures caused many people to remain in their homes, residential sales
5 increased by more than 8% in that same month. Total retail sales began to climb
6 later in 2020 as business began to reopen and people returned to their pre-pandemic
7 lives. At the end of 2020, retail sales were down 2.2% as compared to the prior
8 year. Residential sales ended the year up 3.4%, while the commercial and industrial
9 classes were down 5.3% and 4.5%, respectively. Although 2021 commercial sales
10 remained below 2019 levels, total retail sales for 2021 finished higher than pre-
11 pandemic levels due to growth in the residential and industrial classes.

12 **Q. WHAT IS GEORGIA POWER'S FORECAST FOR THE POST-**
13 **PANDEMIC ECONOMY?**

14 A. As Georgia continues to return to post-pandemic life, the state is expected to return
15 to a period of healthy economic growth. Georgia's low cost of doing business and
16 low cost of living, the deep pool of knowledge and technical workers coming from
17 its university system, its globally connected airport and transportation infrastructure
18 (e.g., ports and highways), and its business-friendly environment will continue to
19 attract businesses. As businesses continue to relocate and expand in Georgia, the
20 state will experience solid employment growth, which will attract new residents.
21 As a result, population growth will remain above the U.S. average.

22 As a result of additional businesses choosing to locate in Georgia and relatedly, a
23 growing population, Georgia Power anticipates a boost to energy sales. From 2022
24 to 2041, total energy sales are projected to grow at an average annual rate of 0.8%.
25 Residential sales are expected to grow by an average of 1.1% per year over this
26 period as customer growth outpaces the reduction in use-per-customer resulting
27 from energy efficiency. Industrial sales are expected to increase at an average
28 annual rate of 0.9%. Sales to the commercial class are expected to grow slightly

1 over this period by an average of 0.4% per year, due in part to increased energy
2 efficiency. Summer and winter peak demands are expected to increase at an average
3 rate of 0.7% per year during this period.

4 **Q. HOW HAS THE DIFFERENCE BETWEEN THE SUMMER AND WINTER**
5 **PEAK DEMANDS CHANGED?**

6 A. Over the past decade, especially following the Great Recession, the difference in
7 energy consumption in the winter and summer months has narrowed, causing
8 winter and summer peak demand projections to also narrow in consecutive
9 forecasts. Additionally, the growth in energy sales has slowed measurably since the
10 Great Recession. This decline in growth rates has been more pronounced in the
11 summer months than in the winter months, further driving the narrowing between
12 winter and summer peaks. In fact, since 2007, average annual growth in weather
13 normal energy sales in the month of January has been positive 0.3%, whereas
14 average annual growth in energy sales in July has been negative 0.3%. In the 15-
15 years prior to the Great Recession, both January and July energy sales grew at
16 approximately 2.5% annually on a weather normal basis. Tighter HVAC efficiency
17 standards over time have been a significant driver of the decline in energy use in
18 the summer months.

19 **III. DEMAND SIDE STRATEGY**

20 **Development of the DSM Portfolio**

21 **Q. PLEASE DESCRIBE HOW GEORGIA POWER'S CURRENT DSM**
22 **PORTFOLIO COMPARES TO ITS PROPOSED DSM PORTFOLIO.**

23 A. The Company is proposing to continue energy efficiency programs consistent with
24 the levels in the 2019 IRP. The Company's current DSM portfolio consists of
25 energy efficiency programs, demand response programs, pricing tariffs, and other
26 activities. The Company projects that by 2025, its current DSM portfolio will
27 represent approximately 1,500 MW, or approximately 9% of the Company's

1 current peak demand. In this 2022 IRP, the Company is proposing a DSM plan that
2 will result in an additional 431 GWh of annual energy savings and 113 MW of peak
3 demand savings for the years 2023 - 2025.

4 **Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE PROPOSED DSM**
5 **PLAN.**

6 **A.** In accordance with the 2019 IRP Order, the Company continued to work with the
7 DSMWG, including Commission Staff, and followed the DSM Program Planning
8 Approach. The Company retained third-party consultants to assist with the
9 planning, implementation, and evaluation of the DSM programs certified in the
10 Commission's 2019 IRP Order. The Company completed a Technical Reference
11 Manual in December 2020 and completed and filed the Achievable Energy
12 Efficiency Potential Assessment in February 2021 in Docket No. 43030. In October
13 2021, the Company filed Process and Impact Evaluation result reports for the DSM
14 programs currently certified.

15 The Company continues to follow the Commission's economic screening policy
16 outlined in the 2004 IRP Final Order in Docket No. 17687, which directs that the
17 proposed DSM plans minimize upward pressure on rates and maximize economic
18 efficiency. The Company evaluates the impact of its DSM programs on rates
19 through the RIM Test and determines the economic efficiency of its DSM programs
20 using the TRC Test. As demonstrated through the Company's planning processes,
21 DSM is given priority and reduces the Company's energy and demand forecast
22 before supply-side alternatives are considered. The Company followed the DSM
23 Program Planning Approach in developing its proposed DSM plan. The DSM
24 Program Plans included in the DSM Application represent a well-balanced
25 portfolio of residential and commercial DSM programs that are structured to help
26 customers reduce and better manage their energy usage.

1 **Q. DOES THE PLANNING PROCESS THAT THE COMPANY USED TO**
2 **DEVELOP THE PROGRAMS FOR THIS FILING SATISFY THE**
3 **COMMISSION’S DSM EVALUATION RULE?**

4 A. Yes. Completion of the DSM Program Planning Approach, including the filing of
5 the Achievable Energy Efficiency Potentials Assessment and the development of
6 the DSM Aggressive Case, satisfies the requirements of Commission Rule 515-3-
7 4-.04(4).

8 **Q. WHAT ASSISTANCE DID THE DSMWG PROVIDE IN THIS PROCESS?**

9 A. The Company met with the DSMWG eight times in 2020 and 2021 and engaged
10 with the DSMWG in an effort to collaboratively develop program concepts for the
11 2022 IRP. The Company also met with a subset of the DSMWG to assist with DSM
12 program ideation. The DSMWG provided feedback on the Achievable Energy
13 Efficiency Potential Assessment, the Technical Reference Manual, and the
14 measures and programs being evaluated. The Company shared the results of the
15 economic screening with the DSMWG and incorporated several proposed
16 suggestions within the Company’s Proposed Case.

17 **Q. WHAT PROGRAM EVALUATION WAS CONDUCTED FOR THE**
18 **PROGRAMS CERTIFIED BY THE COMMISSION IN THE 2019 DSM**
19 **APPLICATION?**

20 A. In accordance with the 2019 IRP Order, the Company provided Commission Staff
21 with detailed evaluation plans for each of the certified DSM programs to solicit
22 feedback on the proposed evaluation plans in advance of the evaluations
23 themselves. The Company selected BrightLine and Illume to perform the program
24 evaluations. Program evaluations were completed and shared with Commission
25 Staff on October 29, 2021. The results of the program evaluations were then
26 considered in the development of the 2022 IRP and applied to the program plans
27 included in the DSM Application.

1 **Q. WHAT SPECIFIC APPROVALS IS THE COMPANY SEEKING IN THIS**
2 **CASE?**

3 A. In Docket No. 44161, the Company seeks Commission approval of a certificate of
4 public convenience and necessity for one new DSM program, an amendment to the
5 certificate for ten previously certified DSM programs, decertification of two DSM
6 programs, the requested waiver of the TRC requirement within Commission Rule
7 515-3-4-.04(4)(a)(3) for the Residential Thermostat Demand Response (“TSTAT
8 DR”) program, and a revised Additional Sum calculation methodology, as detailed
9 further in the Company’s 2022 DSM Application. The Company also intends to
10 continue the Residential Investment for Saving Energy (“RISE”) pilot approved in
11 the 2019 IRP, as well as the Company’s Education and Energy Efficiency
12 Awareness initiatives. Consistent with the 2019 IRP Order, the Company seeks
13 Commission approval of a budget for pilot studies, which are used to better
14 understand emerging energy efficiency options for customers.

15 **The DSM Programs**

16 **Q. PLEASE DESCRIBE THE RESIDENTIAL HOPEWORKS PROGRAM**
17 **THAT THE COMPANY SEEKS TO CERTIFY.**

18 A. HopeWorks is an existing, non-certified program that has been in place for many
19 years. In this IRP, Georgia Power seeks to increase financial support for the
20 program and to certify the program. This program aims to promote energy
21 efficiency improvements in existing single-family homes primarily owned by
22 income-qualified seniors. Georgia Power will work with community partners and
23 local nonprofits to identify, assess, and implement projects. The HopeWorks
24 program will offer direct installation of energy efficiency measures for income-
25 qualified single-family properties. Eligible energy efficiency measures include, but
26 are not limited to, smart thermostats, efficient lighting, air and duct sealing, attic
27 insulation, and HVAC system servicing and repairs. Georgia Power will provide

1 eligible customers with up to \$3,750 of energy efficiency improvements to their
2 home to offset the cost of the energy efficiency improvements.

3 **Q. PLEASE DESCRIBE WHY THE COMPANY SEEKS TO DECERTIFY**
4 **THE RESIDENTIAL POWER CREDIT PROGRAM.**

5 A. The Company requests decertification of the Residential Power Credit program due
6 to the limited scope and effectiveness of the program as compared to the Residential
7 TSTAT-DR Program. The HVAC control equipment under the Power Credit
8 Program is less reliable than the equipment that serves the TSTAT-DR Program.
9 Further, the Power Credit program served only summer peak events, whereas the
10 TSTAT-DR program focuses on the transition to winter and summer peak seasons.
11 As a result of its declining effectiveness, Georgia Power requests decertification of
12 the Power Credit Program.

13 **Q. PLEASE DESCRIBE WHY THE COMPANY SEEKS A WAIVER OF**
14 **COMMISSION RULE 515-3-4-.04(4)(a)(3) FOR THE RESIDENTIAL**
15 **TSTAT-DR PROGRAM?**

16 A. Although the TSTAT-DR program does not reflect positive TRC results for the
17 2022 IRP cycle, as it has in prior cycles, it is nevertheless expected to reflect
18 positive TRC results in 2031. As such, considering the demand response value this
19 program provides, the Company requests a waiver of the TRC requirement in
20 Commission Rule 515-3-4-.04(4)(a)(3) so that it may continue offering this
21 program.

22 **Q. PLEASE DESCRIBE WHY THE COMPANY SEEKS TO DECERTIFY**
23 **THE COMMERCIAL MIDSTREAM PROGRAM.**

24 A. The Company requests decertification of the Commercial Midstream program due
25 to market transformation with the program's distributors during the current IRP
26 cycle. Because the market has matured, evaluations of the Commercial Midstream
27 program indicate that participation in the program leads to high levels of free

ridership and that additional incentives are not necessary. However, several of the measures that were included in the Commercial Midstream program were still deemed viable, and those have been moved to the Commercial Prescriptive program.

Q. FOR WHICH PROGRAMS IS THE COMPANY REQUESTING AMENDMENTS TO PROGRAM CERTIFICATES?

A. Georgia Power is requesting to amend the certificates of the following programs: Residential Behavioral; Residential Home Energy Improvement; Residential Refrigerator/Freezer Recycling; Residential Specialty Lighting; Residential Home Energy Efficiency Assistance; Residential TSTAT-DR; Commercial Custom; Commercial Prescriptive; Commercial Small Commercial Direct Install; and Commercial Behavioral.

Evaluation and Impact of DSM Programs

Q. WHAT IMPACTS ARE THE COMPANY'S PORTFOLIO OF PROPOSED DSM PROGRAMS EXPECTED TO HAVE ON PEAK DEMAND AND ENERGY USAGE?

A. The Company projects that its proposed energy efficiency programs will result, on average, in approximately 113 MW of peak demand reduction and 431 GWh of energy reductions annually for 2023-2025, based on the planned implementation levels.

Q. WHAT IS THE IMPLEMENTATION SCHEDULE FOR THE DSM PROGRAMS DESCRIBED IN YOUR TESTIMONY?

A. If the Commission approves the DSM Application, the Company will finalize its plans for implementing these DSM programs during the last six months of 2022. This process will include continuation of existing programs, modifications of existing programs, and start-up activities for new programs, such as infrastructure

1 refinement and contracting with third-party vendors, where applicable. Barring any
2 unforeseen issues, the Company will begin promoting these programs to customers
3 during the first quarter of 2023.

4 **Q. HOW WILL GEORGIA POWER MEASURE THE SUCCESS OF THE**
5 **THESE DSM PROGRAMS?**

6 A. The Company will track program performance and progress toward achieving
7 established goals on an ongoing basis. In addition, Georgia Power will contract with
8 independent, third-party evaluators through a Request for Proposals solicitation to
9 conduct comprehensive program evaluations at regular intervals (initially planned
10 for three-year intervals). The evaluations will include market, process, and impact
11 evaluations to review the program's operations, evaluate the program's impact on
12 the local market, and verify the energy and demand savings produced by the
13 program. The Company will begin implementing evaluation results and applying
14 deemed savings to the new program cycle beginning in January 2026 to be
15 consistent with the Company's three-year IRP and DSM planning cycles.

16 **Q. PLEASE DESCRIBE THE COST-EFFECTIVENESS OF THE PROPOSED**
17 **DSM PROGRAMS.**

18 A. For years 2023 through 2025, the DSM programs in the Company's Proposed Case
19 will average approximately \$78 - \$103 million in TRC benefits, while putting
20 upward pressure on rates of approximately \$264 - \$283 million annually. Relative
21 to the 2019 IRP economic test results, the TRC Test results declined and RIM Test
22 results remain negative for the Company's Proposed Case. For comparison, in the
23 2019 IRP, the Company's Proposed Case averaged approximately \$118 million in
24 TRC benefits while putting upward pressure on rates of approximately \$238 million
25 annually for years 2019 through 2022. Notwithstanding the declining TRC benefits,
26 the Company is proposing to continue energy efficiency programs consistent with
27 the levels in the 2019 IRP.

1 **Q. WHAT IS THE PRIMARY CAUSE OF DECLINING DSM PROGRAM**
2 **ECONOMICS?**

3 A. The declining program economics and benefits from the Company's DSM portfolio
4 reflects a declining avoided cost due to three main drivers: (1) lower forecasted
5 natural gas prices; (2) modest load growth; and (3) an increase in renewable
6 resources. The overall decline in the cost of natural gas has reduced the marginal
7 cost of generating electricity. The lower cost of natural gas not only saves
8 customers money, but also lowers the Company's avoided cost. With these lower
9 avoided costs, the value of each kWh saved through DSM participation has
10 declined. These changes in avoided cost savings have a negative impact on the
11 economics of the Company's current and proposed DSM programs.

12 **Q. WHY IS THE COMPANY CONCERNED WITH THE DECLINING TRC**
13 **TEST RESULTS AND THE NEGATIVE RIM TEST RESULTS?**

14 A. The Company continues to follow the Commission's policy outlined in the 2004
15 IRP Order, Docket No. 17687, which requires the Company to offer a DSM plan
16 that minimizes upward pressure on rates and maximizes economic efficiency. This
17 Commission policy has been affirmed by the Commission in each IRP since 2004.
18 The Company used this same philosophy in analyzing the slate of programs
19 considered for certification in the 2022 DSM Application and the 2022 IRP. As the
20 benefits from these programs decline and the cost in terms of rate impact increases,
21 it becomes more challenging to maintain that balance.

22 **Q. DID THE COMPANY CONSIDER THE POTENTIAL IMPACT OF A**
23 **COST OF CARBON WITH RESPECT TO ITS DSM ECONOMIC**
24 **ANALYSIS?**

25 A. Yes, the Company considered the potential impact associated with a cost of carbon
26 in its DSM program economic analysis. The Company's DSM program economic
27 analysis includes an evaluation of the moderate-gas, twenty-dollar ("MG20")

1 scenario. For the 2022 IRP, the Company used the MG20 scenario to provide an
2 additional sensitivity in its evaluation based on the potential that evolving carbon
3 policy could impact its future resource planning decisions. The Company did not
4 make any decisions in this case based on the MG20 planning scenario since the
5 sensitivity was informational in nature.

6 **DSM Pilot Programs & Awareness Initiatives**

7 **Q. IS THE COMPANY PROPOSING ANY PILOT PROGRAMS IN THIS IRP?**

8 A. Yes. The Company is seeking Commission approval to extend the RISE Pilot
9 through the 2022 IRP cycle. In addition, and similar to the Company's request in
10 the 2019 IRP, the Company seeks Commission approval to continue a residential
11 and commercial pilot budget to develop and evaluate pilot projects. DSM pilots
12 allow the Company to gather valuable information to aid in the examination of new
13 technologies and additional ways to enhance and deliver energy efficiency
14 programs to customers. Conducting small scale pilots allows the Company to test a
15 program in a controlled environment with limited financial or customer satisfaction
16 risks. The knowledge gained through pilots allows the Company to get programs
17 up and running quickly and smoothly when they are approved for certification.

18 **Q. PLEASE DESCRIBE THE RISE PILOT.**

19 A. The Company proposes to continue offering the RISE pilot (previously approved
20 as the Income-Qualified Tariff-Based Financing pilot), as a non-certified pilot
21 program that focuses on income-qualified households that are historically under-
22 represented in energy efficiency program participation. Upfront cost is one of the
23 reasons income-qualified customers typically do not participate in energy
24 efficiency programs. The RISE pilot is intended to reach 500 income-qualified
25 residential customers in select energy burdened areas of the state, with the goal of
26 saving up to 25% of the baseline household electric energy usage with the
27 Company's investment in energy efficiency upgrades not to exceed an average cost

1 of \$7,500 per household. The Company proposes to maintain the eligibility criteria
2 and the intended number of residential customers that were previously approved in
3 the 2019 IRP.

4 **Q. WHY IS THE COMPANY PROPOSING TO CONTINUE THIS PROGRAM**
5 **AS A PILOT RATHER THAN A FULL-FLEDGED PROGRAM?**

6 A. Due to the COVID-19 pandemic and social distancing restrictions, the Company
7 curtailed its rollout of this pilot as originally planned. In addition, Georgia Power
8 is the only utility in the country specifically implementing this type of program for
9 income qualified customers. Given these challenges, the Company proposes to
10 continue the RISE pilot as a pilot program for an additional IRP cycle. Georgia
11 Power will continue to work with the Commission Staff on the implementation of
12 this program.

13 **Q. IS THE RISE PILOT THE ONLY INCOME-QUALIFIED DSM PROGRAM**
14 **THE COMPANY OFFERS?**

15 A. No. In addition to the RISE pilot, the Company is requesting to certify the
16 HopeWorks and Home Energy Efficiency Assistance programs; together, these
17 pilots and programs demonstrate the Company's continued commitment to in-home
18 energy efficiency assessments and improvements for income-qualified seniors and
19 other income-qualified customers. Additionally, income-qualified customers are
20 eligible to participate in all of Georgia Power's residential DSM programs. As part
21 of the 2022 IRP, the Company has included specific targets for income-qualified
22 customers for many of the residential programs, thereby helping to increase
23 program participation for customers who can benefit the most from program energy
24 savings.

1 **Q. WHAT IS THE COMPANY’S REQUESTED BUDGET FOR PILOT**
2 **STUDIES?**

3 A. The Company seeks Commission approval of \$1.5 million for residential and \$1.5
4 million for commercial pilot studies, which is equal to the amounts approved in the
5 2019 IRP.

6 **Q. IS THE COMPANY PROPOSING TO CONTINUE ITS ENERGY**
7 **EFFICIENCY AWARENESS AND LEARNING POWER INITIATIVES?**

8 A. Yes. The Company has proposed to continue offering its energy efficiency
9 awareness initiatives to customers and to school-aged children through the
10 Learning Power Education Initiative. During the remote school and work
11 environment, the Company adapted its program offerings and created an online
12 platform where schools and students could view prerecorded lessons at their own
13 pace and schedule. Based on the continued success of these initiatives, the
14 Company has requested Commission approval of a budget of \$4 million per year
15 for these activities, which is consistent with what the Commission approved in the
16 2019 IRP.

17 **Certified Cost of DSM Programs and Additional Sum**

18 **Q. WHAT DSM COSTS IS THE COMPANY ASKING THE COMMISSION TO**
19 **APPROVE?**

20 A. The Company is requesting Commission approval of the costs for all approved and
21 certified DSM programs, pilots, and other DSM activities. In addition, the
22 Company requests the continued collection of an additional sum amount. The
23 budgets and costs for the Company’s DSM programs are set forth in Appendix C
24 to the DSM Application, and the additional sum amounts are set forth in Appendix
25 F to the DSM Application.

1 **Q. PLEASE DESCRIBE GEORGIA POWER'S REQUEST FOR AN**
2 **ADDITIONAL SUM.**

3 A. As stated in the DSM Application, the Company requests an additional sum equal
4 to four cents for every kWh saved using verified gross energy savings values
5 applied to all certified DSM programs in the residential and commercial DSM
6 portfolios. Moreover, the Company proposes a tiered scale approach to encourage
7 achievement of certified energy savings goals while ensuring cost-effective
8 program implementation. Under this approach, if the reported energy savings
9 grow higher than 120% of certified energy savings goal by class, or as a portfolio
10 during any year within the IRP cycle, the additional sum on the reported savings
11 beyond 120% will be collected at five cents per kWh saved. Any authorized
12 additional sum will be specific to the corresponding customer class and will be
13 collected through the Residential and Commercial DSM tariffs.

14 **Q. WHY DOES THE COMPANY WANT TO CHANGE THE ADDITIONAL**
15 **SUM METHODOLOGY?**

16 A. The proposed additional sum methodology is simpler than the existing
17 methodology and likely to be more stable. The proposed change in methodology
18 also better aligns the additional sum with the energy savings achieved from the
19 customer classes eligible to participate in the Company's residential and
20 commercial DSM programs. Furthermore, under the current methodology, Georgia
21 Power receives little to no additional sum from residential DSM programs that
22 deliver kWh savings. The Company believes the proposed approach will also help
23 streamline the reporting process and provide additional clarity around the annual
24 DSM tariff true-up process.

25 **Q. SHOULD ENERGY SAVINGS BE ADJUSTED FOR MARKET EFFECTS?**

26 A. No. Market effects such as free-ridership and spillover are recognized in the
27 industry as important data points for evaluating DSM programs and deciding

1 whether to modify or continue DSM programs. Market effects are useful for
2 program evaluations and modifications, as well as future program design and
3 system planning. However, with respect to energy savings targets and the additional
4 sum, verified gross energy savings are a better indicator of program success.

5 **Q. WHY IS IT INAPPROPRIATE TO ADJUST THE ENERGY SAVINGS FOR**
6 **MARKET EFFECTS USED IN CALCULATING THE ADDITIONAL SUM?**

7 A. There are several reasons why it would be inappropriate to adjust energy savings
8 for market effects in calculating the additional sum. First, market effects are
9 constantly changing and thus should not be used as the basis for a static adjustment
10 to the additional sum. While the Company employs industry-standard methods to
11 quantify market effects, the estimate generated only provides information regarding
12 a snapshot in time when the surveys are conducted.

13 Second, the Company has no control over free riders and does not have the ability
14 to structure programs in such a way as to eliminate free ridership. The additional
15 sum is intended to serve as an incentive to the Company to incorporate more DSM
16 into its resource mix. However, the measures, programs, and energy savings targets
17 proposed by the Company and approved by the Commission are based on a group
18 of fixed assumptions. To adjust energy savings for market effects in the calculation
19 of the additional sum would alter those assumptions after the fact to reduce the
20 additional sum calculation to account for market effects outside the Company's
21 control. It is not appropriate to penalize the Company for market effects over which
22 it has no control. On the other hand, factors over which the Company *has* control,
23 such as program implementation and budgets, directly influence gross energy
24 savings; as such, gross energy savings are the more appropriate basis for calculation
25 of the additional sum.

26 Third, the Company's DSM programs are intended to bring about market
27 transformation. Over time, market transformation will naturally result in increasing
28 levels of free ridership because customers will adopt the energy efficient behavior

1 without needing the Company-provided incentives, while still benefiting from the
2 DSM rebate. As such, it runs contrary to the goals of the Company's programs to
3 hold the Company accountable for free riders in the calculation of its additional
4 sum.

5 **Q. HOW DOES THE COMPANY PROPOSE TO COLLECT DSM PROGRAM**
6 **COSTS AND THE PROPOSED ADDITIONAL SUM?**

7 A. Georgia Power proposes to collect the costs of approved and certified DSM
8 programs and activities, as well as the additional sum amount for certified DSM
9 programs, through the existing Residential and Commercial DSM tariffs. These
10 tariffs would be filed as part of the Company's 2022 base rate case and would be
11 implemented with any approved change in rates on January 1, 2023.

12 **Q. WILL THE DSM TARIFFS BE TRUED UP?**

13 A. Yes. Consistent with current practice, the DSM tariffs will initially be based on
14 projected program costs and participation levels, and projected additional sum
15 values approved in the 2022 IRP and DSM Application. Subsequently, the DSM
16 tariffs will be trued-up annually based on actual program costs and participation
17 levels, and actual revenues collected using the true-up methodology agreed to by
18 the Company and Commission Staff.

19 **IV. DER CUSTOMER PROGRAM**

20 **Q. WHAT ARE DISTRIBUTED ENERGY RESOURCES?**

21 A. A Distributed Energy Resource (DER) is any resource located on the distribution
22 system, any subsystem thereof, or behind a customer meter. Examples of DERs
23 include solar facilities, battery storage systems, internal combustion generators,
24 microturbines, flywheels, electric vehicles, Volt/Volt-Amps Reactive applications,
25 interruptible loads, critical pricing programs, and demand response.

1 **Q. PLEASE DESCRIBE THE NEW DER CUSTOMER PROGRAM THAT**
2 **GEORGIA POWER IS PROPOSING IN THE 2022 IRP.**

3 A. Georgia Power is proposing a new, tariff-based customer program where the
4 installation and operation of dispatchable DER located behind the meter of a
5 participating customer can be leveraged to increase the reliability and resilience of
6 the grid and provide resilience solutions to Georgia Power's participating
7 customers. The Company will limit eligible DER to dispatchable assets that are, if
8 applicable, certified and permitted to meet standards for non-emergency use under
9 requirements from both the U.S. Environmental Protection Agency and the Georgia
10 Environmental Protection Division. Examples include battery energy storage
11 systems, microgrids, fuel cells, combustion turbines or reciprocating internal
12 combustion engines. As proposed, the DER Customer Program will be available to
13 eligible commercial and industrial customers and include two optional tariffs: (1)
14 the Resiliency Asset Service Tariff (RAST-1); and (2) the DER Demand Response
15 Tariff (DRC-1).

16 **Q. PLEASE DESCRIBE RAST-1.**

17 For customers participating on RAST-1, Georgia Power will design, procure,
18 install, own, operate and maintain a dispatchable DER behind the customer's meter
19 to meet their resiliency needs. Participating customers on RAST-1 will pay a
20 monthly resilience service charge and receive resiliency service provided by
21 Georgia Power for their benefit during a local loss of service event. Georgia Power
22 will have sole operations of the asset and utilize it to ensure continued service to
23 the customer in the event of a local loss of electricity to the customer. The costs to
24 be recovered through RAST-1 will be determined by the revenue requirements of
25 the asset and corresponding expenses over the life of the contract, plus annual fuel
26 expenses.

1 **Q. PLEASE DESCRIBE DRC-1.**

2 Customers participating in RAST-1 will also have the option to participate in DRC-
3 1. Under DRC-1, Georgia Power will provide participating customers with a credit
4 on their electric bill in exchange for the Company's ability to use the DER – which
5 will be located behind the participating customer's meter – for demand response
6 purposes during system reliability events. Georgia Power's utilization of these
7 assets during system reliability events will reduce the demand on the system via
8 demand response, thereby lessening the reliability constraints on the system. The
9 net result will be a benefit to all customers by leveraging the diverse resiliency
10 resources that provide value to the grid.

11 **Q. WHAT ARE THE BENEFITS OF THE DER CUSTOMER PROGRAM?**

12 A. The DER Customer Program provides demand response value and corresponding
13 system reliability benefits for all customers during a system reliability event while
14 also supporting commercial and industrial customers with enhanced resiliency
15 needs. The DER Customer Program leverages DER to strengthen grid reliability
16 for all customers, creates a more flexible and diverse resource mix, promotes
17 cleaner DER resources, and increases resilience for Georgia Power's participating
18 customers.

19 **Q. HOW DOES THE DER CUSTOMER PROGRAM PROVIDE**
20 **RELIABILITY BENEFITS TO ALL CUSTOMERS?**

21 A. Through DRC-1, customers' demand will be reduced during system reliability
22 events by having their energy served through the onsite DER. By reducing
23 participating customers' demand served via the grid during system reliability
24 events, the DRC-1 portion of the DER Customer Program will decrease the
25 reliability constraints on the system overall, and in so doing, benefit all customers.
26 This is very similar to how interruptible programs work, but because the demand
27 response is provided via an onsite DER maintained and operated by Georgia Power,

1 the response has a higher availability factor and is produced without a disruption to
2 the participating customers' operations. This provides more value to the system and
3 allows participating customers to maintain normal operations, which is expected to
4 result in higher customer satisfaction from participating customers.

5 **Q. WHICH CUSTOMERS ARE ELIGIBLE TO PARTICIPATE IN THE DER**
6 **CUSTOMER PROGRAM?**

7 A. As presently designed, qualifying commercial and industrial customers with a
8 resilience need of 1 MW or greater will be eligible to participate in RAST-1.
9 Customers may aggregate load and assets at multiple accounts to meet the 1 MW
10 requirement, provided that each account's DER and qualifying load are 250 kW or
11 greater. Only customers already participating in RAST-1 will be eligible to
12 participate in DRC-1 at this time. Additionally, customer load served through Fixed
13 Pricing Alternative (FPA), Electric Arc Furnace (EAF), Time of Use – Supplier
14 Choice (TOU-SC) or enrolled in the Demand Plus Energy Tariff will not be eligible
15 for DRC-1. Customers enrolled in Real Time Pricing may participate in the DRC-
16 1 with their Customer Baseline Load (CBL).

17 **Q. WHY IS DRC-1 LIMITED TO THOSE CUSTOMERS PARTICIPATING IN**
18 **RAST-1?**

19 A. The Company must ensure that the DER relied on during critical reliability events
20 are fully operational and able to respond. Limiting DER to those maintained and
21 operated by Georgia Power ensures an appropriate level of operational oversight,
22 decreases the operational risk profile of the program overall, and provides greater
23 administrative efficiency.

1 **Q. WHY ARE ASSETS THAT ARE CERTIFIED AND PERMITTED FOR**
2 **NON-EMERGENCY USE THE ONLY ASSETS UTILIZED IN THE DER**
3 **CUSTOMER PROGRAM?**

4 A. The goal of DRC-1 is to ensure system reliability and prevent a loss of electricity
5 supply to our customers. Assets permitted for emergency use may only be run once
6 an outage has already occurred and, therefore, cannot meet this need. Additionally,
7 assets certified and permitted for non-emergency use have a cleaner emissions
8 profile.

9 **Q. HOW IS THE DRC-1 CREDIT VALUE DETERMINED?**

10 A. The DRC-1 credit value is determined based on the capacity value of the demand
11 response that will be recognized in the Company's IRP. The demand response value
12 is based on the Company's assumed cost of capacity in terms of \$/kW multiplied
13 by the Incremental Capacity Equivalent ("ICE") Factor of the response. In
14 recognition of the technological attributes and limitations of some DER, DRC-1
15 will offer three tranches of demand response values for assets that can enable an 8-
16 hour continuous response, 4-hour continuous response, and 2-hour continuous
17 response. This program element ensures that commercial battery energy storage
18 systems can participate since most have continuous response times of only four
19 hours or two hours. The credit values for each tranche will be based on the
20 corresponding value (i.e., ICE Factor) that the response duration has to the system.
21 This program element also ensures that the program will be able to evolve with
22 emerging technology.

23 **Q. ARE THERE ANY LIMITATIONS ON HOW OFTEN GPC CAN**
24 **DISPATCH THE DER?**

25 A. Georgia Power may dispatch the DER in the event of a local loss of electricity for
26 the participating RAST-1 customer's resiliency. Georgia Power may also dispatch

1 the DER under the DRC tariff during system reliability events up to 200 hours per
2 year, with a maximum of eight hours per event.

3 **Q. HOW WOULD THE DER CUSTOMER PROGRAM COSTS BE**
4 **COLLECTED AND CREDITS BE PAID?**

5 A. Georgia Power proposes that costs and/or credits of the DER Customer Program be
6 collected and/or paid through two new tariffs, RAST-1 and DRC-1. These tariffs
7 would be developed and submitted for Commission review following the approval
8 of the DER Customer Program.

9 **V. CONCLUSION**

10 **Q. WHAT ARE GEORGIA POWER'S DSM AND DER REQUESTS IN THIS**
11 **CASE?**

12 A. Regarding the Company's DSM Application in Docket No. 44161, Georgia Power
13 requests the Commission approve the DSM Application and take each of the
14 following actions:

- 15 1. Grant a certificate for the Residential HopeWorks program;
- 16 2. Decertify the Residential Power Credit program and the Commercial
17 Midstream program.
- 18 3. Amend the Certificate for ten previously certified programs: Residential
19 Behavioral, Residential Home Energy Improvement, Residential
20 Refrigerator/Freezer Recycling, Residential Specialty Lighting, Residential
21 Home Energy Efficiency Assistance, Residential TSTAT DR, Commercial
22 Custom, Commercial Prescriptive, Small Commercial Direct Install, and
23 Commercial Behavioral;
- 24 4. Grant a waiver of the TRC requirement within 515-3-4-.04(4)(a)(3) for the
25 Residential TSTAT DR program;

- 1 5. Approve the revised Additional Sum calculation methodology; and
- 2 6. Approve the Company's other activities as further specified in the
- 3 Company's 2022 IRP in Docket No. 44160, including the Energy Efficiency
- 4 Awareness Initiative and Learning Power Education Initiative.

5 Regarding DER, the Company requests approval of the DER Customer Program as

6 described in the 2022 IRP, and notes that the tariffs associated with the program

7 would be filed following Commission approval of the program.

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

9 **A. Yes.**

1 MS. PRYOR: With your permission, Chair, I'd
2 like Mr. Valle to summarize the prefiled testimony
3 of this panel.

4 MADAM CHAIR PRIDEMORE: Go ahead.

5 WITNESS VALLE: Good morning, Commissioners.
6 Our panel is here to support the budget 2022 load
7 and energy forecast, the company's DSM proposal, and
8 the company's request for certification,
9 decertification, and amended certificates, as well
10 as the proposed DER customer program.

11 The company's budget 2022 load and energy
12 forecast provides a 20-year forecast of energy sales
13 and peak demand to meet Georgia Power's planning
14 needs. The major drivers of the long-term forecast
15 are the economy and the penetration and efficiency
16 trends in electric end uses. Although the United
17 States and Georgia have both experienced solid
18 economic growth since 2013, the onset of the
19 COVID-19 pandemic in March of 2020 caused a short
20 but deep recession that then rebounded. The
21 COVID-19 pandemic significantly impacted Georgia
22 Power's retail sales as many individuals remained in
23 their home in response to social distancing and
24 isolation measures put in place during the pandemic.

25 As Georgia returned to post-pandemic life, the

1 state expects to return to a period of healthy
2 economic growth. As business continue to relocate
3 and expand in Georgia, employment growth and
4 population growth should follow. Georgia Power
5 anticipates that total energy sales will grow at an
6 average annual rate of .8 percent over the next
7 20 years.

8 As in prior IRPs, the company's continue to do
9 implementation of demand-side programs and remains
10 an important component of the 2022 IRP. As stated
11 in the company's DSM application, the company seeks
12 certification of one new DSM program, a certificate
13 amendment for ten previously certified programs,
14 decertification of two DSM programs, a waiver of a
15 Commission rule for one previously certified DSM
16 program, and Commission approval of certain other
17 energy efficiency-related activities.

18 For all certified DSM programs, the company is
19 requesting an additional sum equal to 4 cents for
20 every kilowatt hour saved using verified gross
21 energy savings in the first year of each certified
22 program.

23 The proposed DSM programs will develop
24 following a thorough evaluation using the
25 Commission's approved processes and in collaboration

1 with Commission staff and the demand-side management
2 working group.

3 Based on the planned implementation levels, the
4 company projects that the proposed DSM programs will
5 result on average in approximately 113 megawatts of
6 demand reduction and 431 gigabyte hours of energy
7 reduction annually until the next IRP.

8 It is important to note that due to lower
9 avoided costs, many of the current DSM programs
10 still appear less favorable under the total resource
11 cost and great impact measure tests when compared to
12 the 2019 IRP. However, the company believes
13 continuing these programs is beneficial in the
14 current environment as customers are responding
15 favorably and market efficiencies can be achieved by
16 maintaining a presence in the marketplace.

17 In addition to the aforementioned DSM programs,
18 a key component of this panel's testimony pertains
19 to dispatchable distributed energy resources. To
20 leverage the resilience and reliability benefits
21 that dispatchable DERs can provide and meet
22 growing -- a growing customer need, the company
23 seeks approval in this IRP of its new tariff-based
24 DER customer program.

25 The DER customer program will provide demand

1 response value and corresponding system resiliency
2 and reliability benefits for all customers and
3 support commercial and industrial customers with
4 enhanced resiliency needs.

5 The company's load and energy forecast and
6 demand-side management plan inform and support the
7 company's request in this 2022 IRP. The company
8 asks the Commission to approve the DER customer
9 program, as well as its specific request identified
10 in the 2022 IRP and DSM application. Thank you.

11 MS. PRYOR: Thank you.

12 The witnesses are now available for questions
13 from the bench and for cross-examination.

14 MADAM CHAIR PRIDEMORE: Questions from
15 Commissioners?

16 (No response.)

17 MADAM CHAIR PRIDEMORE: Okay. Georgia Public
18 Service Commission.

19 MR. THOMAS: Thank you.

20 CROSS-EXAMINATION

21 BY MR. THOMAS:

22 Q Good morning, Panel. I'm Preston Thomas with
23 Public Interest Advocacy staff. And I will be handling
24 the DER issues and load forecasting and then I will be
25 handing the panel over to Mr. Davis for DSM issues.

1 I wanted to see if you could just describe the
2 service the company would be providing under the
3 resiliency asset service tariff, also known as RAST-1.

4 A (Witness Evans) Yes.

5 Commissioners, under the resiliency asset
6 service tariff, Georgia Power will install, maintain, and
7 operate behind-the-meter generation or storage asset to
8 meet that individual customer's resiliency needs. That
9 customer will pay the revenue requirements through the
10 charges on the resiliency asset service tariff over the
11 life of the contract.

12 Q And are these services available from
13 unregulated firms competing in the market for backup,
14 power supply, energy procurement, and construction EPC?

15 A (Witness Evans) Yes. That's correct. Third
16 parties provide this service today to our customers and
17 will be able to continue to provide this service to our
18 customers.

19 With the DER program, we see benefits that the
20 system can extract from these assets through the
21 combination of the RAST program and the DRC, the demand
22 response component, that leverages these assets for the
23 good of the system.

24 Q So can you explain why if they're available in
25 the free market that GPC should be allowed to offer them

1 as a regulated service?

2 A (Witness Evans) Yes. These are available in
3 the market, but, again, Georgia Power cannot leverage
4 these assets for the reliability of the system. Through
5 the DER program that we filed here today, we can call on
6 these assets during times of reliability emergencies or
7 conditions or constraints to reduce demand on the system
8 and provide a benefit to all customers. That component
9 is something that third parties cannot do.

10 Q And you mentioned in your summary that these
11 backup power supplies would be added to the rate base,
12 but the participating customer would pay for the
13 associated revenue requirement. Will this charge be
14 added to the customer's electric bill?

15 A (Witness Evans) That's correct.

16 Q Okay. And will GPC allow other firms that
17 offer these services to add their costs to the electric
18 bill?

19 A (Witness Evans) I'm not quite sure I follow
20 your question there.

21 Q So I guess my question is: Does the fact that
22 GPC's program costs appear on the customer's electric
23 bill while competing firms can't do that, does that
24 constitute an advantage for the GPC program over
25 competing firms?

1 A (Witness Evans) No. I don't believe so. I
2 think the method of payment appearing on the bill is not
3 a competitive advantage.

4 Q Even though that might make it easier for the
5 customer, that's not an advantage?

6 A (Witness Evans) I can't speak to the payment
7 methods that third parties deploy to their customers
8 today. I think as a regulated service that the company
9 is offering it's appropriate to appear on the bill.

10 VICE-CHAIRMAN ECHOLS: Mr. Thomas, I want to
11 ask a follow-up question on this.

12 So would this be a precursor to maybe tapping
13 into electric vehicle batteries that would be
14 plugged into the home in the future?

15 Have you all discussed that possibility down
16 the road?

17 WITNESS EVANS: We do think that there are
18 possibilities as this program grows and we become
19 more familiar in this space to further leverage DER
20 assets to the extent the systems sees benefits from
21 it. This could be expanded to different customers
22 or understanding the different use cases that these
23 assets can be deployed for the benefits of the
24 system.

25 VICE-CHAIRMAN ECHOLS: And the -- another

1 follow-up, Mr. Thomas, if you don't mind.

2 So the townhomes in Atlanta that Pulte did with
3 y'all and the Birmingham project, are you leveraging
4 lessons learned from that?

5 And, if so, what were those lessons?

6 WITNESS EVANS: We haven't for this particular
7 program, mainly because this one focuses on large
8 commercial and industrial customers. To the extent
9 the program eventually in the future might extend to
10 residential, those are lessons learned that we can
11 leverage for sure.

12 This program leveraged conversations with
13 commercial industrial customers focused on meeting
14 their resiliency needs, understanding what those
15 are, how the customer -- or the company might serve
16 in this space. And then, from there, understanding
17 how those assets can be further leveraged for demand
18 response value on the system.

19 VICE-CHAIRMAN ECHOLS: And just one more on the
20 commercial customers. Are you leveraging diesel
21 generators, as well, Caterpillar generators that
22 might be attached to a facility, maybe in 15-minute
23 intervals for DER?

24 WITNESS EVANS: Yes. The types of assets that
25 we'll leverage in this program are going to be

1 driven by those customer's needs. They're going to
2 have a say in how that -- what best fits their
3 individual resiliency needs, provided it meets our
4 qualifications. And that is a type of asset that we
5 do see participating in the program with that quick
6 start capability.

7 VICE-CHAIRMAN ECHOLS: Thank you.

8 MADAM CHAIR PRIDEMORE: I believe this C&I DER
9 proposal is similar to some -- what some other
10 states have done with natural gas-fired generators
11 for resiliency purposes, states like Louisiana.

12 Have you looked at what other states,
13 particularly in the southeast have done, and taken
14 best practices and knowledge from that?

15 WITNESS EVANS: We have. And you're exactly
16 right. We do see other utilities around the country
17 proposing different types of resiliency programs to
18 different customers. Different jurisdictions,
19 different considerations in each one of them. But
20 we have reviewed those and taken certain elements of
21 those programs into consideration.

22 MADAM CHAIR PRIDEMORE: But this is primarily
23 driven by what C&I ratepayers are looking for?

24 WITNESS EVANS: That's correct.

25 MADAM CHAIR PRIDEMORE: Okay.

1 BY MR. THOMAS:

2 Q And do you think that GPC's cost of capital is
3 less than the cost of capital of competing EPC firms?

4 A (Witness Evans) I don't know the cost of
5 capital of other providers in this market.

6 Q But if the cost of capital were lower for
7 Georgia Power than competing firms, would that constitute
8 an advantage for GPC over competing EPC firms?

9 A (Witness Evans) Just to make sure I follow, can
10 you restate your question or repeat your question?

11 Q Sure. So I understand that you don't know what
12 the cost of capital is for other firms. But if it is
13 lower for Georgia Power than other firms, would that
14 constitute an advantage?

15 A (Witness Evans) I -- I don't know. I can't
16 speak to how they price their products or what -- I
17 think -- or what price the customer would ultimately see
18 there. So I don't know.

19 Q And how will Georgia Power ensure that costs
20 won't be paid by any non-participating customers?

21 A (Witness Evans) So the charges that the
22 customer will pay through the resiliency asset service
23 tariff will be based on the revenue requirements that the
24 company will see during that contract.

25 So as the costs will be included in the rate

1 base, but also that revenue that that customer is paying
2 is meant to offset those costs over the contract.

3 Q Okay. So what happens if a participating
4 customer closes up shop or leaves this state?

5 How is that handled?

6 A (Witness Evans) Those will be handled in the
7 terms and conditions of the contract. We'll have,
8 obviously, risk mitigation elements making sure that
9 general ratepayers are not bearing the cost of that.

10 Q Okay. So if a participating customer refuses
11 to pay the backup power bill or any cost,
12 non-participating customers won't be forced to pay for
13 those rate-based assets?

14 A (Witness Evans) Well, I think in the contracts,
15 we'll have elements that shield customers -- our general
16 customers from that element for sure. Also, one of the
17 benefits of this program is that the assets themselves
18 can be redeployed to new customers within the program and
19 new -- and value extracted for that new participating
20 customer in the system. So in the event that that does
21 occur, the asset itself being transferable we see as a
22 great benefit.

23 Q So I heard you say that there are shields for
24 the customer and that the asset can be reused, but I
25 didn't actually hear the answer to the question whether

1 -- if there are costs where they refuse to pay the power
2 -- backup power bill, is there any scenario where other
3 customers could be forced to pay for those rate-based
4 assets?

5 A (Witness Evans) I can't speak definitively. We
6 think that's a very low occurrence. And just like we do
7 in every area of our business, we're going to construct
8 this program to ensure that the participating customers
9 pay for the cost of it. But I think they're -- I can't
10 say in every instance, but we think the probability is
11 very small.

12 Q Okay. So although a small probability, the
13 probability exists. Do you think that that might create
14 an advantage over other firms where other firms have to
15 worry more about bad debt because they don't have the
16 ability to pass that on in any scenario to other
17 customers?

18 A (Witness Evans) Well, I think Georgia Power
19 cares very much about controlling bad debt and mitigating
20 that risk today. So I don't think that's any different
21 from any other provider.

22 Q Right. And there --

23 A (Witness Evans) And --

24 Q I'm sorry.

25 A (Witness Evans) Go ahead.

1 Q But there is a scenario where this might be
2 passed on to non-participating customers. Other firms
3 can't pass that on to other customers.

4 Do you see this as any type of advantage
5 Georgia Power might over other firms?

6 A (Witness Evans) I don't know how other firms
7 would handle breach of contract.

8 COMMISSIONER McDONALD: What's other firms,
9 please?

10 MR. THOMAS: Free market firms, EPCs that offer
11 the same service that Georgia Power wants to offer
12 as a regulated service.

13 BY MR. THOMAS:

14 Q Did I allow you to completely answer that?

15 A (Witness Evans) I can't speak to how other
16 firms handle breach of contract.

17 Q Sure. So I'd like to move to the DRC-1 tariff.
18 And I wonder if you can explain for the Commission the
19 demand plus energy credit, DPEC-4 tariff, and how this
20 proposed DCR-1 tariff is different.

21 A (Witness Evans) Sure. I will try. I'm not an
22 expert in the demand plus energy credit tariff, but I can
23 speak to some of the high level differences there.

24 Starting with -- the demand plus energy credit
25 tariff is commonly referred as a type of interruptible

1 program. And that does not require a behind the meter
2 generation or storage asset behind the customer's meter,
3 but more so relies on the interruption of their
4 operations to reduce load on the system.

5 That is fundamentally different from the
6 resiliency asset service tariff and the demand response
7 credit tariff because we can see those same benefits from
8 the system without interrupting that customer's
9 operations. Simply shifting their load from the grid to
10 that on-site resource, where they can continue to make
11 their product, provide their service, during these times
12 of critical reliability events without experiencing a
13 disruption, but the system can receive and see the same
14 benefits.

15 Q So am I understanding that the tariffs are --

16 MADAM CHAIR PRIDEMORE: Mr. Thomas, can I ask
17 you -- move the mike. Straighten the bend of it and
18 get it closer to you, please.

19 MR. THOMAS: Thank you.

20 BY MR. THOMAS:

21 Q So am I understanding that the tariffs are
22 similar in concept that they both provide a bill credit
23 to the customer for reducing their connected load when
24 requested by the company?

25 A (Witness Evans) Well, we haven't -- we have not

1 designed the tariffs for DRC. But the concept of that
2 program is that, yes, during a reliability event we would
3 call on that asset to shift the load from that customer's
4 to the on-site resource, reducing the load serve from the
5 grid, and alleviating some of those constraints that the
6 system is seeing at that time.

7 All customers would receive a benefit from that
8 because it is dispatchable. We could -- we could target
9 that during the times that we need it to come on most and
10 the system would receive that benefit and the customer --
11 and by that I mean the participating customer through the
12 resiliency asset service tariff would receive credits
13 corresponding with that benefit.

14 VICE-CHAIRMAN ECHOLS: Let me ask you a
15 question on the software. Is it -- you're
16 aggregating these resources. Are you doing this
17 through an automatic control or would this be a
18 human action call on that particular battery asset
19 at that moment?

20 WITNESS EVANS: It would be automatic.

21 BY MR. THOMAS:

22 Q So is the primary advantage to DPCR -- or DRC-1
23 tariff over the DPEC-4 tariff that Georgia Power gets to
24 determine when the resources come online and have more
25 control since they own the resource?

1 A (Witness Evans) I think there's a greater level
2 of assurance in that that response will materialize
3 because it is backed up by a firm generation or storage
4 asset, as opposed to the flexibility of a customer's
5 operations. So I do think there's a benefit there.

6 Additionally, because that asset has a long,
7 useful life and can ensure that response over that period
8 of time, there's also a benefit in that assurance over
9 the life of the asset or the life of the contract.

10 Q And is there a reason the company doesn't just
11 propose to change the DPEC tariff?

12 A (Witness Evans) Well, again, they serve very
13 different purposes. The DER customer program is meant
14 to, one, serve customer's resiliency needs and provide a
15 system benefit during reliability events without
16 interrupting that customer.

17 The demand plus energy credit tariff does not
18 require such backup assets and relies on that customer
19 being interrupted. So I'd say they serve different
20 customers and different needs.

21 MADAM CHAIR PRIDEMORE: It might be helpful if
22 you could provide us with a use case in each. Just
23 give us an example for each of them. How would they
24 be deployed?

25 WITNESS EVANS: Sure. So the demand plus

1 energy credit tariff, for instance, an industrial
2 customer might have flexibility in -- when an event
3 is called, they might shut down an operations line,
4 right, to reduce load served by the grid.

5 Whereas, a grocery store, for instance, that
6 sees benefit in having resiliency because they might
7 be located on the coast and sees a benefit of being
8 able to provide that needed service to the community
9 in times of hurricanes; right?

10 We might call on that asset to shift load from
11 that grocery store to the generator, but that
12 grocery store can still continue to serve the
13 community without experiencing an interruption. But
14 from the grid's perspective, we'd see the same
15 benefit, provided the response was materialized.

16 BY MR. THOMAS:

17 Q And so, just like I asked about adding cost to
18 the customer's bill, do you think the opportunity to
19 provide bill credits to the customers constitutes a
20 competitive advantage over other firms?

21 A (Witness Evans) I'm a little unclear. So the
22 credits provided through the demand response portion of
23 the program is in -- is in response to the benefit the
24 system receives. So we're -- we're the only ones, as the
25 electric service provider in the state, that can receive

1 those benefits to the grid. And it's an appropriate
2 compensation back to that customer for the benefits
3 provided.

4 Q I'd like to turn our attention to load
5 forecast. At page 10, lines 6 through 9 of your
6 testimony, you indicate that over the past decade,
7 especially following the great recession, the difference
8 in energy consumption in the winter and summer months has
9 narrowed, causing winter and summer peak demand
10 projections to also narrow in consecutive forecasts.

11 I think the panel yesterday mentioned in a
12 brief answer that this was due to heat pump usage, but
13 staff is also curious if the company can provide a more
14 detailed response and explain what the company is doing
15 to address that narrowing.

16 A (Witness Valle) Yeah. Certainly. So the --
17 it's a fact. The difference between the winter and the
18 summer peaks have been narrowing over time.

19 And the explanation for that -- for that
20 narrowing has been twofold. In the summer, you have
21 increased efficiencies on, you know, air conditioning
22 units and, you know, energy efficiency standards that are
23 driving that use per customer down for the summer.

24 In the winter, you have more penetration of
25 electric uses; heat pumps, water heaters. And so that

1 has created a growth in the -- in the winter.

2 Q And what exactly is the company doing to try to
3 address this narrowing?

4 A (Witness Valle) So twofold. So, first, our
5 model. Our load forecasting models are well suited to
6 capture these trends in the historical data.

7 So the -- in the short term, we have these
8 models that are called econometric models. Think about
9 relationships that get established between drivers and
10 the use of electricity. And so any trends, any
11 information that is part of the historical data gets
12 incorporated in the model and then it gets propagated
13 throughout the forecast.

14 The second part that we were actively, you
15 know, looking to reflect was as a result of that 2019
16 stipulation item where there was a concern that the
17 breakdown in the annual energies in the long term would
18 not appropriately capture the trends in seasonal sales.

19 So the company investigated trends. We
20 implemented a methodology that is looking at the end
21 uses, at the activities that are driving the electric use
22 in our territory in the long term.

23 So these are very specific and granular
24 information that gets built up at a class level to
25 determine the -- you know, the monthly breakdown and

1 the -- and the -- and sort of the contribution of summer
2 peaks and winter peaks going forward.

3 Q And it looks like the company has not projected
4 a continued narrowing of winter and summer peak demands
5 in future years. Given the historical pattern of
6 converging winter and summer peak demands, can you
7 explain to us why it's not expected to continue?

8 A (Witness Valle) Yeah. So when we do our
9 models, you know, we develop them with strong statistical
10 properties. So they're very robust and they're collected
11 based in science, based in math. And so that part is not
12 picking up a continued decline into the future.

13 What is happening and where you see the -- sort
14 of the narrowing effect is that when you look at forecast
15 over forecast, the narrowing -- the winter and summer
16 peaks are getting smaller and smaller forecast after
17 forecast. But we don't see them growing at a different
18 rate into the short or long-term rates.

19 VICE-CHAIRMAN ECHOLS: Let me ask you about the
20 EV load again. You know, I know you all are using a
21 medium growth model. And I think that agrees with
22 where Cox Automotive and Kelley Blue Book, those
23 guys that own all the wholesale auctions are. They
24 don't think it's going to be as aggressive as maybe
25 many people think.

1 Do you anticipate the EV load having more
2 impact in the summer or in the winter or have you
3 not looked at that?

4 WITNESS VALLE: So, yes, we have looked. As of
5 this IRP and with the information that we have
6 incorporated -- remember, we always use the best
7 information available to us. It's translated
8 into -- into a bigger impact in the summer versus
9 the winter.

10 And that is -- that is driven by the -- sort of
11 the underlying assumptions between residential use
12 and commercial use for these -- for this EV going
13 forward.

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

15 MR. THOMAS: Chair Pridemore, at this time, I'd
16 like to turn the panel over to Mr. Davis.

17 MR. DAVIS: Good morning, Commissioners,
18 gentlemen.

19 WITNESS EVANS: Good morning.

20 CROSS-EXAMINATION

21 BY MR. DAVIS:

22 Q I'm going to just direct my questions at the
23 panel generally. And whoever feels most appropriate to
24 answer, feel free to answer.

25 So the company is proposing to maintain the

1 same DSM savings targets that were approved in the 2019
2 IRP; is that correct?

3 A (Witness Phillips) Yes.

4 Q Why?

5 Why maintain the same target savings levels?

6 A (Witness Phillips) When developing the
7 company's proposed case for the Commission to consider,
8 the company develops the proposed case in accordance with
9 the Commission-approved DSM program planning approach.

10 We also seek to achieve the Commission's
11 guidance of developing a proposed case that maximizes
12 economic efficiency while minimizing the upward impact on
13 rates. We consider a number of factors when we develop
14 the proposed case. We consider results of the potential
15 study. We also consider results of recent program
16 performance, as well as any specific guidance received
17 from this Commission.

18 When we consider those factors for this
19 particular proposed case, the company elected to keep THE
20 savings consistent with those that were established in
21 the previous IRP. One other thing that's important to
22 consider is since the 2019 IRP, avoided costs have
23 continued to decline.

24 And so in trying to achieve a balance of
25 maximizing economic efficiency, while minimizing the

1 upward impact on rates, the company elected to keep the
2 savings consistent, even though avoided costs and overall
3 benefits of the portfolio have declined from what they
4 were in the 2019 IRP.

5 COMMISSIONER McDONALD: In other words, you're
6 saying: If it ain't broke, don't fix it?

7 Is that what you're saying?

8 WITNESS PHILLIPS: That's a good way to
9 describe it, Commissioner. I would agree with that,
10 yes.

11 BY MR. DAVIS:

12 Q Did the company consider adding any new
13 programs to the portfolio, such as the manufactured homes
14 retrofit and replacement program?

15 A (Witness Smith) We did consider that program in
16 particular. We've actually adopted part of those
17 recommendations for that program into our program base
18 case. The retrofit aspect of manufactured housing is in
19 our HEIP program, and we looked at a variety of other
20 programs, as well.

21 Q And -- but that program, even though it passed
22 economic screening or the TRC test, was not wholly added
23 to the portfolio; correct?

24 A (Witness Smith) That's correct. In looking at
25 the whole program offering, while it does pass TRC, we

1 had concerns around the replacement part of that program
2 to where manufactured housing would be built and
3 replacing any existing manufactured housing. There were
4 concerns in how that would be implemented and how the
5 energy -- long-term energy would be avoided from it. And
6 so for those reasons we did not include that aspect of
7 it.

8 COMMISSIONER SHAW: Mr. Smith, you mentioned
9 y'all looked at some of the recommendations.
10 Explain -- what recommendations are you referring
11 to?

12 WITNESS SMITH: Commissioner, we had several
13 meetings with demand-side management working group
14 over 2020 and 2021. We met with that group
15 eight times. And we also had a couple of additional
16 meetings with subgroups for program ideation. Our
17 energy efficiency and demand response program
18 ideation.

19 They submitted 11 ideas for programs for us to
20 consider. Programs or measures for our
21 consideration. And in working through those, we
22 actually have accepted over 50 percent, 6 of those
23 11, into our program offerings.

24 They included anything from the program that we
25 just heard about around manufactured housing, to

1 programs around deeper savings opportunities for
2 whole house improvements and our HEIP program. A
3 variety of measures like that.

4 We did -- of the six that we accepted, we did
5 not add them as separate programs. We added them
6 into existing programs to control administrative
7 costs of having different marketing, different
8 staff, and different contractors to run those
9 programs. We felt that was in the best interest of
10 our customers.

11 COMMISSIONER SHAW: Okay. Thank you.

12 WITNESS SMITH: Thank you.

13 BY MR. DAVIS:

14 Q I'd like to turn now to HopeWorks. And if you
15 would refer to page 13, lines 18 to 27, of your direct
16 testimony. I believe that's where it's brought up.

17 A (Witness Smith) You said page 13?

18 Q Yes, sir. Page 13, lines 18 to 27.

19 A (Witness Smith) I'm there.

20 Q Would you please explain why the company is
21 seeking to certify the HopeWorks program, even though it
22 has not been certified in the past?

23 A (Witness Smith) Sure. We are seeking to
24 certify that program as it is growing to a size almost
25 40 percent higher than what it's been in the past. And

1 like all of our other programs that are funded through
2 the DSM tariff, those energy savings are counted. And
3 for those reasons we feel that energy savings for these
4 customers who are receiving a service very similar to
5 HEEAP should be counted in the company's energy savings,
6 as well.

7 Q HEEAP?

8 A (Witness Smith) I'm sorry. That's an acronym
9 for one of our other programs. It's home energy
10 efficiency assistance program.

11 Q Thank you.

12 When -- if this program were certified, the
13 company would earn an additional sum on the savings that
14 it generated; is that correct?

15 A (Witness Smith) Under the methodology the
16 company proposes, yes.

17 Q Okay. So that's to say under the current
18 methodology, it would not?

19 A (Witness Smith) Correct.

20 Q Is the proposed HopeWorks program cost
21 effective?

22 A (Witness Smith) It is cost effective.

23 Q And are you aware of any administrative issues
24 or burdens that the certification of this program would
25 cause to HopeWorks?

1 A (Witness Smith) We've had several discussions
2 with HopeWorks through the last several months and year.
3 And they are supportive of the program and they have
4 addressed none to us.

5 Q I'd like to turn now to page 14, lines 16 to
6 21, regarding the residential thermostat demand response
7 program. Is the company concerned that the thermostat
8 DR program does not pass the TRC test?

9 A (Witness Phillips) Well, the company is
10 concerned that it doesn't pass the TRC test. It did pass
11 the TRC test in the previous IRP. And once the company
12 began implementing the program, we realized that it
13 needed to be considered differently, in terms of the
14 overall benefits and how we calculate the TRC cost
15 effectiveness.

16 Initially the program had been evaluated
17 consistent with how other energy efficiency programs are
18 evaluated. Typically an energy efficiency program or
19 measure has an upfront cost. And take, for example,
20 installing insulation.

21 There is an upfront cost of installing the
22 insulation and the customer realizes the benefits over
23 the life of that measure. And that was the way the TRC
24 program had been modeled initially.

25 Once we began implementing the program after

1 the 2019 IRP, we realized that there are annual costs
2 also included to help make that DR capacity available.
3 And so the company, along with guidance of their
4 consultant AEG, chose to evaluate the thermostat
5 DR program on a one-year life in that the capacity is
6 made available each year as long as the customer is
7 willing to participate.

8 AEG also confirmed that other utilities across
9 the country with similar programs evaluate the thermostat
10 program on a one-year lifetime basis. And so it does --
11 excuse me. It does fail TRC. The company is mindful of
12 that, but we are asking for the TRC waiver in this case
13 so that the program can continue.

14 It's an existing program. It is providing
15 value. And we have a number of customers engaged in the
16 program.

17 Q Thank you.

18 I'd like to turn your attention to the RISE
19 pilot program. RISE, that's residential investment for
20 saving energy.

21 The current pilot and tariff were approved in
22 2020. And the company is requesting to continue this
23 program; is that correct?

24 A (Witness Smith) That's correct.

25 Q And am I correct that the RISE pilot was

1 designed to serve 500 customers, but only currently
2 serves around 17?

3 A (Witness Smith) That's correct.

4 Q What changes does the company expect to
5 implement to increase participation in this program?

6 A (Witness Smith) So the company expects to
7 implement several changes and have actually been working
8 with staff to address these implementation issues as they
9 arise.

10 One, hopefully we're coming out of the COVID
11 world that we've been in and it will make implementation
12 of the pilot easier and allow us to get into more
13 customers' homes to assess their availability.

14 But we've also found issues around -- as we
15 currently implement that program coming out of the 2019
16 IRP, there were things -- like considerations were only
17 being given for the savings on the electric side of
18 improvements that were being made. And so we've worked
19 with staff and we start to unlayer those concerns.

20 And we've also worked around issues around
21 expanding the ZIP codes in the city of Atlanta from six
22 to ten. That opens up a different set of customers.

23 So as you see with most pilots, they're a
24 learning experience. And we are learning what things to
25 fix and change to hopefully make that pilot more

1 successful and get a customer group large enough to
2 properly evaluate coming out of this IRP.

3 Q I'd like to turn now to additional sum
4 questions. In this IRP the company is proposing a new
5 methodology for how it calculates the additional sum;
6 correct?

7 A (Witness Smith) Correct.

8 Q Under the new proposal, the company would
9 receive an additional sum of 4 cents for each kilowatt
10 hour of electricity saved in the first year of
11 implementing the relevant DSM program; correct?

12 A (Witness Smith) That's correct.

13 Q And then it would jump up to 5 cents per first
14 year kilowatt hour saved in excess of 120 percent of the
15 certified energy savings goal for each year?

16 A (Witness Smith) For the savings from
17 120 percent and above. It would not impact the 0 to
18 120 percent.

19 Q And in contrast to the current program, there's
20 no decrease in additional sum amounts generated if the
21 total additional sum amount exceeds total program costs?

22 A (Witness Smith) No. Correct. We're seeking a
23 methodology that is more predictable, more reliable, and
24 allows us to value every kilowatt hour equally,
25 regardless of the program.

1 Q And is there a threshold amount of savings that
2 must be generated before the company earns an additional
3 sum?

4 A (Witness Smith) Not in our proposal.

5 Q Is it true that under the company's additional
6 sum proposal a program that saves 10,000 kilowatt hours
7 -- I'm sorry -- 10 million kilowatt hours a year for just
8 one year and an insulation program that saves 10 million
9 kilowatt hours for 30 years would both receive the same
10 additional sum?

11 A (Witness Smith) It would be based on a per
12 kilowatt hour save, regardless of the measure life or the
13 program that it happens in. It's just a flat kilowatt
14 hour. Cents per kilowatt hour.

15 Q Cents per kilowatt hour, but generated in the
16 first year; correct?

17 So a program that had ongoing savings benefits
18 past the first year, would it generate different
19 additional sum amounts compared to a program that only
20 generated savings the first year that it was implemented?

21 Does that make sense?

22 A (Witness Phillips) I think what you're asking
23 for is a program that realizes all the benefits in year
24 one versus a program that realizes its total benefits
25 over a number of years, what would the additional sum

1 difference -- or calculation result be?

2 Q Yes, sir. Exactly.

3 A (Witness Phillips) So the additional sum will
4 only be paid on that first year -- first year kilowatt
5 hour savings for either instance. So if there's a
6 measure that has all of its benefits or savings realized
7 in the first year, the additional sum would only be paid
8 on that amount.

9 If there is a measure or program that has an
10 additional sum where benefits are spread out over
11 10 years, only the savings from that first year would be
12 included in that year's additional sum calculation.

13 Q Are you -- thank you.

14 Are you aware of any other utilities that
15 receive an additional sum incentive of 4 cents per first
16 year of kilowatt hour saved?

17 A (Witness Smith) We've evaluated a number of
18 programs. There are none that that is the direct design
19 of the additional sum calculation. It is the net outcome
20 of one program in Minnesota. But there is no one that is
21 specifically a cents per kilowatt hour.

22 Q Thank you.

23 And would you agree, subject to check, that
24 using the company's proposed methodology, the DSM
25 additional sum would be over \$17 million per year on

1 average for the years 2023 to 2025?

2 A (Witness Smith) If program goals were met as
3 filed, yes, I would agree to that. And that puts it in
4 line with the value of additional sum that this company,
5 the PSC staff, and the Commission approved in the 2010
6 IRP.

7 And over that time I would say that our
8 programs have grown. They've more than doubled over that
9 time. So the additional sum would be equal under this
10 methodology to what it was back in the 2010 order.

11 Q Subject to -- subject to check, would you agree
12 that the additional sum between 2017 and 2021 averaged
13 around \$10 million per year?

14 A (Witness Smith) Subject to check.

15 And I will say that's one of the reasons that
16 the methodology that's currently in place is based on
17 avoided costs. And so as avoided costs have come down
18 over time, the additional sum changes. Whereas, our
19 program goals are doubling over that same period of time.

20 Q On the topic of free ridership, when the
21 company spends money to implement a DSM program, some
22 customers that receive an incentive are people who would
23 have taken the action or bought, for example, a
24 thermostat regardless of the program in place; correct?

25 A (Witness Smith) Correct.

1 Q The current additional sum methodology is based
2 on net savings, which is calculated by deducting savings
3 attributable to free riders from gross savings; is that
4 correct?

5 A (Witness Smith) Correct. As well as spillover,
6 which is customers that do more than what they were
7 incented to do.

8 Q And under the proposed methodology, the
9 company's additional sum would be based on gross savings,
10 meaning that the additional sum savings could increase
11 because of a DSM program, even if the individuals
12 participating in the program were identified as free
13 riders?

14 A (Witness Smith) well, Measures over time get
15 evaluated. And as they get evaluated, those changes get
16 implemented into the next program cycle.

17 So those impacts would be -- if approved, those
18 impacts, both positive and negative, would be applied to
19 the next program cycle. And those discounts or additions
20 would be seen there to the savings.

21 Q But just to clarify, the -- under the current
22 program, those savings would not be counted towards
23 additional sums?

24 A (Witness Smith) Are you asking under our
25 proposed?

1 Q Under the current additional sum methodology.

2 A (Witness Smith) The current methodology, the --
3 a new measure, it would be identical. It would only be
4 -- those methodologies for evaluation, those free
5 ridership and spillover impacts would be seen when we
6 file our case under each updated IRP.

7 Q On page 22 of your direct testimony on lines 13
8 through 14, it's stated that the -- the company has no
9 control over free riders and does not have the ability to
10 structure programs to eliminate free ridership. However,
11 I just want to ask a few questions.

12 Is it not true that the company selects the
13 eligible energy efficiency measures for the DSM programs?

14 A (Witness Smith) Correct.

15 Q And the company also defines who are eligible
16 participants in these programs?

17 A (Witness Smith) The company, along with its
18 implementation contractor; correct?

19 Q And the company determines the level of
20 incentives paid to program participants in these
21 programs?

22 A (Witness Smith) Yes.

23 Q And did the EM&V reports completed by the
24 company in 2021 or 2018 provide methods as to how free
25 ridership can be reduced?

1 A (Witness Smith) They do. And then the company
2 takes those methodologies and implements them either
3 realtime, if they're process driven, or futuristic in
4 programs if they're impact driven.

5 Q And has the company made any of the changes to
6 the DSM programs suggested by --

7 A (Witness Smith) In the evaluations?

8 Q Yes, sir.

9 A (Witness Smith) We do, yes.

10 Q Did the company experience difficult or --
11 sorry. I'm referring to page 12, lines 20 to 27, of your
12 direct testimony.

13 A (Witness Smith) I'm sorry. Page 12?

14 Q Yes, sir. Page 12, lines 20 to 27.

15 A (Witness Smith) Okay.

16 Q Did the company experience difficulties
17 completing the EM&V for several programs last year due to
18 COVID?

19 A (Witness Smith) Our evaluation contractors did
20 run into difficulty in evaluations as stated in their
21 reports around that for several of the programs.

22 Q And for several programs the net-to-growth
23 ratio were not considered statistically valid by the
24 evaluator; is that correct?

25 A (Witness Smith) Yeah. I believe that's right.

1 Q Would you agree then that the EM&V results for
2 -- were affected by COVID-19?

3 A (Witness Smith) Some of the programs were
4 impacted; therefore, their ability to evaluate them was
5 impacted.

6 Q Does the company propose to use the 2018 EM&V
7 results for any programs?

8 A (Witness Smith) Certain programs we will use
9 those evaluation results. And they're ones that are less
10 impacted due to COVID. So think about lighting. So
11 residential lighting could have been purchased online.

12 And the majority of the impacts that we saw
13 from that program evaluation were due to code changes and
14 ISA standards. So the impacts there of that evaluation
15 were not driven by COVID like ones would have been that
16 involved being able to do work in customer's homes and
17 businesses.

18 Q Of the programs that you have identified as
19 being affected by COVID, are all of those programs
20 residential?

21 A (Witness Smith) No.

22 Q No?

23 So will the company use the 2018 EM&V results
24 for both residential and commercial programs?

25 A (Witness Smith) So the company will actually

1 use what was recommended by the evaluators in those
2 programs. So where those programs were impacted by COVID
3 and the evaluator did not feel that the results were
4 representative of how that program would have worked
5 under normal conditions, they stated that we should use
6 the older evaluation results or information from TEAPOT
7 studies and things of that line.

8 We will use it regardless of which way they
9 said to go. We're not -- you know, we're not picking and
10 choosing which ones we will follow and not follow.

11 Q And just a few more. Georgia Power Company,
12 assisted by the Brattle Group and the Georgia DSM working
13 group, completed a DSM white paper in 2021 that examined
14 the feasibility of using their Aurora IRP model and allow
15 DSM measures to compete head to head with supply-side
16 generation sources; is that correct?

17 A (Witness Phillips) Yes.

18 Q And is it correct that one of conclusions of
19 that white paper is that: Evaluating DSM resources
20 alongside supply-side resource in the company's resource
21 planning process is possible?

22 A (Witness Phillips) Yes. That was one of the
23 conclusions, along with a number of other conclusions
24 that resulted from that particular study.

25 An additional conclusion also noted that in

1 modeling demand-side resources in the supply-side system
2 there are certain limitations and challenges. And the
3 company concluded that the current methodology is the
4 more appropriate way for evaluating and modeling
5 demand-side resources.

6 Q And one other conclusion was that the Aurora
7 modeling system is well-suited for evaluating EE,
8 alongside supply resources; correct?

9 A (Witness Phillips) I think specifically we said
10 that it was technically possible. I don't recall that we
11 concluded that it was well-suited.

12 We did show that it is technically possible to
13 model demand supply resources in a supply-side system.
14 But along with that, there were certain adjustments and
15 work-arounds that required that that are not required in
16 our current methodology.

17 And so that led the company to conclude with
18 the limitations and challenges of modeling demand-side
19 resources in a supply-side system, the current
20 methodology that has guided development of our proposed
21 cases for a number of years is the most appropriate way
22 for modeling and evaluating demand-side resources.

23 A (Witness Valle) And, Commissioners, that is an
24 important point because, you know, with the white paper
25 we did the exploration that was required. But, you know,

1 given the sophistication of the tool, in order to prepare
2 the inputs, you know, and appropriately model this DSM
3 programs in the system, alongside with supply sources,
4 you had to do a lot of grouping, a lot of bundling. And
5 it's a complex process. So while it's doable, I want to
6 make you aware of the complexities of adding this extra
7 step within -- within our planning approach.

8 MR. DAVIS: Thank you, gentlemen. That's all I
9 have.

10 MADAM CHAIR PRIDEMORE: Thank you, Mr. Davis.

11 I have a couple of questions for the panel
12 before we start with the intervenors.

13 So to follow on staff's questions about COVID
14 impact to the DSM programs, I'm interested to unpack
15 if there's any correlation to not paying a monthly
16 electric bill and ratepayers subscription to
17 demand-side resources.

18 So in a March 2022 New York Times article
19 titled, Utility Bills Piled Up During The Pandemic.
20 Will Shutoffs Follow, they cite the fact that
21 residents of New York and New Jersey owe a
22 staggering sum of more than \$2.4 billion to utility
23 companies due to a moratorium and shutoffs.

24 Although the state of Georgia limited the
25 moratorium on utility shutoffs for non-paying

1 customers more than New York and New Jersey has, how
2 did the moratorium and the pandemic overall affect
3 the subscription of ratepayers to these DSM programs
4 offered by Georgia Power?

5 WITNESS SMITH: So, Chair Pridemore, if I
6 understand your question, we saw a decline in
7 participation that we expect or is tied direct to
8 COVID.

9 In 2020, we saw an overall participation rate
10 in our programs of 56 percent of goal and 70 percent
11 in 2021. So, you know, our attribution is that
12 those programs did not meet goal due to COVID
13 impacts.

14 MADAM CHAIR PRIDEMORE: Have you determined if
15 the programs dropped off even more so during the
16 moratorium?

17 WITNESS SMITH: I have not researched that, but
18 it's something I think we can go look at.

19 MADAM CHAIR PRIDEMORE: Okay. Interesting.

20 Okay. So a March 29, 2022, E&E News article
21 went through President Biden's budget and how energy
22 and energy programs are affected. So I'm going to
23 read to you just the budget numbers. You probably
24 have heard these. I know we all have.

25 The President's \$5.8 trillion energy proposal

1 would spend 3.3 billion on clean energy growth
2 alone. He goes on to be quoted: My budget lowers
3 family energy costs with tax credits to help people
4 make their homes more efficient. This is considered
5 to be the largest invested in energy efficiency. So
6 the budget would allocate \$4 billion to the
7 Department's Office of Energy Efficiency and
8 Renewable Energy, a significant jump from the
9 3.2 billion Congress provided in fiscal 2022.

10 So with the largest proposed investment in
11 energy efficiency in American history proposed, how
12 are these Georgia Power DSM proposals in this docket
13 positioned to leverage this proposed large federal
14 investment?

15 WITNESS SMITH: So our programs will always
16 work to partner with other dollars and other
17 processes that are put in place.

18 What we've seen is the vast majority of those
19 savings are really -- were geared more towards -- or
20 excuse me. The vast majority of those dollars that
21 we were aware of are geared more towards billing
22 assistance and rent relief, more so than actual
23 energy efficiency improvements that reduced those
24 costs. But wherever those programs dollars are
25 available and programs are in place that can line up

1 with ours, we would seek to partner with those
2 programs.

3 MADAM CHAIR PRIDEMORE: Okay. On page 14 of
4 your prefiled direct testimony you mention two
5 programs, the decertification of the Power Credit
6 program that you seek to decertify this time and the
7 decertification of the Commercial Midstream program.

8 Are you purposing to decertify these two
9 programs because they have low subscription rates?

10 WITNESS SMITH: We're proposing to decertify --
11 I'll start with Power Credit. We are seeking to
12 decertify that because we have a -- what we feel is
13 a better program for demand -- residential demand
14 response in place with TEMP Check, the thermostat
15 control device.

16 And we're also seeing a natural attrition of
17 participation in that program over time. It's
18 dropping -- it's off about 40 percent from its
19 program high and it's dropping about 10 percent
20 naturally. So it's more for the fact that it's a
21 better customer experience, as well as a higher
22 demand savings per device with the new program.

23 With the Commercial Midstream program, we're
24 seeking to decertify it because the program,
25 according to the evaluation that we did on it, is

1 that that market has transformed. What we're seeing
2 is those distributors that we were incenting to
3 stock high-efficient equipment where it was
4 available, that wasn't the case when that program
5 was launched and approved by this Commission two
6 cycles ago. But now they're saying 75 to 85 percent
7 of the time they're stocking that anyway.

8 MADAM CHAIR PRIDEMORE: Okay.

9 WITNESS SMITH: And so it is just a -- to the
10 earlier point, it's turned into a high level of free
11 ridership due to market transformation.

12 So what we are finding, though, is that the
13 measures, the HVAC and the cooking measures, save a
14 significant amount of energy. And so we have moved
15 those measures back into customer-based incentives
16 in the prescriptive program. That was also one of
17 the suggestions from the demand-side management
18 working group is a measure they would like to see in
19 that program.

20 MADAM CHAIR PRIDEMORE: So, in other words,
21 market and new technology is surpassing some of
22 these programs and how they're outlined?

23 WITNESS SMITH: Correct.

24 MADAM CHAIR PRIDEMORE: Yeah.

25 Okay. On page 17 so how -- on line 16 it says

1 that what's proposed in this DSM energy efficiency
2 package, quote: That minimizes -- the DSM plan
3 minimizes upward pressure in rates and maximizes
4 economic efficiency.

5 In your analysis, how does this compare to
6 previous DSM plans to accomplish the same two goals?

7 WITNESS PHILLIPS: When comparing the company's
8 current proposed case with what was proposed in the
9 2019 IRP, overall TRC benefits have declined by
10 30 percent. And that's due to a decline in avoided
11 costs since the last IRP.

12 Also, when comparing both proposed cases for
13 this IRP and the previous IRP, overall RIM results,
14 or rate impact measure results, have declined or
15 worsened by 20 percent.

16 MADAM CHAIR PRIDEMORE: Anybody else care to
17 add to that one?

18 (No response.)

19 MADAM CHAIR PRIDEMORE: Okay. Page 18. So we
20 talk about the RISE pilot. So does this
21 income-qualified energy efficiency program that's
22 proposed in this docket have a corporate sponsorship
23 like the income solar program outlined on page 48 of
24 the Grubb, Mallard, Robinson, Weathers prefiled
25 direct testimony?

1 WITNESS SMITH: So, Chair Pridemore, just to
2 make sure I'm understanding, you're asking do any
3 other corporations fund this program?

4 MADAM CHAIR PRIDEMORE: Yes.

5 WITNESS SMITH: With the exception of Georgia
6 Power, no.

7 MADAM CHAIR PRIDEMORE: Okay. All right.
8 That's all I have. Thank you.

9 Americans for Affordable Clean Energy.

10 MR. GALLOWAY: Madam Chair, no questions.

11 MADAM CHAIR PRIDEMORE: Commercial Group is not
12 present.

13 Okay. Concerned Ratepayers of Georgia.

14 (No response.)

15 MADAM CHAIR PRIDEMORE: Not present.

16 Cypress Creek Renewables is not present.

17 Georgia Association of Manufacturers.

18 MR. JONES: Yes, ma'am.

19 Thank you, Madam Chair, Commissioners.

20 CROSS-EXAMINATION

21 BY MR. JONES:

22 Q Panel, good morning. I just have a few brief
23 questions for you about the DER program.

24 So the assets that would be involved in the DER
25 program would be under your proposal owned and operated

1 by the company; correct?

2 A (Witness Evans) Yes.

3 Q Okay. And do you envision this program always
4 being that way or do you envision a possibility where
5 customer-owned assets might be able to participate in the
6 program?

7 A (Witness Evans) I can't predict the future, but
8 that's the program we put forth today is just on
9 company-owned assets.

10 Q Okay. And did you consider whether to -- in
11 developing the program for this IRP, did you consider
12 whether there might be existing assets out there that
13 would also benefit the system if they were able to
14 participate in the program?

15 A (Witness Evans) In developing the program, we
16 did look at different alternatives and that was something
17 that was looked at. And also the risk that those imposed
18 on the system and the operations.

19 Q Okay. So the DRC aspect of this, you only
20 participate in if -- you can only participate in if
21 you're also participating in the RAST program; is that
22 right?

23 A (Witness Evans) That's correct.

24 Q The way you have it designed.

25 And in this case you haven't submitted a

1 specific tariff or rates for either of these program; is
2 that right?

3 A (Witness Evans) No. We'll make those -- we'll
4 provide those to the Commission in a subsequent filing.

5 Q Would you agree with me that the terms and
6 conditions of that tariff and of the contracts and the
7 pricing will be critical, in terms of incentivizing
8 customers to participate in the program?

9 Would you agree with that statement?

10 A (Witness Evans) Can you repeat it?

11 Q Would you agree that the terms and conditions
12 of these contracts and the tariff provisions and the
13 pricing will be critical in incentivizing customers to
14 participate in the program?

15 A (Witness Evans) Yes. I think the program
16 structure and terms and conditions of the contracts and
17 tariffs is very important for participation.

18 Q And, for example, Mr. Thomas asked a question
19 about: Well, what if a company participates and then
20 they close up shop? It might be important in those terms
21 and conditions to provide -- address the issues of
22 assignability, for example, of the existing contract?

23 A (Witness Evans) Yes, that's an element that
24 would be in there.

25 Q Okay. And the more flexibility you provide,

1 the more likely you are to be able to get people to sign
2 up, all other things being equal, would you agree with
3 that statement?

4 A (Witness Evans) Yes. It's a balance, right, of
5 participation and the benefits that come with that
6 participation and the risks that might be imposed with
7 certain elements.

8 Q Okay. And the final question, just to confirm,
9 the pricing is intended and is designed to be fully paid
10 for by the customer that's participating in the program
11 and not distributed or shared to other customers or
12 spread to other customers; is that correct?

13 A (Witness Evans) The pricing in the resiliency
14 -- I'm sorry. I assume you're talking about the
15 resiliency asset service portion?

16 Q Yes.

17 A (Witness Evans) Yes. The pricing in the
18 resiliency asset service portion of the program will be
19 structured to recover the revenue requirements that the
20 company is exposed to during that contract life.

21 MR. JONES: Okay. That's all I have,
22 Madam Chair. Thank you.

23 MADAM CHAIR PRIDEMORE: Thank you, Mr. Jones.
24 Georgia Center for Energy Solutions.

25 MR. HUBBARD: Madam Chair, no questions.

1 MADAM CHAIR PRIDEMORE: Georgia Coalition of
2 Local Governments.

3 MS. BROWN: Yes, ma'am.

4 Good morning, everybody, Commissioners.

5 CROSS-EXAMINATION

6 BY MS. BROWN:

7 Q I want to start with some questions on the RISE
8 pilot. So you mentioned that the RISE pilots only had
9 about -- I think you said 17 people sign up so far; is
10 that correct?

11 A (Witness Smith) Seventeen that have
12 participated in the Tier 2, the deeper retrofits.

13 Q So that would be those who have received more
14 than a direct install?

15 A (Witness Smith) Correct.

16 Q Okay. And you said COVID was certainly a
17 factor in that. But are there any other factors that you
18 would say in your experience are holding that back?

19 A (Witness Smith) One of the factors that --
20 that's impacting it is that it has to have a high average
21 monthly bill for a customer to save enough to pay back
22 the cost of those improvements over the measured life.

23 Q So, as a general rule, which customers would
24 you say tend to have those higher bills; lower income
25 customers or more affluent customers?

1 A (Witness Smith) So higher bills aren't
2 necessarily tied to an income. They're tied to energy
3 usage in a house. So I don't know that I can say that it
4 specifically ties to any one customer type.

5 Q Let's say you're in financial straits, though,
6 and you are trying to make decisions that minimize your
7 electricity bill, like you're trying not to turn on your
8 heater, you're trying not to use your A/C as much. You
9 would have a lower bill; correct?

10 A (Witness Smith) So if you're asking if I were
11 making intentional efforts to reduce my energy usage,
12 would I have a lower bill? Yes, I would agree with that.

13 Q So certain low income customers have
14 historically been making choices to control their bills
15 that may prevent them from participating in this program
16 that's meant to increase their comfort, control their
17 energy savings while still having some access to A/C,
18 HVAC; is that correct?

19 A (Witness Smith) Can I ask you to restate that
20 question? I don't know that I got what you're asking.

21 Q Have you noticed that certain low income
22 customers have made choices with their behavior that
23 artificially reduced their energy use below what it would
24 be if they weren't financially constrained and actually
25 could achieve a level of comfort?

1 A (Witness Smith) I don't know that -- I'm still
2 not understanding your question. I mean, if you're
3 asking do customers make choices to reduce energy, then I
4 would say that applies to all customers that make that
5 choice, not just because of an income level.

6 COMMISSIONER JOHNSON: Let me see if I can
7 help. I'm having some difficulty, as well, so I
8 want to ask. Are you saying because I am making a
9 conscious choice as a low income earner to lower, I
10 then cannot participate in the RISE program?

11 MS. BROWN: That's -- that's correct.

12 COMMISSIONER JOHNSON: Because of those --
13 because of those -- because of my --

14 MS. BROWN: Right. Like if I've decided to
15 keep my heater on 60 degrees because I cannot afford
16 to pay more, I'm not going to be able to achieve
17 that 25 percent reduction that the RISE pilot
18 requires?

19 WITNESS SMITH: Thank you, Commissioner. That
20 was helpful.

21 BY MS. BROWN:

22 Q I apologize for that.

23 A (Witness Smith) No. That's fine.

24 The way the program works is an audit is
25 actually done of that house. So those types of measures

1 would not impact the evaluation of what is achievable by
2 making improvements to the house versus behavioral
3 changes.

4 Q And you mentioned that there's some issues with
5 only electricity costs being included in the reduction
6 that has to be achieved. The 25 percent reduction.

7 Are you saying you've worked with staff to now
8 include gas savings, as well?

9 A (Witness Smith) Correct. We've worked with
10 staff to make other improvements, as well. As you just
11 mentioned, it no longer has to have a 20 -- it doesn't
12 have to follow the home energy improvement path of having
13 to have a 25 percent energy reduction.

14 If the savings, regardless of what those are,
15 allow that customer to pay back the cost of those
16 investments within the measured life, then they are now
17 able to go through the process.

18 Q Can you -- you mentioned geography and you
19 mentioned how you're expanding ZIP codes in, I believe,
20 Atlanta. Is that going to follow with Athens and are
21 there any plans to expand this to other cities, as well?

22 A (Witness Smith) So the ZIP codes that were
23 expanded in Atlanta were in the same geographic area as
24 well -- Athens, I don't know that there are any
25 additional ZIP codes for us to expand to. We are looking

1 at another city as well to be potentially expanded to.

2 But before we expand to another city or seek to
3 expand to another city through communication with staff
4 and the Commission, it's got to show that there is a
5 potential customer size there worth that -- that cost of
6 adding another city.

7 So the benefit of the two cities that we
8 currently have is they're geographically close to one
9 another. And the same contractors can do that work and
10 so it reduces administrative costs, but we are looking at
11 other opportunities.

12 Q You're mentioning the size of the customer base
13 that could be reached as a factor in where you locate
14 geographically. Can you explain why this is only an
15 income-qualified program when that artificially limits
16 the reach of the people that can participate?

17 A (Witness Smith) Sure. So the original intent
18 of the pilot was for income-qualified customers.
19 Customers that don't have -- potentially don't have the
20 upfront dollars to invest in the improvements in their
21 homes or the homes that they're in.

22 Customers -- you know, the broader customer
23 base can participate in HEIP through its whole house
24 path, through it's unbundled path, or through other
25 programs that we have. So the intent of the pilot was an

1 income-qualified for that reason.

2 Q But if RISE ultimately recovers the capital
3 invested in the program through the regular payments back
4 on the tariff, why would it make any difference what your
5 income is if that money is ultimately recovered?

6 A (Witness Smith) Again, the pilot was focused --
7 I mean, the pilot had a specific focus, which is
8 income-qualified customers that could not afford to make
9 improvements without it.

10 Q So is it your opinion that if you are above
11 200 percent of the federal poverty level you can
12 automatically afford to make these improvements?

13 A (Witness Smith) No, that's not my opinion. I
14 don't have any information to make a decision along that
15 with that question.

16 Q Okay. You mentioned administrative costs at
17 one point and that's also been reflected in your comments
18 about the declining total resource cost test results for
19 these programs. Are there any efforts in place to reduce
20 some of the overhead costs that are contributing to
21 declining total resource cost economics?

22 For example, efforts to streamline
23 administration, marketing?

24 A (Witness Smith) We -- I think if you look at
25 our administrative and marketing percentages of our

1 budget since the 2019 IRP, they've gone down by
2 11 percent. So we are making efforts to reduce
3 administrative costs and increase the percentage of
4 incentives that are in program budgets.

5 Q Definitely glad to see that. But, of course,
6 as local governments, we're always interested in making
7 sure that there aren't artificial barriers to
8 participation in these programs. Specifically when it
9 comes to income qualification, has there been any effort
10 through RISE or HEEAP or any of these other programs to
11 look at more of a census-track-type approach and the
12 demographics of an area as opposed to the conditions of
13 an individual person?

14 A (Witness Smith) So the questions you're asking
15 don't necessarily, if I'm understanding them right,
16 impact the way a program is designed. It may impact the
17 way we market a program. And we're always looking for
18 better ways to focus in on programs and reduce
19 administrative and marketing costs.

20 Q And to that point about marketing, you
21 mentioned partnerships with trade allies. You mentioned
22 partnerships on your lighting programs with food banks.
23 But have there been any efforts to formalize partnerships
24 with community organizations and local governments when
25 it comes to things like HEEAP and joint marketing

1 efforts?

2 A (Witness Smith) Could you define what you mean
3 by "formalize"?

4 Q I mean, perhaps even have a relationship with a
5 local government where they are charged with marketing
6 the program and even provided the marketing resources to
7 do because these they have those relationships?

8 A (Witness Smith) We are always open to
9 opportunities that are out there. We've been doing some
10 work for the last two years with a group of folks in the
11 City of Atlanta. We've also worked with different
12 housing authorities around the state, as well. And we're
13 always open to opportunities.

14 Q To this point about feedback and being open to
15 suggestions and new ideas, you've mention the DSM working
16 group being a factor in the programs that you're putting
17 forth and putting forth aggressive cases and advocacy
18 cases for the EE portfolio.

19 Will that group be continuing for the next IRP
20 cycle?

21 A (Witness Smith) That'll be at the determination
22 of this Commission. We're seeking for it to be.

23 Q Okay. And how were those original participants
24 identified for this last go-round?

25 A (Witness Smith) I don't know that -- we are not

1 the entity that customers or groups seek participation
2 in. So I would think that would be a question for staff.

3 Q Okay. Shifting gears entirely, I believe it's
4 being proposed to eliminate the automated benchmarking
5 tool for commercial buildings; is that correct?

6 A (Witness Smith) We're not seeking to eliminate
7 it. We're just not seeking to continue it.

8 Q Okay. Can you tell me how many people are
9 currently using that tool; how many buildings?

10 A (Witness Smith) Out of 2021 -- at the end of
11 2021, there were 554 building reports generated. That
12 does not necessarily mean it was 554 businesses. A
13 report could have been generated multiple times on one
14 business. But that was the number as of the end of 2021.

15 Q And can you explain the justification for
16 failing to continue that program?

17 A (Witness Smith) So, again, I mean, your term of
18 failing to continue, we're just not seeking to continue
19 it. Essentially it is a tool that under the original
20 ideation of it was that it would provide building owners
21 or people representing those building owners to get
22 aggregated data of building with multiple accounts with
23 the intent that they would then be able to identify
24 opportunities to reduce energy in those buildings.

25 When we evaluated the tool in 2020, there were

1 little to no energy savings happening from the users of
2 the tool. And so because of that, we don't feel that
3 it's right to pass those costs through on a demand-side
4 management tariff if there's no demand-side reductions
5 happening.

6 Q What would you estimate the cost of that tool
7 as being?

8 A (Witness Smith) It's between 150,000 and
9 \$200,000 a year right now.

10 Q So you would need to see a commensurate amount
11 of energy savings to propose to continue?

12 A (Witness Smith) No, I'm not saying anything
13 around a -- you know, an equal value is what justifies
14 it. It's that it's doing what the tool was intended to
15 do.

16 We're not saying that the tool doesn't need to
17 exist or that we agree that it should or shouldn't. We
18 just don't feel that it should be funded by demand-side
19 management dollars.

20 Q Are you aware that the cities of Atlanta and
21 the cities of Savannah are in the White House's Building
22 Performance Standards Coalition?

23 A (Witness Smith) No, I'm not.

24 Q Are you familiar with what that coalition has
25 agreed to do or committed to do?

1 A (Witness Smith) I am not.

2 Q So, just in brief, we have committed to pass
3 legislation or ordinances by 2024 for building
4 performance standards.

5 Would that change the calculus in any way if
6 plans are underway for those kinds of building
7 performance monitoring and improvement?

8 A (Witness Smith) Again, it still does not show
9 energy savings as a result to it. So it wouldn't change
10 our opinion.

11 Q Okay. Moving to demand response, you have two
12 different tariffs that are being proposed. One is
13 on-site for a customer's use and one is on-site for the
14 system's benefit; is that correct?

15 A (Witness Evans) Do you mean the DER customer
16 program?

17 Q Yes. The DRC and the RAST programs.

18 A (Witness Evans) Yes. That will be comprised of
19 two elements: one, those RAST, resiliency asset
20 service tariff, which we provide that on-site generation
21 or storage resource for the individual participating
22 customer, and then the DRC, which leverages that same
23 asset for the good of the system during reliability
24 events.

25 Q So many of our governments in this coalition

1 are interested in the idea of resiliency hubs where
2 somebody can go if there's a hurricane and power is out.
3 Perhaps they're medically dependent on electricity.

4 If you're on that tariff for the benefit of the
5 entire Georgia Power system, will there be any
6 opportunities to opt out in the event of a severe weather
7 event?

8 A (Witness Evans) So we're not -- currently we're
9 not contemplating allowing opt-outs primarily because the
10 benefit that the system would see by an opt-out is
11 severely diminished. If we can't count on those
12 resources to respond, that degrades the value of the
13 entire program.

14 So as far as an opt-out, no. However, these
15 assets can run for individual resiliency needs of the
16 participating customer. So if a storm was coming and
17 there was a local outage event or anticipation
18 potentially of a local outage event for that
19 participating customer, that's what they're paying for
20 the asset to provide them is that resilience. So I don't
21 know that there would be a need to in that specific
22 circumstance.

23 Q So that resiliency -- but it wouldn't
24 necessarily be sending electrons to the grid. It would
25 be generating electrons that could be used on-site for

1 the benefit of the whole system?

2 A (Witness Evans) That's correct. The program is
3 not constructed to supply energy to the grid, but
4 facilitate a reduction of demand from the grid.

5 Q I see. Is there any basis for the minimum size
6 requirement of 250 kilowatts?

7 A (Witness Evans) So we looked at the potential
8 of our customers that could participate in this program
9 and saw that the vast majority of that potential existed
10 with customers that could aggregate or had 1 megawatt of
11 demand response capability. So it was to reduce
12 administrative costs while realizing the maximum benefit
13 in the program.

14 Q Okay. And just shifting back to broader
15 income-qualified programs as my last question, something
16 that we've noticed in our conversations with Georgia
17 Power and just in our observations in our own communities
18 has been that the state of the housing stock is often a
19 barrier. And that's the case for small businesses, as
20 well.

21 When it comes to RISE and it comes to HEEAP,
22 are there any efforts underway to make more funds
23 available for pre-weatherization-type work that enables
24 the energy efficiency improvements themselves?

25 A (Witness Smith) We have been having

1 conversations with other groups that receive funding or
2 are philanthropic in nature and do structural
3 improvements to houses. It's to have a potential
4 partnership there to work together. But we have not done
5 anything formally. It's what we've proposed in our
6 programs currently.

7 Q Will the donation platform for HEEAP be
8 maintained and more aggressively advertised?

9 A (Witness Smith) We are seeking to have the
10 crowdfunding aspect maintained. And we would expect to
11 market it more. It didn't make sense during COVID to go
12 out and raise funds that we couldn't spend at the time.
13 So I would expect as things continue to return to normal
14 that we would market that more.

15 Q And, actually, one last question. In your
16 experience, does the \$5,000 average that's spent in the
17 HEEAP program for income-qualified typically cover the
18 needs in the home?

19 A (Witness Smith) So we're currently in the
20 program we're administering right now that's a \$3,750
21 value or cap. We are seeking to extend it to \$5,000 per
22 home. And that is from direct input from members of the
23 working group, along with companies that do that type of
24 work that feel that is the right value.

25 MS. BROWN: All right. Thank you so much.

1 WITNESS SMITH: Thank you.

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

5 MS. KYSOR: Good morning, Commissioners. Good
6 morning, panel.

7 WITNESS PHILLIPS: Good morning.

8 CROSS-EXAMINATION

9 BY MS. KYSOR:

10 Q The company views DSM as a resource; correct?

11 A (Witness Valle) Correct.

12 Q And I think in your testimony you note that
13 there is 113 megawatts of reduced demand built into the
14 load forecast as a result of the company's DSM portfolio;
15 correct?

16 A (Witness Phillips) Yes. The 113 megawatts is
17 in relation to the proposed case.

18 Q And there's a benefit to all customers, not
19 just participants by this lower demand; right?

20 A (Witness Phillips) Could you be more specific
21 in what you mean by "benefit"?

22 Q Sure. By lowering the demands that you have,
23 that could lower the need to bring on that additional
24 amount in supply-side resources; correct?

25 A (Witness Phillips) Yes. Energy efficiency does

1 result in less capacity needed to serve through other
2 resources.

3 Q And on page 10 of your testimony, lines 26 and
4 27, you state that the company's current DSM portfolio
5 will account for 1,500 megawatts of peak demand reduction
6 by 2025; correct?

7 A (Witness Phillips) That's correct.

8 Q About how much of that 1,500 megawatts of peak
9 demand reduction is associated with or attributable to
10 the RTP program?

11 A (Witness Valle) I can take this one.

12 It's about 230. So there are two -- on the --
13 on the demand -- on the load forecasting side, there is
14 a -- subject to check, 230 megawatts of demand response.

15 Q Thank you.

16 And on the load forecast, in one of your
17 responses to a data request you noted that the company
18 used to rely on a 20-year rolling analysis of weather
19 years; correct?

20 A (Witness Valle) That's correct.

21 Q And now the company -- the new methodology
22 introduced in I think 2018, under that the company will
23 always start at 1980 and just go up to the current year
24 in each update?

25 A (Witness Valle) That is correct, yes.

1 Q And the purpose of that was to minimize
2 variations in the set of data?

3 A (Witness Valle) Yes. So one of the -- one of
4 the goals of -- of weather normalizing the load, the
5 forecast, is to create a reference to isolate the impacts
6 of weather in the forecast.

7 So when you have that reference, one of the
8 attributes that is desirable for planning purposes is to
9 be stable. So a longer definition like the one we use
10 provides more of that stability that is less impacted by
11 extreme weather events.

12 Q Do you think it's useful to study trends over
13 time and how energy usage is related to weather patterns?

14 A (Witness Valle) Can you be more specific?

15 Q Sure. If you're using like an ever growing set
16 of years in your study, might that dilute some of the
17 impacts in how trends may change over time?

18 A (Witness Valle) Are you thinking specifically
19 about the 20 year -- the last 20 years versus the
20 definition of weather normal that we use?

21 Q Right. Like I think you use a 41-year -- a
22 41-year period in this current study. If you're looking
23 at that, you might dilute some of how customer behavior
24 during severe weather events might change over the
25 decades as homes become more efficient or technology

1 changes.

2 A (Witness Valle) So I would say, in terms of
3 temperature, the trends that you have seen in the last
4 20 years are also present in capturing the longer
5 definition that the company uses.

6 So I'm trying to -- I don't know if I'm
7 answering your question.

8 Q I think that's fine. We can move on. Thanks.

9 Okay. I think I heard you in response to
10 staff's counsel's question note that one of the reasons
11 that the company doesn't propose higher savings targets
12 is because of program economics in large part due to low
13 or avoided cost rates; is that correct?

14 A (Witness Phillips) That's correct. Since the
15 2019 IRP overall benefits have declined from -- or
16 compared with what was proposed in the 2019 IRP.

17 Q And lower avoided cost rates is a big part of
18 that?

19 A (Witness Phillips) Yes, yes.

20 Q And customers generally benefit when there's
21 lower avoided cost rates?

22 A (Witness Phillips) Yes. The fact that the
23 company's avoided cost has declined shows that we are
24 managing our fleet of resources efficiently and
25 effectively and capitalizing on all of the resources

1 available to help manage our load.

2 Q And then I'm trying to understand then when it
3 comes to the proposed additional sum methodology, there
4 it seems like the company is asking to remove the
5 relationship to avoided cost and switch to a different
6 methodology. And by removing that relationship to
7 avoided cost it might result in higher costs to customers
8 for the additional sum.

9 A (Witness Phillips) So the current methodology
10 does incorporate the avoided cost component. And what we
11 have seen over time with the decline in avoided costs is
12 that some residential programs barely pass the TRC
13 benefit. And, therefore, commercial customers, in terms
14 of additional sum, are carrying more of the overall
15 weight of providing additional sum.

16 The company's proposed methodology to base
17 additional sum on overall kilowatt hours saved is more in
18 line with the -- it allows the incentives to be more in
19 line with where the savings are actually realized.

20 Q Approximately what's the annual budget for the
21 proposed DSM portfolio?

22 A (Witness Smith) The entire budget is around
23 84 million, I believe. That's including all aspects of
24 things funded through the DSM, not just the programs.

25 Q Do you have -- do you know about what it is

1 with just the programs?

2 A (Witness Smith) I can look real quick.

3 A (Witness Phillips) Are you asking for just the
4 certified programs, not some of the other programs, like
5 Learning Power and Energy Efficiency Awareness?

6 Q Either is fine. Just a ballpark.

7 A (Witness Smith) So the budgets for the program
8 is 71 million.

9 Q So the budget is about 71 million. And under
10 the new methodology the company, if it hits its targets,
11 could make 17 million in additional sum, maybe even more?

12 A (Witness Smith) If the -- if the kilowatt
13 savings goals were hit, then that would be the additional
14 sum mark, yes.

15 Q Thanks. I'm going to shift gears to the
16 distributive energy resource or DER program. I'm going
17 to try not to retread any ground.

18 So, I guess, first, I think I heard you say
19 that the participating customer would have a say in what
20 type of DER resource would be implemented or installed?

21 A (Witness Evans) That's correct.

22 Q And would solar plus storage be one of those
23 options?

24 A (Witness Evans) Potentially. The dispatchable
25 nature of the storage battery would be the resiliency

1 aspect. And that would be the piece that could
2 participate in the demand response credit.

3 Q And so ultimately it's -- is it the customer's
4 choice or the result of a conversation between the
5 company and the customer?

6 Like, does the company have some input, as
7 well?

8 A (Witness Evans) Well, the company will have
9 requirements, such as the environmental permitting
10 requirements of the assets, to ensure they're able to run
11 when called upon. But the customer's resiliency needs
12 are driving the selection of that asset.

13 Q And the cost recovery will be the same whether
14 a customer participates in both RAST-1 or RAST-1 and
15 DRC-1; correct?

16 A (Witness Evans) Yes. The payments that the
17 company receives from that individual participating
18 customer through RAST-1 will be the same whether they
19 participate in DRC or not. The DRC would just provide a
20 credit.

21 Q And then a couple of questions about the RAST-1
22 program. Will the DER only operate when the grid goes
23 down?

24 A (Witness Evans) So under the resiliency asset
25 service tariff, the asset will operate in the event of a

1 loss of local -- a local event to that individual
2 customer. Or to the extent that they're participating in
3 the DRC that asset will also run during a reliability
4 event on the system.

5 Q If they're only an RAST-1 participant, it will
6 only run during a loss of load event?

7 A (Witness Evans) That's correct.

8 Q And so is it, in essence, Georgia Power would
9 be providing kind of traditional backup power for those
10 customers that are only participating in the RAST-1?

11 A (Witness Evans) Yeah. Yes. We'll be providing
12 that resiliency service that we've heard from our
13 customers that they're looking for and other utilities
14 across the nation are providing.

15 Q And that resiliency benefits the participant.
16 Does it also benefit non-participants if you're only
17 looking at participation in the RAST-1 program?

18 A (Witness Evans) Just the participating in the
19 RAST-1 is just a benefit for that participating customer.
20 And they'll -- as a result, they will be the ones paying
21 for that asset; right?

22 The DER customer program in total leverages its
23 reality that customers are installing these assets for
24 their individual resiliency needs and seeing the
25 opportunity for Georgia Power to now provide that

1 additional DRC program on top of it to leverage those
2 assets for the good of the system.

3 Q And then you said that they'd be paying for it.
4 I think I heard you say that the capital costs -- the
5 upfront costs would be rate based; right?

6 A (Witness Evans) That's correct.

7 Q And so if it's rate based, it's paid for by all
8 customers or however it gets distributed in the cost
9 allocation in the rate case or -- I just want to make
10 sure.

11 A (Witness Evans) Sure. Let me clear that up.
12 So it will be rate-based assets, but the revenue received
13 through the RAST will also be above the line revenue
14 offsetting those revenue requirements in keeping
15 non-participating customers costs -- the costs will not
16 shift to non-participating customers as a result.

17 Q Shifting to a couple of questions about the
18 DRC-1 tariff. Will Georgia Power operate the DER only
19 when the grid goes down or -- and when there's a
20 reliability event?

21 A (Witness Evans) Well, we'll operate the assets
22 through the DRC to prevent the grid -- as you said, the
23 grid from going down. It will be during reliability
24 constrained times, but to prevent that from occurring.

25 Q Will Georgia Power operate the DER at any times

1 outside of reliability events?

2 A (Witness Evans) No. As currently constructed,
3 the program would only operate the assets during
4 reliability events.

5 Q Sorry. Some of the -- some of this is a bit
6 technical for me. So I think I heard you earlier say --
7 and I might be wrong though because this is a different
8 framing.

9 Under the DRC-1 is the DER callable by Georgia
10 Power in a loss-of-load event or is it only available to
11 the participating customer to meet their load on-site?

12 A (Witness Evans) Help me with the example you're
13 -- I'm not quite sure I'm following.

14 Q If there is a loss-of-load event -- if a
15 customer participates in both the RAST and the DRC
16 tariffs and there's an actual loss-of-load event, will
17 that DER be available first and only to the participating
18 customer to meet their demand?

19 A (Witness Evans) Well, the asset is only going
20 to serve that customer's individual demand, no matter
21 what.

22 Q Okay.

23 A (Witness Evans) It's not sized to export to the
24 grid. It's sized for their individual load. So whether
25 it's called for a local event, right, like as we have

1 trees fall down on lines creating a very local outage
2 event, that asset will run for that individual customer.

3 If there's a system reliability event, it will
4 still run and meet that individual customer's needs, but
5 by reducing the load on the system, the system will see
6 that reliability benefit.

7 Q And you got to my next question I was going to
8 ask. So how will you determine the appropriate sizing?

9 Is it limited to the customer's load?

10 A (Witness Evans) That's correct.

11 Q And when Georgia Power uses the DER that's
12 behind the meter of a DRC-1 customer, does that customer
13 receive a dual benefit where they're getting both a bill
14 credit for their participation in DRC-1 and a reduced
15 electricity bill because they're not importing kilowatt
16 hours off the grid?

17 A (Witness Evans) Well, I -- they would see a
18 slight reduction in their electricity bill. Because,
19 again, these assets are not going to be called for DRC
20 that often, only during reliability events. But they're
21 paying for that asset. So they're paying for the ability
22 to call on that asset.

23 And the system is then providing a credit
24 because of the reliability benefit that that asset is
25 providing. So they would see both the credit and a

1 slight reduction in their bill only when those
2 reliability events are called.

3 Q And the program is only open to company-owned
4 assets. And, I'm curious, is the long-term goal of this
5 program to prove out model of Georgia Power deploying
6 company-owned DERs or is this more of a bridge toward a
7 DER program that could involve customer-owned assets?

8 A (Witness Evans) We proposed it just for
9 customer-owned assets because we think that limits the
10 risk -- the reliability risk that third-party ownership
11 could impose on the program. We also see the benefits of
12 leveraging that for the system's benefits and the
13 administrative efficiency that Georgia Power's ownership
14 provides.

15 VICE-CHAIRMAN ECHOLS: Let me ask you a
16 question. How is -- how is this grid benefit
17 different than a company or an individual that
18 puts -- that puts solar on their home?

19 How is it different?

20 WITNESS EVANS: Sure. So the dispatchable
21 nature of the call when the asset starts up. You
22 know, as we heard yesterday, the growing winter
23 reliability; right?

24 If an event occurs pre-sunset -- or
25 pre-sunrise, right, we can call on these assets to

1 reduce that constraint on the system. So it really
2 boils down to the dispatchable nature of the asset
3 ensuring that it can respond when we need it to.

4 VICE-CHAIRMAN ECHOLS: Thank you.

5 MADAM CHAIR PRIDEMORE: It was about 3:30 in
6 the morning on Sunday and I was driving up in
7 north Bartow County and there were multiple plants
8 Sunday that were operating in the dark still, what,
9 three, maybe four hours from sunup.

10 In the case of an outage for them, these DERs
11 could provide them with the necessary energy so that
12 they could operate a shift; right?

13 WITNESS EVANS: That's correct.

14 MS. KYSOR: I have no more questions. Thank
15 you.

16 MADAM CHAIR PRIDEMORE: Georgia Large Scale
17 Solar Association and Advanced Power Alliance.

18 MR. CARVER: No questions, Madam Chair.

19 MADAM CHAIR PRIDEMORE: No questions.

20 Okay. Georgia Solar Energy Industries
21 Association, Solar Energy Association, and Vote
22 Solar.

23 MR. THOMASSON: Good morning, gentlemen. I
24 just have a couple quick questions on the DER
25 customer program.

1 CROSS-EXAMINATION

2 BY MR. THOMASSON:

3 Q With regard to the company ownership of the DER
4 assets, is the company planning to do competitive
5 solicitations for EPC for those assets?

6 A (Witness Evans) Yes. We're currently looking
7 at what capabilities exist in the DER market from both
8 the OEMs, the original equipment manufacturers, and EPC
9 providers in the space to learn how we can better
10 leverage them when the -- should the program get approved
11 in the report.

12 Q But the intent is to competitively procure
13 those like you would for other resources?

14 A (Witness Evans) That's correct.

15 Q Okay. And then one clarification on the
16 revenue requirement that sort of brings in for other
17 customers. I heard you tell Mr. Jones that the revenue
18 requi- -- assets are going to be rate based and the
19 revenue requirement will be recovered from the customers
20 participating in RAST during their participation and that
21 they will only pay that revenue requirement for the term
22 of their participation; is that correct?

23 A (Witness Evans) That's correct.

24 Q What happens if the company, say, owns more
25 assets for this program than customer demand justifies

1 over time?

2 Is that revenue requirement that's not being
3 paid by customers during the life of that asset then
4 recovered by -- from other customers in rate base, or
5 does that just accrue to other customer -- or does the
6 company pay that when it's not being -- when an asset is
7 not actively being used in the program and having that
8 revenue requirement?

9 A (Witness Evans) So we're going to have -- these
10 assets are going to be procured for the individual
11 customer and installed per their requirements for their
12 resiliency needs. So they'll be integrated behind the
13 meter into their electrical system serving their needs.
14 So there's not going to be a stockpile of inventory to
15 deploy. I'm not sure I understand the question.

16 Q I thought I heard you testify earlier that one
17 advantage of these assets, these resources, is that they
18 could be redeployed for other customers?

19 A (Witness Evans) Yes. I think he was asking
20 about in the event of a breach of contract where the
21 customer did not fulfill their obligation. And a benefit
22 of the program is that these assets can be, you know,
23 redeployed to new customers. And in that event, they
24 would have been be somewhat depreciated and be a great
25 value to a new customer in the RAST program.

1 Q Okay. I won't dwell on that. I think that
2 covers my question.

3 Moving on to the DRC bill credit. What's the
4 nature of the bill credit? How is it structured?

5 Is it a fixed fee or a fixed payment to the
6 customer based on the capacity amount or on that -- that
7 value or is-- and is it fixed, regardless of how much the
8 resource is actually activated or the -- during an outage
9 event?

10 Is it sort of a flat-fee payment, more like a
11 capacity or availability payment?

12 A (Witness Evans) Sure. So the DRC credit
13 portion will be fixed. A monthly payment over the
14 contract life that'll correspond with the asset contract.
15 And it will be independent of if the asset is called upon
16 or not.

17 And the reason is because -- just like with the
18 company's other dispatchable demand-side programs, this
19 will be reflected on the resource ledger and defer future
20 capacity needs. So the system will receive benefits and
21 all customers will receive benefits of this program,
22 regardless of if it's actually needed and called upon in
23 a given year because of that capacity deferment.

24 Q And there's not any additional compensation or
25 credit for each time that it's actually called upon; it's

1 just a flat-rate regardless?

2 A (Witness Evans) That's correct.

3 Q Okay. And, just to clarify, is it -- is it
4 correct that the benefit that comes from those payments
5 and the resources isn't that those resources are directly
6 serving the grid, but more that they are allowing sort of
7 an islanding of that load during an outage event?

8 So what you're paying them for is to take their
9 load off, not that the DER is essentially a grid asset,
10 but it's a system resource in a -- similar to a demand
11 response that they are taking their load off the grid is
12 the benefit; correct?

13 A (Witness Evans) That's correct. And I wouldn't
14 characterize necessarily it as "islanding" because a good
15 number of customers might not choose to completely cut
16 off service from the grid, but just reduce service during
17 those outages.

18 Q Okay. So it could be an incremental?

19 A (Witness Evans) Exactly. So it doesn't
20 necessarily have to be an islanding situation, but a
21 reduction in demand served by the grid.

22 Q Okay. And I know that you've answered the
23 question about having customer-owned or third-party-owned
24 assets within this program and that the company is not
25 currently looking at that. But has the company

1 considered -- similar to a couple of questions that
2 Commissioner Echols asked, other compensation programs,
3 other crediting programs that might be structured a
4 little differently, but that could compensate customers
5 for resources that they own themselves or the third party
6 owns for any benefits that they may provide that may not
7 be quite as firm or as dispatchable as this program is
8 intended?

9 A (Witness Evans) We haven't at this time. This
10 program was focused on realizing the growing need in
11 customers to meet their resiliency needs and how we can
12 leverage the installation of those assets going forward
13 for the benefits of the system. We didn't look at
14 developing anything else out of that.

15 Q And no immediate plans to look at -- develop a
16 program like that in the future?

17 A (Witness Evans) Not at this time.

18 MR. THOMASSON: Okay. That's all the
19 questions.

20 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
21 Association. Not present.

22 Georgia Watch.

23 UNIDENTIFIED SPEAKER: She's in the restroom.

24 MADAM CHAIR PRIDEMORE: She stepped out.

25 Interstate Gas Supply.

1 MR. CARVER: No questions, Madam Chair.

2 MADAM CHAIR PRIDEMORE: Resource Supply

3 Management. Not present.

4 Georgia Watch.

5 MS. COYLE: I thought he might have a few more

6 questions. I had to run to the ladies room.

7 MADAM CHAIR PRIDEMORE: Well, since you missed

8 a couple, we're going to make sure you don't

9 duplicate them.

10 MS. COYLE: I don't think I'll have any extra

11 questions.

12 Good morning still.

13 THE PANEL: Good morning.

14 CROSS-EXAMINATION

15 BY MS. COYLE:

16 Q I have several questions I think. Mr. Smith --

17 I'm going to have fun calling you Mr. Smith for today, at

18 least. Most of them will be ones for you to answer, but

19 certainly anyone can feel free to jump in at any point.

20 I wanted to just start with a quick follow-up

21 question to Ms. Kysor's question. She asked you about

22 the budget for DSM and then asked you to break out the

23 program budget.

24 Do you recall that? I believe the answer was

25 71 million.

1 A (Witness Smith) That's right.

2 Q Okay. Could you further break that down for me
3 as it relates to your proposal in this IRP to -- I might
4 be paraphrasing a little bit. But it appears that you're
5 going to aim to have more of the additional sum collected
6 tied to the actual customer class where the program often
7 incurred.

8 I believe I heard you testify earlier that
9 right now commercial customers are paying more of the
10 additional sum than residential customers?

11 A (Witness Smith) Correct. The commercial class
12 in the case that we're proposing would pay -- would
13 pay -- it's broke down by the percentage of savings. So
14 it would be 70-plus percent would come from the
15 commercial class. You're asking in the future?

16 Q In the current -- I'm asking in your proposal
17 of that 17 million in additional sum, how much would now
18 be borne by -- well, maybe currently and then in the
19 future.

20 How much of the 17 million is currently borne
21 by commercial versus residential and how much would that
22 change with your new proposal?

23 A (Witness Smith) So I think I would have to
24 address it by percent because they're different amounts;
25 right?

1 So current -- in the proposed program -- let
2 me, if you don't mind, reference the filing.

3 Q Uh-huh.

4 A (Witness Smith) Bear with me. I'm sorry.

5 Q That's quite all right.

6 A (Witness Smith) So in Appendix F in the
7 filing --

8 Q Uh-huh.

9 A (Witness Smith) Residential, based on the
10 proposed plan, would be about 3.8 million of the 17.

11 Q Okay.

12 A (Witness Smith) And --

13 COMMISSIONER McDONALD: Mr. Smith, get close to
14 that microphone, please, sir.

15 WITNESS SMITH: Sorry, Commissioner.

16 Residential would be about 3.8 million of the
17 17 and 13.4 would come from the commercial class.

18 BY MS. COYLE:

19 Q And am I correct that that 3.8 million would be
20 paid by all your residential customers, regardless of
21 whether they participated in the DSM programs?

22 A (Witness Smith) Correct.

23 Q So would it surprise you that according to the
24 2020 U.S. Census, 14 percent of people living in Georgia
25 are living in poverty?

1 A (Witness Smith) I would not say it surprises
2 me.

3 Q And would you agree there are many low to
4 moderate income -- and let me just say I'm going to be
5 referring to that in the future questions as LMI, low to
6 moderate income for shortening sake.

7 A (Witness Smith) Okay.

8 Q Would you agree there are many low to moderate
9 income, or LMI, Georgians in your service territory?

10 MADAM CHAIR PRIDEMORE: Ms. Coyle, I'd prefer
11 it if you would say out each time because LMI is not
12 a standard acronym we use in the utility industry.

13 MS. COYLE: Yes, ma'am. Yes, ma'am.

14 MADAM CHAIR PRIDEMORE: Thank you.

15 WITNESS SMITH: I'm sorry. Would you restate
16 the question?

17 BY MS. COYLE:

18 Q Would you agree there are many low to moderate
19 income Georgians in your service territory?

20 A (Witness Smith) We don't ask our customers to
21 identify income level. So I can't say to the word
22 "many," but I would say there are, you know, low to
23 moderate income customers of ours.

24 Q Would you agree lower income people often live
25 in older, less efficient housing?

1 A (Witness Smith) Again, I don't -- we don't ask
2 them to tell us about their housing stock, so...

3 Q Would you agree that the customers you
4 currently are serving with your income-qualified programs
5 often live in older, less efficient housing?

6 A (Witness Smith) The customers that we currently
7 serve, I would agree. Because, you know, those are the
8 homes that have the savings opportunities.

9 Q And would you say that those individuals might
10 be living in single-family, as well as multifamily
11 housing?

12 A (Witness Smith) Correct. We have participation
13 in both single-family and multifamily dwellings in our
14 income-qualified programs.

15 Q And would you agree many of your low to
16 moderate income customers experience a higher energy
17 burden, meaning they pay a significant portion of their
18 monthly income on utility bills?

19 A (Witness Smith) We don't -- so when you use the
20 term "energy burden," you know, that defines 6 percent or
21 more of their household income going towards all energy.
22 And we don't have access into that data to be able to say
23 percentages.

24 Q So let me ask it to you this way. If a
25 household is a lower or moderate income household, does

1 that mean that their monthly budgets for all of their
2 expenses are lower than a higher income household?

3 A (Witness Smith) Can you ask it again?

4 Q Would you agree that people of lower income
5 have lower monthly budgets for all of their household
6 expenses than someone of higher income?

7 A (Witness Smith) I would agree that their income
8 is lower. But as far as what their expenses are for
9 their budgets would be tied specifically to them.

10 Q But everybody -- would you agree that
11 regardless of your income, you need shelter, you need
12 food, you might need medicine, you'll have transportation
13 costs, and you'll certainly have water, electric, and
14 maybe gas costs?

15 A (Witness Smith) I would agree that all people
16 have basic needs, yes.

17 COMMISSIONER McDONALD: Would that not take
18 into consideration of other help, outside sources;
19 i.e., federal government, other programs that would
20 be involved -- that other group above what you're
21 talking about would not participate in?

22 MS. COYLE: And many moderate income Georgians
23 are not necessarily taking advantage of those
24 programs, as well. I would agree with that.

25 BY MS. COYLE:

1 Q But I believe you answered earlier -- I forget
2 which intervenor asked you that -- she was asking a
3 question about whether lower income customers or higher
4 income customers used more or less electricity. And I
5 believe your answer was: It's not a factor of income.
6 It's a factor of energy use in the household.

7 A (Witness Smith) Correct. Subject to check,
8 that was said.

9 Q But if someone is making, you know, under
10 \$30,000 a year, but has, you know, the same energy use as
11 someone making \$100,000 a year and they have the other,
12 you know, expenses that -- you know, housing, et cetera,
13 would it not be a bigger chunk of the paycheck for that
14 30,000 or below income to pay the same power bill as
15 someone with a higher income?

16 A (Witness Smith) Yes. In your example, if
17 income levels are different and the energy use is the
18 same, then, yes, the lower income earner would have a
19 higher percentage of their earnings.

20 Q Yes. And that's all I was -- it really wasn't
21 a trick question.

22 Okay. And so would you further agree that many
23 of your customers who would most benefit from demand-side
24 management programs you offer can least afford the
25 upfront cost?

1 That lower income customers can least afford
2 the upfront cost of DSM programs?

3 A (Witness Smith) Correct. And, you know, that's
4 part of the budget difference from last cycle to this
5 cycle is a higher percentage of income-qualified
6 customers are in our program offering and that requires a
7 higher expenditure of improvement costs.

8 Q So would you agree that over the years I've
9 been a big fan of your income-qualified programs?

10 A (Witness Smith) I would agree that you're a big
11 fan of income-qualified programs, yes.

12 Q Especially when they're designed in ways that
13 have the greatest benefit for your income-qualified
14 customers.

15 Would you also agree that customers
16 experiencing frequent disconnect and reconnect and
17 possible -- leading possibly to uncollected bad debt
18 increases costs to all residential customers?

19 A (Witness Smith) I'm not the right person for
20 that.

21 Q Is anyone else able to answer that?

22 A (Witness Phillips) Could you repeat your
23 question again?

24 Q When customers experience -- is it --
25 Mr. Smith, is it correct that some of these

1 income-qualified programs that you offer in your
2 department, including the prepaid program --

3 A (Witness Smith) Prepay is not an energy
4 efficiency program.

5 Q No. But, I mean, some of these programs have a
6 specific intent of trying to help prevent disconnect.
7 Helping people be able to afford their power bills, maybe
8 pay off their arrearages, and keep the lights on. It's
9 good for them to keep their lights on.

10 But are there not costs associated with the
11 system of frequent disconnect/reconnect and then, in some
12 cases, bad debt that never gets collected from the
13 customer, don't you ultimately spread that out to all
14 your residential customers? That might be a rate case
15 question.

16 A (Witness Smith) Again, I'm a witness for energy
17 efficiency, not on the rate side of the business.

18 Q Okay. Fair enough. Thank you. So now with
19 that context I'm going to turn to your testimony.

20 There we are, finally. So I wanted to ask you
21 about the -- actually, that one was asked and answered.
22 I was paying attention.

23 On page 7, line 24 of your testimony, you talk
24 about having the DER can providing meaningful customer --
25 can meet a growing customer need.

1 Is it customer need that you've identified or
2 is it customer demands?

3 Is this something your customers are asking
4 for?

5 A (Witness Evans) I think it's both. I think
6 we've identified customers in certain segments that have
7 a need and have been seeking solutions from Georgia
8 Power.

9 Q And then a little bit further down, line 27 of
10 that same page, you mention: Demand response value and
11 corresponding system resilience.

12 Would this -- are we talking about -- again, I
13 know this is not a rate case, but would the smart usage
14 program that you offer be the kind of demand response
15 that you're indicating in this testimony.

16 A (Witness Phillips) I don't know that smart
17 usage is considered a demand response.

18 Q Well, there's a demand charge tied to if you're
19 on that rate.

20 A (Witness Phillips) Correct. There's also a
21 demand charge for a number of our commercial rates, but
22 they're not included in our demand response portfolio.

23 Q That's not what you're talking about on this
24 page --

25 A (Witness Evans) That's correct.

1 Q -- so I'll move beyond that.

2 MADAM CHAIR PRIDEMORE: Ms. Coyle, don't make
3 me get out the Final Jeopardy music.

4 MS. COYLE: I heard about that last night. I'm
5 sorry I missed that. I was just making sure I
6 didn't --

7 MADAM CHAIR PRIDEMORE: You still have an
8 opportunity to hear it.

9 MS. COYLE: I was just making sure I didn't ask
10 questions I already heard asked earlier. I thought
11 I might have time over lunch to go back and cross
12 out some of my questions, but everybody moved
13 through quickly today.

14 BY MS. COYLE:

15 Q So I wanted to ask you some questions --
16 several -- beginning on page 11, but really a few times
17 in your testimony, there's a reference to the
18 Commission's economic screening policy outlined in the
19 2004 IRP order directing proposed DSM plans minimize
20 upward pressure on rates and maximize economic
21 efficiency; is that correct?

22 A (Witness Phillips) Yes.

23 Q Are you aware of whether this -- the rule
24 number is written somewhere. You have the rule number --
25 actually, where is it at?

1 COMMISSIONER McDONALD: Ms. Coyle, you remember
2 me. You can't read all that and then ask them if
3 that's correct. They swore that it is correct.

4 MS. COYLE: I just want to make sure they know
5 what --

6 COMMISSIONER McDONALD: Thank you.

7 MS. COYLE: -- the lead-up to my question is.

8 BY MS. COYLE:

9 Q Yes. Well, somewhere in there you have the
10 actual rule number.

11 Would you agree -- would you say that the
12 Commission has ordered Georgia Power to make sure that
13 all of the company's plans and the IRP, whether they're
14 supply- or demand-side, minimize upward pressure on rates
15 and maximize economic efficiency?

16 A (Witness Phillips) I can't speak to the
17 specifics of the supply-side plan. But as it relates to
18 development of the demand-side plan, the company does
19 seek in developing its overall proposed case to achieve
20 the directive that was set forth by the Commission in the
21 2004 IRP to put forth a case that seeks to maximize
22 economic efficiency while minimizing upward impact on
23 rates. And the company has considered that in a number
24 of IRPs since then and those programs are eventually
25 approved by this Commission.

1 Q Would you agree that there are aspects of this
2 IRP and every IRP that ultimately will put upward
3 pressure on rates because most IRPs are followed by a
4 rate case when the company asks for a rate increase?

5 A (Witness Phillips) I can't speak to specific
6 IRPs. But, as you said, we seek to minimize those upward
7 impact on rates wherever possible.

8 Q Do you have any reason to think that there is a
9 particular burden on the demand-side to not put upward
10 pressure on rates?

11 There was a lot of discussion about the -- not
12 passing the TRC test some of the programs that you're
13 recommending continuing. That maybe there's a greater
14 challenge or push on the demand-side to not put upward
15 pressure on rates.

16 A (Witness Phillips) Well, the company calculates
17 the cost effectiveness in accordance with a number of
18 industry standards, specifically the California standards
19 for cost-effectiveness tests. And these specific tests
20 are included in both the IRP rules and the DSM program
21 planning approach. And part of a number of those
22 cost-effectiveness tests incorporate the avoided costs of
23 both generation, transmission, and distribution.

24 And so as avoided costs continue to decline,
25 which is a good thing for all of our customers, it does

1 put pressure on some programs to continue to pass the
2 TRC test specifically.

3 Q And, yet, you -- and just now I want to -- in
4 follow up to that, I'm on page 13 of your testimony,
5 beginning on line 6.

6 You're describing your request to waive the TRC
7 requirement for -- specifically for the residential
8 thermostat demand response. And you had quite a bit of
9 response to earlier questions about why that is.

10 But I'm interested whether you considered
11 asking for a waiver for any of the other programs that
12 might not have done so well on the TRC.

13 A (Witness Phillips) No, we did not consider
14 that. There are some unique attributes related to the
15 thermostat DR program where the company felt that a
16 waiver was appropriate to ask for in this case.

17 As I mentioned, it's already an existing
18 program in place. It is capacity that is included on our
19 resource ledger. We're planning on that capacity to be
20 available and we have a number of customers that are
21 already engaged and support that program.

22 Q Is there a reason you didn't consider applying
23 a waiver request to any of the other programs?

24 A (Witness Phillips) Well, for those reasons I
25 just stated is why we specifically cited or suggested or

1 requested that a waiver be considered for the thermostat
2 DR. We felt that given those specific attributes of the
3 thermostat DR program and the fact that it did pass TRC
4 and the previous IRP and doesn't pass TRC now because we
5 changed the way it's modeled.

6 The TRC program is expected to be cost
7 effective within this 12-year planning cycle. And so for
8 those reasons we are requesting that the Commission
9 consider the TRC waiver for that specific program.

10 A (Witness Smith) Additionally, it's the only
11 program that has a measure already in place. All other
12 programs are incenting to change behaviors or change
13 measures.

14 Q Okay. Thank you for that.

15 And now this one is definitely going to be for
16 you, Mr. Smith. At the bottom of page 13 you're
17 describing the HopeWorks program.

18 Would you agree that I'm a big fan of the
19 HopeWorks program?

20 A (Witness Smith) You say you are. So I would
21 agree with that.

22 Q And so in seeking to increase financial support
23 for the program, you -- you also acknowledge that this is
24 a program that exclusively serves the single-family home;
25 is that correct?

1 A (Witness Smith) Correct. HopeWorks model is
2 senior citizen single-family homes. They're income
3 qualified.

4 Q And would you agree that you're seeking to
5 increase the budget and make -- certify the program
6 because they have been so successful with that task?

7 A (Witness Smith) It is -- we are seeking to
8 increase and certify the program because it has been
9 effective over the years and there's additional
10 opportunity with that customer base.

11 Q Are you able to make a comparison between the
12 success of the HopeWorks program and the existing HE- --
13 home energy efficiency -- wait. Home energy
14 efficiency -- what does the "A" stand for again?

15 A (Witness Smith) Home energy efficiency
16 assistance program.

17 Q Assistance program, yes. Thank you.

18 A (Witness Smith) I don't understand your
19 question. Could you restate it?

20 Q Well -- so HopeWorks has a specific
21 long-standing approach to improving the energy efficiency
22 of income-qualified seniors' homes. You have another
23 income-qualified program that's somewhat similar with
24 HEEAP; is that correct?

25 A (Witness Smith) They have similar customers in

1 mind, yes.

2 Q Would -- and I believe I heard you just say
3 that you believe that HopeWorks has an effective program.

4 A (Witness Smith) Their program has proven
5 effective through -- as we have worked with them, yes.

6 Q And so I'm asking for a -- and I recognize that
7 HEEAP is a newer program. I'm just asking whether that
8 you can make a comparison in terms of the delivery of
9 savings for HEEAP customers as compared to HopeWorks
10 customers.

11 A (Witness Smith) Yes. I don't feel that we can
12 make that comparison right now. HEEAP launched,
13 obviously, during the pandemic. And we have not had, you
14 know, a large enough participation group to say that I
15 feel that there is any tie there.

16 Q Would you say that as we get further into this
17 2023 to '25 cycle and you have further opportunity to,
18 post-COVID, roll out HEEAP -- would you agree that that
19 would be a fair question to ask?

20 A (Witness Smith) I agree that the evaluations of
21 both of those programs if approved by this Commission
22 would point out savings for each customer group. You
23 know, cost per customer group, process findings. Those
24 would be outlined in those evaluations.

25 Q And because the HopeWorks program is

1 specifically seniors and single-family housing and you're
2 proposing to increase the budget there, would it be
3 appropriate for you to direct more of the budget for
4 HEEAP to non-seniors and non single family households?

5 A (Witness Smith) I would point out that another
6 program -- and I apologize for all the acronyms,
7 Commissioners. But HEIP, which is the home energy
8 efficiency improvement program, it does have a carve-out
9 of \$500,000 for income-qualified multifamily improvement
10 projects. And then any customer, regardless of age, can
11 participate in HEEAP, as well.

12 Q I appreciate that. And I do appreciate the
13 carve-out in the HIEP [sic] program. But because the
14 HopeWorks program is so specifically targeted to
15 income-qualified seniors in single-family homes, in
16 addition to the 500,000 carve-out in the HIE- --

17 A (Witness Smith) HEIP program.

18 Q -- HIEP [sic] program, would the company
19 consider being more deliberate about targeting through
20 marketing or other measures more non-senior customers for
21 the HEEAP program?

22 A (Witness Smith) Sorry. I'm trying to unpack
23 all the acronyms myself.

24 How we market, the way we go about doing that,
25 will be determined once an implementation company is

1 selected if these programs are approved. And at that
2 point in time we would know who we're more specifically
3 marketing to under HEEAP.

4 Q So that's a "maybe"?

5 A (Witness Smith) Yeah.

6 Q Thank you.

7 A (Witness Smith) I'm saying we have to implement
8 them before we know how to adjust them.

9 Q But is it reasonable for one on the advocacy
10 side to want to make sure that all of your
11 income-qualified customers have the opportunity to
12 experience the benefits of these programs and not just
13 seniors?

14 A (Witness Smith) That's your call, I mean, as an
15 advocate. I mean, you're going to advocate for what you
16 think is right.

17 Q Fair enough. Did that one.

18 And, again, I'm going to just go back to the --
19 and, again, in your testimony on page 17, lines 14
20 through 17, the company continues to follow the policy,
21 which we've just discussed, that you asked for a waiver
22 for the thermostat program.

23 Is this a policy that might -- that you might
24 want to consider asking for a waiver for the policy going
25 forward for all of the programs?

1 A (Witness Phillips) To my knowledge, the company
2 has never requested for a TRC waiver in previous IRPs.
3 We see this as an exception.

4 And for the reasons we shared earlier, we feel
5 like the thermostat DR program, the request for a waiver
6 was merited given the specific nature and benefits of
7 that program and the fact that it's already existing
8 today. So we do not see that the waiver will be a
9 standard practice. It's an exception to the rule and a
10 rule that has guided development of our proposed case for
11 a number of IRPs.

12 Q Thank you. And in that same paragraph as you
13 talk -- and, again, as it relates to the economics of the
14 programs, you testified that the benefits from the
15 programs decline. Would you say that that statement
16 applies to customers who can afford the upfront cost of
17 installing these measures without the incentive less and
18 not so much to the customers we've just discussed who
19 can't afford the upfront costs?

20 A (Witness Phillips) I'm not sure I understand
21 the question. Can you rephrase that?

22 Q Would you say that the benefits of the
23 company's demand-side management programs have declined
24 in some ways because of the term you've used, free
25 ridership, that you have more customers who are choosing

1 without an incentive to make their homes more energy
2 efficient?

3 A (Witness Phillips) I can speak to the benefits
4 as it relates to the TRC. Let me see if I can answer
5 that question --

6 Q Okay.

7 A (Witness Phillips)-- and then we can continue
8 further.

9 The benefits are declining because avoided
10 costs are declining. And avoided costs are declining not
11 because of any particular customer situation, but because
12 of the way that we are operating our system.
13 Specifically, as we stated in the testimony, low natural
14 gas prices, as well as low to moderate growth, and an
15 increase in renewables are driving the reduction in
16 avoided costs. So that's what's driving the reduction in
17 benefits.

18 Q In the case of the TRC?

19 A (Witness Phillips) Yes. Well, we include
20 avoided costs in a number of our cost-effectiveness
21 tests, but that's specifically related to the TRC was
22 what I was speaking to.

23 Q Thank you.

24 A (Witness Smith) And to further add to that
25 point, with the exception of income-qualified specific

1 programs, we don't ask customers to identify their income
2 level in the other programs that we have. So we're
3 evaluating the program for all participants, which could
4 include income-qualified and non-income-qualified
5 customers.

6 Q Thank you. And so let me -- moving on from
7 there -- and I mentioned free riders. Is that a term
8 that means people who are taking advantage of programs
9 even if they didn't need to or does that mean they are
10 already going to be buying -- they're planning to buy LED
11 light bulbs and that you just happen to have a special on
12 them for your program and so that makes them free rider?

13 A (Witness Smith) So free ridership is determined
14 through survey questions as part of an evaluation. And
15 it can be partial free ridership or holistic free
16 ridership.

17 So a customer may answer, "Yes, I would have
18 done this anyway," and we would not receive credit
19 through the evaluation for those energy savings.

20 Or they can say, "It partially influenced me,"
21 and then we would receive partial credit for that.

22 Q Okay. And I -- again, I recognize that in some
23 cases you're not finding out about whether your customers
24 specifically are income qualified or not. But is it
25 theoretically likely that there are fewer free riders who

1 are also low income?

2 A (Witness Smith) I don't know that I can answer
3 that question.

4 Q Thank you. And then I'm just -- I'm curious.
5 This is the bottom of page 19, lines 22 through 24, where
6 you're talking about you do have specific targets for
7 income-qualified customers for your residential programs
8 to increase customer participation.

9 So when you've said on the one hand you don't
10 ask your customers what their income is, how do you plan
11 to target them?

12 A (Witness Smith) We ask them if they are in an
13 income-qualified program. They have to qualify.

14 Q Yeah. Right.

15 A (Witness Smith) But the way you target them
16 varies on what the program is. It could be anything as
17 far as -- as somebody mentioned earlier, using census
18 track data. It could be working with other organizations
19 that are already qualifying customers through the
20 programs that they're working in. And we would partner
21 with them to implement our program to that same customer
22 group.

23 Q And you did have a few questions about that
24 earlier and I think the response was you haven't really
25 done much of that yet, but you would be willing to work

1 with local governments or other avenues to better market
2 these programs to lower income communities?

3 A (Witness Smith) Again, with all of our
4 programs, including income-qualified programs, if there
5 are other opportunities to work with other groups or
6 partner with other organizations, we are always willing
7 to entertain that.

8 MADAM CHAIR PRIDEMORE: Wouldn't they be
9 identified through the similar channels that the
10 Salvation Army programs are identified through?

11 You've got non-governmental entities that do
12 that type of work and serve those communities and
13 they're the ones that -- that find the customers or
14 find the ratepayers for you?

15 WITNESS SMITH: That's correct, Chair
16 Pridemore.

17 MADAM CHAIR PRIDEMORE: Okay.

18 BY MS. COYLE:

19 Q And on page 21 of your testimony, beginning at
20 line 3, you begin to describe the company's proposal for
21 a -- basically a tiered price increase. You call it a
22 tiered scale approach, but is it not a price increase
23 going from 4 cents to 5 cents at above the 120 percent of
24 savings?

25 A (Witness Smith) Can you ask that question

1 again?

2 Q On page 21 at line 6, you testify the company
3 proposes a tiered scale approach to encourage achievement
4 of certified energy savings; is that correct?

5 Tiered scale approach, page 21, line 6.

6 A (Witness Phillips) Can you restate your
7 question, Ms. Coyle?

8 Q Yes, yes. Well, so am I correct that this
9 tiered scale approach you're describing here relates to
10 what you discussed earlier, which is that the company is
11 requesting for your additional sum a methodology that
12 you're proposing to change there and in this approach --
13 your additional sum will go from 4 cents to 5 cents for
14 the incremental amount above 120 percent of savings?

15 A (Witness Smith) Correct.

16 Q Okay. So I -- I apologize for calling that a
17 tiered price increase. That's just what it seemed like
18 to me. It's a slight price increase?

19 A (Witness Phillips) And I think it's important
20 to note that this additional sum is not a price increase.
21 Our customers do not pay for additional sum directly like
22 they do the price of their energy bill. It's a result of
23 the savings that the company realizes through its
24 residential and commercial programs.

25 Q But customers do pay the additional sum?

1 A (Witness Phillips) Yes. Additional sum is
2 incorporated as part of the overall DSM tariff. But the
3 way you phrase it as a price increase, I wanted to make
4 sure --

5 Q I won't use price increase.

6 A (Witness Phillips) -- the Commission understood
7 this is not a price specifically charged to our customers
8 like it is the price of energy.

9 Q You are asking to be able to earn a penny
10 higher additional sum on savings above 120 percent. And
11 you're also working to design the program in a way that,
12 as we've discussed earlier, more of the savings that go
13 to a certain customer class will be charged that customer
14 class. I think you said 3.4 million of the 17 million
15 will now -- in your proposal would be charged to the
16 residential class because that's where these savings are
17 coming from?

18 A (Witness Phillips) Yes. I believe that was the
19 amount.

20 What's your question?

21 Q My question is: Well -- so residential
22 customers if they experience in their programs -- the
23 residential programs savings above 120 percent, will they
24 be paying an extra penny in additional sum?

25 A (Witness Smith) It's not customers -- it's not

1 based on customers saving above 120 percent. It's if our
2 programs exceed 120 percent of their goals.

3 Q Right, right. If the programs exceed more than
4 120 percent of their goals, the customer class where that
5 program occurs -- so if it's a residential customer
6 program and you achieve savings of -- company targets
7 above 120 percent, the customers in that class will pay
8 that extra penny?

9 A (Witness Phillips) Customers fund the -- all of
10 the DSM -- all of the DSM programs through the DSM
11 tariff. It's based upon a certain percentage applied for
12 the base bill for both residential and commercial
13 customers. And so additional sum is funded through the
14 DSM tariff just like program costs and incentive costs
15 are funded through the DSM tariff.

16 And so the DSM tariff is where the additional
17 funds would be realized under the current or -- excuse
18 me -- under the proposed methodology, in terms of
19 providing or funding additional sums.

20 Q Customers will pay for the additional sum?

21 MADAM CHAIR PRIDEMORE: Ask a question for us,
22 Ms. Coyle.

23 MS. COYLE: Well, I think I've been asking
24 this -- I don't --

25 MS. PRYOR: Objection. I think it's been asked

1 and answered.

2 MS. COYLE: Okay.

3 MADAM CHAIR PRIDEMORE: Sustained.

4 BY MS. COYLE:

5 Q So -- and this is the case whether or not a
6 customer participates in these programs; right?

7 All customers will pay for the higher
8 additional sum?

9 A (Witness Phillips) All residential and
10 commercial customers do fund the DSM tariff, regardless
11 of whether they participate in our energy efficiency
12 programs or not.

13 MS. COYLE: Thank you. And I believe that is
14 the end of my questions.

15 MADAM CHAIR PRIDEMORE: Sierra Club, how many
16 questions do you have?

17 MR. FABISH: Three.

18 MADAM CHAIR PRIDEMORE: Three? Come on up.

19 As Drew Carey says: Come on down. You're the
20 next exciting contestant on the Price is Right.

21 MR. FABISH: Thank you.

22 CROSS-EXAMINATION

23 BY MR. FABISH:

24 Q So, very briefly, you assess the impacts of
25 electric vehicle adoption on overall demand for the

1 planning period; right?

2 A (Witness Valle) Yes. As part of the load
3 forecast. It's more or less an adjustment to it.

4 Q Okay. Has the company evaluated as part of its
5 IRP the transmission Make Ready projects and other
6 charging infrastructure that would be needed to power
7 those additional electric vehicles?

8 A (Witness Valle) No. For the purposes of the
9 load forecast, we're interested in providing an
10 assessment of the customer needs. How many -- how much
11 usage is going to come from the customers. The
12 infrastructure is assumed to come with it, but it will be
13 a part of a discussion of a different panel.

14 Q Okay. A different panel during this IRP?

15 A (Witness Valle) So infrastructure was probably
16 better covered yesterday on panel one and then rate
17 related will be for the rate case.

18 Q Okay.

19 A (Witness Phillips) Is your question
20 specifically to the Georgia Power Make Ready program?

21 Q Yeah. Just to the extent the company has done
22 an assessment of, like, what will be the Make Ready and
23 other needs to actually get the chargers in place to
24 serve those EVs that would be causing that load.

25 A (Witness Phillips) I know that there are other

1 organizations in Georgia Power that do assess the Make
2 Ready needs, as well as the needs to serve customers who
3 are going to have electric vehicles, both residential,
4 commercial, and industrial.

5 That's not something that we specifically study
6 here specific to either DER or DSM or load forecasting.

7 MR. FABISH: Okay. Thank you. That's all I
8 have.

9 THE STENOGRAPHER: Your name?

10 MR. FABISH: I'm Zach Fabish for the Sierra
11 Club. Thank you.

12 MADAM CHAIR PRIDEMORE: Thank you, Mr. Fabish.

13 Okay. Southern Alliance for Clean Energy and
14 Southface Energy Institute. Mr. Baker, Mr. Jacobs,
15 how much time?

16 Talk to me about time so I can plan.

17 MR. BAKER: About 30, 40 minutes.

18 MADAM CHAIR PRIDEMORE: About 30, 40 minutes,
19 okay. I think that now would be a good time for us
20 to take a break.

21 Let's break for lunch. We will reconvene at
22 1:25.

23 (A recess was held from 12:21 p.m. until
24 1:25 p.m.)
25

1 (Mr. Johnson begins serving as Chairman from
2 this point forward.)

3 COMMISSIONER JOHNSON: All right, Mr. Baker.
4 Your witness.

5 MR. BAKER: Okay. Thank you, Commissioner.

6 CROSS-EXAMINATION

7 BY MR. BAKER:

8 Q Panel, my name is Robert Baker. I represent
9 the Southern Alliance for Clean Energy and the Southface
10 Energy Institute. Thank you for your time today. I have
11 a few follow-up questions on Chairman Pridemore's --
12 asked about leveraging federal funding for energy
13 efficiency.

14 Is the company aware that the federal
15 low-income residential weatherization program received
16 \$3.5 billion?

17 A (Witness Smith) We're familiar that they
18 received an amount of money. Not that specific amount.

19 Q Okay. Thank you.

20 What are Georgia Power's plans, if any, to work
21 with the Georgia Environmental Finance Authority to
22 maximize the impact of the company's residential home
23 retrofit programs?

24 A (Witness Smith) Again, Georgia Power is
25 willing to work with and discuss opportunities to

1 leverage joint programs at any time. We actually have
2 reached out to GEFA early on when state -- when federal
3 dollars were being discussed in coming to the state. So
4 we've initiated initial discussions and are, again,
5 willing to do -- have conversations along that line.

6 Q Okay, thank you.

7 And, finally, what are the barriers to working
8 with state and local governments as partners to deliver
9 home energy efficiency programs? Are there any barriers?

10 A (Witness Smith) I'm not prepared to discuss
11 any today that I'm aware of.

12 COMMISSIONER McDONALD: Do you ever run into
13 any problems with HO, homeowners' associations, in
14 renovations like, of course, we do with solar
15 paneling? But I just wondered if you ever had that?

16 WITNESS SMITH: Not as it directly relates to
17 energy efficiency, Commissioner.

18 BY MR. BAKER:

19 Q All right. Let me refer you to page 7, line 14
20 of your prefiled testimony. And the company projects a
21 demand reduction of 431 gigawatt hours of energy
22 reduction annually for 2023, 2025.

23 Are the 431 gigawatts net or gross savings?

24 A (Witness Phillips) The 431 gigawatt hours are
25 gross savings for the overall portfolio.

1 Q Thank you. In evaluating the DSM programs, do
2 you use a single avoided cost for the full year, or do
3 you use avoided cost -- or do avoided costs vary hourly?

4 A (Witness Phillips) Could you restate your
5 question? I want to make sure I understood what you were
6 referring to around using a single avoided cost value.

7 Q Right. Do you use a single number as the
8 avoided cost number for evaluating DSM programs, or do
9 you have the avoided cost broken out on an hourly basis?

10 A (Witness Phillips) It's broke -- yes, okay.
11 I'm sorry. I understand.

12 Yeah. The avoided cost values that the company
13 uses are broken out hourly across the year and across a
14 number of years based upon the company's overall
15 projected avoided cost value. So they change hourly.

16 Q So those are dynamic numbers? Changing hourly,
17 you say?

18 A (Witness Phillips) They are dynamic in that
19 they do change from hour to hour.

20 Q Okay. Does the location impact an avoided
21 cost, the location of a resource?

22 A (Witness Phillips) No. We do not consider
23 locational value in setting avoided costs for our energy
24 efficiency programs.

25 Q Okay. Thank you.

1 At page 7 you say, "Due to lower avoided costs,
2 many of the current DSM programs still appear less
3 favorable under the total resource cost and rate impact
4 measure test when compared to the 2019 IRP."

5 Are you discussing net benefits there?

6 A (Witness Phillips) When you say net benefits,
7 what exactly are you referring to? That's -- because
8 we're referring to overall benefits. I don't know what
9 you mean by net benefits.

10 Q Net benefits in the sense that you're making
11 some adjustment to the gross figure.

12 Is it your testimony that you would be only
13 using gross, the gross?

14 A (Witness Phillips) Yes. That -- yes.

15 Q Okay.

16 A (Witness Phillips) To the best of my
17 knowledge, that is the value that we would use in
18 evaluating the cost effectiveness of our programs.

19 Q All right. And could you generally tell me
20 what is included in calculating the avoided cost amount?
21 Big picture.

22 A (Witness Phillips) The company calculates
23 avoided cost based upon generation avoided cost,
24 transmission, and distribution avoided cost. All three
25 of those are included in the avoided cost values for the

1 total resource cost test, as well as other cost
2 effectiveness tests.

3 Q Okay. And would you agree that DSM programs
4 provide a capacity value to the company?

5 A (Witness Phillips) Yes. In that energy
6 efficiency lowers overall demand, and therefore, that
7 negates capacity having to be generated to serve that
8 need.

9 Q Okay. And at page 8, line 13, you refer to
10 "trends and electric end uses." What are the "trends and
11 electric end uses" that are identified? What are you
12 referring to?

13 A (Witness Valle) I can take that question.
14 So -- so trends -- so we have seen trends in
15 use per customer. Those are part of the -- of the
16 models. We have used -- we have seen trends in terms of
17 the number of customers moving into our territory. So
18 the statement, it's about -- it's about the drivers of
19 the use, of the total electricity use in our territory.

20 Q Thank you. Was the growth in the number of
21 electric heat pumps one of those trends in electric end
22 uses that affected winter load forecast?

23 A (Witness Valle) It is one of the elements,
24 yes. So like I had explained before in the morning,
25 the -- the decline in the growth for summer peak demand

1 has been -- has been coming from increased energy
2 efficiency standards, so more penetration of those
3 standards.

4 And in the winter, it's more use, more electric
5 use for space heating, for water heater, and not so much
6 on the efficiency part.

7 Q Thank you. You state at page 9, "Residential
8 sales are expected to grow by an average of 1.1 percent
9 per year over this period as customer growth outpaces the
10 reduction in use per customer resulting from energy
11 efficiency."

12 Isn't it true that the proposed DSM/energy
13 efficiency measures in this IRP aren't even sufficient to
14 keep up with customer growth?

15 A (Witness Valle) Sorry. Is your question
16 about -- are you trying to clarify the impact of DSM on
17 the growth? Electric growth of residential customers?

18 Q Well, based on what you're proposing, you are
19 estimating that or expected to see an average growth of
20 1.1 percent a year for residential customers. Is that
21 correct?

22 A (Witness Valle) Correct.

23 Q Okay. Based on what is being proposed in this
24 IRP DSM program, are you keeping -- is there enough in
25 the program to keep up with the increase in the

1 residential growth to cover all the demand for
2 residential customers?

3 A (Witness Valle) I'm having trouble following
4 your question. So are you -- are you -- are you asking
5 me for the drivers of the 1.1 percent growth per year?

6 Q Well, what about -- I am referring to the
7 growth and energy use of customers.

8 Is the DSM program going to be keeping up with
9 the growth in energy use based on the 1.1 percent
10 annually?

11 A (Witness Valle) I see. So the 1.1 percent,
12 Commissioners, is the result of -- think about two
13 driving forces. One is the economy; right? We have a
14 good driving economy in Georgia that is attracting
15 businesses. It is creating population growth, so the
16 number of customers will go up.

17 At the same time, we have use per customer that
18 has declined as energy efficiency standards get in place.
19 You know, people replace their old air-conditioners with
20 newer versions, so the use of the base goes down. So
21 those two forces are the result of that.

22 And also, you have to remember that the total
23 forecast include adjustments, and one of those
24 adjustments is for DSM. So the number that you are
25 quoting is for everything included.

1 Q Thank you.

2 COMMISSIONER McDONALD: So the answer would
3 have been yes?

4 WITNESS VALLE: Yes. Long answer.

5 BY MR. BAKER:

6 Q And you had a few questions about the TSTAT DR
7 program. And I believe you said -- correct me if I'm
8 wrong. Did you say that it would take 12 years before it
9 was cost effective? Is that the prediction, or is that
10 your projection?

11 A (Witness Phillips) Based upon the current
12 modeling assumptions, the thermostat DR program would be
13 cost effective in the year 2031.

14 Q Okay. And not any time -- not any time before
15 that?

16 A (Witness Phillips) No. And that's based upon
17 our current modeling assumptions.

18 Q Is that due to the number of customers you need
19 participating in the program to get it up to a certain
20 level to make it cost effective?

21 A (Witness Phillips) No. That is not dependent
22 upon the number of customers. That's a result of the --
23 the TRC test compares the overall benefits compared to
24 the overall costs, and so the benefits are less than the
25 costs, and therefore, the TRC is overall negative for the

1 thermostat DR program.

2 Q And let me direct your attention to page 17 of
3 your prefiled testimony. And up there beginning at
4 page -- at line 3 of page 17, you identify three factors
5 which have helped to reduce avoided costs. Three main
6 drivers. You say, the lower forecast of natural gas
7 prices, modest load growth, and an increase in renewable
8 resources.

9 Do each of these drivers contribute equally to
10 the declining program economics and benefits of the
11 company's DSM portfolio?

12 A (Witness Phillips) I'm not aware of that.
13 Witness Weathers would be the best person to ask that
14 since it's his organization that's responsible for
15 calculating the avoided costs.

16 Q Okay. Could you rank in magnitude these three
17 drivers in their significance to impacting avoided costs?

18 A (Witness Phillips) No, I cannot.

19 Q Okay. And isn't it true that if natural gas
20 prices increase, the company can apply for a fuel cost
21 adjustment? Is that true? If natural gas prices
22 increase further?

23 A (Witness Phillips) Are you referring to the
24 fuel cost recovery rider?

25 Q Yes, sir. Yes, sir, I am.

1 A (Witness Phillips) That would be something
2 that would be separate from demand-side management
3 program.

4 Q But could the company ask for a fuel cost
5 increase of gas prices --

6 A (Witness Phillips) Yes, that's --

7 Q -- generally?

8 A (Witness Phillips) There's no requirements
9 that would be required in order to ask for that
10 adjustment, but yes, that's my understanding.

11 Q Okay. If -- hypothetically, if gas prices
12 increase for the company, shouldn't the company's avoided
13 cost calculation for DSM programs also be adjusted to be
14 fair, as far as taking into account the additional cost
15 of natural gas?

16 A (Witness Phillips) I believe Witness Weathers
17 testified yesterday that the company uses long-term
18 forecasts in setting those avoided costs, and in doing
19 that, some of the short-term impacts are not considered,
20 and as of now, the company's long-term forecast continues
21 to project that same trend in avoided costs.

22 Q Thank you.

23 And turning -- just a general question about
24 free ridership. Do you know if the company could modify
25 its program design to substantially reduce the amount of

1 free ridership? Is there anything that y'all have
2 considered to help reduce that problem?

3 A (Witness Smith) Yes. So as programs are
4 evaluated once every cycle, those evaluation results come
5 back with suggestions on how to improve programs to lower
6 free ridership, and we take those into account in future
7 implementations.

8 Q Have the changes been working?

9 A (Witness Smith) I would say so. It doesn't
10 mean that future issues don't lead to additional free
11 riders, but the ones that are identified, we take those
12 changes in and the program moves forward, as long as it
13 still passes economics.

14 Q All right. And would you please clarify
15 whether the figures throughout the IRP and DSM filings
16 reflect net or gross energy efficiency savings? Are
17 those -- based on your prior answer, it's gross -- gross
18 savings?

19 A (Witness Phillips) Well, the 431 gigawatt
20 hours is gross savings.

21 Q Okay. So are -- do you use net energy
22 efficiency savings in any other -- for any other figure?
23 Is there any other figure that uses net energy savings?

24 A (Witness Phillips) Not that I recall, no.

25 Q All right. Turning to page 24, you describe

1 the new distributed energy resource customer program with
2 two optional tariffs, the RAST-1 and DRC-1.

3 Will those programs -- could the RAST program
4 be offered to residential customers in the future or a
5 RAST-like program be offered to the customers in the
6 future?

7 A (Witness Evans) The company doesn't have any
8 plans at this time to extend it beyond the commercial and
9 industrial customers we have laid out. Going forward,
10 we'd have to weigh what benefits could be realized for
11 the system and what administrative costs that would be
12 incurred.

13 Q Okay. And just so I understand the -- is the
14 financial benefit or the attractiveness of the RAST
15 program the fact that the company will pay the capital
16 expense of purchasing the generation equipment that's
17 being installed at the customer's premises rather than
18 the customer having to go into their pocket and pay for
19 the generation resource?

20 A (Witness Evans) I think there's multiple
21 benefits with the program. One is that it does allow
22 Georgia Power to provide this service to our customers
23 that they are seeking but then, also, Georgia Power's
24 ability to further leverage those assets during
25 reliability events for the good of the system.

1 Q All right. But isn't one of the benefits -- if
2 I were to participate and apply for the RAST program,
3 would Georgia Power pay for the entire capital expense or
4 purchasing the generation asset that's being installed at
5 my factory or business?

6 A (Witness Evans) Georgia Power would provide
7 that asset, and we would be the owners of it. But that
8 individual participating customer through their
9 resiliency asset charge would pay for the revenue
10 requirements associated with that asset over the
11 contract.

12 Q But that's over -- is that over the life of the
13 asset, or is it a five years, ten years? How long is the
14 payback period for that capital investment?

15 A (Witness Evans) The payback period of the
16 investment? The payback period would be over the life of
17 the asset.

18 Q Okay. But once again, just the company --

19 A (Witness Evans) Okay.

20 Q I want to install a back-up diesel generator at
21 my facility under the RAST program. It cost \$1 million.
22 Do I have to spend \$1 million to buy that generator to
23 put in my factory?

24 A (Witness Evans) No, not -- I think I
25 understand the question a little bit better now. So yes.

1 No, not up front. Again, Georgia Power is going to buy
2 these assets, install them behind the customer's meter
3 for their individual services. The customer then will
4 pay through a monthly charge the revenue requirements.
5 And whenever I say "revenue requirements," I mean the
6 depreciation expense, the carrying cost on the asset, the
7 associated operations and maintenance expense with it,
8 along with any incurred fuel costs to run the asset.

9 So all the cost of the asset over that contract
10 life will be incorporated into what that monthly charge
11 is for that customer.

12 VICE CHAIRMAN ECHOLS: A quick question. Are
13 you familiar with Green Mountain Power in Vermont?

14 WITNESS EVANS: Somewhat, yes.

15 VICE CHAIRMAN ECHOLS: Have you seen their
16 program about home battery? I know we're talking
17 about commercial here. But that -- he's asking
18 about residential programs. They have -- were you
19 aware they have a bring-your-own device, so if
20 you've already got a battery system, you can get on
21 their program.

22 Or you can get a Tesla Powerwall from them or
23 an Enphase IQ battery; right? And so you can pay
24 for it with -- you know, on your bill. And then
25 they also have the program where they can tap into

1 that. So are you familiar with any of those
2 programs?

3 WITNESS EVANS: I am familiar with that program
4 and a couple other new ones like it across the
5 country, yes.

6 VICE CHAIRMAN ECHOLS: You think the company
7 would be open to taking a look at this in the future
8 as battery prices continue to go down, especially if
9 you've got a chance to evaluate it on a
10 commercial -- in a commercial program?

11 WITNESS EVANS: Yes. I think this program does
12 have the benefit of being able to serve as a
13 platform, that, yeah, as the company sees benefits,
14 that we can extract from these type of distributed
15 resources going forward in the future; that we can
16 expand the program as those opportunities present
17 value to all customers.

18 VICE CHAIRMAN ECHOLS: Thank you.

19 MR. BAKER: Thank you, Commissioner.

20 BY MR. BAKER:

21 Q Turning to pages 27 and 28 of your prefiled
22 testimony, you discuss limitations on how often Georgia
23 Power Company can dispatch the DER under DRC tariff.
24 Does the 8-hour limit apply even for customers enrolled
25 in the 4-hour and 2-hour tranches?

1 A (Witness Evans) No. Let me clear that up. So
2 this is a programmatic element that we deliberately
3 installed to allow for battery technology participation.
4 We designed the program technology agnostic, meaning we
5 weren't requiring certain technologies to participate.
6 But also not blind to the limitations that certain
7 technologies like storage assets have.

8 So we allowed for three types of participation.
9 Assets that have the ability to run for 8 hours of
10 consecutive use, and a lot of those -- think of your
11 generators, your typical behind-the-meter generators that
12 customers rely on.

13 But also, that customers seeking battery or
14 storage solutions that can only potentially run for 2
15 hours of consecutive use or 4 hours of consecutive use.
16 They still can participate in the program.

17 And with a specialized demand response credit,
18 calculated at the value the system would receive from
19 that shortened response time.

20 Q Thank you. Thank you.

21 The company's requesting a 4 percent additional
22 sum and with a higher 5 cent additional sum if the
23 savings grow higher than 120 percent of the certified
24 energy savings goal by class.

25 If the company is asking for an incentive to --

1 for superior performance, would it also be fair to also
2 have some type of provision in the additional sum that
3 also provides a disincentive for poor performance, such
4 as in a situation if energy savings are only 75 percent
5 or less of the target or goal by class, wouldn't it be
6 appropriate based on your request also to have some kind
7 of incentive for you to meet your basic goal or standard?

8 A (Witness Smith) So the additional sum by
9 statute is to incent the utility to do energy efficiency,
10 not to penalize them. But to be fair, if we don't -- if
11 we don't reach goals and we don't save kilowatt hours,
12 there is no 4 cents per kilowatt hour that we didn't get.

13 So we believe the methodology that we put
14 forward encourages us to get to goal and put every effort
15 forward to get as much as we can with the budget that's
16 approved.

17 Q You don't think you'd have a little more
18 incentive, if you didn't meet your basic goal and you
19 knew you were going to get an incentive but a little less
20 than an incentive than what you had asked for?

21 A (Witness Smith) So what I'll say is, again, it
22 is an incentive by statute. The other thing I would say
23 is Georgia Power has had energy efficiency program goals
24 since 2011. And historically, with the exception of the
25 two COVID years, we have exceeded our program goals. So

1 we put forth every bit of effort to meet our DSM savings
2 targets already.

3 Q Thank you.

4 A (Witness Valle) Commissioners, just real
5 quick. I want to make sure that the commissioners
6 understand that the current methodology is not really
7 working the way that it's supposed to be, and so our
8 proposal is to first simplify, to create something that
9 is, you know, not an algorithmic trouble; provides the
10 right incentives and reasonable -- and get us back to
11 what the additional sum was at the beginning of this
12 program, because as the avoided cost and the economics
13 keep deteriorating, we're going to get less and less and
14 less, although we are keeping these programs alive for
15 the benefit of the customers.

16 So it's -- you know, regardless of the ins and
17 outs of how this gets implemented, it's a matter of
18 recovering and getting us back to what it is meant to be.

19 Q All right. Next set of questions. Over the
20 IRP planning period, is the company's total revenue
21 requirement less with the base case DSM portfolio than it
22 would be without it? Want me to repeat it?

23 A (Witness Valle) I don't think we can talk
24 revenue requirements in this panel. Sorry.

25 Q All right. Could you explain -- you're asking

1 for a change in the additional sum.

2 Why isn't the current additional sum formula
3 working right now?

4 A (Witness Smith) As we stated previously, the
5 current methodology is based on avoided cost and program
6 cost. And as we previously outlined, that is driving it
7 down at a rate of 40 percentish from what it was
8 originally approved at while our program goals have more
9 than doubled over that same time horizon.

10 So the intent of it being there to incent us is
11 not necessarily keeping pace with what it was originally
12 designed to do. And furthermore -- and again, it is set
13 as an incentive to encourage the utility to do more; and
14 in the residential space, under the current methodology,
15 it would be -- it would be almost zero in the grand total
16 of things if that current methodology applies forward
17 into this cycle.

18 Q Okay. Thank you.

19 Focusing on the base case portfolio and the
20 efficiency savings levels proposed for the next three
21 years, does this mean that over the IRP planning period
22 the amount customers will pay the company through rates
23 is less with the base case than without it?

24 A (Witness Smith) I'm not sure I understand your
25 question. Can you ask it again?

1 Q Yes. I will go through it again.

2 Focusing on the base case portfolio and the
3 efficiency savings levels proposed for the next three
4 years, does this mean that over the IRP planning period
5 the amount customers will pay the company through rates
6 is less with the base case than without it?

7 A (Witness Phillips) I am not sure that we can
8 speak specifically to that question. When we develop the
9 proposed case, the company follows the nine-step
10 Commission-approved DSM program planning approach. As we
11 said earlier, we strive in setting those program targets
12 to achieve a balance of maximizing economic efficiency
13 while minimizing the upward impact on rates.

14 Those are the considerations in developing
15 them. We don't consider any rate impact that might
16 result. And we don't consider that because it's not part
17 of the DSM program planning approach.

18 A (Witness Valle) And, Commissioners, I want to
19 make sure that you understand that there -- I mean, one
20 word is "revenues," but when we are talking about revenue
21 requirements and company revenues, we're talking about
22 the amount of money that serves to pay the investments
23 and the fuel and the O&M that we incur.

24 The revenues that are part of the DSM
25 discussion are a marginal impact that is supposed to

1 measure sort of the subsidization or the -- of the
2 nonparticipants. So it's not a company revenue. It's
3 more of a -- the analysis of, like, are we doing the
4 right thing by cross subsidizing?

5 Q Okay. Let me just throw this question out and
6 see if you can handle it -- answer it. Over the IRP
7 planning period, is the company's total revenue
8 requirement less with the advocate's case DSM portfolio
9 than it would be with either no DSM portfolio or the
10 company's base case?

11 A (Witness Phillips) Like I said, I don't think
12 we're prepared to speak to revenue requirements when
13 we're referring to either the -- the company's proposed
14 case or the advocate's case.

15 We -- in developing those, as we said, we try
16 and achieve this balance of -- of TRC, the overall
17 benefits versus the rate impact measure in minimizing the
18 upward impact on rates.

19 We do know that as proposed the company's case
20 has an average RIM impact of negative \$283 million. That
21 would drive rates up. The advocate's case as it's
22 proposed would have a RIM impact of negative
23 \$543 million, so a much more significant impact in terms
24 of increasing overall rate pressure when compared to the
25 company's proposed case.

1 VICE CHAIRMAN ECHOLS: Let me ask you while he
2 is looking up something. We've been talking about
3 the transmission issues we've got and the upgrades,
4 South Georgia being flush with energy there, needing
5 it in North Georgia.

6 Does the proximity or the location of some of
7 the programs that you have, does it in a -- you
8 know, does it or could it have an impact on
9 transmission planning at all?

10 WITNESS PHILLIPS: Commissioner, I don't think
11 so. Not that I'm aware of. In terms of how we
12 evaluate the avoided cost of energy efficiency,
13 those avoided costs, as we said earlier, which
14 include generation, transmission, and distribution,
15 we evaluate that at a system level, or a company
16 level, and so we don't assign that to specific parts
17 of the state.

18 VICE CHAIRMAN ECHOLS: What about just from an
19 electron standpoint? Does it make sense that if we
20 had more -- more DSM in North Georgia that it would
21 positively impact us having to make upgrades or keep
22 us from having to build that next substation? I
23 mean, that may be out of your -- beyond the scope of
24 what you guys want to answer.

25 WITNESS PHILLIPS: I guess the answer is it

1 could, but we don't have any information at least in
2 terms of how we assess or evaluate energy efficiency
3 programs at this point to say whether it would or
4 wouldn't.

5 VICE CHAIRMAN ECHOLS: All right. Thank you.

6 MR. BAKER: Mr. Chairman, just to make this
7 question a little easier on the panel, could I give
8 them a document to refer to? I've shown it to
9 Georgia Power counsel and --

10 COMMISSIONER JOHNSON: Yes, you may approach.

11 BY MR. BAKER: :

12 Q I'm going to ask you a question about this
13 attached page.

14 All right, gentlemen. Just for the record,
15 this is -- I handed you a document from Volume II --
16 III -- it's III, the 2022 IRP DSM case summary data Mg0
17 demand-side management working group advocacy case, the
18 economic summary for all programs.

19 And I'm going to refer you to line 111, Rows C,
20 D, and E. I've highlighted the -- those three numbers on
21 the tab page there in front of you.

22 And I just want to ask you, the advocate's case
23 has net benefits of about 170, 206, and \$244 million for
24 the years 2023 through 2025 for a total of approximately
25 \$621 million of net benefits to the utility system for

1 the portfolio over the next three years.

2 Is that a correct statement of the numbers on
3 that chart?

4 A (Witness Valle) I'm sorry. Could you tell us
5 again where -- where you're looking? We're having
6 trouble finding the numbers.

7 Q It's the highlighted. Row 111, C, D, and E.
8 Columns C, D, and E.

9 A (Witness Phillips) Okay.

10 Q It is the tab --

11 A (Witness Phillips) I'm not seeing row -- I'm
12 not seeing Row 111, and I'm not seeing a column labeled
13 C, D, and E.

14 Q Oh, I'm sorry. This is the highlighted
15 numbers.

16 A (Witness Phillips) Okay. All right. So --
17 all right. So -- okay. Yeah. If you could -- I think
18 we're on the same page now, Mr. Baker. Could you restate
19 your question?

20 Q I just want to confirm that based on the
21 advocate's case net benefits, that it shows that 170,
22 206, and \$244 million over the years 2023 through 2025
23 for a total of approximately \$621 million of net benefits
24 to the utility system for the portfolio over just the
25 next three years.

1 Is that a correct statement of that document?

2 A (Witness Phillips) Yes. The individual -- the
3 incremental measure -- or the incremental values that you
4 spoke of are highlighted -- and specifically these are --
5 so the page that we're looking at calculates the -- it's
6 the eco- -- it's the economic summary. It's the cost
7 effectiveness test results for the advocacy case.

8 And Mr. Baker has highlighted the row that
9 speaks to the program administrator cost test. And so
10 those values that you highlighted, the incremental values
11 are correct.

12 Q Okay. And the total net present value benefits
13 over the 12 years shown on this table are \$3,345,000,000;
14 is that correct?

15 A (Witness Phillips) I'm sorry. Could you say
16 that number one more time, Mr. Baker?

17 Q Is the total net present value benefits over
18 the 12 years shown on the table \$3,345,000,000?

19 A (Witness Phillips) Yes.

20 Q And when all the costs and benefits are
21 accounted for, for total cost -- system cost, the
22 customer cost would be \$3,345,000,000 higher if the
23 company did no DSM compared to the DSM portfolio in the
24 advocate's case; is that correct?

25 A (Witness Phillips) Restate your question one

1 more time.

2 Q Okay.

3 A (Witness Phillips) I want to make sure I'm
4 following your premise.

5 Q Okay. When all the costs and benefits are
6 accounted for for total system costs, the customer costs
7 would be \$3,345,000,000 higher if the company did no DSM
8 compared to the DSM portfolio in the advocate's case; is
9 that correct?

10 A (Witness Phillips) I don't know that I can
11 agree with that as we understand the program
12 administrator cost test.

13 So the program administrator cost test tries to
14 answer the question of, is this program or is this
15 portfolio good for the utility. And so it compares the
16 benefits the utility realizes versus the cost, and
17 specifically it's some of the benefits that we've spoken
18 about earlier. It's the avoided costs of generation,
19 transmission, and distribution compared to the costs of
20 offering the program.

21 And so what this -- what this is showing us is
22 that there are positive net benefits to the company by
23 offering these programs as the advocacy case has been
24 developed.

25 Of course, in trying to achieve the

1 Commission's directive of maximizing economic efficiency
2 while minimizing the upward impact on rates, those
3 benefits to the utility would come at a cost to all
4 customers.

5 Specifically in those years, it's negative
6 300 -- if I can read this -- 396 million, negative
7 543 million in the year 2024, negative 688 million. And
8 that's the number I said earlier on average.

9 The advocate's case would result in negative
10 543 million on average in upward impact on rates. And so
11 those benefits do come at a cost to consumer- -- excuse
12 me -- to customers as well -- it's all customers. It's
13 the customers that choose to participate in our programs
14 and the customers who choose to not participate. They
15 would bear the costs of the -- of the programs based upon
16 the advocate's case at those levels.

17 Q Okay. Thank you for that answer.

18 But if you compare the present value savings of
19 the advocate's case to those of the base case, aren't the
20 savings from the advocate's case more than a billion
21 dollars more than the base case?

22 A (Witness Phillips) I don't have the base case
23 information in front of me. I'm looking just at the
24 advocate's case. But I do -- the advocate's case does
25 include higher savings compared to what the company's

1 proposed case is.

2 And as I said earlier, those higher savings do
3 come at higher costs to customers. Both the customers
4 who choose to participate in the programs and those that
5 do not.

6 Q And just for clarification, aren't the TRC
7 benefits net benefits above and beyond cost? Just for
8 clarification. Are the TRC benefits the net benefits?

9 A (Witness Phillips) The TRC -- the total
10 resource cost test evaluates the benefits -- it takes a
11 societal perspective. It considers the benefits
12 regardless of who realizes the benefits and it compares
13 it to the cost regardless of who pays the costs.

14 And so it evaluates the benefits to the society
15 or the community as a whole; whereas, some of the other
16 cost effectiveness tests are specifically directed at one
17 entity, whether it be the participant or the program
18 administrator.

19 Q Thank you. Thank you very much.

20 And how do energy -- annual energy efficiency
21 savings levels in the base case compare to those required
22 by the Commission in the 2019 IRP?

23 A (Witness Smith) Sir, just for clarity, are you
24 asking what the savings totals are for this IRP compared
25 to the previous?

1 Q Approximately.

2 A (Witness Smith) They're -- they're the same.
3 431 gigawatt hours a year.

4 A (Witness Phillips) And just for clarification,
5 they're the same based upon the results of the IRP. The
6 431 gigawatt hours that we are including in our proposed
7 case are 15 percent higher than what the company proposed
8 in the 2019 IRP.

9 But in terms of what this proposed case equates
10 to versus what was settled in the previous IRP, they are
11 roughly the same. They're consistent.

12 Q And when developing the IRP and the proposed
13 DSM portfolio, did the company pursue increases in the
14 levels of energy efficiency and demand response resources
15 as a solution to the issues of power plant retirements,
16 load growth, and winter peak and reliability concerns?

17 A (Witness Phillips) No, not specifically
18 related to how the company's proposed case was developed.

19 As we stated earlier, when developing the
20 company's proposed base case, we consider a variety of
21 factors, but we do follow the Commission-approved DSM
22 program planning approach.

23 And I don't recall there's any steps in the DSM
24 program planning approach that include some of those
25 factors that you specifically cited in your question.

1 Q All right.

2 A (Witness Valle) And one thing, Commissioners,
3 you have to -- I want to remind you is that -- is that
4 when we plan for the DSM programs, in the planning
5 process, we reduce the load forecast by the amount of
6 energy and peak demand that are coming from there. So in
7 that respect, it's treated as a priority resource, right,
8 and it's -- it's savings on the peak demand that don't
9 have to be served in the future. So to that extent, they
10 do capture that value in our planning.

11 Q Okay. Thank you very much.

12 This question may be a hearing request, but let
13 me ask it of you and see if you can answer.

14 What is the program administrator cost
15 effectiveness ratio for both the base case and advocate's
16 case respectively for the years 2023, 2024, and 2025?

17 A (Witness Phillips) Are you asking what the
18 ratio is when one is divided by the other?

19 Q Yes.

20 A (Witness Phillips) I don't have that ratio
21 right offhand, but that -- that result can be calculated
22 by the information that's been provided where you compare
23 the savings from the advocate's case versus the proposed
24 case, but --

25 Q And where --

1 A (Witness Phillips) -- we don't have that
2 today.

3 Q Would you refer me to a document or to a
4 spreadsheet that that information could be pulled from?

5 A (Witness Phillips) That information was
6 included in the Technical Appendix 2, I believe,
7 Volume 2, as part of the company's main filing. It would
8 be the same source from where you had this DSM advocacy
9 case information.

10 Q Oh, okay. All right. Thank you very much.
11 All right. According to the white paper, at
12 page 20 -- 21, the TEAPOT study identified 3,877 gigawatt
13 hours of cost effective and achievable energy efficiency
14 savings for the year 2032 while the competitive analysis
15 through Aurora showed as much as 3,050 gigawatt hours;
16 correct?

17 A (Witness Phillips) I want to make sure I'm
18 looking at the same page. Did you say page 21?

19 Q Yes, sir.

20 A (Witness Phillips) And can you restate those
21 numbers, Mr. Baker?

22 Q Yes, sir. Referring to the TEAPOT study, that
23 was the figure of 3,877 gigawatt hours. Okay?

24 A (Witness Phillips) Yes.

25 Q And then referring to the Aurora study showed

1 3,050 gigawatt hours; is that correct?

2 A (Witness Phillips) That's correct.

3 Commissioners, this is referring to the DSM
4 white paper that we spoke of earlier. This is where the
5 result of the 2019 order directed the company to
6 collaborate with staff to investigate methodologies for
7 evaluating energy efficiency in the supply-side system.

8 And so as a result of that order, the company
9 did collaborate with staff. It did investigate
10 methodologies and did produce the white paper in
11 accordance with the order.

12 And so what Mr. Baker is specifically referring
13 to is a table within the white paper that compares the
14 cost effective achievable potential from the TEAPOT study
15 or the energy efficiency study with one of the three
16 methodologies that was modeled in the white paper.

17 And so in this particular case, the TEAPOT
18 study, the energy efficiency potential study did identify
19 more cost-effective energy efficiency than what was
20 modeled in the supply-side system for that specific
21 approach or methodology.

22 Q Thank you. Thank you very much.

23 And now, isn't it correct that the Aurora model
24 is a model that was developed by the company? Is that
25 correct?

1 A (Witness Phillips) Aurora was not developed by
2 the company. Aurora is a model that is provided by a
3 separate company, and the company utilizes Aurora in
4 evaluating its supply-side systems. Witness Weathers, I
5 believe, might have spoken about Aurora more specifically
6 yesterday.

7 Q Okay. And that's still being used today?

8 A (Witness Phillips) Yes.

9 Q All right. But isn't it correct that the
10 amount -- referring back to the two figures from the
11 TEAPOT study and from the Aurora study, isn't it correct
12 that the amount of energy efficiency savings proposed by
13 Georgia Power in its base case is only about 430 gigawatt
14 hours over the next three years and even lower in 2032
15 compared to the potential savings from TEAPOT and Aurora?

16 A (Witness Smith) It is 431 gigawatt hours
17 annually.

18 A (Witness Phillips) And I think it's important
19 to note that the values that we spoke of earlier, the
20 3,877 gigawatt hours, that the energy efficiency
21 potential study, the current process, identified as cost
22 effective, that value is based upon the year 2032. And
23 as Mr. Smith just noted, the 431 gigawatt hours included
24 in the company's proposed case is an incremental value
25 based upon the years '23, '24, and '25.

1 So it's not an exact apples-to-apples
2 comparison, Mr. Baker, based upon the way you were asking
3 that question.

4 Q All right. Well, thanks -- thank you for the
5 clarification. I did not know that.

6 Is the explicit purpose of the Aurora analysis
7 to show the least cost way to meet future energy needs by
8 having DSM compete directly against supply-side
9 resources?

10 A (Witness Phillips) I'm not an expert in
11 Aurora. That's Witness Weathers' organization that's
12 responsible for the Aurora system and the Aurora
13 modeling.

14 As it relates to the white paper, what I can
15 speak to are the adjustments, the additional steps that
16 the company had to take in order to model demand-side
17 resources in the supply-side system. Those are
18 additional steps that are not required in our current
19 methodology.

20 So I can speak to some of the additional work
21 required to model demand-side resources in Aurora. I can
22 speak to the extra work that was required on the back end
23 of modeling energy efficiency or demand-side resources in
24 our supply-side system. What I can't speak to is the
25 Aurora system itself.

1 Q All right. When using the Aurora competitive
2 analysis method, the company's revenue requirement is
3 lower than the cost of supply when the company ramped up
4 to 3,050 gigawatt hours of efficiency savings by 2032,
5 that they could have used.

6 Doesn't a lower revenue requirement mean lower
7 utility cost overall?

8 A (Witness Phillips) I'm not exactly sure I
9 understood the question. You included a number of items
10 in there. I think you specifically cited some of the
11 results of the -- from the DSM white paper as well as a
12 question about revenue requirements. So can you restate
13 that question?

14 Q Yes. It was a compound question. Sorry. Let
15 me just ask a simple question:

16 Doesn't a lower revenue requirement mean lower
17 utility cost as a general proposition?

18 A (Witness Phillips) Are you asking lower
19 revenue requirements lead to lower costs for customers?

20 Q Yes, sir. Generally.

21 A (Witness Phillips) I think so. I'm -- like I
22 said, in terms of how we developed the DSM economics,
23 revenue requirements is not something that we consider
24 and it's not part of the DSM program planning approach.

25 Q Thank you. Thank you for your response.

1 And would you say that cost-effective energy
2 efficiency programs lower -- are lower than avoided cost?

3 A (Witness Phillips) Yes. As it's defined,
4 cost-effective energy efficiency programs, depending upon
5 which cost effectiveness measure is being utilized,
6 because there are different inputs to each one of the
7 different cost effectiveness tests, but the company does
8 evaluate cost effectiveness in a variety of ways, and so
9 I didn't know if your question was specifically referring
10 to TRC or some other cost effectiveness test.

11 Q I'll move on to my next question.

12 Referring to the IRP main document at
13 page 8-53, "If electric avoided costs were to
14 significantly increase in the time period 2022 to 2024,
15 would the company increase its energy efficiency program
16 budgets and savings"?

17 A (Witness Phillips) I'm turning to that page.
18 Could you restate that page again?

19 Q Sure. It's IRP main document, page 8-53.

20 A (Witness Phillips) And then what specific part
21 of that document or that page were you reading?

22 Q Dealing with the avoided cost -- avoided costs
23 were to significantly increase due to -- due to the
24 economy of cost with the company --

25 COMMISSIONER JOHNSON: Hold on, Mr. Baker.

1 MS. PRYOR: Objection. This question calls for
2 speculation.

3 COMMISSIONER JOHNSON: Sustained.

4 Move on.

5 BY MR. BAKER: :

6 Q All right. Just have a few questions about the
7 manufactured housing retrofit and replacement program.
8 Was the -- was this program cost effective under the TRC
9 test and program administrator cost test?

10 A (Witness Smith) I know it was for TRC. I'm
11 not 100 percent sure on the program administrator test.

12 Q Do you happen to know what the -- approximately
13 what the cost effectiveness score was for the program
14 under the TRC test or the program administrator cost
15 test?

16 A (Witness Smith) For TRC -- and subject to
17 check --

18 Q Subject to check.

19 A (Witness Smith) -- I want to say it is around
20 1.6 or 1.8.

21 Q Okay. Subject to check.

22 A (Witness Smith) On TRC.

23 Q Got it.

24 Do you know how -- approximately how many
25 manufactured homes are in Georgia Power's service

1 territory, approximately?

2 A (Witness Smith) I do not.

3 Q Okay. Subject to check, would you be surprised
4 that -- would you agree that possibly 145,000
5 manufactured homes are in the service territory?

6 A (Witness Smith) Again, I'm not aware.

7 Q And would you agree that energy efficiency used
8 per square foot for manufactured homes, especially older
9 homes, is typically higher than other types of housing?

10 A (Witness Smith) I would say older homes that
11 have not had improvements are typically more -- use more
12 energy than similar homes that are newer.

13 Q And generally, would you agree that the people
14 who -- customers, residents who live in manufactured
15 homes, meet the low-income threshold by a greater
16 proportion?

17 A (Witness Smith) I'm not aware of that number.

18 Q Okay. And finally, did the Georgia Power
19 achieve the required energy efficiency targets ordered by
20 the Commission in the 2019 IRP?

21 A (Witness Smith) Are you asking if we achieved
22 goal for our --

23 Q Yes.

24 A (Witness Smith) As previously stated, we
25 achieved 56 percent of our goal in 2020 and 70 percent of

1 our goal in 2021. Residentially, we were above
2 100 percent of goal in 2021, though.

3 Q So -- okay. With these numbers you just gave
4 me, 56 percent in '20, that was for commercial or
5 blended?

6 A (Witness Smith) That's total.

7 Q Total.

8 A (Witness Smith) That's total.

9 Q Total. But for residential, you were over --

10 A (Witness Smith) In 2021.

11 Q Okay. Should the company be required to
12 capture additional savings in future years when it fails
13 to hit the required savings targets in prior years?

14 A (Witness Smith) Well, that's a determination
15 for the Commission to make. Historically, they are
16 annual targets. They don't carry forward. And again,
17 historically, excluding the COVID years, we've averaged
18 111 percent of goal over those years. Minus 2020 and
19 2021.

20 Q Thank you.

21 VICE CHAIRMAN ECHOLS: And, Mr. Smith, part of
22 the COVID issue was that you couldn't get into the
23 homes; right? You couldn't go in and implement the
24 program?

25 WITNESS SMITH: Yes, Commissioner. There were

1 several issues. That was definitely one of them.
2 The inability to safely go into customer homes and
3 businesses, work force issues that were prevalent
4 throughout the COVID time frame, economic situations
5 which were -- resulted from COVID. There was a
6 myriad of reasons. Yes, sir.

7 BY MR. BAKER: :

8 Q And final question. In your transmission and
9 distribution system planning processes, do you consider
10 distribution and transmission system projects that could
11 be deferred or voided by locationally targeted DSM
12 resources?

13 A (Witness Phillips) I think Witness Robinson is
14 the best witness to direct any transmission or
15 distribution questions to.

16 MR. BAKER: All right. Thank you very much,
17 gentlemen. Thank you for your time and patience.
18 Thank you, Commissioners.

19 COMMISSIONER JOHNSON: Thank you, Mr. Baker.

20 Mr. Mahan, are you online?

21 MR. MAHAN: Yes. And I have no questions.

22 Thank you.

23 COMMISSIONER JOHNSON: Thank you. All right.

24 Ms. Pryor, redirect?

25 MS. PRYOR: Yes. Just a few questions.

REDIRECT EXAMINATION

BY MS. PRYOR:

Q Mr. Evans, earlier today you were asked several questions regarding the RAST-1 tariff and how it compares to market products.

Is Georgia Power proposing to deploy this service because customers have requested it?

A (Witness Evans) Yes.

Q And is it the intent of this offering to offer a company-owned asset to address those customers' identified need?

A (Witness Evans) Yes.

Q And is it accurate that similar programs have been offered in other jurisdictions and in that regard Georgia Power is simply just making a similar service available?

A (Witness Evans) Yes.

Q And, Mr. Smith, I believe Ms. Brown asked you a question earlier about the automated benchmarking tool.

Can you please clarify the company's position as to why it's proposing to no longer continue offering this product?

A (Witness Smith) Sure. The company is no longer proposing to offer the product because there's no energy savings associated with it.

1 It should also be noted, though, that that is
2 not a Georgia Power-owned resource. It's a publicly
3 available tool that anyone can go out and contract for.

4 Q Thank you.

5 And finally, Commissioner Pridemore asked a
6 question about the impacts of COVID on DSM participation.

7 Can Georgia Power determine by month and by
8 program how far the company was below its goal in 2020
9 and 2021?

10 A (Witness Smith) Yes. The company can look by
11 program by month in each of those years and determine how
12 far below that monthly goal we were and attribute that
13 back to social distancing and safety protocols that were
14 put in place due to COVID.

15 MS. PRYOR: Thank you.

16 No further questions.

17 COMMISSIONER JOHNSON: Thank you, Ms. Pryor.

18 Do you have any further exhibits to put in?

19 MS. PRYOR: No. I think that was covered
20 earlier.

21 COMMISSIONER JOHNSON: Okay.

22 MS. PRYOR: And if there are no further
23 questions, I'd ask that the panel be dismissed.

24 COMMISSIONER JOHNSON: Okay, thank you.

25 All right. At this time, thank you very much,

1 gentlemen, for your time. You are excused.

2 We are going to take -- it's 2:20. Let's come
3 back, and we're going to start the final panel at
4 2:30.

5 COMMISSIONER McDONALD: Mr. Chairman, before we
6 do that --

7 COMMISSIONER JOHNSON: Yes.

8 COMMISSIONER McDONALD: -- could we kind of get
9 a feeling from the commissioners here that we will
10 finish tonight no matter how long people speak?

11 COMMISSIONER JOHNSON: All right. You guys
12 heard him.

13 VICE CHAIRMAN ECHOLS: I checked with Georgia
14 building authority and they are going to keep the
15 air on until ten o'clock tonight for us.

16 COMMISSIONER JOHNSON: We will not be here
17 until ten o'clock.

18 VICE CHAIRMAN ECHOLS: We've got that squared
19 away. We're good.

20 COMMISSIONER McDONALD: All right.

21 COMMISSIONER JOHNSON: All right. Sooner we
22 get back, the sooner we can get going. 2:30 sharp.
23 Thank you.

24 (Whereupon, a recess was taken.)

25 COMMISSIONER JOHNSON: All right, Mr. Marzo.

1 If you'll swear in the witnesses.

2 MR. MARZO: Thank you, Mr. Chairman.

3 At this time, Georgia Power Company would like
4 to call its final panel of Dr. Mark Berry and
5 Mr. Aaron Mitchell. They are currently seated in
6 the box. With your permission, Mr. Chairman, I'll
7 swear them in.

8 COMMISSIONER JOHNSON: Proceed.

9 MR. MARZO: Gentlemen, would you raise your
10 right hand.

11 Thereupon,

12 AARON D. MITCHELL,

13 MARK S. BERRY,

14 having been duly sworn, testified as follows:

15 DIRECT EXAMINATION

16 BY MR. MARZO:

17 Q Dr. Berry, please state -- start by stating
18 your full name, your employer, and your responsibilities
19 for the record.

20 A (Witness Berry) My name is Mark Simpson Berry.
21 I currently serve as vice president of the environmental
22 and natural resources for Georgia Power Company.

23 With Georgia Power Company, I'm responsible for
24 the environmental compliance stewardship programs, the
25 natural resource portfolio, and the real estate

1 portfolio.

2 I also serve as vice president of research and
3 development for Southern Company Services. In that role,
4 I'm responsible for Southern Company's research and
5 development program.

6 Q Thank you, Dr. Berry.

7 Mr. Mitchell, would you do the same?

8 A (Witness Berry) Sure. My name is Aaron
9 Mitchell. I'm director of environmental affairs for
10 Georgia Power Company. I lead a team that is responsible
11 for environmental compliance, permitting, and oversight,
12 as well as production of the environmental compliance
13 strategy and implementation and oversight of the
14 company's CCR compliance program.

15 Q Thank you, gentlemen.

16 Dr. Berry, on March 11 of this year, did you
17 prefile or cause to be prefiled 35 pages of direct
18 testimony in question-and-answer format in this case?

19 A (Witness Berry) Yes, I did.

20 Q Gentlemen, are there any corrections you need
21 to make to your prefiled testimony?

22 A (Witness Berry) No.

23 Q If I were to ask you the same questions today
24 under oath, would your answers be the same as set forth
25 in your prefiled testimonies?

1 A (Witness Berry) Yes.

2 MR. MARZO: Commission, just for the record,

3 their trade secret and public disclosure version of

4 the environmental compliance strategy that has

5 previously been entered as GPC 1 PD and GPC 1 TS was

6 entered with the first panel's testimony.

7 COMMISSIONER JOHNSON: Okay.

8 MR. MARZO: Chair Johnson, also, the court

9 reporter has been previously provided a copy of the

10 prefiled direct testimony, and I now ask that the

11 direct testimony be entered into the record as if

12 given here orally today.

13 COMMISSIONER JOHNSON: Proceed.

14 (Whereupon, the prefiled direct testimonies

15 of Mr. Mitchell and Mr. Berry follows:)

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STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	)	Docket No.44160
2022 Integrated Resource Plan and	)	
	)	

DIRECT TESTIMONY OF
MARK S. BERRY AND AARON D. MITCHELL

March 11, 2022

**DIRECT TESTIMONY OF
MARK S. BERRY AND AARON D. MITCHELL
IN SUPPORT OF GEORGIA POWER COMPANY'S
2022 INTEGRATED RESOURCE PLAN**

GPSC DOCKET NO. 44160

I. INTRODUCTION

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

2 A. My name is Dr. Mark S. Berry. I am the Vice President of Environmental and
3 Natural Resources for Georgia Power Company ("Georgia Power" or the
4 "Company") as well as Vice President of Research and Development for Southern
5 Company Services ("SCS"). My business address is 241 Ralph McGill Boulevard,
6 N.E., Atlanta, Georgia 30308.

7 A. My name is Aaron D. Mitchell. I am the Director of Environmental Affairs for
8 Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E.,
9 Atlanta, Georgia 30308.

10 **Q. DR. BERRY, PLEASE SUMMARIZE YOUR EDUCATION AND**
11 **PROFESSIONAL EXPERIENCE.**

12 A. I graduated from Alabama A&M University with a degree in Mathematics. I also
13 graduated from the University of Alabama at Birmingham with a bachelor's degree
14 and master's degree in mechanical engineering and completed a doctorate program
15 in interdisciplinary engineering. Additionally, I earned a master's degree in public
16 and private management from Birmingham Southern College and am a registered
17 professional engineer in the state of Alabama. Prior to working at Southern
18 Company, I attained the commissioned rank of lieutenant commander in the United
19 States Navy as a surface warfare officer. I served on active duty upon the USS
20 Gunston Hall as a deck officer and Combat Information Center officer. After

1 joining the reserves, I served as an engineering officer supporting the USS Sentry
2 and as an intelligence officer supporting the Defense Intelligence Agency.

3 I started working at Southern Company in 1996, where I worked in various roles of
4 increasing responsibility for the next 17 years. In 2012, I took on the role of Director
5 of Research and Technology Management, managing a portfolio of research related
6 to emission controls, energy efficiency, renewables, power delivery, central station
7 generation, and carbon capture utilization and storage. In 2013, I worked as the
8 manager of environmental assessment for Southern Company's Research and
9 Environmental Affairs organization. In that role, I managed the Company's
10 regulatory response to federal rulemaking activity and the environmental science
11 research program.

12 I left Southern Company at the end of 2013 to begin working with the Southern
13 Research Institute as the Director of Energy and Environment. In 2014, I accepted
14 a position to serve as the Director in the generation sector at the Electric Power
15 Research Institute ("EPRI"). I returned to Southern Company in 2015 and am now
16 the Vice President of Environmental & Natural Resources for Georgia Power as
17 well as Vice President of Research and Development for SCS. I am responsible for
18 maximizing the value from Georgia Power-owned natural resources, acquiring real
19 estate to support Company operations, and managing the Company's
20 environmental compliance and stewardship programs to ensure compliance with all
21 environmental laws and regulations applicable to Georgia Power. In my Research
22 and Development role, I am responsible for leading our research program to
23 develop integrated solutions that provide affordable and reliable energy production
24 and delivery systems to support sector transformation and serve customer energy
25 needs holistically.

1 **Q. DR. BERRY, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS**
2 **COMMISSION?**

3 A. Yes. I testified in Georgia Public Service Commission (“Commission”) Docket No.
4 42310, Georgia Power’s 2019 Integrated Resource Plan (“IRP”).

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

7 A. I graduated with a Bachelor of Science degree in Environmental Health Science
8 from the University of Georgia, where I focused my studies on environmental
9 science, environmental regulations and compliance, toxicology, epidemiology and
10 related areas. I have worked at Southern Company since 2001, where I began my
11 career as an Environmental Specialist, first at Savannah Electric & Power Company
12 and then at Georgia Power until 2009. During that time, I worked with the
13 Company’s power generation, distribution, and transmission operations, where I
14 was in charge of environmental compliance and permitting related to air, land, and
15 water regulations. I also managed environmental permitting and related compliance
16 for numerous projects including the construction of Plant McIntosh Combined
17 Cycle Units 10 and 11, Plant McDonough Combined Cycle Units 4-6, the
18 McDonough natural gas pipeline, scrubbers at Plants Bowen and Hammond, and
19 landfills at Plants Hammond, McIntosh, and Kraft, among others.

20 I then served as the Air Programs Supervisor for Georgia Power until 2014, where
21 I led a team responsible for the Company’s air permitting, reporting, and
22 compliance program related to federal Clean Air Act (“CAA”) and Georgia Air
23 Quality Control regulations. While in this position, I was responsible for managing
24 the Company’s Environmental Compliance Strategy (“ECS”). I led the
25 development of the Company’s strategy for compliance with numerous
26 environmental regulations, including the federal Mercury and Air Toxics Standards
27 (“MATS”) rule, which resulted in the retirement of Plants Branch, Kraft, McManus,

1 Mitchell, and Yates 1-5, and installation of controls at Plants Bowen, Hammond,
2 Scherer, and Wansley.

3 Beginning in May of 2014, I worked as the Assistant to the Executive Vice
4 President of External Affairs where I was responsible for supporting the
5 management of operations of the Company's Community and Economic
6 Development, Corporate Communications, Environmental Affairs, Government
7 and Regulatory Affairs, and Land departments. In 2015, I served as a Georgia
8 Power Area Manager for the Brunswick Area including five counties in coastal
9 Georgia where I was responsible for customer service, distribution, engineering,
10 and external functions for the area.

11 I currently serve as the Director of Environmental Affairs at Georgia Power and
12 have been in this role since January 2016. I am responsible for the overall day-to-
13 day environmental compliance of all generating, distribution, and transmission
14 facilities, and other business unit operations at the Company in addition to various
15 regulatory issues related to compliance with existing and anticipated environmental
16 laws and regulations. This responsibility includes the creation and implementation
17 of the Company's ECS and supporting processes.

18 **Q. MR. MITCHELL, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS**
19 **COMMISSION?**

20 **A.** Yes. I testified in Docket No. 42310, Georgia Power's 2019 IRP.

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

22 **A.** The purpose of our testimony is to support the Company's ECS filed as part of
23 Georgia Power's 2022 IRP. We will also address specific aspects of the ECS,
24 including: the compliance pathways for flue gas desulfurization ("FGD")
25 wastewater for the Effluent Limitations Guidelines ("ELG") rule; management of
26 the Company's ash pond closure plans approved in the 2019 IRP, and ash pond and
27 coal combustion residuals ("CCR") landfill activities undertaken to comply with

1 state and federal CCR rules. In addition, our testimony discusses the Company's
2 beneficial use of CCR, Georgia Power's approach to considering carbon pressures
3 on the generating fleet, and certain research and development initiatives discussed
4 in the 2022 IRP.

5 **Q. PLEASE SUMMARIZE GEORGIA POWER'S ENVIRONMENTAL**
6 **COMPLIANCE STRATEGY.**

7 A. Georgia Power's ECS is a comprehensive strategy designed to provide cost-
8 effective plans for the Company to comply with applicable environmental
9 requirements. Georgia Power is committed to meeting its environmental
10 compliance obligations while also providing customers with clean, safe, reliable,
11 and affordable energy. The Company's ECS seeks to continually optimize
12 compliance plans in an increasingly dynamic and uncertain regulatory
13 environment. The comprehensive annual strategy development process considers
14 existing and potential legislative and regulatory requirements and determines plant-
15 specific compliance options. These options are evaluated based on available
16 technologies, cost, schedule, and impact to plant operations, the environment, and
17 surrounding communities. This iterative approach is designed to provide the
18 Company the necessary flexibility to develop and refine its compliance plans in the
19 best interests of customers as additional information becomes known.

20 As provided in Commission Rule 515-3-4-.04(1)(c), the Company's ECS, filed
21 with the 2022 IRP, includes a detailed overview of the applicable current and
22 proposed environmental regulations, existing environmental law, potential
23 legislation, and a comprehensive strategy for compliance.

1 **Q. PLEASE DESCRIBE THE ENVIRONMENTAL REGULATORY**
2 **FRAMEWORK APPLICABLE TO GEORGIA POWER AND HOW THE**
3 **ECS ASSURES COMPLIANCE WITHIN THE FRAMEWORK.**

4 A. Georgia Power's environmental compliance strategy contains actions necessary to
5 comply with federal and state mandates and is influenced by multiple regulators,
6 including the United States Environmental Protection Agency ("EPA"), the
7 Georgia Environmental Protection Division ("EPD"), and the Georgia Public
8 Service Commission ("Commission"). The EPA creates, maintains, and enforces
9 national standards under a variety of environmental laws and establishes these
10 standards through the development of Federal Regulations. The Georgia EPD is the
11 implementing body for federal and state laws through rules, policies, and permits
12 to protect human health and the environment. Finally, the Commission, during the
13 IRP process, reviews the Company's ECS, along with the cost estimates to
14 implement that strategy, and determines if the strategy and associated costs are
15 reasonable.

16 The development of the ECS annually, and the Company and Commission's
17 triennial IRP, provides an opportunity for the Company to respond to changing
18 environmental regulations and incorporate new information as it becomes available
19 over the course of this long-term planning process. While the strategy itself will
20 continue to necessarily evolve over time to address changes in state and federal
21 regulations, the purpose of the process has always been to maintain flexibility,
22 produce cost-effective compliance solutions that minimize the impact to customers,
23 and assure compliance with all environmental requirements.

24 **Q. PLEASE SUMMARIZE THE TESTIMONY OF THE PANEL.**

25 A. Georgia Power's ECS outlines the Company's plans to comply with all applicable
26 state and federal environmental laws and regulations, including the CAA, Clean
27 Water Act, and the Resource Conservation and Recovery Act. The strategy enables
28 Georgia Power to effectively address environmental compliance through the

1 implementation of cost-effective and commercially available environmental
2 control technologies.

3 Georgia Power continues to manage numerous regulatory requirements associated
4 with its generation plants. The 2022 ECS builds on and refines the Commission-
5 approved ECS in the 2019 IRP filing (Docket No. 42310), as well as the Company's
6 2020 and 2021 ECS compliance filings with the Commission. As such, the
7 Company is focused on the investment and actions needed to comply with land and
8 water regulatory requirements, including the ELG rule and both the federal and
9 state CCR rules for the Company's coal-fired plants. Since the 2019 IRP, the
10 Company has completed the installation of dry fly ash and bottom ash handling
11 equipment, as well as wastewater treatment systems to facilitate ash pond closure.

12 The Company's 2022 ECS, including necessary environmental controls and
13 compliance actions, supports the planned fleet transition, which is best
14 accomplished through long-term planning that appropriately balances numerous
15 factors, as discussed by Georgia Power Witnesses Grubb, Mallard, Robinson, and
16 Weathers. With compliance deadlines approaching for existing environmental
17 requirements and regulatory uncertainty likely to continue for the foreseeable
18 future, it is imperative that the Company continue to take a long-term approach to
19 planning decisions, including investing in appropriate environmental controls and
20 making plans for fleet transition, to ensure that customers' needs are met.

21 The major components of Georgia Power's ECS are as follows:

- 22 • The Company's ELG strategy, including retirement of nine units and
23 installation of additional environmental controls at four units, effectively
24 considers increasing environmental regulatory requirements, pressures, and
25 costs, the continued cost-effectiveness of low- and zero-carbon resources, and
26 future system reliability and resiliency needs.

- 1 • The Company's CCR strategy approved in the 2019 IRP, which includes the
2 closure of all 29 ash ponds and 12 landfills (each a "CCR Unit"), continues to
3 be effectively implemented with significant progress made over the last three
4 years. The Company continues to evaluate opportunities to refine and optimize
5 its closure plans, including consideration of plant retirements proposed in this
6 IRP in the closure strategy, and pursue opportunities to create value through
7 beneficial use.
- 8 • The Company's climate approach uses a long-term outlook and assumes a
9 carbon-constrained future to appropriately mitigate risks and challenges
10 associated with potential climate policies that could impact customers. The
11 Company's climate approach includes long-term planning scenarios that
12 consider a range of carbon costs, including \$50 per metric ton, that escalate over
13 time, which emphasizes the importance of proactively preparing for possible
14 future carbon policy.

15 The 2022 ECS describes the Company's plans to comply with environmental laws
16 and regulations through retirement or by implementing cost-effective and
17 commercially available environmental control technologies consistent with the
18 Company's commitment to supply clean, safe, reliable, and affordable energy to its
19 customers. The Company requests Commission approval of the ECS and the related
20 capital, operations and maintenance ("O&M"), and CCR asset retirement
21 obligation ("ARO") costs and associated measures taken to comply with
22 government-imposed environmental mandates.

23 **Q. HOW IS YOUR TESTIMONY PRESENTED?**

24 A. Section II addresses the Company's milestone emissions and environmental
25 compliance achievements, including responses to key regulatory changes since the
26 2019 IRP. Section III describes the ELG rule, its evolving requirements, and
27 Georgia Power's compliance strategy. Section IV describes the requirements of
28 state and federal CCR rules, including relevant developments applicable to CCR

1 since the 2019 IRP. Section V discusses Georgia Power's compliance strategy for
2 the state and federal CCR rules. Section VI addresses the Company's research and
3 commitment to the beneficial use of CCR. Section VII addresses Georgia Power's
4 approach to proactively mitigating long-term carbon risk to customers through the
5 state regulatory process. Finally, Section VIII discusses the Company's various
6 research and development initiatives included in the 2022 IRP.

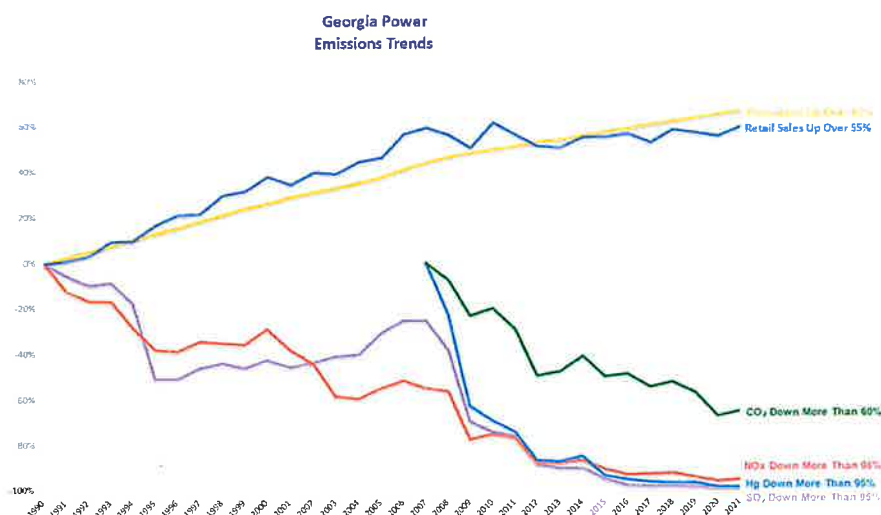
7 **II. MILESTONE ACHIEVEMENTS AND CHANGES TO**
8 **ENVIRONMENTAL COMPLIANCE REGULATIONS SINCE 2019**

9 **Q. WHAT ARE SOME OF THE COMPANY'S MILESTONE**
10 **ACHIEVEMENTS WITH REGARD TO ENVIRONMENTAL**
11 **COMPLIANCE?**

12 **A.** From 1990 to 2021, Georgia Power's execution of its environmental compliance
13 strategy through the installation of environmental control equipment to meet state
14 and federal regulatory requirements has reduced the Company's nitrogen oxide
15 ("NO_x") and sulfur dioxide ("SO₂") emissions by more than 96 and 99 percent,
16 respectively. The installation and continued operation of baghouses, selective
17 catalytic reduction systems, FGDs, and other controls related to the MATS rule
18 have enabled the Company's generating fleet to comply with new, more stringent
19 regulations. In fact, Georgia Power's efforts have reduced its 2021 mercury
20 emissions by approximately 99 percent from 2007 levels. In addition, through 2020,
21 Georgia Power's generating fleet has achieved carbon dioxide ("CO₂") emission
22 reductions of more than 60 percent since 2007.

23 Figure 1 below depicts the substantial reductions in NO_x, SO₂, CO₂ and mercury
24 emissions that Georgia Power has achieved, notwithstanding significant increases
25 in population and increased electric retail sales.

FIGURE 1 – Georgia Power Emission Trends



To comply with CCR and ELG rules and meet mandated compliance deadlines, Georgia Power completed the construction and installation of equipment necessary for dry/zero discharge ash handling equipment for nine units and installed 14 wastewater treatment systems in preparation for ash pond closures. In compliance with the federal and state CCR rules, Georgia Power has advanced closure construction activities at 22 ash ponds and conducted preliminary sitework and final design at the remaining seven ash ponds. The Company has continued to recycle more than 85% of operational CCR and continued to focus on the beneficial use of ash from ash ponds and landfills demonstrated by work being conducted at the Ash Beneficial Use Center (“ABUC”), Plant Mitchell, and the ongoing beneficial use request for proposals (“RFP”).

Q. WHAT RELEVANT ENVIRONMENTAL REGULATIONS HAVE BEEN INTRODUCED, CHANGED, OR FINALIZED SINCE THE 2019 IRP?

A. Since the 2019 IRP, EPA actions and court decisions have resulted in numerous changes to environmental regulations, including in CCR, ELG, and power plant carbon emission rules. In 2020, EPA approved Georgia EPD’s CCR Permitting

1 Program under the Water Infrastructure Improvements for the Nation Act with
2 respect to Georgia's authority to enforce rules promulgated under its solid waste
3 statute related to CCR activities, as well as to issue permits and to enforce
4 compliance. In addition, the federal CCR rule was amended twice in 2020 in
5 response to ongoing litigation, which changed closure initiation deadlines, revised
6 the definitions for lined and unlined ponds, revised requirements for annual
7 groundwater reports, and updated requirements for publicly accessible CCR
8 websites. Legal proceedings also impacted the ELG rule. In April 2019, the U.S.
9 Court of Appeals for the Fifth Circuit vacated portions of the 2015 ELG rule
10 regulating combustion residual leachate and legacy wastewater and remanded them
11 back to EPA for reconsideration. Separately, in October 2020, the EPA published
12 revisions to the ELG compliance dates and added alternative options that included
13 necessary additional time for compliance for utilities that provided notification for
14 alternative compliance pathways, termed the Notice of Planned Participation
15 (NOPP), to the state environmental agency by October 13, 2021. Finally, in July
16 2019, EPA finalized the repeal of the Clean Power Plan and replaced it with the
17 Affordable Clean Energy (ACE) rule, which was subsequently vacated by the D.C.
18 Circuit Court in April 2021.

19 **III. THE ELG RULE**

20 **Q. WHAT IS THE ELG RULE AND WHAT DOES IT REQUIRE?**

21 A. As a result of the November 2015 rule update to incorporate more stringent
22 requirements, the ELG rule requires installation of dry ash handling equipment and
23 new wastewater treatment systems at the Company's coal-fired power plants. The
24 2015 ELG rule addressed six waste streams: FGD wastewater; fly ash transport
25 water; bottom ash transport water; combustion residual leachate; gasification
26 wastewater; and flue gas mercury control wastewater. Of these six waste streams,
27 fly ash transport water, bottom ash transport water, combustion residual leachate,
28 and FGD wastewater are the primary waste streams regulated from Georgia
29 Power's operations.

1 Since the issuance of the ELG Rule in 2015, the requirements have been changed
2 multiple times either by court action or EPA rule changes. Most recently, in October
3 2020, EPA published the “Steam Electric Reconsideration Rule” (“ELG
4 Reconsideration Rule”), which provided important new and updated compliance
5 pathways for the Company’s FGD wastewater. First, the ELG Reconsideration
6 Rule adjusted the latest possible compliance date for the generally applicable FGD
7 wastewater effluent limitations from December 31, 2023 to December 31, 2025.
8 Second, the rule added the following alternative options that included necessary
9 additional time for compliance, provided notice was filed with the state
10 environmental agency by October 13, 2021:

- 11 • Compliance through the Voluntary Incentives Program (“VIP”) with more
12 stringent FGD wastewater effluent limitations by December 31, 2028.
- 13 • Compliance with the ELGs by permanently ceasing coal combustion by
14 December 31, 2028.

15 In 2021, the EPA announced it will revise the 2020 ELG Reconsideration Rule
16 based on a review of the rule completed under the Biden Administration’s
17 Executive Order 13990. The EPA stated it will consider whether more stringent
18 ELGs are appropriate for FGD wastewater based on the advancement of treatment
19 technologies, including membrane-based treatment. Importantly, the notice of
20 rulemaking clarified that permitting authorities must continue to implement the
21 current regulations (ELG Reconsideration Rule) during the rulemaking process.
22 The EPA intends to issue a proposed rule for public comment in the Fall of 2022
23 and a final rule in the Fall of 2023.

1 **Q. WHAT DID THE COMMISSION APPROVE IN THE 2016 AND 2019 IRPS**
2 **RELATED TO THE COMPANY'S COMPLIANCE WITH THE ELG**
3 **RULE?**

4 A. The Commission previously approved the Company's compliance strategy for the
5 ELG rule in the 2016 and 2019 IRPs, including the installation of dry ash handling
6 equipment and wastewater treatment systems to eliminate coal ash transport water,
7 as well as wastewater treatment systems to replace the treatment function of the ash
8 ponds for all waste streams, including low-volume wastewater and FGD
9 wastewater. A key component of the Company's approved compliance plan in both
10 2016 and 2019 was to continue to study FGD wastewater treatment technology to
11 ensure the future technology investment can meet the required discharge limitations
12 and compliance obligations while the EPA was revising applicable sections of the
13 evolving ELG rule.

14 **Q. HAS GEORGIA POWER ADJUSTED ITS PLAN FOR ELG COMPLIANCE**
15 **IN RESPONSE TO RECENT RULE CHANGES?**

16 A. Yes. The Company's ELG compliance strategy has been refined since the initial
17 ELG rule publication in November 2015. The numerous changes to the rule made
18 it necessary for the Company to utilize the environmental compliance strategy
19 process to update and optimize plans with each rule iteration, and to continue
20 studying evolving technologies, while meeting compliance obligations. The
21 Company closely evaluated the impacts of the 2020 ELG Reconsideration Rule on
22 the continued operations of coal-fired generating units and determined that a mix
23 of unit retirements and installation of new environmental controls is in the best
24 interest of customers.

1 **Q. HAS THE COMPANY PROVIDED THE REQUIRED NOTIFICATION TO**
2 **THE GEORGIA EPD OF ITS ELG COMPLIANCE PLAN?**

3 A. Yes. On October 13, 2021, the Company submitted ELG compliance filings to the
4 Georgia EPD, which stated:

5 • Georgia Power's intent to permanently cease coal combustion no later
6 than December 31, 2028, for Plant Bowen Units 1 and 2, Plant Scherer
7 Unit 3, and Plant Wansley Units 1 and 2.

8 • Georgia Power's intent to pursue ELG compliance through the VIP
9 subcategory with a compliance deadline of December 31, 2028, for Plant
10 Scherer Units 1 and 2.

11 • Georgia Power's intent to comply with the generally applicable
12 requirements by December 31, 2025, for Plant Bowen Units 3 and 4.

13 In addition, on October 13, 2021, Alabama Power filed a notification for Plant
14 Gaston Units 1-4 on behalf of SEGCO to the Alabama Department of Environmental
15 Management. The notification stated that Plant Gaston Units 1-4 would permanently
16 cease coal combustion through retirement no later than December 31, 2028.

17 **Q. WHY HAS THE COMPANY RECOMMENDED DIFFERENT**
18 **COMPLIANCE PATHWAYS FOR DIFFERENT UNITS?**

19 A. Compliance with the ELGs for FGD wastewater requires a plan tailored to each
20 site's specific water chemistry and water volume needs, as well as site-specific
21 logistics and space availability. This site-specific approach makes the use of
22 standardized designs and modular construction techniques largely impractical. In
23 addition, the Company considered various other unit- and site-specific factors,
24 including the results of the Unit Retirement Study, system reliability needs, and the
25 need for an orderly fleet transition, in making compliance determinations.

1 **Q. WHY DID THE COMPANY ELECT TO COMPLY WITH THE ELG RULES**
2 **THROUGH CESSATION OF COAL COMBUSTION AT CERTAIN UNITS**
3 **BUT NOT OTHERS?**

4 A. Through the Company's comprehensive regulatory and planning process, seeking
5 approval from this Commission to retire units by December 31, 2028 provides an
6 appropriate alternative to the installation of controls for ELG compliance at the nine
7 units with recommended retirement dates in the 2022 IRP: Plants Bowen Units 1
8 and 2; Gaston Units 1-4; Scherer Unit 3; and Wansley Units 1 and 2. After evaluating
9 existing and potential future environmental requirements and carbon pressures, these
10 units face economic challenges for continued long-term operation. As such, the
11 alternative cessation of coal combustion compliance option provided for in the ELG
12 rule is appropriate to consider. Further, as discussed more fully by Georgia Power
13 Witnesses Grubb, Mallard, Robinson, and Weathers, establishing a known
14 retirement date provides the Company with an opportunity to reduce operating costs
15 associated with these units, while providing necessary time to prepare the system for
16 the retirement of these units.

17 **Q. HOW DID THE COMPANY DETERMINE THE COMPLIANCE**
18 **PATHWAY OF INSTALLING ELG CONTROLS AT BOWEN UNITS 3**
19 **AND 4?**

20 A. The Company's election to install controls at Plant Bowen Units 3 and 4 recognizes
21 that the transmission system cannot reliably accommodate the retirement of all units
22 at Plant Bowen by December 31, 2028. As such, Plant Bowen Units 3 and 4 must
23 pursue compliance with the generally applicable effluent limits through installation
24 of physical-chemical-biological FGD wastewater treatment by December 31, 2025.

1 **Q. HOW DID THE COMPANY DETERMINE THE COMPLIANCE**
2 **PATHWAY OF INSTALLING ELG CONTROLS AT SCHERER UNITS 1**
3 **AND 2?**

4 A. The Scherer Units 1 and 2 co-owners elected to continue operation of these units by
5 installing ELG controls. As a minority owner, Georgia Power does not have primary
6 decision-making authority for Plant Scherer Units 1 and 2. Due to plant-specific
7 equipment and operational characteristics, Plant Scherer may benefit from the VIP
8 compliance option using membrane-based technology as an alternative to physical-
9 chemical-biological treatment. Therefore, for Plant Scherer Units 1 and 2, the 2022
10 ECS reflects the Company's and co-owners' plans to maintain flexible options by
11 pursuing parallel paths of (1) maintaining plans for installing physical-chemical-
12 biological controls to meet the generally applicable effluent limits by December 31,
13 2025, and (2) evaluating the membrane-based treatment systems that would be
14 required to comply with the VIP pathway by December 31, 2028.

15 ELG Controls will be installed for continued operation of Plant Scherer Units 1
16 and 2. Should the evaluation of the membrane-based treatment system show
17 appropriate technical performance, reliability, operational flexibility, and cost
18 compared against the physical-chemical-biological controls, the Company will
19 install the membrane-based system.

20 **Q. WHY IS THE VIP POTENTIALLY AN APPROPRIATE OPTION TO**
21 **PURSUE FOR PLANT SCHERER UNITS 1 AND 2 BUT NOT FOR OTHER**
22 **UNITS?**

23 A. The unique and site-specific water quality and quantity characteristics at Plant
24 Scherer make it the only plant where a VIP pathway can be feasibly pursued on both
25 a technical and economic basis. Pursuing the VIP compliance pathway at Scherer
26 Units 1 and 2 affords Georgia Power an additional three years to complete
27 installation of controls. With this additional time, the Company can perform further
28 research and development, adjust to future regulatory changes, and update the

1 strategy or pursue retirement should conditions change. While the research and
2 testing to date indicates that a membrane-based treatment solution shows promise at
3 Plant Scherer, on-going research, testing, and design of the full membrane-based
4 treatment solution is needed and underway to work through technical, operational,
5 and regulatory compliance evaluations. The additional research efforts at Plant
6 Scherer are scheduled for completion prior to the conclusion of the 2022 IRP
7 proceedings. The Company will update the Commission and Commission Staff
8 during that process.

9 **Q. HOW DOES THE COMPANY'S OVERALL ELG COMPLIANCE**
10 **STRATEGY ALLOW FOR FLEXIBILITY TO RESPOND TO FUTURE**
11 **REGULATORY CHANGES?**

12 A. Georgia Power's ELG strategy benefits customers by providing a balanced plan to
13 comply with existing requirements while addressing reliability risks, enabling an
14 orderly fleet transition, and maintaining flexibility to select the most appropriate
15 unit-specific compliance options at certain sites. This plan best addresses the
16 continuing uncertainty around the ultimate outcome of EPA's latest review of the
17 ELG rule by moving forward on implementation of ELG controls at certain units to
18 ensure compliance by the required deadlines, while continuing to study wastewater
19 treatment technology where there may be promising alternatives. This strategy
20 provides the Company an ability to adapt to changing regulations and economic
21 conditions moving forward.

22 **IV. THE CCR RULES**

23 **Q. WHAT IS CCR?**

24 A. Coal Combustion Residuals or CCR are the byproducts produced from burning coal
25 in coal-fired generation plants. CCR as it relates to Georgia Power's operations is
26 defined as fly ash, bottom ash, and gypsum. Fly ash and bottom ash are direct

1 byproducts of the coal combustion process, whereas gypsum is the byproduct
2 produced by the FGD process.

3 **Q. PLEASE DESCRIBE THE FEDERAL AND STATE REQUIREMENTS FOR**
4 **CLOSING CCR ASH PONDS AND LANDFILLS?**

5 A. Georgia Power is required to comply with both the federal and state CCR rules at
6 its ash ponds and CCR landfills. The federal CCR rule was finalized in 2015 and
7 established national minimum criteria for certain CCR landfills and ash ponds,
8 including location restrictions, design and operating criteria, annual inspections,
9 groundwater monitoring, corrective action, closure requirements and post-closure
10 care, recordkeeping, notification, and internet posting requirements. The federal
11 CCR rule mandates strict regulatory deadlines to complete closure of ash ponds
12 with which the Company must comply.

13 In addition, the Georgia CCR rule was finalized in 2016 and, unlike the federal
14 CCR rule, regulates all ash ponds and CCR landfills in the state. While Georgia
15 Power must comply with both rules, the state CCR rule is more stringent than the
16 federal CCR rule. The state CCR rule requires comprehensive permitting,
17 oversight, and monitoring for all Georgia facilities by Georgia EPD.

18 The federal and state CCR rules explicitly authorize both closure in place and
19 closure by removal as options for compliance, with each option subject to its own
20 set of closure performance criteria. Neither rule mandates or precludes the use of
21 either closure option in any particular instance. In fact, in establishing the federal
22 CCR rules, EPA confirmed that both methods of closure – closure-in-place and
23 closure-by-removal – are equally protective when the relevant performance criteria
24 are properly implemented.

25 Both the federal and state CCR rules have been amended numerous times over the
26 past few years and are expected to continue to be reviewed and updated in the

1 future. Additional information about these rules and their history is detailed in the
2 Company's 2022 ECS.

3 **Q. IS GEORGIA POWER CLOSING ITS ASH PONDS?**

4 A. Yes. Georgia Power is in the process of permanently closing its ash ponds in
5 accordance with the state and federal CCR rules. The Company presented its
6 compliance strategy to comply with the federal and state CCR rules in the 2019
7 ECS, which was reviewed and approved by the Commission in the Company's
8 2019 IRP (Docket No. 42310). The Company has 29 ash ponds and 12 existing
9 CCR landfills and plans to build two new landfills that will be permitted to support
10 ash pond closures in the future.

11 **Q. HAS THE EPA RECENTLY ANNOUNCED A NEW POSITION ON CCR**
12 **COMPLIANCE METHODS FROM THE EXISTING RULE?**

13 A. Yes. In January 2022, the EPA published proposed determinations for the CCR rule
14 Part A for nine facilities across the Midwest and Northeast that requested
15 extensions for compliance with the federal CCR rule. In these determinations, the
16 EPA announced new positions on the 2015 CCR Rule for closure in place
17 performance standards and groundwater monitoring networks, statistical analysis
18 methods, alternate source demonstrations, and groundwater corrective action. The
19 Company is in the process of reviewing the new positions and supporting
20 information provided in the EPA's recent determinations.

21 **Q. WHAT IS GEORGIA POWER'S RESPONSE TO THE EPA'S NEW**
22 **POSITION?**

23 A. Georgia Power continues to evaluate the EPA's new positions. The Company's
24 environmental compliance plans are based on long-standing rule interpretations
25 held by both industry and environmental regulators and employ industry- and
26 agency-accepted engineering practices utilized for closure designs that are
27 consistent with the solid waste regulatory requirements on which the CCR rule is

1 based. At all times, the Company's plans have been supported by sound engineering
2 designs and certified by Professional Engineers with expertise in solid waste
3 permitting and design.

4 The Georgia EPD has recognized the EPA's actions as new interpretations and is
5 also evaluating the impact of the EPA's new positions. The Company's CCR
6 compliance strategy process is designed to respond to changing regulations such as
7 these and contemplates that the strategy will evolve over time. The Company will
8 continue to work with the EPA and Georgia EPD to ensure the safe and effective
9 closure of the Company's ash ponds in accordance with state and federal law.

10 **Q. DOES EPA'S NEW POSITION CHANGE THE COMPANY'S REQUEST IN**
11 **THIS CASE?**

12 A. No. The Company will keep the Commission informed of any impact that EPA's
13 new position may have on the Company's current closure strategy approved by the
14 Commission. The Company will adapt as needed and is committed to producing
15 cost-effective compliance solutions that will mitigate risk to customers while
16 achieving environmental objectives and ensuring compliance with all requirements.

17 **V. CCR COMPLIANCE STRATEGY**

18 **Q. PLEASE DESCRIBE THE CCR COMPLIANCE STRATEGY APPROVED**
19 **IN THE 2019 IRP.**

20 A. As approved in the 2019 IRP, the Company's compliance strategy includes
21 permanently closing all 29 ash ponds by removing the ash from 19 ponds and
22 closing the remaining 10 ponds in place using proven engineering methods
23 designed to meet the requirements of the regulations. A description of the closure

1 plan for each of Georgia Power's ash ponds and landfills is included in the CCR
2 Strategy detailed in Table 4.3-1 of the ECS.

3 **Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO**
4 **IMPLEMENTING ITS ASH PONDS AND CCR LANDFILL CLOSURE**
5 **STRATEGY.**

6 A. The Company consulted third-party experts with expertise in solid waste permitting
7 and design to evaluate the volume, complexity, and duration of the required
8 activities on a site-specific basis to create comprehensive closure plans, designs,
9 and construction schedules necessary to comply with the CCR rules. These plans
10 are certified by independent professional engineers following a detailed, site-
11 specific engineering analysis.

12 The Company is using proven engineering methods to implement the closure plans
13 for its ash ponds and landfills. Proven engineering methods refer to the
14 technologies, equipment, and engineering approaches that will be incorporated into
15 the Company's closure plans, which are designed to enhance groundwater
16 protection, improve closure effectiveness, and minimize future maintenance.
17 Proven engineering methods considered for the closure plans include ash
18 consolidation, slurry walls, in-situ stabilization, accelerated dewatering, and final
19 cover system enhancements. The Company's site-specific ash pond closure
20 designs, including the proven engineering methods deployed, are all designed and
21 certified by professional engineers and are part of state CCR permits where they
22 are reviewed by the Georgia EPD. Regardless of the closure method selected for
23 each CCR Unit, the Company will comply with applicable federal and state
24 regulations as currently or subsequently enacted.

1 **Q. WHAT PROGRESS HAS THE COMPANY MADE WITH**
2 **IMPLEMENTING ITS APPROVED STRATEGY?**

3 The Company has made significant progress in effectuating the approved
4 compliance strategy, including active closure construction at 22 ash ponds and
5 preliminary sitework and final design at the remaining ponds to prepare the sites to
6 begin closure construction activities in the near future. While the Company's CCR
7 ARO semi-annual progress report submitted to the Commission through Docket
8 No. 43083 provides additional details on the program's implementation status,
9 highlights include, but are not limited to:

- 10 • 3.5 million safe work hours performed without significant injury.
- 11 • Advancement of closure construction activities at 22 ash ponds located at
12 nine facilities, which include dewatering, ash excavation, ash consolidation
13 and placement, installation of closure cover systems, installation of
14 engineering controls, and site restoration.
- 15 • Significant progress with ongoing work at the remaining seven ponds not in
16 active closure including engineering studies, design, closure evaluations,
17 constructability reviews, and other early site work and pre-construction
18 activities for these sites.
- 19 • In 2021, 3,000 groundwater samples collected by independent, third-party
20 groundwater professionals with results included in 78 routine groundwater
21 reports submitted to the Georgia EPD and posted to the Company's public
22 website.
- 23 • In 2021, 998 million gallons of water treated and 643 sampling events
24 conducted by independent wastewater treatment and sampling contractors,
25 with water quality monitoring data reported to the Georgia EPD and
26 summarized on the Company's public website monthly.

- 1 • Construction of the ABUC and completion of full commissioning and
2 acceptance testing for the facility.
- 3 • Removal of approximately 149,500 tons of ash at Plant Mitchell for
4 beneficial use.
- 5 • Initiation and significant progress with the Company's RFP for beneficial
6 use of stored ash.

7 **Q. WHAT IS THE STATUS OF THE COMPANY'S PERMITTING PROCESS**
8 **WITH THE GEORGIA EPD?**

9 A. The Georgia EPD has approved dewatering plans for nine of the Company's sites,
10 and two of those dewatering projects – at Plant McManus and Plant McIntosh – are
11 now complete. The dewatering plans describe the water treatment system, controls,
12 and monitoring that will be used during the dewatering process to ensure that the
13 water is discharged in compliance with wastewater permits and is protective of
14 water quality standards.

15 To date, the Georgia EPD has issued seven final CCR permits for closure by
16 removal units. Additionally, Georgia EPD has issued one final permit and one draft
17 permit for two closure in place projects. The Company continues to respond to the
18 Georgia EPD's requests for information and comments on the permit applications
19 submitted in 2018.

20 To date, Georgia Power has provided landfill and ash pond closure certifications to
21 the Georgia EPD for certain CCR Units at Plants Branch, Hammond, Kraft,
22 McDonough, McManus, McIntosh, and Yates. These closure certifications
23 document important information regarding the closure activities, quality control,
24 and verification of compliance with the CCR rules. Georgia EPD has issued
25 acknowledgement letters for completion of CCR removal for certain CCR Units at
26 Plants McManus, McDonough, McIntosh, and Yates, demonstrating the

1 Company's compliance with the closure requirements of the Georgia CCR rules as
2 well as the Georgia EPD's active oversight regardless of final permit status.

3 **Q. WHY IS IT NECESSARY FOR THE COMPANY TO CONTINUE ITS ASH**
4 **POND CLOSURE ACTIVITIES?**

5 A. In order to advance ash pond closures and meet the stringent regulatory deadlines
6 associated with the federal and state CCR rules, regardless of permit issuance, the
7 Company must continue to proceed with work, including groundwater monitoring,
8 detailed engineering designs, construction activities, as well as developing and
9 implementing site-specific and comprehensive ash pond dewatering processes.
10 This progress will allow Georgia Power to remain in compliance with applicable
11 mandated CCR closure deadlines.

12 **Q. HOW DOES THE COMPANY KEEP STAKEHOLDERS INFORMED OF**
13 **ITS PROGRESS?**

14 A. Georgia Power provides stakeholders and the public regular updates on its CCR
15 compliance program through multiple avenues. Georgia Power maintains a
16 comprehensive website detailing environmental compliance and project progress.
17 The CCR permit application process with the Georgia EPD provides extensive
18 information on the Company's closure plans and opportunities for engagement
19 from multiple stakeholders. The results of the Company's water treatment and
20 groundwater sampling efforts, which are performed by independent third-party
21 professionals and analyzed by accredited independent third-party laboratories, are
22 routinely posted to the Company's website. The Company also complies with semi-
23 annual groundwater monitoring reporting requirements, which are submitted to the
24 EPD and posted to the Company's website. Additionally, as ordered in the 2019
25 IRP, Georgia Power has provided semi-annual progress reports to this Commission
26 since 2020 and filed annual updates with the ECS. The Company has collaborated
27 with Commission Staff on the content of its CCR ARO semi-annual progress
28 reports to ensure they are relevant and informative.

1 **Q. HAS GEORGIA POWER REVISED THE COST ESTIMATES FOR ITS**
2 **CCR COMPLIANCE STRATEGY?**

3 A. Yes. Georgia Power consistently monitors and evaluates project assumptions,
4 including, but not limited to, timing and schedule assumptions for permits and
5 construction, project scope, post-closure activities, and estimated future escalation.
6 The Company provides these updates semi-annually to the Commission in its CCR
7 ARO semi-annual progress reports filed in Docket No. 43083. As reflected in the
8 CCR ARO tables in the Selected Supporting Information section of Technical
9 Appendix Volume 1, Georgia Power's current forecast applicable to retail
10 customers over the next 60 years is approximately \$8.99 billion, which includes
11 \$944 million in project to date actual costs incurred through December 31, 2021.

12 **Q. DOES THE COMPANY'S FLEET TRANSITION PROPOSAL IN THE 2022**
13 **IRP IMPACT ITS CURRENT ASH POND CLOSURE STRATEGY?**

14 A. Yes. The Company's request to retire Plant Wansley Units 1 and 2 provides an
15 opportunity to modify the current ash pond closure plans at the site and move from
16 a closure in place to a closure by removal strategy for the Wansley ash pond. The
17 continued operation of the coal-fired units at Plant Wansley requires the use of the
18 on-site permitted CCR landfill to support the plant's environmental controls and
19 handling of ash and gypsum byproducts. With the retirement of Units 1 and 2, this
20 on-site landfill would be available for use in conjunction with the ash pond closure.
21 In its 2022 IRP filing, the Company informed the Commission that an evaluation
22 of this option was underway, and, as the evaluation progressed, additional
23 information would be provided during the IRP.

24 **Q. WHAT IS THE COMPANY'S RECOMMENDED CLOSURE STRATEGY**
25 **FOR PLANT WANSLEY?**

26 A. If the Commission approves retirement of the coal units at Plant Wansley, Georgia
27 Power recommends modifying its ash pond closure plans at the site from closure in

1 place to closure by removal. Through the Company's evaluation, efforts continue
2 to assess current capacity and expansion capability of the existing on-site landfill,
3 CCR material movement and placement, and long-term considerations associated
4 with post-closure care in utilizing the landfill as part of the site's ash pond closure
5 strategy. While the current closure in place strategy utilizing a cover system and
6 containment structure provides a robust solution, the assessment indicates that
7 closure by removal and placement of CCR material from the ash pond into the
8 landfill provides the opportunity to maximize the use of the existing landfill asset,
9 manage construction and operational risks associated with the current closure in
10 place design, and provide for future beneficial use of the ash as driven by the
11 market.

12 **VI. BENEFICIAL USE**

13 **Q. WHAT EFFORT IS THE COMPANY MAKING TOWARDS THE** 14 **BENEFICIAL USE OF CCR?**

15 The Company's CCR beneficial use efforts are detailed in the 2022 ECS and
16 primarily center around three areas: (1) marketing of CCR from ongoing plant
17 operations; (2) development of new research and technology for the beneficial use
18 of CCR; and (3) implementation of beneficial use projects at the Company's ash
19 ponds and landfills.

20 **CCR Marketing:** Georgia Power currently markets more than 85 percent of the
21 CCR generated from plant operations for beneficial use, which helps to minimize
22 or offset costs related to CCR storage, landfill construction, and associated O&M.

23 **New Research and Technology:** The Company, in partnership with EPRI and
24 other utilities across the industry, has developed the ABUC at Plant Bowen with
25 the goal of developing new technologies or processes that drive downward cost
26 pressure associated with beneficial use and expand current and potential markets.
27 The core capability of the center is pre-processing harvested ash, including drying,

1 classifying, storing, and delivering ash, for use in demonstrating new technologies
2 and processes to facilitate beneficial use. Studies are underway evaluating ash
3 harvested from different locations and ponds, which will ultimately provide
4 information about the performance and energy requirements of the pre-processing
5 equipment as well as a comparison of the relative beneficial use potential of the
6 different sources of ash.

7 **Implementation of Beneficial Use Projects:** At Plant Mitchell, the Company
8 continues with plans to remove the stored coal ash at its three ash ponds for
9 beneficial use. Over the next several years, the Company plans to remove
10 approximately two million tons of ash from the Plant Mitchell site to help create
11 Portland cement, which is used to make concrete. Furthermore, the Company is
12 nearing completion of its ongoing RFP process for beneficial use of stored coal ash
13 at Georgia Power facilities and expects that additional projects will be viable to
14 implement in the near term.

15 **Q. WHAT IS THE STATUS OF GEORGIA POWER'S BENEFICIAL USE RFP**
16 **PROCESS?**

17 A. In December 2019, Georgia Power launched its Beneficial Use RFP seeking bids
18 to identify new beneficial use opportunities for the coal ash stored at the Company's
19 active and retired plants across the state. Significant progress has been made,
20 including a public announcement for interested parties, the pre-qualification of
21 bidders, distribution of site-specific informational packets to support the bid
22 development, and robust evaluation of the proposals received. The Company, with
23 support from a third-party engineering consultant, is performing an in-depth
24 analysis of the bids received, including the effects of the various beneficial use
25 proposals on closure plans and project timelines, project costs, project sequencing,
26 and infrastructure requirements. As the Beneficial Use RFP evaluation process
27 concludes, the Company will proceed with projects that provide value to customers
28 and place ash into the market for beneficial use. Georgia Power is negotiating with
29 vendors and expects to complete the RFP process in 2022.

1 **Q. WHAT ARE THE BENEFITS OF INCORPORATING BENEFICIAL USE**
2 **INTO CERTAIN ASH POND CLOSURES?**

Possible future benefits associated with the beneficial use proposals include increased ash sales, reduced closure costs, and reduced long-term liability. Reduced costs could take the form of reduced ash volumes moved during closure, a reduced closure footprint, reduced landfill space needed to support closure, and/or reduced post-closure care. To achieve the benefits included in the beneficial use proposals, the Company must invest in ash processing infrastructure at applicable facilities over the next three years.

10 **VII. CLIMATE & CARBON RISK**

11 **Q. WHAT ARE THE CARBON PRESSURES ON GEORGIA POWER'S**
12 **COAL-FIRED GENERATING FLEET FROM CLIMATE AND**
13 **ENVIRONMENTAL POLICY?**

A. Environmental policy and requirements have become more stringent over time and coal-fired power plants are likely to face additional environmental compliance costs in the future. In the last five years, there has been a significant shift upward in the projected magnitude and impact of potential carbon-constraining programs, as demonstrated by numerous legislative proposals and climate policy analyses. In addition, in the near term, EPA is required to promulgate carbon emissions standards for power plants under the CAA. Following the vacatur of the ACE rule in January 2021, EPA is expected to take a more aggressive approach with respect to carbon emission reductions, as indicated by the Biden Administration's recommitment to the Paris Agreement. The Company anticipates that the growing support and policy movement toward greater carbon-constraining initiatives will continue to gain momentum in the years to come.

Georgia Power has already reduced and will continue to reduce carbon emissions effectively through the constructive regulatory planning process with this

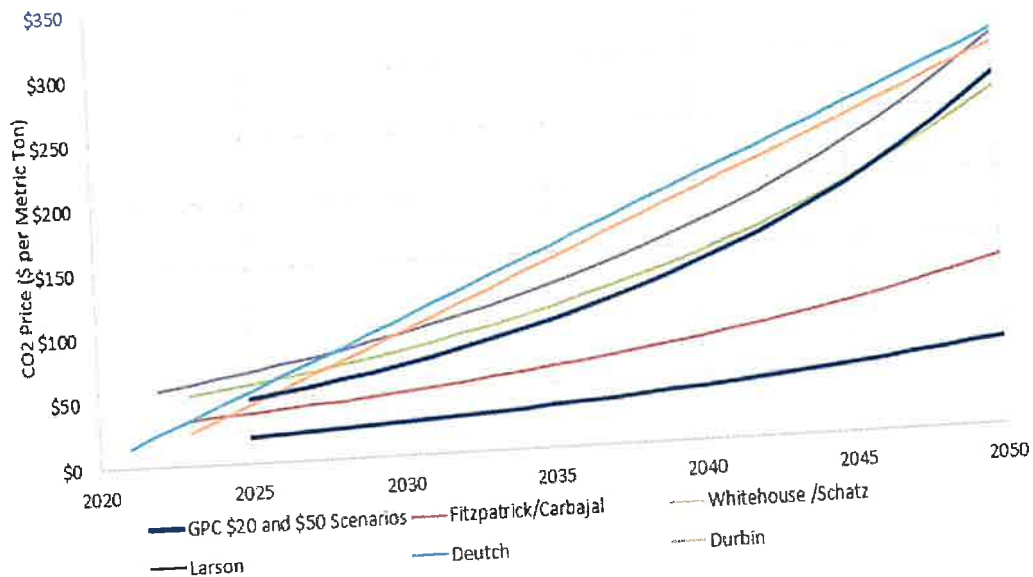
1 Commission. The utility industry, as a whole, has also already reduced carbon
2 emissions significantly compared to other sectors. In order to go beyond the
3 significant reductions already achieved by the utility industry, including Georgia
4 Power, and achieve the considerable emissions reductions across the economy that
5 are sought by federal and state climate programs, increasing carbon price pressure
6 will be required. As such, the overall shift to higher costs and impacts from future
7 carbon requirements is a lasting trend that is expected to continue over the long
8 term.

9 **Q. HOW IS THE COMPANY INCORPORATING THIS INCREASED**
10 **CARBON PRESSURE INTO ITS PLANNING PROCESSES?**

11 **A.** As discussed more fully by Georgia Power Witnesses Grubb, Mallard, Robinson,
12 and Weathers, the Company continues to use a range of carbon costs in its long-
13 term planning scenarios. This includes the existing \$20 carbon case as well as the
14 new \$50 per ton carbon case that escalates over time. Figure 2 provides an
15 illustration of how these scenarios compare to recently contemplated carbon
16 policies, plotting the carbon price points of various legislative proposals from 2021
17 with the Georgia Power CO₂ planning scenarios.

FIGURE 2

Georgia Power CO2 Scenarios Compared with
Proposed Federal Carbon Tax Legislation in 2021



Q. WHAT IS GEORGIA POWER'S APPROACH TO PREPARING FOR A CARBON-CONSTRAINED FUTURE?

A. Georgia Power is taking proactive steps to prepare for a carbon-constrained future. As a direct result of working with the Commission through the IRP process, the Company has already made significant cost-effective and reliable resource planning decisions, resulting in a lower-carbon mix of energy resources to the benefit of all customers. The Company continues to focus on the importance of planning strategically within the state regulatory framework to address the risks presented by carbon policy by ensuring a flexible generation fleet that can respond to the pressures of a low carbon future. Georgia Power recognizes that the feasibility of continued progress toward a low-carbon future is highly dependent on the continued use of natural gas and continued technology advancements. The Company's long-term planning approach considers these factors through a diverse resource portfolio leveraging low- and zero-carbon technologies, the development of new technologies to lower greenhouse gas ("GHG") emissions, and constructive

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1 engagement with stakeholders to address the evolving energy needs and
2 preferences of customers.

3 **VIII. RESEARCH AND DEVELOPMENT INITIATIVES**

4 **Q. DESCRIBE HOW THE SOUTHERN COMPANY R&D PROGRAM**
5 **SUPPORTS GEORGIA POWER'S ELECTRIC FUTURE.**

6 A. The research conducted by Southern Company Research and Development
7 ("R&D") explores a diverse range of solutions to help Georgia Power keep pace
8 with the evolving energy landscape – from hydrogen, carbon capture, and advanced
9 nuclear to fuel cells, microgrids, renewables, and energy storage, plus next-
10 generation power delivery and end-use innovations. Southern Company's R&D
11 strategy is centered around four key customer needs:

- 12 • Delivering advanced technologies that can enable a sustainable, low-carbon
13 energy future.
- 14 • Providing energy storage and delivery technologies to effectively integrate
15 the increasing penetration of renewable generation, distributed storage,
16 electric transportation, and electrified industrial processes into the grid.
- 17 • Advancing the existing generation fleet by minimizing cost and improving
18 efficiency, while leveraging developments in technology.
- 19 • Developing energy end-use technologies to support expanding customer
20 needs.

21 **Q. PLEASE PROVIDE EXAMPLES OF HOW R&D PROJECTS ARE**
22 **SUPPORTING GEORGIA POWER'S ENVIRONMENTAL COMPLIANCE**
23 **EFFORTS.**

24 A. In addition to the ABUC work discussed in Section VI, examples include the Water
25 Research and Conservation Centers at Plants Bowen and McDonough that are
26 identifying the most promising technologies to better manage and conserve water
27 across our thermoelectric power generation sites, as well as achieve short- and long-

1 term water management goals. Water Research Center studies of physical-
2 chemical-biological FGD wastewater treatment have contributed to increased
3 understanding of the technology and have enabled the Company to reduce design,
4 construction, and operational cost risk. Early testing of advanced membrane
5 systems at the Water Research Center was instrumental in demonstrating the
6 potential use of membrane treatment for FGD wastewater. These advanced
7 membrane systems are now being evaluated as a potential solution for FGD
8 wastewater treatment at Plant Scherer.

9 Additionally, evaluations have been conducted on options to more effectively
10 manage large-scale handling and movement of ash, which may support the
11 Company's ash pond closure plans where appropriate. Further, Georgia Power and
12 Southern Company are involved with several DOE-supported projects to research
13 the extraction of rare earth elements and critical minerals from coal ash on a
14 commercial scale, with a goal of leveraging the benefits of existing coal ash located
15 in the southeastern United States.

16 **Q. WHAT ARE SOME EXAMPLES OF R&D PROJECTS THAT ARE**
17 **SUPPORTING GEORGIA POWER'S FLEET TRANSITION?**

18 As the energy landscape continues to evolve, new and emerging technologies have
19 the potential to fundamentally alter the way energy is created, transported, stored
20 and ultimately consumed. Southern Company's R&D program monitors
21 technology cost and performance to prepare for the potential adoption of these
22 technologies. For the 2022 IRP, the Company has identified long-duration storage,
23 hydrogen and tall wind technologies as areas of focus due to their potential to
24 provide customers with benefits as renewable penetration increases and technology
25 improvements occur.

- 26 • Commercial viability of long-duration, or multi-day, storage solutions
27 require additional testing, monitoring, and demonstration. These
28 technologies can utilize relatively abundant materials, such as iron, for

1 energy storage applications that can be optimized to store energy for 100-
2 hour durations. This multi-day storage technology can also reduce the risk
3 of thermal runaway and is considered easier to recycle than other battery
4 storage chemistries.

- 5 • Hydrogen is a potential new zero-carbon energy source for numerous
6 applications, including as a natural gas alternative, that also requires further
7 study. Using a process known as electrolysis, hydrogen can be created
8 using electrical energy and water. In certain circumstances, the electrolysis
9 process has the potential to utilize otherwise curtailed solar energy to
10 produce green hydrogen. Commercial viability of hydrogen in the future
11 would provide new options for dispatchable electricity resources.

- 12 • Building upon prior R&D efforts, the Company has identified the potential
13 for tall wind in Georgia. As discussed by Georgia Power Witnesses Grubb,
14 Mallard, Robinson, and Weathers, in the Commission's 2016 IRP Order,
15 the Commission authorized Georgia Power to study this high wind
16 potential and validate certain site-specific locations. The Company's study
17 results indicate that wind resources in Georgia could be economically
18 developed at hub heights of 120 meters or higher. The Company's 2022
19 IRP seeks to unlock this potential through an innovative demonstration
20 project, which may provide an avenue to remove construction barriers and
21 make tall wind a viable option in the future. The Company's 2022 IRP
22 generic expansion plan reflects the possibility that wind generation may be
23 cost-effective, and tall wind may enable Georgia to host competitive
24 resources for the benefit of customers.

25 In addition, Georgia Power continues to study avenues to reduce the risk of carbon
26 on customers. While carbon capture and storage ("CCS") is one potential carbon
27 reduction technology for fossil fuel power plants, unknown geologic feasibility for
28 CCS in the state of Georgia presents an obstacle for considering this option in the
29 future for Georgia Power facilities. Even though the Company is not required to

1 deploy CCS today, the R&D program seeks to reduce the potential obstacles over
2 the long term through exploration and study of Georgia geology in the event this
3 option is necessary in the future.

4 **Q. WHAT RESEARCH PROJECTS ARE BEING REQUESTED FOR**
5 **APPROVAL WITHIN THIS IRP?**

6 A. In addition to the tall wind demonstration project described in the pre-filed
7 testimony of Georgia Power Witnesses Grubb, Mallard, Robinson, and Weathers,
8 Georgia Power proposes an integrated hydrogen microgrid demonstration that will
9 create hydrogen from electrolysis utilizing grid energy. The hydrogen produced
10 will be utilized in a fuel cell microgrid as a transportation fuel for three Class 4
11 through 6 hydrogen fuel-cell trucks. The power from the microgrid will also supply
12 three Class 4 through 6 electric vehicles. The hydrogen microgrid concept has the
13 potential to serve as a key enabler for zero-emission transportation while
14 developing infrastructure that will serve as a distributed energy resource, create fuel
15 flexibility, create grid resiliency, and could be deployed incrementally without the
16 need for system-wide infrastructure changes.

17 These key research pilots will position Georgia Power to meet the rapidly changing
18 technology landscape while minimizing cost and mitigating risk to customers.

19 **VIII. CONCLUSION**

20 **Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN**
21 **THE 2022 IRP AS IT RELATES TO THE ECS AND ENVIRONMENTAL**
22 **COMPLIANCE?**

23 A. The Company seeks approval of the ECS. This includes the capital, O&M, and
24 CCR ARO costs and associated measures taken to comply with government-
25 imposed environmental mandates, as set out in the ECS in Technical Appendix

1 Volume 2 and the ECCR and CCR ARO tables in the Selected Supporting
2 Information section of Technical Appendix Volume 1.

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

4 **A. Yes.**

1 COMMISSIONER McDONALD: Mr. Marzo?

2 MR. MARZO: Yes, sir.

3 COMMISSIONER McDONALD: My memory's short, but

4 did you swear the witnesses?

5 MR. MARZO: Yes, sir, I did.

6 COMMISSIONER McDONALD: Thank you very much.

7 MR. MARZO: I would not forget that.

8 COMMISSIONER McDONALD: Good. I forgot it.

9 MR. MARZO: It wasn't very memorable.

10 COMMISSIONER McDONALD: That's the reason I

11 asked him.

12 COMMISSIONER SHAW: I just wanted you to ask.

13 MR. MARZO: That's your colleague.

14 For the record, Chair Johnson, the company

15 filed on March 3rd of 2022 a demonstrative exhibit

16 to accompany the summary of the panel. That's been

17 handed out to commissioners and provided to counsel.

18 COMMISSIONER JOHNSON: Okay. Thank you.

19 BY MR. MARZO:

20 Q Dr. Berry, would you please summarize your

21 prefiled testimony?

22 A (Witness Berry) Yes.

23 Good afternoon, Commissioners. We appreciate

24 the opportunity to appear before you today. The purpose

25 of our testimony is to support Georgia Power's

1 environmental compliance strategy, or ECS, which is a
2 comprehensive strategy designed to provide cost-effective
3 plans for the company to meet -- to meet environmental
4 compliance obligations while providing customers with
5 clean, safe, reliable, and affordable energy.

6 Building on the success of previous ECS
7 filings, the company's ECS seeks to continually optimize
8 compliance plans in an increasingly dynamic and uncertain
9 regulatory environment.

10 The ECS considers existing and potential
11 legislative and regulatory requirements and determines
12 plant specific compliance options.

13 These options are evaluated based on an
14 available technology, cost schedule, plant operations,
15 and the environment. This iterative approach is designed
16 to provide the company the necessary flexibility to
17 develop and refine its compliance plan in the best
18 interest of customers as additional information becomes
19 known.

20 Georgia Power's ECS includes the following
21 major components. First, the company's ELG strategy
22 effectively considers increasing environmental pressures
23 on coal units, the availability of cost-effective load
24 and zero carbon resources, and future system reliability
25 needs.

1 The ECS details the unit-specific compliance
2 options selected for each site, including wastewater
3 treatment controls required for ELG compliance at Plant
4 Bowen Units 3 and 4 and Scherer Units 1 and 2, as well as
5 the proposed retirement of Bowen Units 1 and 2, Scherer
6 Unit 3, and Wansley Units 1 and 2.

7 The ECS describes the unique opportunity to
8 pursue parallel compliance path for ELG, for Scherer
9 Units 1 and 2 while the company continues to evaluate the
10 membrane-based treatment systems needed to comply with
11 the voluntary incentive program pathway by 2028.

12 Preliminary results from the evaluation
13 indicate that the VIP pathway is potentially feasible at
14 Scherer.

15 The company expects to provide additional
16 information, including updated cost estimates and
17 associated research on the membrane-based treatment
18 system to this Commission in May.

19 Second, the company's CCR strategy approved in
20 2019 IRP which includes the closure of all 29 ash ponds
21 and 12 landfills continues to be effectively implemented
22 with significant progress made over the last three years.

23 The company continues to evaluate opportunities
24 to refine and optimize its closure plans, including
25 consideration of plant retirements proposed in this IRP

1 in the closure strategy.

2 If the Commission approves retirement of the
3 coal units at Plant Wansley, Georgia Power recommends
4 modifying its ash pond closure plans at the site from
5 closure in place to closure by removal.

6 The retirement of Plant Wansley presents a
7 unique opportunity to use the existing on-site landfill
8 to support the ash pond closure.

9 The company will provide an updated ECS and
10 associated technical appendices to support this
11 recommendation to the PSC in the coming weeks.

12 While the current closure in place strategy
13 provides a robust solution, closure by removal provides
14 the opportunity to maximize the use of the existing
15 landfill asset, manage construction and operational risks
16 associated with the current closure in place design, and
17 preserve the option for future beneficial use of ash as
18 driven by the market.

19 Overall, Georgia Power is seeking to identify
20 market-driven opportunities and maximize the value for
21 the beneficial use of stored ash at its active and
22 retired plants across the state.

23 Currently the company is in the final stages of
24 evaluation of bids, responding to the requests for
25 proposal for the beneficial use of stored coal ash at

1 Georgia Power facilities and will move forward with
2 opportunities that present expected value to the ash pond
3 closure strategy.

4 To realize this value, the company will begin
5 investing in ash processing infrastructure at applicable
6 facilities over the next three years.

7 As with any commodity, there are inherent
8 market risks that could impact the assumed volumes of ash
9 reuse. However, the following graph depicts an example
10 of long-term value that could be achieved through
11 strategic installation of ash processing infrastructure
12 as market opportunities develop.

13 The red line indicates the cumulative cost of
14 the closure program without beneficial use. The blue
15 line represents the potential value of beneficial use
16 through the expected reduction in overall cost of the
17 closure program.

18 Third, the company's climate approach uses a
19 long-term outlook and assumes a carbon-constrained future
20 to appropriately mitigate risks and challenges associated
21 with potential climate policies that could impact
22 customers. This approach emphasizes the importance of
23 proactively preparing for possible future carbon policy.

24 Finally, research and development is a
25 longstanding cornerstone of Georgia Power's environmental

1 strategy and continues to play a pivotal role in the
2 company's compliance plan.

3 The company leverages R&D to bring alternative
4 and cost-effective technologies to market and to inform
5 our decision-making to bring value to customers.

6 The tall wind and hydrogen microgrid
7 demonstration projects requested in this IRP are key R&D
8 efforts to position Georgia Power to meet the rapidly
9 changing technology landscape while minimizing costs and
10 mitigating risk to customers.

11 With the Commission's oversight, the company is
12 well positioned to continue to build on successes for the
13 benefit of customers with its 2022 ECS through robust
14 research efforts, cost-effective strategy optimization,
15 reliable operations, and environmental compliance.

16 Thank you, Commissioners.

17 COMMISSIONER JOHNSON: Thank you, Mr. Berry.

18 MR. MARZO: Chair Johnson, we do have copies
19 available of the demonstrative exhibit. I'd also
20 like to mark that as Georgia Power Exhibit No. 3.

21 COMMISSIONER JOHNSON: Okay. Thank you.

22 The document referred to was marked for
23 identification as Georgia Power Exhibit 3.)

24 MR. MARZO: With that, Chair Johnson, the
25 witnesses are available for cross-examination.

1 COMMISSIONER JOHNSON: All right. Thank you.
2 Commissioners, any questions for the witnesses?

3 (No response.)

4 COMMISSIONER JOHNSON: All right. Georgia
5 Public Service Commission.

6 MR. THOMAS: Thank you. Preston Thomas on
7 behalf of Public Interest Advocacy Staff.

8 CROSS-EXAMINATION

9 BY MR. THOMAS:

10 Q If you could turn to the main docket --
11 document, page 1-13, Item No. 15, it indicates that the
12 company is requesting approval of the capital O&M and
13 CCR ARO cost but not yet the recovery of this cost.

14 Am I correct that the ECCR revenue requirement
15 is not subject to true-up or reconciliation to actual
16 costs?

17 A (Witness Mitchell) I am not -- Commissioners,
18 I am not a rate witness. However, generally, that is my
19 understanding.

20 Q That is your understanding? Okay.

21 So the company doesn't maintain tracking of
22 whether it is over-recovering its ECCR cost, does it?

23 A (Witness Mitchell) Well, the company maintains
24 and projects to this Commission in various forms in the
25 environmental compliance strategy the costs associated

1 with activities that are necessary to comply with
2 environmental mandates, whether they are federal or
3 state.

4 We update those to this Commission on an annual
5 basis depending on the type of cost. If it's CCR ARO
6 costs related to ash ponds, that's done semiannually, and
7 then every years, of course, in its filing. An exact
8 comparison I'm not aware of -- of an exact comparison, if
9 that's your question.

10 Q So I guess my question is, is there a way for
11 staff and the Commission to tell whether in 2020 or 2021
12 the company overrecovered its ECCR cost?

13 MR. MARZO: Chairman Johnson, I think if there
14 are questions about the cost tables presented in
15 this case, that's obviously fair game. To the
16 extent that we're talking about what has occurred in
17 a prior period where it's -- it's covered by the
18 county order, we have an ASR docket where that
19 information is provided.

20 We also went through a rate case, obviously.
21 The ASR is ongoing, an annual review of that
22 process. These witnesses are not revenue
23 requirements witnesses that will speak to
24 necessarily that. If there's questions about the
25 cost, generally for environmental controls that's

1 included in this docket, they are prepared to speak
2 to that.

3 COMMISSIONER JOHNSON: I will sustain.

4 MR. THOMAS: Commissioner, then I would -- may
5 I approach the witnesses with a response to a data
6 request? May I approach?

7 COMMISSIONER JOHNSON: Counselor, are you --

8 MR. MARZO: I still remain concerned, but I
9 mean, I'll -- you know, I'll obviously let staff
10 counsel ask the question and then levy an objection
11 if needed.

12 MR. THOMAS: Okay. All right.

13 COMMISSIONER JOHNSON: You may approach.

14 MR. THOMAS: Thank you.

15 BY MR. THOMAS:

16 Q And after you look at this, this data response,
17 STF-LA-4-12 in this docket, does it help you better
18 answer that question at all, even if you can't give
19 depth? Can you give a yes or no answer as to whether
20 it's possible for the Commission to tell in 2020 or 2021
21 if the company overrecovered its ECCR cost?

22 A (Witness Mitchell) Well, specifically the
23 response says the company does not maintain an under- or
24 overrecovery balance related to the ECCR tariff.

25 Q Okay. And the company's proposed ECCR cost

1 include amount for contingencies; right?

2 A (Witness Mitchell) Yes, Commissioners. The
3 company does -- not on all projects, but where
4 relevant -- include contingency consistent with industry
5 practice on large projects or longer-term projects to
6 ensure that we're providing the best cost estimate
7 possible for completion of that project.

8 Q And so the -- if the company has an ECCR that
9 includes contingency amounts and then in a given year it
10 doesn't incur the full amount estimated for that
11 contingency, that could result in overcollection of
12 actual costs; right?

13 A (Witness Mitchell) While it's true that if
14 that scenario played out, that the company may recover
15 more than is actually spent, it's also true that if the
16 company overspends as compared to our estimate, that the
17 company would underrecover the actual costs compared to
18 the original estimate based on what is in the ECCR
19 tariff.

20 Q But if you don't track it, there's no way for
21 the Commission to know.

22 A (Witness Mitchell) Do you have a specific
23 question?

24 Q So just -- you said it could be overrecovered
25 or it could be underrecovered.

1 A (Witness Mitchell) Sure.

2 Q But we don't have a way of knowing that; is
3 that correct?

4 A (Witness Mitchell) Well, as your DR you handed
5 me showed, Commissioners, we don't track that, and that
6 is not required, as I understand, by the Commission for
7 the ECCR tariff.

8 Q And the company has announced that Scherer
9 Unit 3 will be retired and has requested decertification
10 of that unit; right?

11 A (Witness Mitchell) That's correct.

12 Q And even though the company is proposing these
13 closures, it's still planning on spending a substantial
14 amount for capital expenditures on Unit 3, 4, scrubbers,
15 SCRs, and back houses; correct?

16 A (Witness Mitchell) You are referring to the --
17 the --

18 Q Scherer Unit 3.

19 A (Witness Mitchell) The dollars included in the
20 ECCR table and selected supporting information?

21 Q Right. So even though that they're planning to
22 be retired, substantial amounts are expected to be spent
23 for compliance; right?

24 A (Witness Mitchell) Commissioners, the company
25 does intend to continue to invest to maintain reliable

1 unit at Plant Scherer Unit 3 as well as invest in the
2 necessary environmental controls to ensure that we comply
3 with our permits related to continued operation of that
4 unit. Those costs are included through the requested
5 retirement date of December 31, 2028, for Unit 3 at
6 Plant Scherer.

7 COMMISSIONER McDONALD: What will that amount
8 be, the cost of that?

9 WITNESS MITCHELL: The total cost?

10 COMMISSIONER McDONALD: Yes.

11 WITNESS MITCHELL: Commissioners, I do not have
12 that total number.

13 COMMISSIONER McDONALD: Approximately?

14 WITNESS MITCHELL: I believe it's in the unit
15 retirement study. Commissioner, I can look that up
16 if you would like.

17 COMMISSIONER McDONALD: Well, just
18 approximately.

19 WITNESS MITCHELL: I don't know specifically.

20 COMMISSIONER McDONALD: Okay.

21 BY MR. THOMAS:

22 Q So since the company has decided that
23 Plant Scherer Unit 3 is uneconomical to run and is re- --
24 is requesting this decertification, could any of these
25 capital expenditures have been avoided?

1 A (Witness Mitchell) These projected capital
2 expenditures that we have included?

3 Q That's right.

4 A (Witness Mitchell) I'm not familiar with the
5 specifics of all those expenditures that are included. I
6 know that the expenditures related to environmental
7 capital O&M and costs that are necessary to comply with
8 environmental regulations were included in this ECCR
9 table throughout the period and up until -- well,
10 throughout this three-year period for this IRP.

11 As to whether or not those costs can or would
12 be avoided, I think, depends on this Commission's
13 decision on the company's recommendation to retire that
14 unit.

15 Q So then, I guess, was your answer that they
16 couldn't have been avoided? Any of those costs?

17 A (Witness Mitchell) Any of the costs in the
18 three-year projection?

19 Q Right. I'm sorry, it was a long answer, so I
20 was just trying to determine whether, you know, you were
21 saying that none of those capital expenditures for Unit 3
22 could have been avoided since they're going to be
23 decertified?

24 A (Witness Mitchell) Well, I would say -- I
25 would say, Commissioners, our request to decertify that

1 unit is 2028. We've included costs in the ECCR table for
2 the next three years through 2025. Those costs would be
3 required to be incurred to comply with our current
4 permits and operate the existing environmental controls
5 at Plant Scherer through 2025, whether or not the
6 Commission orders the company to retire Scherer Unit 3 in
7 2025.

8 COMMISSIONER McDONALD: Doctor, do we have any
9 units that are going to retire prior to that in the
10 scheme of all the retirements we're talking about?

11 WITNESS BERRY: Yes, Commissioner.
12 Wansley Units 1 and 2.

13 COMMISSIONER McDONALD: Okay. There won't be
14 any cost to keep Wansley through this year, would
15 it? Environmental upgrades? Anything like that?

16 WITNESS MITCHELL: Not upgrades.

17 WITNESS BERRY: Not upgrades, but O&M to
18 operate the equipment.

19 COMMISSIONER McDONALD: Is there anything
20 between Wansley and Scherer that's going to be
21 retired?

22 WITNESS BERRY: No. No, sir. All of the
23 retirements listed here are for 2028.

24 COMMISSIONER McDONALD: And up?

25 WITNESS BERRY: To take advantage of the ELG,

1 boiler cessation option. The Wansley 1 and 2 units
2 would -- are requested to retire this year, and you
3 would only have O&M costs, not costs to -- to
4 install new equipment.

5 Commissioner, am I being responsive to your
6 question?

7 COMMISSIONER McDONALD: That's -- that's -- my
8 question is more vague than your answer is.

9 WITNESS BERRY: Well, that sounds like I'm
10 being responsive.

11 COMMISSIONER McDONALD: We're getting there.
12 We're getting there. I'm a little slow like that.
13 But I'm trying to see if we could move the closure
14 of Unit 3 at Scherer back this way and not have to
15 expend all those costs. That's where I'm kind of
16 trying to go. And I'll ask that question later.

17 WITNESS BERRY: Okay.

18 MR. THOMAS: All right. Mr. Chairman, may I
19 approach?

20 COMMISSIONER JOHNSON: Sure. You may approach.

21 BY MR. THOMAS:

22 Q So looking at -- looking at the company's data
23 request to STF-LA-4-13, which mentions the capital
24 expenditures in the ECCR table for 2022 through 2025, are
25 228.9 million, and that includes a contingency of

1 9.5 million for all projects valued at more than \$1
2 million.

3 Does that \$9.5 million contingency include the
4 contingency amounts for CCR AROs that are listed in the
5 response, or not?

6 A (Witness Mitchell) Just to be sure I
7 understand your question. Of the --

8 Q Right.

9 A (Witness Mitchell) Of the values listed here
10 in this response, you're asking, are CCR ARO
11 contingencies included in that amount?

12 Q In that \$9.5 million contingency.

13 A (Witness Mitchell) No, they are not.

14 Q Okay. So the company is requesting Commission
15 approval for projected spending to develop beneficial
16 uses for stored coal combustion residuals such as coal
17 ash; right?

18 A (Witness Mitchell) That's correct.

19 Q And the company hasn't quantified the savings
20 from beneficial use of CCR, has it?

21 A (Witness Mitchell) Well, the illustration or
22 the slide or demonstrative that the company --
23 Dr. Berry's summation was an early depiction of
24 information as we continue to work through the requests
25 for proposals and negotiate with bidders. That shows an

1 early indication of what the investment in beneficial use
2 at ash ponds and the resulting benefit would provide.

3 I know those numbers and charts may be small to
4 see. The -- the actual investment included in the filing
5 is trade secret as we're still negotiating with vendors.
6 However, the overall benefit based on a couple of
7 sites -- and again, this is an early indication -- is
8 approximately a \$300 million downward pressure on the
9 total costs of the closures for those two sites.

10 That's primarily due to two factors. One is
11 the actual sales of the ash. That goes into a beneficial
12 use market. Those get credited back directly to offset
13 the costs of the closures.

14 Secondly, the value -- it reflects the
15 value of placing that ash into a beneficial use market.
16 Therefore, the company does not have to incur costs
17 associated with ash pond closure because that ash is
18 gone.

19 So the resulting closure costs of less
20 volume at any given site is less. Cumulatively that
21 equates to that approximately 300 million, based on the
22 early estimates resulting from the RFP.

23 VICE CHAIRMAN ECHOLS: Were you aware that this
24 insulated concrete form technology -- I don't know
25 if you have seen this. I was at a Habitat for

1 Humanity ribbon-cutting the other day just on the
2 foundation that they were doing. Actually was using
3 ready-mix with coal ash in it to build the first of
4 its kind Habitat home here in Georgia.

5 So it's a newer technology they're trying that
6 I guess is taking some of our ash and putting it,
7 you know, into a home, rendering it inert, and
8 helping a person in the process.

9 WITNESS BERRY: Commissioner, I really
10 appreciate those comments. We do see continued
11 demand for the ash from our operational units, so
12 right now we're seeing 85 percent overall use. And
13 for fly ash, that percentage is actually higher.

14 As we see the coal units reduce in use and also
15 retiring, we expect that demand to continue. And we
16 saw a good response in the RFP where we were seeing
17 ready-mix folks coming in and saying, "Hey, we want
18 this material. It adds benefits in the
19 marketplace." So we think the demand will continue
20 into the future.

21 COMMISSIONER McDONALD: Doctor, are you
22 reaching out beyond just the use for concrete and
23 other technology for the use of coal ash?

24 WITNESS BERRY: Yes, Commissioner, we are. So
25 we started a research facility up at Plant Bowen.

1 Last year, it was commissioned. And we're getting a
2 lot of interest from various parties that are
3 interested in testing their particular technology.

4 We're looking into rare earth and critical
5 materials space. Lots of interest there. We are
6 using that facility to kind of classify the material
7 that we're offering for sale and gaining insights
8 that are helping us in the RFP.

9 So we are casting our net far and wide. We
10 think this material is a valuable material and it
11 will continue to deliver value to customers in the
12 future.

13 COMMISSIONER McDONALD: The assessment of these
14 materials, though, where are they being studied?
15 Georgia Tech, or where? Where are they --

16 WITNESS BERRY: So we are working with some
17 universities. Most of the research is actually
18 being done at the facility itself. So we have
19 infrastructure at the facility.

20 We are coordinating with vendors who have
21 interest, so we have shipped material to them to
22 say, "Hey, why don't you try this material out
23 yourself. And then come back to us if you're
24 interested in pursuing additional testing
25 opportunities."

1 BY MR. THOMAS:

2 Q So of that projected savings, do you have any
3 idea what portion of that savings is in early years and
4 what portion is in later years?

5 A (Witness Mitchell) Well, as an illustration,
6 the same document that we just referenced as part of
7 Dr. Berry's summation shows that the later years show the
8 most value, although sales of ash would occur almost
9 immediately as we engage with a vendor and they begin
10 those ash sales.

11 The larger impact and the larger value is from
12 the reduction in the amount of ash and the volume of ash
13 that we actually have to close and a reduction in --
14 resulting reduction in the total closure construction
15 costs.

16 Q So what's the projected spending for developing
17 the beneficial use applications?

18 A (Witness Mitchell) So we have included the
19 costs based on this RFP and the short list of bidders in
20 this IRP. Specifically we've given a range -- again,
21 that number is trade secret. It's included in the
22 environmental compliance strategy while we are still
23 negotiating price.

24 We have included the costs at one facility in
25 the budget in our ARO numbers over 2022 and 2023 to get

1 the infrastructure in place to begin the beneficial use
2 activities.

3 Q So the savings will come mostly in the later
4 years. Am I correct that the spending will come mostly
5 in the early years to develop the beneficial use?

6 A (Witness Mitchell) That's right. Again, over
7 a two-year period, 2022 and 2023, for one facility, we
8 have costs estimated and included in the budgets in the
9 selected supporting information in the ARO tables.

10 Once that investment is made, about three to
11 four years later, you would start to see the larger
12 impacts of the closure -- reduction in closure costs.
13 Although, again, just to repeat, once that facility is
14 active, ash sales and the benefits of those sales will
15 be -- begin -- will be realized immediately and we will
16 credit that against the costs of the ash pond closures
17 for customers.

18 A (Witness Berry) Commissioners, if I can just
19 explain, kind of maybe give some context of why this
20 investment is needed.

21 If you're going to sell ash into the ready-mix
22 market, it has to meet a certain classification, Class C
23 or Class F. And the ash that is in our closures don't
24 necessarily meet that specification.

25 So you have to do some investment in order to

1 kind of upgrade that material so you can actually sell it
2 into the market. So this investment is needed in order
3 to realize that benefit.

4 VICE CHAIRMAN ECHOLS: Just one clarification.

5 Mr. Thomas had asked you about the true-up on the
6 fund. So what -- what you're saying, Doctor, is
7 that the sale of the ash, it's not just going to go
8 back into -- against that fund, it's going to be
9 credited to ratepayers directly, so it's not going
10 to get lost in something that's not trued up; right?

11 WITNESS MITCHELL: It will -- it will offset
12 the costs. There won't be a credit issued to
13 customers. Customers will never be charged for the
14 ash pond closure costs equal to the amount of the
15 value of the beneficial use, if that makes sense.

16 VICE CHAIRMAN ECHOLS: Okay.

17 BY MR. THOMAS:

18 Q Did the company's projections show that the
19 revenues from -- projected revenues from the beneficial
20 use will outpace the costs spent to develop the
21 beneficial use?

22 A (Witness Mitchell) So let me answer that
23 twice. Or -- twice. In two ways, Commissioners, if
24 you'll be patient.

25 Q Don't accuse me of asking it twice.

1 A (Witness Mitchell) And I may end up answering
2 it twice. First, the -- the chart that we showed does
3 show that this small investment in the beginning, if you
4 look at the red line, it drops below, it shows an
5 increase in early spend. And that's, again, due to the
6 capital infrastructure. Quickly, though, thereafter, the
7 delta between the lines grows significantly.

8 So that -- that's a long way of saying the
9 benefits more than pay for themselves, if you will, in
10 the long term.

11 As far as what's included in the company's
12 budgets. In the CCR ARO tables in the selecting
13 supporting information, while the company has included
14 for one facility the capital infrastructure necessary to
15 begin that process, we have not yet reflected in our
16 outgoing budgets the benefit of that.

17 So we've kept the budget the same while, again,
18 we finish signing contracts and negotiating with the
19 successful bidders. Once the contracts are signed, we
20 will not only include the capital infrastructure, we will
21 also forecast the benefit in the budgets for the specific
22 facilities going forward.

23 VICE CHAIRMAN ECHOLS: Do you think that it's
24 possible in the future, many years off from now,
25 that one day we will actually use all the ash that

1 we have -- you know, maybe it's -- maybe it is 20,
2 30, 40, 50 years into the future -- and we won't
3 have any coal ash in the ground and it will all be
4 gone because it is gone to beneficial use because
5 there aren't any other coal plants in America
6 creating coal ash?

7 WITNESS MITCHELL: I think, Commissioner,
8 there's a high likelihood that a vast majority of
9 the ash could be leveraged. And I'll give you an
10 example.

11 One of the facilities that we're looking at has
12 a fairly large volume of ash stored in the ash pond.
13 The beneficial use project that we are looking to
14 implement would in just the 15-year closure period
15 use half of that volume. Millions of tons of ash to
16 be beneficially reused and gone from that facility.

17 The company would like to see ongoing use of
18 that, as Dr. Berry testified, I believe, in 2019,
19 the fact that very much so we would like your
20 statement to be true; and, in fact, if we were to
21 continue that success after the 15-year period, we
22 would expect more of the remaining half of the ash
23 volume to be utilized.

24 VICE CHAIRMAN ECHOLS: That's great.
25

1 BY MR. THOMAS:

2 Q Based on your current projections, we're
3 talking about a very small percentage right now, though;
4 right?

5 A (Witness Mitchell) Maybe ask me that again
6 specifically -- more specifically.

7 Q Okay. The beneficial use that's being
8 projected now would just represent a small percent of the
9 coal ash; right?

10 A (Witness Mitchell) Of the total coal ash that
11 the company has in our ponds, it would be a smaller
12 percentage. But again, using the example that I just
13 gave to the Commissioner, millions of tons at one
14 facility over the long term are projected -- again, that
15 depends on market factors, as Dr. Berry stated earlier.
16 But if we're successful in leveraging these RFPs to
17 beneficially reuse this ash, I believe the percentages
18 could be significant over the long term, as the
19 Commissioner referenced.

20 Q Right. But my question is just for right now,
21 are we talking about less than 5 percent? Less than
22 10 percent?

23 A (Witness Mitchell) Over the 15-year period --
24 I can't give you specifics, again, because we're still
25 negotiating and selecting the bidders. It would result

1 in millions of tons of ash. That is maybe 10 percent
2 plus, if we're successful.

3 VICE CHAIRMAN ECHOLS: If we have -- do we have
4 around 90 million tons? Is that what you estimate?

5 WITNESS MITCHELL: That's approximately
6 correct, Commissioner.

7 VICE CHAIRMAN ECHOLS: And it seems like you
8 had said that we would use 10 million over 15 years,
9 so that's -- you know, that's about 10 percent. Is
10 that about right?

11 WITNESS MITCHELL: That's about right. And
12 that's -- that's just a couple of projects; right?
13 As we continue and advance this, we'd like to
14 explore more of this and more applications.

15 Again, it is market dependent. As Dr. Berry
16 said, we want to give these vendors a steady
17 consistent supply of quality ash that they can use
18 that should heighten their expectation, as well as
19 looking, as Commissioner McDonald said, for other
20 markets to invest in as well.

21 VICE CHAIRMAN ECHOLS: And it benefits us to
22 get ahead of other states, building the equipment,
23 having the -- the equipment that will remediate the
24 ash and turn it into a beneficial product; right?

25 WITNESS MITCHELL: Correct, Commissioner. And

1 I would point out that Georgia Power has elected to
2 do it differently than other states. Other states
3 have mandated beneficial use regardless of the
4 market capacity for it, and those utilities have
5 ended up paying people to take the ash.

6 We've elected to have the market compete for
7 the benefit of customers and provide us viable
8 options that actually puts downward pressure on our
9 total closure costs instead of upward pressure, as
10 other utilities and states have experienced.

11 BY MR. THOMAS:

12 Q And the spending that will be done in the early
13 years to enable the development of the beneficial uses,
14 is the company asking for ratepayers to pay those costs?

15 A (Witness Mitchell) Yes, we are including those
16 costs. Again, we have included those in one facility
17 where we are negotiating contracts, and we will include
18 those in our ARO estimates that we provide to the
19 Commission.

20 Again, those come in semi-annually in a
21 separate docket, as ordered in 2019. And we'll continue
22 to reflect those. I might add that those costs are cost
23 shared with these vendors that we are engaging in
24 business with.

25 Q All right. I'd like to turn to ash pond

1 closures. Am I correct to say that the closure estimates
2 and selected methods have been developed with input from
3 external and internal experts; is that correct?

4 A (Witness Mitchell) That's correct. We have --
5 Georgia Power has engaged third-party engineers,
6 third-party experts, third-party geologists that are
7 experienced in solid wastes, landfill closures, and ash
8 pond closures to develop our closure plans, help us
9 develop our permitting documents and designs, as well as
10 construction plans, to execute compliance with the
11 federal EPA rules.

12 Q And the company has told the Commission that
13 the site-specific closure method is the most cost
14 effective to allow compliance with CCR rules, support
15 permit requirements, and mitigate environmental risk.

16 How does the Commission know that the
17 site-specific closure method is the most cost-effective
18 method for compliance? Has the company done any analysis
19 on alternatives?

20 A (Witness Mitchell) Let me respond and see if I
21 hit your question correctly.

22 The company has stated that each of the ash
23 pond closures is a site-specific determination. And
24 even -- even ash ponds on the same property require
25 different engineering and closure designs. We have

1 engaged the third parties that we referenced in the
2 previous question to ensure that we address all those
3 site specifics.

4 But in all cases, those designs are developed
5 in compliance with both the federal and the state coal
6 combustion residuals rule, which lists specific
7 performance standards that you have to meet for the
8 closures of each ash pond and landfill.

9 COMMISSIONER McDONALD: Would Plant McDonough
10 be an example of what you just said?

11 WITNESS MITCHELL: Plant McDonough? Yes, sir.
12 We are -- there are four ash ponds at
13 Plant McDonough. One of those ash ponds is being
14 closed by removal. The other three are being closed
15 in place, but even those three have very specific
16 designs associated with them based on their
17 site-specific nature.

18 COMMISSIONER McDONALD: And the technology
19 proves that that particular type of restructure, you
20 monitor the water table and all of those things that
21 go in to make it in compliance with EPA, et cetera,
22 et cetera?

23 WITNESS MITCHELL: That's right, Commissioner.
24 Not only the way that we close the ponds and the
25 specific designs are specified in the rules; but as

1 you referenced, the monitoring of the groundwater
2 before, during, and after the closures is mandated.
3 Reporting that to Georgia EPD is mandated.

4 So all those are aspects of both the federal
5 and the state rules that the company has to comply
6 with.

7 COMMISSIONER McDONALD: Would that same type of
8 technology be applicable at Scherer?

9 WITNESS MITCHELL: Type of technology? The
10 closure in place?

11 COMMISSIONER McDONALD: Just like you've
12 mentioned at McDonough. To do the same thing, would
13 it meet the qualifications, et cetera, in the
14 certificate of approval?

15 WITNESS MITCHELL: Well, again, Commissioner,
16 they're all different. And they all require a
17 little different design. The performance standards
18 for closures in place are very specific. Those
19 third-party engineers look at those performance
20 standards to ensure that the site specifics are
21 taken into account. At McDonough Unit 1, that --
22 that unit has been closed in place.

23 I'm sorry. Ash Pond 1 has been closed in
24 place. And we are adding a subsurface barrier wall
25 around that ash pond to close it. At Ash Pond 3 and

1 4, those are closed in place, and a combination of
2 expanding or extending the cover system as well as
3 enhanced dewatering systems are installed to comply
4 with that.

5 At Scherer, some very similar and specific
6 attention is being given to the site-specifics there
7 to comply with those performance standards, which
8 include taking the ash pond from approximately
9 550 acres down to approximately 300 acres.

10 And consolidating that ash, extending the cover
11 system beyond the edge of the waste, as well as
12 ensuring that it's dewatered and monitored as part
13 of that closure.

14 COMMISSIONER McDONALD: What about Branch?

15 WITNESS MITCHELL: Plant Branch has -- had five
16 ash ponds. One of them has been removed. So there
17 are four left. We are closing those by removal.
18 Constructing a new landfill and placing the ash from
19 the ponds in that landfill.

20 COMMISSIONER McDONALD: On-site?

21 WITNESS MITCHELL: Yes, sir.

22 MR. THOMAS: May I approach?

23 COMMISSIONER JOHNSON: Yes, you may approach.

24 MR. THOMAS: And, Madam Court Reporter, can you
25 tell me which exhibit number staff is at?

1 COURT REPORTER: I don't know.

2 BY MR. THOMAS:

3 Q So I'd like to turn your attention to
4 STF-LA-4-4, the company's response to staff data request.
5 And if you go towards the last paragraph on the first
6 page, it states that, "The site-specific closure method
7 is the most cost effective to allow compliance with CCR
8 rules, support permit requirements, and mitigate
9 environmental risks."

10 So again, I just want to ask, and, you know,
11 there's a very long answer. So how does the company --
12 the Commission know that this is the most cost-effective
13 approach to allow compliance with CCR rules, support
14 permit requirements, and mitigate environmental risks?

15 A (Witness Mitchell) Well, the company has
16 designed each to be compliant; and, Commissioners, they
17 may not be the cheapest option to be evaluated, but the
18 company has determined that they are the most
19 cost-effective option to comply with the requirements of
20 the rule.

21 Certainly, the company looked at other
22 alternatives, even at a cursory level, that would have
23 cost more. And those scenarios were eliminated for that
24 reason.

25

1 BY MR. THOMAS:

2 Q Were analyses done and provided the Commission
3 on alternatives?

4 A (Witness Mitchell) No.

5 Q Did you cost out alternatives?

6 A (Witness Mitchell) In some cases early, when
7 the 2015 federal rule came out, the company engaged with
8 these engineers that we have been discussing to look at
9 what are the viable options for compliance and assessed
10 the site-specific nature of each ash pond and landfill to
11 determine what was feasible and achievable to be the most
12 cost effective to comply.

13 In some cases there was one option that was
14 considered. Again, we talked about a number of factors
15 previously with this Commission when they approved our
16 2019 ash pond closure strategy. Those factors include
17 the size of the ash pond, the volume of material in the
18 ash pond, the proximity to lakes and rivers, and our
19 ability to effectively execute construction because of
20 that proximity.

21 So all those things factored in to, as well as
22 the cost, what the ultimate closure strategy is for each
23 and every ash pond.

24 Q Okay. But just to be clear, the answer was,
25 no, I believe, to whether alternative analysis was

1 provided to the Commission; correct?

2 A (Witness Mitchell) That's correct.

3 Q Okay. Referring to page 20, line 10 of your
4 testimony, where it reads, "Does EPA's new position
5 change the company's request in this case?" And you
6 state, "No."

7 Is the company's answer of "no" due to the
8 legal standing of EPA's rule amendments?

9 A (Witness Mitchell) When you ask related to
10 EPA's rule amendment, you mean their -- their press
11 release in January?

12 Q Right.

13 A (Witness Mitchell) Okay. Our answer is, no,
14 that the EPA's announcement in January does not affect
15 our closure plans.

16 Commissioners, just a little background on
17 that. EPA issued determinations for specific facilities
18 in the midwest and the northeast related to their
19 compliance with the CCR rule. In that, EPA expanded upon
20 the well-understood interpretation of the 2015 CCR rule.

21 In doing so, they addressed inadequacies with
22 those specific facilities. They did not change the
23 rules. So there has been no rule change. And therefore,
24 the company has not changed our strategy as a result.
25 And as this Commission knows, Georgia EPD has been

1 delegated authority by EPA to oversee and implement CCR
2 and ash pond closures in the state. The company has and
3 will continue to work with EPD to ensure that we comply
4 with those requirements.

5 MR. THOMAS: And also, Mr. Chairman, as we move
6 on, I wanted to see if I could request that
7 STF-LA-4-4 be marked as Staff Exhibit No. 8.

8 (The document referred to was marked for
9 identification as Staff Exhibit 8.)

10 COMMISSIONER JOHNSON: Okay.

11 BY MR. THOMAS:

12 Q So the company's pursuing, I think you
13 mentioned, closure in place for 10 ash ponds. You know,
14 referring to 40 CFR, Section 257, 102-D, it states that,
15 "The owner-operator of a CCR unit must ensure that at a
16 minimum the CCR unit is closed in a manner that will
17 control, minimalize, or eliminate to the maximum extent
18 feasible postclosure infiltration of liquids into waste
19 and release of CCR leachate and contained runoff to
20 groundwater surface waters of the atmosphere."

21 So would you agree that it is possible by
22 removing instead of covering in place to have none?
23 Would that not be the maximum extent feasible?

24 A (Witness Mitchell) No, it wouldn't.

25 Q Okay.

1 A (Witness Mitchell) The specific provision you
2 read is under a section for closure in place. The
3 previous section, 102 -- it's C perhaps, I believe -- is
4 related to performance or includes performance standards
5 for closure by removal options.

6 Back to your reference, the 102-D lists the
7 requirement that you read, as well as many others, that
8 you have to comply with when you close an ash pond in
9 place. As we referenced earlier, the third-party
10 engineers that we've engaged have looked at that specific
11 performance standard, as well as the others, and ensured
12 that the company's designs for the ten closure in place
13 ash ponds do control, minimize, or eliminate postclosure
14 infiltration as part of our designs.

15 And that's what we've included in our
16 applications that we submitted to Georgia EPD in 2018.
17 And that's what we believe complies with the rules, and
18 we'll work with Georgia EPD as they continue to issue
19 those permits.

20 Q So it sounds like the company is confident that
21 they're in compliance. But I'm sure you're aware that
22 the EPA met with Georgia EPD earlier this year regarding
23 Georgia's coal combustion residuals permit program;
24 right?

25 A (Witness Mitchell) Yes.

1 Q And can you tell us the nature of those
2 conversations?

3 A (Witness Mitchell) I was -- I was not a part
4 of those conversations, Commissioners, but I understand
5 that EPD and EPA continue to meet about Georgia Power's
6 applications at EPD to ensure that they are aligned on
7 issuance of those permits.

8 Q Okay. And --

9 COMMISSIONER McDONALD: When you're talking
10 about that and you're talking about these meetings
11 with EPD and EPA and Georgia Power, now, some of
12 these facilities are jointly owned. Not just
13 Georgia Power. Are these other parties involved in
14 that same engagement of meetings?

15 WITNESS MITCHELL: No, Commissioner. And to be
16 clear, we were not involved -- Georgia Power was not
17 involved in the meetings with EPA and EPD, though we
18 have met with both separately over the last few
19 years.

20 COMMISSIONER McDONALD: I just gathered that
21 they were meeting y'all -- those three parties were
22 meeting.

23 WITNESS MITCHELL: Oh, no, sir. The co-owners,
24 though -- on the co-owned facilities at Scherer and
25 Wansley, Georgia Power is the agent and operates the

1 power plant on behalf of all owners, as well as
2 represents the --

3 COMMISSIONER McDONALD: Even though they're not
4 majority owners in some of those facilities?

5 WITNESS MITCHELL: Correct. My team does the
6 permitting, the compliance reporting, and the
7 environmental compliance oversight for those
8 co-owned facilities on behalf of all owners. That's
9 part of the ownership agreement, and we're obligated
10 to act in the best interests of all owners of those
11 facilities.

12 BY MR. THOMAS:

13 Q But you would agree that there are methods that
14 would cause no penetration of groundwater; right?

15 A (Witness Mitchell) Could you ask me again?

16 Q There are methods that would not cause these
17 same concerns that closure in place causes; right?

18 A (Witness Mitchell) Well, again --

19 Q Removal; correct?

20 A (Witness Mitchell) I'm sorry?

21 Q Removal would be another option; right?

22 A (Witness Mitchell) Well, the EPA approved, in
23 fact, two methods in the rule, and both are approved
24 methods for closure. And the EPA has said that both
25 methods are equally as protective of the environment if

1 the performance standards are complied with. And those
2 two methods are both closure in place and closure by
3 removal.

4 So there's not simply one method. And it's not
5 the company; it's the EPA that has determined that those
6 methods are protective of the environment.

7 Q I didn't ask whether there were multiple
8 methods or whether they both protected the environment.
9 But there are -- would you agree that there are certain
10 problems that exist with groundwater, with covering in
11 place that don't exist with the other approved method?

12 A (Witness Mitchell) No, I don't think I would
13 agree with that.

14 Q You wouldn't agree with that?

15 A (Witness Mitchell) The EPA determined methods
16 to protect the environment for a closure in place, I
17 believe is your question, and --

18 Q But one doesn't cause concerns that the other
19 can alleviate?

20 A (Witness Mitchell) Well, EPA is the arbiter
21 and determiner of protection of the environment.

22 Q I'm not asking if they're both approved. I'm
23 asking if one has concerns that the other does not.

24 MR. MARZO: Commissioner Johnson, I think the
25 question has been asked and answered by the witness.

1 MR. THOMAS: I believe he has continued to
2 answer that there are two methods and they're both
3 approved. He hasn't actually answered the question
4 of whether one method has concerns that the other
5 does not. I'll give you an opportunity to --

6 MR. MARZO: Mr. Johnson, if there's two
7 acceptable methods under the law, that kind of says
8 both are protective of cleaning up the environment.

9 MR. THOMAS: I'm not asking if they're both
10 protective. I'm asking if one has concerns that the
11 other does not. They can both be approved and
12 protected and one have one set of concerns that the
13 other does not have.

14 COMMISSIONER JOHNSON: Counsel, I'm going to
15 allow him to continue.

16 A (Witness Mitchell) Okay. Could you ask me
17 again, please?

18 BY MR. THOMAS: :

19 Q Sure. Do you think that cover in place has any
20 concerns that removal does not have, in terms of
21 groundwater?

22 A (Witness Mitchell) I think that if the company
23 complies with EPA's performance standards for closure in
24 place, that groundwater is protected adequately as EPA
25 has determined.

1 COMMISSIONER McDONALD: But my question -- or
2 question would be, is it the EPA has concerns or is
3 it John Blow out there that has concerns that lives
4 downstream, where the concern's coming from. Does
5 EPA have a concern over either one of those that
6 they have approved, or are there outside concerns
7 that don't agree with EPA and EPD's position?

8 WITNESS MITCHELL: I think there are parties on
9 all sides, Commissioner. Specific to EPA's
10 activities in January where they addressed the four
11 facilities seeking compliance and permits, EPA
12 specifically said that those four permits -- those
13 four facilities' permit applications and designs
14 were deficient compared to the requirements of the
15 rule. Georgia Power --

16 COMMISSIONER McDONALD: Mr. Thomas, does that
17 kind of meet your effort about concern?

18 BY MR. THOMAS: :

19 Q I -- so are you saying that the concerns are
20 coming from parties including the EPA is looking at this
21 again? Or what is your answer? I'm not sure I
22 understand.

23 A (Witness Mitchell) My answer is that EPA's
24 actions in January were site specific to four facilities
25 that EPA determined that their engineering designs were

1 deficient when compared to compliance with the rules.

2 I'm saying that E -- Georgia -- Georgia Power's
3 position is different in that we believe our designs are
4 compliant. Several of the deficiencies that EPA noted of
5 those four facilities included lack of engineering method
6 description to comply with the performance standards, as
7 well as lack of engineering controls related to the
8 performance standards.

9 And Georgia Power has included both of those in
10 all of our designs, whether it is a closure in place or a
11 closure by removal.

12 Q Okay. So it's your testimony that both
13 methods -- one method doesn't alleviate groundwater
14 concerns? Is that your testimony?

15 A (Witness Mitchell) My testimony is EPA has
16 determined both methods are equally protective if one
17 complies with the rules.

18 Q Okay. So can you confirm for the ten ash ponds
19 that you're pursuing closure in place, that upon closure
20 of each ash pond the company has precluded the
21 probability of future impoundment of water settlement or
22 slurry at the CCR impoundment?

23 A (Witness Mitchell) Yes.

24 MR. THOMAS: And -- I think that that concludes
25 my questions, gentlemen. So I appreciate your time.

1 (Witness Mitchell) Thank you.

2 COMMISSIONER JOHNSON: Thank you, Mr. Thomas.

3 MR. THOMAS: Thank you.

4 And I'd request that Staff Exhibit 8 be entered

5 into the record.

6 COMMISSIONER JOHNSON: It will be.

7 MR. THOMAS: Thank you.

8 (Staff Exhibit 8 was admitted into evidence.)

9 COMMISSIONER JOHNSON: Okay. As we get into

10 our list here of intervenors, I want to remind

11 everybody of Chair Pridemore's guidance early on.

12 If the questions have been asked and answered,

13 please do your very best not to repeat those

14 questions.

15 We will start with Americans for Affordable

16 Clean Energy.

17 MR. GALLOWAY: Mr. Chairman, no questions.

18 COMMISSIONER JOHNSON: Thank you, sir.

19 Commercial Group, not here.

20 Concerned Ratepayers of Georgia?

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

22 I do have a follow-up from yesterday where I

23 requested that the panel have nameplates, very

24 similar to what the Commission has. I think that

25 would be very helpful when you have a panel of two

1 or four people, so -- I don't know, you know, which
2 witness is...

3 COMMISSIONER JOHNSON: If you're still there --
4 we'll take it under advisement, Mr. Prenovitz.

5 MR. PRENOVITZ: Thank you, sir.

6 COMMISSIONER JOHNSON: Yes, sir.

7 Georgia Association of Manufacturers?

8 MR. CHARLES JONES: No questions, Mr. Chairman.

9 COMMISSIONER JOHNSON: Thank you.

10 Georgia Center for Energy Solutions?

11 MR. HUBBARD: Mr. Chairman, no questions.

12 COMMISSIONER JOHNSON: Thank you, sir.

13 Georgia Coalition of Local Government?

14 MS. BROWN: Yes, sir, just a couple. Hey,
15 listen, this isn't my baby.

16 MR. MARZO: So close.

17 MS. BROWN: Gentlemen, thank you for being here
18 today. Commissioners.

19 CROSS-EXAMINATION

20 BY MS. BROWN:

21 Q So as a group of local governments, we're
22 interested in some of the R&D projects that you have
23 underway, and specifically wanted to ask a question about
24 the hydrogen microgrid concept.

25 In the testimony on the very last page it's

1 talking about how a plan to use grid energy and
2 electrolyzer and water is seen as an enabler to zero
3 emission transportation.

4 It is -- is there understanding that if you're
5 using grid energy, this is not giving you full insight
6 into what zero emission hydrogen would look like?

7 A (Witness Berry) Yes. Yes, your
8 characterization is correct.

9 So, Commissioners, in this project we're going
10 to use grid energy such that we really want to
11 investigate the production of hydrogen.

12 We're working with a host of partners on this
13 particular project, and we're trying to demonstrate the
14 concept with the view that in the future, as more
15 renewables come onto our grid, and even in a co-located
16 application, that you will be able to create what they
17 call green hydrogen.

18 But what we're trying to do in this particular
19 project is move forward the development of PEM
20 electrolyzers. So we're working with Nel Hydrogen,
21 working with GM in terms of the vehicles.

22 So we do understand that in this project while
23 using green energy it may not have the attributes that
24 you mentioned, but we're really trying to push the
25 technology forward, and that's why we are using grid

1 energy in this case.

2 Q So there's no interest in seeing just what
3 capacity factor you would need from curtailed solar for
4 the economics to work out? This is more focused on the
5 trucking side of things?

6 A (Witness Berry) It's focused on trucking, but
7 it's also focused on resilience and reliability. In this
8 particular project, we're going to take grid energy,
9 we're going to produce hydrogen that we're going to store
10 on the site, and then we'll use that hydrogen for two
11 purposes.

12 One purpose is to be placed in a fuel cell
13 truck as a fuel; right? And these will be trucks that
14 will serve Georgia Power customers.

15 In the second case, we will take that hydrogen,
16 run it through a fuel cell, and we will use those
17 electrons to power midsized trucks. And also the fuel
18 cell will then be able to provide electricity back to the
19 grid.

20 So we're studying a number of things in this
21 particular project. One is transportation. The other is
22 reliability and resilience.

23 Q Okay. Thank you for that.

24 You also mention in your testimony this idea of
25 a long-duration storage, and it seems to be implying the

1 100 hour iron battery that's being pioneered. I believe
2 in Minnesota is where that's being demonstrated.

3 Are there any solid plans for that right now,
4 or is that just something that is in the works?

5 A (Witness Berry) So I think you are referring
6 to the form energy project. So we -- we are looking at
7 that particular technology. We have a lot of interest.
8 What we see early on is that this particular technology,
9 because of the materials that it used could be ten times
10 less than the cost of a battery technology.

11 And just because of how it would be designed
12 that you could kind of put modules together and make
13 large volumes of energy storage cost effective.

14 So we are interested in the technology. We're
15 going to be following that 1 megawatt demonstration with
16 high interest.

17 I would also say that our R&D program
18 encompasses many other long-duration storage
19 technologies. We're doing thermal storage, other
20 electrochemical technologies like flow batteries, for
21 instance. We're also looking at gravity systems and
22 chemical storage. So the hydrogen microgrid project is a
23 chemical version of energy storage.

24 Q And you mentioned reusing used electric vehicle
25 batteries. Is that going to be for a grid-scale

1 application or is that looking at behind the meter as
2 well?

3 A (Witness Berry) So we're not doing anything
4 right now on that.

5 MS. BROWN: All right. Thank you.

6 VICE CHAIRMAN ECHOLS: Let me --

7 COMMISSIONER McDONALD: Go ahead.

8 VICE CHAIRMAN ECHOLS: I hope you are, because
9 my motion in 2019, you know, compelled you to do it.

10 WITNESS BERRY: No, not in -- not in those
11 particular projects. Not in those particular
12 projects.

13 VICE CHAIRMAN ECHOLS: Is there something you
14 need to talk to me about?

15 WITNESS BERRY: No, no. Commissioner, I meant
16 not in those projects that she mentioned.

17 VICE CHAIRMAN ECHOLS: Okay. Okay. But we do
18 have that thing being teed up; right?

19 WITNESS BERRY: Yes. Yes, Commissioner.

20 VICE CHAIRMAN ECHOLS: Okay.

21 COMMISSIONER McDONALD: It's not teed too high,
22 is it, Doctor?

23 WITNESS BERRY: Nah, nah. I wouldn't whoop it
24 like I would on a golf range there, Commissioner.

25 COMMISSIONER McDONALD: Back to your hydrogen,

1 is it -- am I correct in saying that the use of
2 hydrogen for fuel for over-the-road trucks is --
3 is -- gives an extended mileage over compressed
4 natural gas?

5 WITNESS BERRY: Yes, those technologies are
6 quite similar. What we are doing in this particular
7 project is that we're trying to demonstrate for
8 transportation that the total cost of ownership is
9 the same as a diesel vehicle. But you would have a
10 lot -- you would have zero emissions if you used
11 green hydrogen. So that is the vision in the
12 future.

13 Why this is good for customers, I think we have
14 all seen a raise in prices when it comes to gas and
15 diesel as we drive by the pumps.

16 COMMISSIONER McDONALD: We won't go there this
17 afternoon.

18 WITNESS BERRY: And we see in our electricity
19 prices that we see that they have remained low for a
20 long period of time. So if we're able to
21 demonstrate this technology and able to enable this
22 type of transportation, then we could possibly
23 shift, reduce emissions, and also reduce cost
24 volatility to customers.

25 COMMISSIONER JOHNSON: All right. Thank you,

1 Ms. Brown.

2 Georgia Interfaith Power & Light and

3 Partnership for Southern Equity.

4 MS. KYSOR: No questions. Thank you.

5 COMMISSIONER JOHNSON: Thank you, ma'am.

6 Georgia Large Scale Solar Association and

7 Advanced Power Alliance.

8 MR. CARVER: No questions, Commissioner.

9 COMMISSIONER JOHNSON: Thank you, sir.

10 Georgia Solar Energy Association?

11 MR. MORELAND: No questions.

12 COMMISSIONER JOHNSON: Thank you, sir.

13 I do believe I missed Georgia Solar Energy

14 Industries Association.

15 MR. THOMASSON: I was answering for the one you

16 skipped so...

17 COMMISSIONER JOHNSON: All right. You guys are

18 picking right up on this.

19 All righty.

20 Georgia Watch? Ms. Coyle?

21 (No response.)

22 COMMISSIONER JOHNSON: She's not over there?

23 Come back to her.

24 Interstate Gas Supply.

25 MR. CARVER: No questions.

1 VICE CHAIRMAN ECHOLS: You must be present to
2 win; right?

3 COMMISSIONER JOHNSON: Amen.

4 VICE CHAIRMAN ECHOLS: Especially today.

5 COMMISSIONER JOHNSON: All right. Restore
6 Chattooga Gorge is excused.

7 Sierra Club.

8 CROSS-EXAMINATION

9 BY MR. FABISH: :

10 Q Good afternoon. Zach Fabish for the Sierra
11 Club.

12 A (Witness Mitchell) Good afternoon.

13 A (Witness Berry) Good afternoon.

14 Q Thank you for being here to answer some
15 questions.

16 I think I can trim quite a bit from here,
17 because folks ahead of me have already asked a lot of the
18 questions I might have had.

19 But let me just ask, first, if it's all right,
20 a question about Scherer. So I believe you mentioned
21 that, in your testimony at least, page 17, lines 5
22 through 7, that "As regards effluent limitation
23 guidelines compliance at Scherer, the additional research
24 efforts at Plant Scherer are scheduled for completion
25 prior to the conclusion of the 2022 IRP proceedings"; is

1 that correct?

2 A (Witness Mitchell) You said 17, 5 through 7?

3 Q Yeah, I think that's what I said. It's what I
4 wrote. I hope it's what I said.

5 A (Witness Mitchell) I see that, yes.

6 Q Okay. That's your -- and did you mention
7 earlier that you expect to supplement the IRP or submit
8 some additional information on that point?

9 A (Witness Mitchell) Yes. We anticipate having
10 additional information to submit and update the
11 Commission in May. In the month of May.

12 Q Okay. And there's no preview you can give us
13 now?

14 A (Witness Mitchell) Well, as Dr. Berry stated
15 and we included in our testimony, that the -- and what
16 we're talking about here is scrubber wastewater
17 compliance with the ELG rule. There are a few updates
18 and options since we last met with the Commission in the
19 2019 IRP in that EPA issued a new rule that provided
20 another option or two to -- to evaluate outside of the
21 general compliance.

22 What we've included in this IRP for
23 Plant Scherer are costs and controls associated with the
24 general compliance by 2025. Those include a physical
25 chemical biological treatment system. But in addition,

1 we've told the Commission that we are evaluating a
2 membrane-based water treatment system that would comply
3 with an option provided in the 2020 ELG rule called the
4 voluntary incentive program that gives you three
5 additional years to comply.

6 The evaluation that we're doing right now is an
7 evaluation of that membrane technology and it's not yet
8 completed. And while we see promise in that technology,
9 there are remaining R&D efforts that need to conclude so
10 that we can understand the full costs and ensure the full
11 compliance of that system before we recommend that system
12 as a solution.

13 Q Okay. Thank you.

14 I have a handful of follow-up questions on the
15 CCR beneficial use. So just page 26, line 20, of your
16 testimony, you discuss marketing, 85 percent of, I think,
17 the operational CCR material.

18 Does that sound about right?

19 A (Witness Mitchell) Correct.

20 Q Okay.

21 A (Witness Mitchell) And that's in reference to
22 the ash that comes from the operating power plants.

23 Q Yes. Great.

24 And then I think on page 10, lines 9 through
25 10, you said the company's continued to recycle 87 --

1 85 percent of the operational CCR. So that I just wanted
2 to confirm that these two terms mean the same thing.

3 A (Witness Mitchell) You said page 10?

4 Q Lines 9 through 10 on page 10, yes.

5 A (Witness Mitchell) Okay. Yes, I believe the
6 intent is the same.

7 Q Okay. Thank you.

8 And so -- and then -- and I think -- I
9 appreciated the demonstrative and the opening, but just
10 so I understand, beneficial use is not just limited to
11 the operational coal ash. It's also something that can
12 happen with the legacy CCR materials; right?

13 A (Witness Mitchell) That's correct.

14 Q Okay. And so given -- and this was discussed
15 earlier -- that there are two methods for compliance
16 under the CCR rule for closing and impoundment, either
17 excavate -- closure by removal or closure in place.

18 Does the closure by removal make it easier to
19 beneficially use those CCR materials?

20 A (Witness Mitchell) It could, but,
21 Commissioners, it is -- it is site specific. If -- and
22 dependent on the quantity and quality of the ash at any
23 given ash pond. Certainly, if you're handling the ash
24 anyway, it may be more cost effective to beneficially
25 reuse that ash.

1 But it does not preclude the opportunity from
2 ponds that are closed in place to harvest that ash,
3 process it, and also beneficially reuse the ash from
4 those closed-in-place ponds as well.

5 Q Thank you.

6 COMMISSIONER McDONALD: Does the makeup of the
7 ash now, the difference in ash, determined by the
8 quick type -- now we have what's called "clean coal"
9 versus "old coal" or heights used in the generation
10 process? Are any of those things different that
11 causes a different quality of ash in the end
12 results?

13 WITNESS MITCHELL: Dr. Berry, you want to --

14 WITNESS BERRY: Yeah, yeah. Sure,
15 Commissioner. That is actually a great question.

16 What has happened over the years is that plants
17 across the United States have upgraded their
18 combustion systems and burned out most of the
19 carbon.

20 So the carbon is the constituent that does not
21 allow you to use it in concrete. So if you were to
22 take ash that was produced, say, in the '50s and
23 that is in your pond, then your unburned carbon is
24 actually higher.

25 COMMISSIONER McDONALD: Can you reburn it?

1 WITNESS BERRY: You could, but you have
2 extracted most of the value from the material. So
3 with some ashes, that unburned carbon has to be
4 below 15 percent. So it may be 20 percent. So
5 there's not a lot of value there from recombustion,
6 but it still doesn't meet the specification.

7 So for construction, you have to meet these
8 specifications. So before you would use it, you
9 would have to reduce the unburned carbon from
10 20 percent to below 15 percent.

11 So what we have done in our closure program is
12 we have gone and created profiles of all our ash in
13 our ponds so that we can provide that material when
14 people are investigating if they want to use it for
15 beneficial use. That way they can understand what
16 investment is required to upgrade their material so
17 it meets the specifications.

18 COMMISSIONER McDONALD: But the coal going in
19 is basically the same thing. Is there a difference
20 in coal than clean coal?

21 WITNESS BERRY: So I'm not sure I understand
22 your reference to clean coal, but I will say that
23 the result from the combustion is different with the
24 types of coal you use. So a PRB coal combusts very
25 different. The boiler has to be set up very

1 different than say an Illinois basin or central
2 Appalachian coal.

3 So at Scherer, you have to have for a Class C
4 ash, that would be from Plant Scherer, the unburned
5 carbon has to be less than a percent. So when you
6 look at it, it actually looks yellow because there's
7 no unburned carbon present.

8 If you look at a bituminous ash, like Illinois
9 basin, when you look at it, it looks gray because
10 there is unburned carbon still present.

11 I hope that's responsive to your question.

12 COMMISSIONER McDONALD: At my level of
13 understanding, it's very good.

14 WITNESS BERRY: Okay.

15 BY MR. FABISH: :

16 Q Thank you. Let me just follow up really
17 briefly. So -- but like if you close in place, you've
18 placed an impermeable cap over the top of it. To get at
19 the coal ash, you'd have to bust through that cap; right?
20 You'd have to undo what you just did to close the
21 facility; right?

22 A (Witness Mitchell) Well, you would have to
23 open the cover system up. And anticipating that could
24 add value to beneficially reuse this ash, the company has
25 included as part of our applications to Georgia EPD

1 requests to do that. And EPD has issued permits with
2 that capability to go back in and harvest that out for a
3 beneficial use.

4 That's not new to ash ponds. That's something
5 Georgia Power has done in our landfills for many years.
6 There are examples where we have gone back in to
7 landfills at Plant Bowen and Plant Wansley to
8 beneficially reuse ash and gypsum over the last 15 years.
9 And to a great extent, reuse that material.

10 So that's something that we believe provides
11 value. Whether or not the company has a plan at this
12 point in time to reuse it, but to maintain the option to
13 get the permit with Georgia EPD that allows us to harvest
14 that out at some point into the future.

15 VICE CHAIRMAN ECHOLS: If that ash had been
16 taken to another landfill like ash that was being
17 dumped in Wayne County, Georgia, once it's mixed
18 with other stuff, you can't beneficially reuse it;
19 right? It has to be kept by itself with just --
20 just ash in kind of a monofill; right?

21 WITNESS MITCHELL: That's exactly -- exactly
22 the term, Commissioner. And that's why the company
23 has focused on when not in our own landfills maybe
24 monofill applications where possible to preserve the
25 option of beneficial use in the future.

1 BY MR. FABISH: :

2 Q So I want to ask a couple of follow-up
3 questions about the discussion earlier about EPA's --
4 what EPA did in January.

5 MR. FABISH: Can I approach with an exhibit?

6 COMMISSIONER JOHNSON: You can approach.

7 BY MR. FABISH: :

8 Q Give you a minute to take a look at it.

9 A (Witness Mitchell) Any specific portion?

10 Q Well, just first, are you familiar with this
11 document?

12 A (Witness Mitchell) Yes. This is -- this is
13 one of the determinations that I referenced earlier that
14 EPA made. Specifically for a General James and Gavin
15 plant.

16 Q Thank you. If you could turn to page 40 of the
17 document. It is an excerpt, so you don't have to
18 actually go 40 pages in.

19 If you look at the -- towards the bottom,
20 there's a sentence, it starts "EPA is preliminarily
21 determining that the FAR" -- the flash reservoir -- "unit
22 is in contact with groundwater."

23 Do you see that?

24 A (Witness Mitchell) I do.

25 Q Yes. And do you see where it says "EPA is as a

1 consequence of this proposing to determine that Gavin has
2 failed to meet the requirement to develop an adequate
3 closure plant and demonstrate the performance standards
4 will be achieved"?

5 Do you see that?

6 A (Witness Mitchell) I do.

7 Q Okay. Is this at least part of the position
8 you reference in your testimony that EPA took in January?

9 A (Witness Mitchell) Ask me again. I'm sorry.

10 Q That's all right. Yeah. That's a little --
11 let me rephrase that.

12 Page 19 of your testimony, you mentioned that
13 EPA took some actions in January. Is this part of what
14 you were referring to in your testimony there?

15 A (Witness Mitchell) Yes. This is one of the
16 determinations that they released in January.

17 Q So I guess my question is just a follow-up from
18 the questions earlier. Given that EPA has expressed this
19 opinion that if the CCR materials are in contact with
20 groundwater, the requirements of the CCR rule for closure
21 in place are not met, are CCR materials at any of the
22 facilities that the company is pursuing closure in place,
23 are they in contact with groundwater?

24 A (Witness Mitchell) Well, as I said earlier --
25 and I'm looking for a reference here. But earlier on

1 this same page, on page 40, part of EPA's determination
2 as I said earlier was that in this specific case -- and
3 I'll read here from the third line down.

4 "EPA is proposing to determine that Gavin has
5 not documented how the closure performance standards will
6 be achieved. There are no details in the closure plan,
7 posted on Gavin's website or any other document provided
8 as part of the demonstration, that will allow EPA to
9 determine if the closure performance standards will be
10 met."

11 And so putting in context the sentence you had
12 me read and repeated, I believe, in other parts of this
13 document, the specific facility here EPA has found
14 deficiencies in the closure plans, specifically, as I
15 just read, that the company did not provide details on
16 how they would comply with the performance standards.
17 And specific performance standards.

18 And while there's a statement about
19 groundwater, there are specific performance standards
20 that the -- that have to be met by this and any other
21 facility.

22 Georgia Power, on the other hand, has included
23 specific descriptions of how we will comply and meet the
24 performance standards found deficient in this example but
25 not deficient in Georgia Power's applications.

1 We've also included engineering methods and
2 controls, also EPA finds deficient here in this example.
3 Again, not deficient in Georgia Power's closure plans,
4 because we have included those for each and every of our
5 ash pond closure designs.

6 COMMISSIONER McDONALD: Does this mean that if
7 you proceed, even though you haven't gotten -- they
8 haven't approved your plans, does EPA come in and
9 stop you in the process or does -- you go ahead and
10 finish the process and then when the testing comes
11 into place, and if they find it adequate or if they
12 find it inadequate, you can be penalized and fined
13 for the inadequacy, do they also possibly approve
14 the adequacy?

15 WITNESS MITCHELL: Well, I will have, again,
16 two responses for you, Commissioner.

17 First, again, Georgia EPD has been delegated
18 authority in Georgia to oversee and implement this
19 program. As a result, they've instituted a
20 comprehensive permitting program that we have to
21 comply with. And we've supplied EPD with that
22 information.

23 If EPD finds that our plans are deficient, EPD
24 can ask the company to change. If EPD does that,
25 the company will 100 percent comply with the

1 oversight of EPD through issuance of those permits.

2 Secondly, you mentioned the data and the
3 groundwater compliance. Regardless of the first
4 fact, the company has obligations to continue to
5 monitor groundwater even if compliance has been
6 achieved with the closure and EPD has issued us a
7 permit to close the ash pond.

8 If there are issues with groundwater later, the
9 company is obligated to take corrective actions to
10 remediate the groundwater there.

11 So it's a yes in both cases, Commissioner.

12 BY MR. FABISH: :

13 Q So can I get an answer to my question? Is the
14 CCR material in any of the impoundments that you're
15 proposing to close in place in contact with groundwater?

16 A (Witness Mitchell) We have ten ponds scheduled
17 to be closed in place. It is true that some of those
18 ponds will continue to have saturated ash after the
19 closure has been completed; however, as I've described,
20 the company has included engineering designs and details
21 on how the company complies with the specific performance
22 standards for those closures in place.

23 Q Could I ask you to name which of the
24 impoundments will have -- I forget how you put it, but
25 the liquids in place after closure?

1 A (Witness Mitchell) Yes. Subject to check,
2 Commissioners, we have Plant Hammond in Ash Pond 3. It's
3 called the ash management area at Plant Yates. McDonough
4 Ash Pond 1. And Scherer Ash Pond 1. Again, subject to
5 check.

6 Q Subject to check.

7 MR. FABISH: Given that it's subject to check,
8 could I make that a hearing request?

9 COMMISSIONER JOHNSON: Yes.

10 MR. FABISH: Thank you.

11 That may be all the questions I have, so thank
12 you very much.

13 COMMISSIONER JOHNSON: Thank you, sir.

14 MR. FABISH: Could I move to have the exhibit
15 entered into --

16 COMMISSIONER JOHNSON: It will be.

17 MR. FABISH: Oh, did I ask -- can it be marked
18 Sierra Club Exhibit 1?

19 COMMISSIONER JOHNSON: Did you say Exhibit 1?

20 MR. FABISH: Yeah. I think that was our first
21 one, so -- makes sense.

22 Thank you.

23 COMMISSIONER JOHNSON: All right. Thank you.

24 (The document referred to was marked for
25 identification as Sierra Club Exhibit No. 1 and

1 received into evidence.)

2 COMMISSIONER JOHNSON: Southern Alliance for
3 Clean Energy and Southface Energy Institute.

4 Welcome back, Mr. Baker.

5 MR. BAKER: Thank you, Mr. Chairman. I
6 appreciate it.

7 CROSS-EXAMINATION

8 BY MR. BAKER:

9 Q Good afternoon, gentlemen.

10 A (Witness Berry) Good afternoon.

11 A (Witness Mitchell) Good afternoon.

12 Q Robert Baker for Southern Alliance for Clean
13 Energy and for Southface Energy Institute.

14 Let me refer you to page 8, line 19 of your
15 prefiled testimony in which it states that "The company
16 requests the Commission approval of the environmental
17 compliance strategy and the related capital operations
18 and maintenance and CCR asset retirement obligations,
19 costs, and associated measures taken to comply with
20 government-imposed environmental mandates."

21 My question to you all is approximately how
22 much is the company requesting this Commission approve
23 for those costs?

24 A (Witness Mitchell) So I will -- Commissioners,
25 I will refer to the ECCR table and selected supporting

1 information in the volume of the IRP.

2 Capital -- total capital costs -- I can give it
3 to you by year, Mr. Baker, if -- if that works, for
4 capital costs.

5 Q What -- is there a ballpark figure? Is there a
6 total figure you're asking this Commission to approve in
7 this proceeding? That's what I'm asking.

8 A (Witness Mitchell) It's complicated by the
9 nature of some trade secret information related to the
10 ECCR table on the O&M expenditures. The capital
11 expenditures in total are not trade secret, but they are
12 not summarized by year.

13 Q We're talking billion of dollars; correct?

14 A (Witness Mitchell) Not associated with the
15 ECCR table. But when you -- when you include the value
16 of the CCR ARO program, it does. But again, as we
17 discussed earlier, this Commission approved the company's
18 CCR and ash pond closure strategy in the 2019 IRP. We
19 are recommending some changes to that strategy in this
20 IRP.

21 COMMISSIONER McDONALD: As it stands right now,
22 to answer your last question, when you said
23 "billions," that's plural. That is two or more,
24 yes.

25 MR. BAKER: I -- well, let me be a little more

1 specific.

2 BY MR. BAKER:

3 A Are they requesting approval of \$9 billion from
4 this Commission in this proceeding for cost recovery?
5 That's what I would like to know. Billions. Or you can
6 come to the nearest billion. I don't care. Closest
7 billion that you can come up with.

8 A (Witness Mitchell) Are you referring to the
9 ash pond and --

10 Q I'm referring to your statements here on
11 page 8, lines 19 -- you list here, and you say you're
12 requesting the Commission approval of the ECS and the
13 related capital operations and maintenance and CCR asset
14 retirement obligation costs and associated measures taken
15 to comply with government-imposed environmental mandates.

16 A (Witness Mitchell) Right.

17 Q I'm asking a very broad question.

18 A (Witness Mitchell) Yes.

19 Q How much are you asking this Commission to
20 approve in this proceeding here?

21 A (Witness Mitchell) So, again, we are asking
22 the Commission to approve costs associated with
23 environmental compliance in the ECCR tariff represented
24 in the table. And those are costs -- capital and O&M
25 costs to operate and maintain our environmental controls

1 at our power plants. As well in the environmental
2 compliance strategy, we are asking the Commission to
3 approve our ash pond closure and CCR program strategy and
4 associated costs. --

5 Q How much are you asking this Commission to
6 approve in this proceeding here?

7 A (Witness Berry) So again, we are asking the
8 Commission to approve costs associated with environmental
9 compliance and the ECCR tariff represented in the table,
10 and those are costs -- capital and O&M costs to operate
11 and maintain our environmental controls at our plants, as
12 well in the environmental compliance strategy we're
13 asking the Commission to approve our ash pond closure and
14 CCR program strategy and associated costs.

15 Again, though, with the CCR ARO program the
16 Commission did approve in the 2019 our strategy to close
17 29 ash ponds, 19 by removal and 10 in place.

18 While those actions were approved and the
19 Commission in the resulting 2019 IR rate case approved
20 recovery of the requested dollars in the rate case, the
21 company is updating its CCR ARO ash pond closure strategy
22 to reflect the change in Wansley and other program
23 updates as we have discussed.

24 So I can't give you a specific total. It is
25 true that the ash pond closure program is at

1 \$8.99 billion estimated completion over a 60-year period.

2 Q Okay. Is that the figure you're asking this
3 Commission to approve today? I mean --

4 COMMISSIONER JOHNSON: Mr. Baker, I think we're
5 asked and answered. I am going to have you move on.

6 MR. BAKER: He has not answered the question.

7 COMMISSIONER JOHNSON: He has answered the
8 question. Please, move on.

9 MR. BAKER: It's \$9 billion.

10 COMMISSIONER JOHNSON: Mr. Baker.

11 BY MR. BAKER:

12 Q Due to the magnitude of these expenditures,
13 wouldn't it be more appropriate for these costs to be
14 reviewed and approved in the upcoming rate case?

15 A (Witness Mitchell) So I'm not a rate case
16 witness, Commissioners, but we are presenting the
17 strategy as we have done in prior IRPs and the associated
18 costs for the Commission's review and approval of this
19 strategy and asking the Commission for approval of that.

20 But we are not yet asking for the recovery of
21 that, and that is appropriate for a rate case proceeding.

22 VICE CHAIRMAN ECHOLS: Mr. Thomas had asked
23 you -- tried to get you to answer which -- you know,
24 which was the best. Do you remember that
25 conversation?

1 WITNESS MITCHELL: Yes, sir.

2 VICE CHAIRMAN ECHOLS: So the 8.99 over
3 60 years that we -- the strategy we approved in
4 2019, if the federal government or the state
5 government determines that something else has to be
6 done other than the strategy that you're currently
7 using, you will come back here and ask us for that
8 money, won't you?

9 WITNESS MITCHELL: Yes, Commissioner.

10 VICE CHAIRMAN ECHOLS: Yeah. So it could go
11 from 8.99 to 10.99 or 11.99, but you are coming back
12 here to us for the money; right?

13 WITNESS MITCHELL: Right, we are.

14 VICE CHAIRMAN ECHOLS: Because that's part of
15 our -- that's part of the regulatory compact that we
16 have; right?

17 WITNESS MITCHELL: Yes, sir, Commissioner.

18 VICE CHAIRMAN ECHOLS: And so you are
19 attempting to do this in the most strategic way, but
20 you -- in some way it is risky, right, because we
21 have a federal government that seems to go back and
22 forth on different things; right? And you have
23 waived that risk?

24 WITNESS MITCHELL: Yes, Commissioner. We've
25 put our best plan and our best estimates forward to

1 do that. And as regulations change, even at the
2 state level, as we have done for many, many years,
3 we will update our compliance strategy not only
4 during IRP years. We do that annually to the
5 Commission. And we will inform the Commission of
6 those impacts and related costs.

7 We also update, Commissioner, this Commission
8 semi-annually on the specific ash pond program, and
9 the Commissioners approved -- the Commission
10 approved that in 2019 and ordered the company to
11 bring that every six months to this Commission.

12 VICE CHAIRMAN ECHOLS: But it's your intent to
13 comply with law; correct?

14 WITNESS MITCHELL: We must.

15 VICE CHAIRMAN ECHOLS: And then our
16 responsibility is to make sure that you have got the
17 money to be able to do that, assuming it's a prudent
18 expense; right?

19 WITNESS MITCHELL: Yes, Commissioner.

20 VICE CHAIRMAN ECHOLS: And that's how the
21 relationship works?

22 WITNESS MITHCELL: Yes.

23 COMMISSIONER MCDONALD: Could that mean comply
24 with regulations rather than law? Some of the --
25 there was an administration when a lot of

1 regulations were abstracted from a list of
2 regulations and then regulations have come back in.
3 And like, as I have described earlier to this same
4 audience, I am sure, you look on my door at the cost
5 of energy that's gone up, and it says, "Don't call
6 my office. Call the White House and Secretary of
7 Energy." And so that -- so would regulation be
8 acceptable instead of law?

9 VICE CHAIRMAN ECHOLS: Yes, I think so. And,
10 Commissioner, we've seen administrations change
11 their mind, you know. We saw the clean power plant
12 come and we saw it go. And so there are plenty of
13 people that would like us to go further with this
14 and dig it all up, line every pond, and put it back
15 in there.

16 And you could do that, couldn't you?

17 WITNESS MITCHELL: It is possible, yes.

18 VICE CHAIRMAN ECHOLS: Yeah. And you would
19 come to us for the money?

20 WITNESS MITCHELL: (Nods head.)

21 VICE CHAIRMAN ECHOLS: And then we would go to
22 the ratepayers for that money?

23 COMMISSIONER MCDONALD: If approved.

24 VICE CHAIRMAN ECHOLS: If approved; right. And
25 so in some ways, you know, we are -- we are hoping

1 that the strategy survives this administration. It
2 may; it may not. We don't know. But this
3 Commission is tasked with making sure that we agree
4 with the strategy that you have.

5 It's not that we're rubber-stamping your
6 strategy. We could compel you to spend 11.99 or
7 12.99, or whatever it took. But it's up to this
8 Commission to make sure that you're doing what's in
9 the best interest of everyone in our state,
10 particularly your ratepayers; right?

11 WITNESS MITCHELL: That's correct,
12 Commissioner. And that's precisely what the company
13 has done is looked at those recommendations -- or
14 regulations and put forth a plan that complies in
15 the most cost-effective way possible.

16 VICE CHAIRMAN ECHOLS: Thank you.

17 BY MR. BAKER:

18 Q Just one clarification. So are you only asking
19 this Commission to approve costs that have actually been
20 spent to date?

21 MR. MARZO: Mr. Chairman, I think we have gone
22 far afield with a couple of cross-examinations on
23 cost recovery. The company has asked for approval
24 of its environmental compliance strategy. That is
25 in ours as a specific request. Caveated within that

1 request is the fact that cost recovery is something
2 that will be handled in the rate case.

3 And we keep going down these questions asking
4 about how things are going to be recovered. And
5 this is being done as if this is the first time
6 we've done this, when we've done this in 2019. It's
7 the same sort of filing here where we've provided
8 both the tables of costs in this case as well as the
9 ECS table for the next three years.

10 That information has been available to all
11 parties, and it's the same format. And there is a
12 lot of, I guess, forgetfulness amongst parties today
13 as to how that operates. So I don't really
14 understand why these witnesses are being asked
15 rate-making questions, questions about cost
16 recovery, when that's made entirely clear within the
17 filing the company has made.

18 COMMISSIONER JOHNSON: Sustained.

19 MR. MARZO: Thank you.

20 BY MR. BAKER:

21 Q Turning to page 9 of your testimony, you
22 highlight certain emission reductions through 2021. And
23 why did you only emphasize carbon dioxide reductions up
24 to or through 2020?

25 A (Witness Mitchell) At the time of the filing

1 the company had not completed yet its year-end updates to
2 its emissions. Those take some time when going through
3 and quality assuring those and reporting to the agency,
4 so that reflects that difference.

5 Q Did carbon dioxide emissions increase in 2021?

6 A (Witness Mitchell) No, Mr. Baker. And thank
7 you for asking that. I should have said that
8 nonetheless, even though we only included through 2020,
9 the emissions were consistent and remained greater than a
10 60 percent reduction.

11 Q Turning to page 25 of your prefiled testimony,
12 line 26: If the Commission approves retirement of the
13 coal units at Plant Wansley, Georgia Power recommends
14 modifying its ash pond closure plants at the site from
15 closure in place to closure by removal.

16 Approximately how much extra will this cost
17 compared to the original plant?

18 A (Witness Mitchell) So what I can say,
19 Commissioners, is that the cost is an increase compared
20 to the original plan. We've not yet completed that final
21 analysis and completed report. We plan to update this
22 Commission in April with updated environmental compliance
23 strategy document reflecting a recommendation to close by
24 removal the Wansley ash pond, contingent upon the
25 Commission's approval to retire and decertify those

1 units.

2 As well we will update the cost tables and the
3 selected supporting information for Plant Wansley related
4 to those ARO tables and the change in strategy.

5 Q Thank you. At page 22, line 18 -- are you
6 there? Did any of the 3,000 groundwater samples
7 collected in 2021 show any groundwater contamination?

8 A (Witness Mitchell) While I can't speak to all
9 that number -- large number of results, I can say that at
10 a -- at some facilities we have had limited number of
11 detections of constituents above a federal CCR standard.
12 However, in those instances the company has installed
13 additional wells to ensure that we understand the limits
14 of those detections. And in all cases, the company has
15 confirmed that there is no impact above a drinking water
16 standard off of our property.

17 Q Were the properties or the facilities with the
18 contamination results, were those the ones that had
19 contact with groundwater?

20 A (Witness Mitchell) No. Commissioners, I don't
21 think that was limited to those facilities.

22 Q No, there are more than those facilities, or,
23 no, it wasn't any of the facilities that had contact that
24 you indicated had contact with groundwater?

25 A (Witness Mitchell) Just to be sure I'm clear,

1 you're asking for the facilities I listed earlier? Did
2 those detections occur --

3 Q Yes.

4 A -- at only those facilities?

5 Q You identified, I believe, three facilities
6 where there was ash -- there was contact -- the ash pond
7 had contact or the ash -- the CCR had contact with
8 groundwater. Were any of those the facilities that had
9 the water contamination results?

10 A (Witness Mitchell) Again, there's volumes of
11 data. And subject to check, Commissioners, there were
12 detections at those facilities, but also at some others,
13 other facilities. Again, just to emphasize the work the
14 company has done to ensure that those are limited and
15 that there is no impact to drinking water standards off
16 of our property.

17 Q Thank you.

18 Did any of the 998 million gallons of treated
19 water contain or show any contamination from coal ash or
20 CCR by-products?

21 A (Witness Mitchell) So those -- those numbers
22 are in reference to our dewatering activities at our ash
23 ponds. That's a significant amount of water that we're
24 treating at numerous sites. Our data to date that we
25 submit to Georgia EPD on a monthly basis and published to

1 our website show that we are protective of water quality
2 standards, and EPD has confirmed the same.

3 Q So were there indication -- were there
4 indications of contamination from coal ash for CCR in
5 any of -- it's a large amount of water.

6 A (Witness Mitchell) Yes.

7 Q There was no contamination in
8 998,000,000 gallons?

9 A (Witness Mitchell) Our water discharges were
10 compliant with our NPDS -- our wastewater discharge
11 permits.

12 Q The treated water you're talking about?

13 A (Witness Mitchell) The water we discharge is
14 in compliance with our permits.

15 Q Okay. At page 31, line 6, you discuss the
16 kinds of research conducted by Southern Company research
17 and development. Is any demand-side management research
18 done; and if so, what kind of research?

19 A (Witness Berry) So can you -- can you be more
20 specific in your question?

21 Q Okay. Page 31 -- I'm going to turn to your
22 prefiled testimony -- line 6, you indicate that -- you
23 state that, research conducted by Southern Company
24 research and development explores a diverse range of
25 solutions to help Georgia Power keep pace with the

1 evolving energy landscape. And then you list certain
2 technologies that are being investigated.

3 I'm asking, did any of that research impact or
4 involve DSM Technologies?

5 A (Witness Berry) So can you give me an example
6 of something that you're looking for, in terms of --

7 Q Energy efficiency, demand response.

8 A (Witness Berry) Yes, we are conducting energy
9 efficiency research.

10 Q Okay. Do you happen to know what type of
11 energy efficiency research you're doing?

12 A (Witness Berry) I can't speak to the
13 specifics, but if you -- you can make a request and we
14 can get you that information.

15 Q If you could do that and just -- I don't want
16 you to go to too much trouble, but if you could --

17 A (Witness Berry) Oh, it's no trouble at all.

18 Q Okay. Could I make that as a hearing request?

19 MR. BAKER: Mr. Chairman, could I make that as
20 a hearing request, just to identify -- doesn't have
21 to be too complicated. Just if you can identify
22 certain technologies.

23 A (Witness Berry) Happy to do it.

24 Q Thank you.

25 A (Witness Berry) Yes, sir.

1 COMMISSIONER JOHNSON: Yes, I'll allow it.

2 MR. BAKER: Thank you.

3 BY MR. BAKER:

4 Q Turning to page 30, all scenarios in Figure 2
5 on page 30 indicate higher carbon prices than \$50 a ton.
6 Would the company be opposed to running an additional
7 scenario of its capacity expansion model and production
8 cost model with a carbon price derived from the
9 break-even cost for Vogtle Units 3 and 4?

10 A (Witness Berry) I don't know if I understand
11 your question.

12 A (Witness Mitchell) Commissioner, we're not the
13 witnesses for the modeling. We can speak to the
14 legislation that formed the pricing as depicted in the
15 graph here, but we can't speak to model runs or potential
16 scenarios.

17 Q Could you let me -- could you respond to, how
18 did you pick the \$50 per ton price for doing the model?

19 A (Witness Berry) Oh, yeah. Yeah, sure. So we
20 think that the \$50-per-ton price is representative of the
21 carbon risk that exists. If you look at the proposed
22 bills here that are listed in this table on page 30 of
23 the filed testimony, it represents the tax that are in
24 those bills.

25 So if you look, some of them start below \$50,

1 but in those specific cases, within three years those
2 prices, they escalate at \$10 per year. So by 2025, all
3 of the taxes that are proposed in those bills would be
4 greater than \$50.

5 Those taxes continue to escalate at a certain
6 percentage each year. There are in many of those bills
7 penalties that would exist if the economy does not
8 achieve the desired carbon reductions. That would
9 actually make those costs increase even higher.

10 We also believe that this \$50 per ton price
11 represents compliance, really costs if the EPA required
12 us to retrofit technologies on our fossil-fired
13 facilities. So this \$50-per-ton price represents a wide
14 range of carbon risks that exist.

15 MR. BAKER: Thank you, gentlemen, for your
16 time.

17 Thank you, Commissioners.

18 COMMISSIONER JOHNSON: Thank you, Mr. Baker.

19 Mr. Mahan, are you online?

20 MR. MAHAN: Yes, good evening. No questions.

21 Thank you.

22 COMMISSIONER JOHNSON: Thank you, sir.

23 Mr. Marzo, redirect?

24 MR. MARZO: Thank you, Chairman. Just a few
25 questions.

1 REDIRECT EXAMINATION

2 BY MR. MARZO:

3 Q First off, this morning you were asked some
4 questions from Mr. Thomas about the ECCR. Do you recall
5 those?

6 A (Witness Mitchell) Yes.

7 Q Okay. And are the company's avoided capital
8 costs, including ELG compliance, included in the
9 company's unit retirement studies?

10 A (Witness Mitchell) Yes, they are.

11 Q Okay. And does the ECCR table include recovery
12 already -- of already-installed environmental controls?

13 A (Witness Mitchell) Yes.

14 Q And can the company avoid the costs that have
15 already been spent for those controls?

16 A (Witness Mitchell) No, it cannot.

17 Q Is the company compliant with the Commission's
18 2019 rate case order as it pertains to ECCR?

19 A (Witness Mitchell) Yes, the company is.

20 Q Now, Mr. Mitchell, Dr. Berry, you testified IN
21 the 2019 IRP; is that correct?

22 A (Witness Mitchell) Correct.

23 A (Witness Berry) Yes.

24 Q Is it -- or are you aware or is it your
25 understanding that the Commission approved the ECS in the

1 2019 IRP?

2 A (Witness Mitchell) That is correct.

3 Q Now, you were asked some questions -- and let
4 me just complete that question. Am I also correct that
5 in terms of rate recovery, that was handled in the 2019
6 rate case?

7 A (Witness Berry) In the rate case, yeah.

8 A (Witness Mitchell) Correct.

9 Q And so you were asked some questions by
10 Mr. Thomas related to LA-4-12. Do you recall that? You
11 may still have that in front of you?

12 A (Witness Mitchell) Yes.

13 Q And that was the questions concerning the
14 true-up of the ECCR. And I want to ask you like -- is it
15 your understanding that the ECCR is similar to any other
16 base, sort of base rate?

17 A (Witness Mitchell) Yes.

18 Q Okay. And there's no true-up to base rates; is
19 that right?

20 A (Witness Mitchell) That's my understanding.

21 Q Okay. And am I right to the extent that there
22 is an over/under recovery or there's an over --
23 there's -- if there's additional spend more than what is
24 forecasted, the company takes a risk whether or not that
25 spend is higher than anticipated?

1 A (Witness Mitchell) Yes, and that's what I
2 attempted to communicate.

3 Q Now, we've talked about the announcement by EPA
4 of a new position here this morning. I think that was
5 actually asked by a couple of parties, staff, and I think
6 Sierra Club as well. Do you recall those?

7 A (Witness Mitchell) Yes.

8 Q Now, has there been any change to the CCR rule
9 governing the closure in place performance standards?

10 A (Witness Mitchell) No, there has not.

11 Q So that rule is the same rule that's been in
12 effect the entire time that the company has put its plan
13 in front of this Commission?

14 A (Witness Mitchell) Correct. The CCR rule
15 was -- the federal CCR rule was issued in 2015 followed
16 by the Georgia CCR rule in 2016. And while there have
17 been some minor changes to those rules, none have changed
18 the performance standards related to our
19 Commission-approved strategy in 2019.

20 Q And I believe you mentioned this, but just for
21 clarity, does Georgia have its own federally approved CCR
22 permit program?

23 A (Witness Mitchell) Yes, they do.

24 Q Okay. And has EPD issued final permits for
25 closure in place facilities already under that program?

1 A (Witness Mitchell) Yes. They have issued a
2 final permit at Plant Bowen for a closure in place there
3 at Plant Bowen.

4 Q Okay. Has the draft permit been issued as
5 well?

6 A (Witness Mitchell) They additionally have
7 issued a draft permit for Plant Hammond Ash Pond 3, which
8 is a closure in place.

9 Q Now, as it pertains to the CCR strategy and the
10 spend that goes on to implement the closures in place, do
11 you report to this Commission more often than just in
12 these tri-annual IRP reviews?

13 A (Witness Mitchell) Yes, we do. We -- as
14 ordered in 2019, the company -- the company submits and
15 files a semiannual CCRA ARO filing. That includes a
16 report and update on our ash pond closure compliance
17 activities at all 29 ash ponds, as well as our 12 CCR
18 landfills, and includes details on the two new landfills
19 that the company will build to comply with these rules.

20 It also includes the associated costs and the
21 company's updated cost assumptions and cost projections
22 on a semiannual basis.

23 Q So is it fair to say that to the extent there
24 are any changes or any updates that occur over time,
25 that's something that will come to the Commission's

1 attention fairly quickly?

2 A (Witness Mitchell) Yes.

3 Q Okay.

4 MR. MARZO: Chairman Johnson, I think that's
5 all I have on redirect.

6 COMMISSIONER JOHNSON: Okay. Thank you.

7 MR. MARZOS: Thank you.

8 COMMISSIONER JOHNSON: Do you have any further
9 exhibits to enter?

10 MR. MARZOS: Just Exhibit 3, Georgia Power 3.

11 MR. JOHNSON: It will be entered.

12 (The document referred to as GPC Exhibit
13 No. 3 was entered into evidence.)

14 COMMISSIONER JOHNSON: All right. Are there
15 any other housekeeping, Commissioners, that we need
16 to take up at this time?

17 I'm going to ask the court reporter at this
18 time to make all exhibits part of the record, and
19 thank you, ma'am, for your time.

20 And thank all of you. I know there's some
21 heavy eyes out there. Get some rest tonight. We
22 appreciate your time.

23 Gentlemen, you're excused. And thank you very.
24 We stand adjourned.

25 (Proceedings were adjourned at 4:29 p.m.)

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C E R T I F I C A T E

I, Brenda P. Elwell, Kelley Marie Nadotti, and
Debbie A. Eickhoff, Certified Court Reporters, do hereby
certify that the foregoing transcript is an accurate record
of the proceedings had in the above-entitled matter at the
time and place therein set forth.



Brenda P. Elwell, RPR, CCR, B-2023



Kelley Marie Nadotti, RPR, CRR
CCR 6256-8388-8026-4192



Debbie A. Eickhoff, RPR,
CCR 5090-9084-2699-3664

GEORGIA POWER Ex. 2

Amended 2022 Application

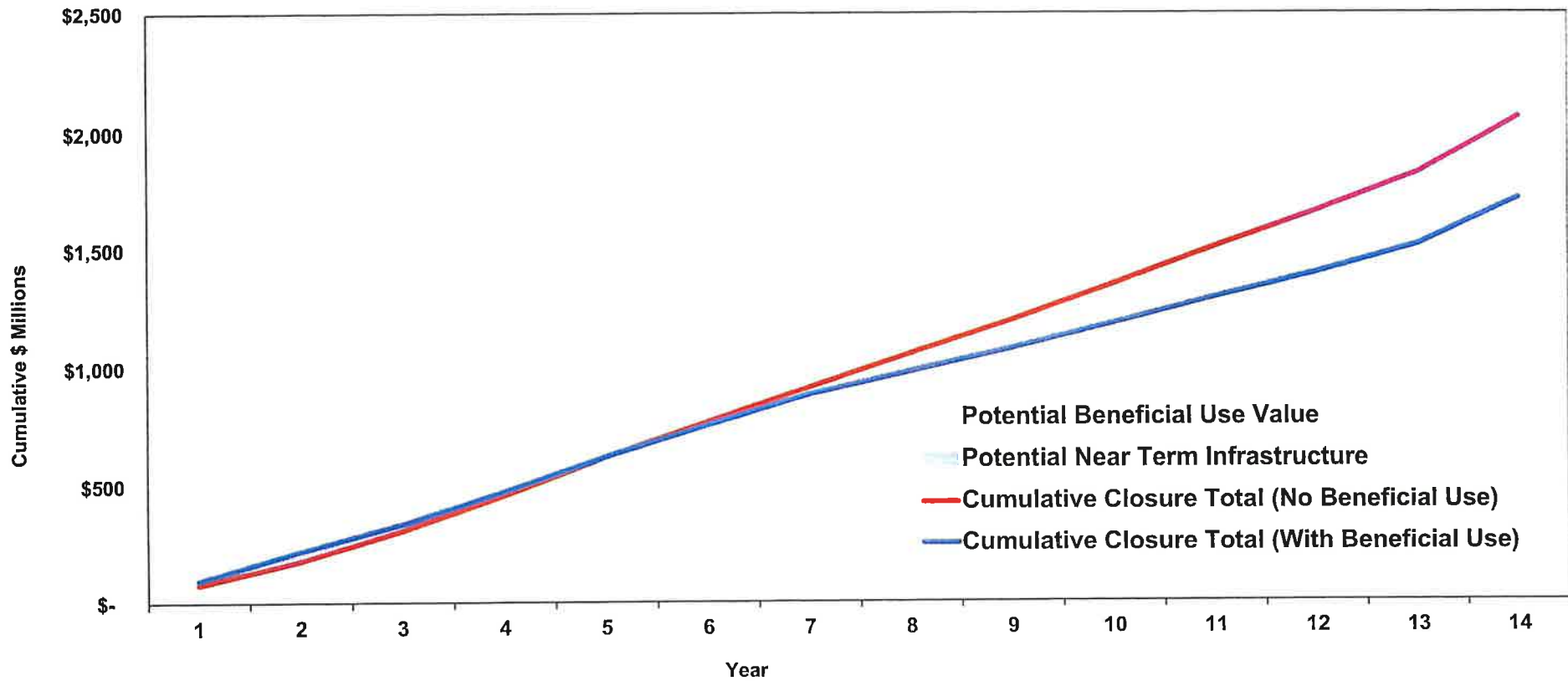
For Certification, Decertification,

And Amended Demand-Side Management Plan

Too large to attach to the transcript. It is filed
with the GPSC.



Potential Range of Closure Cost Outcomes with Beneficial Use



Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 4

STF-LA-4-4

Question:

In response to STF-L&A-5-11 in Docket Nos. 42310 & 42311, the Company explained that the evaluation of the method for ash pond closure and remediation to comply with federal and state CCR rules focuses on the ability to meet regulatory performance standards for the following two allowable closure options set forth in the federal and state CCR Rules: (1) Closure-in-Place (CIP), which involves closing the CCR unit in the existing location and dewatering, backfilling, and capping the impoundment; or (2) Closure-by-Removal (CBR), which involves dewatering the surface impoundment, excavating the CCR, and transporting and placing the ash material in an approved landfill or combining the ash with onsite ash ponds to be closed in place. For each ash pond, please explain in detail how the Company determined which method to use, show the cost of that chosen method, and show in detail how the Company evaluated the alternatives and determined that its chosen method had the lowest cost.

Response:

With STF-L&A-5-11 in Docket Nos. 42310 & 42311, the Company explained the process by which each ash pond was evaluated and how the Company determined the selected closure method. The Company's CCR strategy was approved in the 2019 IRP. This includes the closure of all 29 ash ponds currently being effectively implemented with significant progress made over the last three years. The Company will continue to evaluate opportunities to refine and optimize its closure plans as has been discussed in the 2022 ECS filed as part of Georgia Power's 2022 IRP.

Since the EPA published the CCR rule in 2015, the Company has worked to develop and implement closure plans in compliance with the rule for its 29 ash ponds across the state. The Company developed a compliance strategy that included ceasing placement of coal ash in ash ponds, which occurred in 2019, and putting necessary actions in motion to meet the rule's strict deadlines and requirements to close ash ponds. The Company's plans are based on long-standing rule interpretation held by both industry and environmental regulators. While the Company provides details to this Commission, Georgia EPD ultimately determines the closure and permit requirements, and the Company adjusts scope as necessary to ensure compliance.

The closure cost estimate and selected closure method for each CCR unit has been developed by Georgia Power with input from internal and external experts. The site-specific closure method is the most cost-effective to allow compliance with CCR rules, support permit requirements, and mitigate environmental risks. The Company has continued to update and report closure costs estimates with the Company's CCR Semi-Annual Status Reports in accordance with the Final

Contact: Aaron Mitchell



Docket Nos. 44160 & 44161
Georgia Power Company's 2022 IRP and 2022 DSM Application
STF-LA Data Request Set Number 4

Order of the 2019 Integrated Resource Plan proceeding in Docket No. 42310. Additionally, the Company will continue to periodically update these cost estimates as necessary. See the Company's response to STF-LA-1-8 for cost details of the chosen closure method for each of the individual CCR units.

PROPOSED DECISION

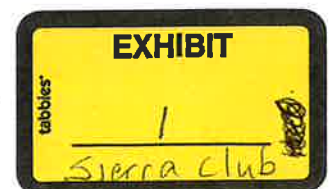
Proposed Denial of Alternative Closure Deadline for General James M. Gavin Plant

SUMMARY:

Gavin Power, LLC (Gavin) submitted a demonstration (the "Demonstration") to the Environmental Protection Agency (EPA) seeking an extension pursuant to 40 C.F.R. § 257.103(f)(1) to allow a coal combustion residuals (CCR) surface impoundment, the Bottom Ash Pond (BAP), to continue to receive CCR and non-CCR wastestreams after April 11, 2021, at the General James M. Gavin Plant located in Cheshire, Ohio. EPA is proposing to deny this extension request. In the Demonstration, Gavin requested an alternative closure deadline of May 4, 2023, for the BAP. EPA is proposing to deny the request for an extension based on a proposed determination that the Demonstration does not meet the requirements of § 257.103(f)(1) and a proposed determination that Gavin has failed to demonstrate that the facility is in compliance with the requirements of 40 C.F.R. 257 subpart D, as required in § 257.103(f)(1)(iii).

DATES: *Comments.* Comments must be received on or before February 23, 2022.

ADDRESSES AND PUBLIC PARTICIPATION: The EPA has established a docket for this notice under Docket ID No. EPA-HQ-OLEM-2021-0590. EPA established a docket for the August 28, 2020, CCR Part A final rule under Docket ID No. EPA-HQ-OLEM-2019-0172. All documents in the docket are listed in the <https://www.regulations.gov> index. Publicly available docket materials are available either electronically at <https://www.regulations.gov> or in hard copy at the EPA Docket Center. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the EPA Docket Center is (202) 566-



1742. You may send comments, identified by Docket ID. No. EPA-HQ-OLEM-2021-0590, by any of the following methods:

- Federal e-Rulemaking Portal: <https://www.regulations.gov/> (our preferred method).
Follow the online instructions for submitting comments.
- Mail: U.S. Environmental Protection Agency, EPA Docket Center, Office of Land and Emergency Management, Docket ID No. EPA-HQ-OLEM-2021-0590, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- Hand Delivery or Courier (by scheduled appointment only): EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m. – 4:30 p.m., Monday – Friday (except Federal Holidays).

Instructions: All submissions received must include the Docket ID No. for this action.

Comments received may be posted without change to <https://www.regulations.gov/>, including any personal information provided. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e., on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia

submissions, and general guidance on making effective comments, please visit

<https://www.epa.gov/dockets/commenting-epa-dockets>.

Due to public health concerns related to COVID-19, the EPA Docket Center and Reading Room are open to the public by appointment only. Our Docket Center staff also continues to provide remote customer service via email, phone, and webform. Hand deliveries or couriers will be received by scheduled appointment only. For further information and updates on EPA Docket Center services, please visit us online at <https://www.epa.gov/dockets>.

The EPA continues to carefully and continuously monitor information from the Centers for Disease Control and Prevention (CDC), local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID-19.

FOR FURTHER INFORMATION CONTACT:

- Lydia Anderson, Office of Resource Conservation and Recovery, Materials Recovery and Waste Management Division, Environmental Protection Agency, 1200 Pennsylvania Avenue NW, MC: 5304T, Washington, DC 20460; telephone number: (202) 566-0523; email address: Anderson.Lydia@epa.gov, and/or
- Kirsten Hillyer, Office of Resource Conservation and Recovery (ORCR), Materials Recovery and Waste Management Division, Environmental Protection Agency, 1200 Pennsylvania Avenue NW, MC: 5304T, Washington, DC 20460; telephone number: (202) 566-0542; email address: Hillyer.Kirsten@epa.gov.
- For more information on EPA's coal ash regulations, please visit <https://www.epa.gov/coalash>.

SUPPLEMENTARY INFORMATION:

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II. Background

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III. EPA Analysis of Demonstration

- A. Evaluation of Gavin's Claim of No Alternative Disposal Capacity On or Off-site
- B. Evaluation of Gavin's Analysis of Adverse Impacts to Plant Operations
- C. Evaluation of Gavin's Site-Specific Analysis for the Alternative Capacity Selected
- D. Evaluation of Gavin's Justification for Time Requested
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IV. Proposed Date to Cease Receipt of Waste

V. Conclusion

VI. Effective Date

List of Acronyms

AHE – Ash Handling Equipment
ASD – Alternate Source Demonstration
BAP – Bottom Ash Pond
CBI – Confidential Business Information
CCR – Coal Combustion Residuals
C.F.R. – Code of Federal Regulations
DCC – Drag chain conveyor
ELG – Effluent Limit Guidelines
EPA – Environmental Protection Agency

earlier the BAP stops receiving any wastestream, particularly larger wastestreams such as the cooling tower blowdown, the sooner it would reduce the risk of further releases from the BAP.

3. Progress towards achieving alternative capacity

Gavin has made progress towards developing the PWP and rerouting the Gavin Plant's non-CCR flows. Gavin has completed some of the subsurface geotechnical investigations required to support design of the new PWP. In the work that it has designated as Phase 1-Part 1, Gavin has, "investigated the BAP to estimate characteristics of the CCR material, identify the interface elevation between the CCR material and underlying clay layer, and to measure the geotechnical parameters of these materials." In Phase 1-Part 2 Gavin has completed "geotechnical investigations: borings into subsurface in areas located around perimeter of BAP embankment and install piezometers within CCR material." This was done to inform construction of the berm in the middle of the BAP. Gavin has also commissioned a pond closure study to model the closure and repurposing of the BAP (water treatment and pond settling model and if the PWP will meet NPDES discharge limits).

E. Evaluation of Gavin's Compliance

The Part A Rule requires that a facility must be in compliance with all the requirements in 40 C.F.R. part 257 subpart D in order to be approved for an extension to the cease receipt of waste deadline. 40 C.F.R. § 257.103(f)(1)(iii). Various compliance documentation must be submitted with the Demonstration for the entire facility, not just for the CCR surface impoundment in question. 40 C.F.R. § 257.103(f)(1)(iv)(B). Additionally, EPA evaluated the information presented in the narrative relating to the closure or retrofit of the impoundment and the development of the new alternative disposal capacities to ensure compliance with the CCR regulations.

The first group of compliance documents required to be included in the Demonstration are related to documentation of the facility's current compliance with the requirements governing groundwater monitoring systems. The Agency required copies of the following documents: 1) map(s) of groundwater monitoring well locations (these maps should identify the CCR units as well); 2) well construction diagrams and drilling logs for all groundwater monitoring wells; 3) maps that characterize the direction of groundwater flow accounting for seasonal variation; 4) constituent concentrations, summarized in table form, at each groundwater monitoring well monitored during each sampling event; and 5) description of site hydrogeology including stratigraphic cross-sections. 40 C.F.R. § 257.103(f)(1)(iv)(B)(2)-(4).

The second group of documents EPA required was the facility's corrective action documentation, if applicable, and the structural stability assessments. A facility must submit the following documentation: the corrective measures assessment required at 40 C.F.R. § 257.96, progress reports on remedy selection and design; the report of final remedy selection required at 40 C.F.R. § 257.97(a); the most recent structural stability assessment required at 40 C.F.R. § 257.73(d), and the most recent safety factor assessment required at 40 C.F.R. § 257.73(e). 40 C.F.R. § 257.103(f)(1)(iv)(B)(5) through (8).

1. Closure of the FAR and the BAP

The regulations provide two options for closing a CCR unit: closure by removal and closure with waste in place. 40 C.F.R. § 257.102(a). Both options establish specific performance standards. 40 C.F.R. § 257.102(c)-(d). Gavin intends to close both the FAR and the BAP by closing with waste in place. Based on the available information, EPA is proposing to determine that Gavin has not adequately demonstrated compliance with the closure regulations at 40 C.F.R. § 257.102(b) and (d), as required by 40 C.F.R. § 257.103(f)(1)(iii).

EPA evaluated the information provided in the Demonstration, as well as in the written closure plans and other documents posted on Gavin's publicly accessible CCR website for the FAR. After review of this information, EPA is proposing to determine that Gavin has not documented how the closure performance standards will be achieved. There are no details in the closure plan posted on Gavin's CCR website or any other document provided as part of the Demonstration that will allow EPA to determine that the closure performance standards will be met, in light of site conditions, at the impoundment. Therefore, EPA is proposing that Gavin has not adequately demonstrated compliance with the closure regulations at 40 C.F.R. § 257.102(b) and (d), as required by 40 C.F.R. § 257.103(f)(1)(iii).

The Demonstration explains that closure of the FAR is nearly finished and is expected to be completed in 2021. The October 2016 closure plan states that closure of the FAR began in 2015. As required by the regulations, Gavin posted its initial closure plan to its CCR website in October 2016, and the closure plan has not been amended since its initial posting.

EPA reviewed available information to determine whether any portion of the FAR is in contact with groundwater and, if so, whether Gavin has explained how the closure performance standards will be achieved for the impoundment. EPA's evaluation considered information in the Demonstration and its appendices, as well as the History of Construction, the Dam & Dike Inspection Report from 2016, the Closure Plan from 2016, and the annual Groundwater Monitoring Corrective Action (GWMCA) Report from 2019. After reviewing this information, EPA is preliminarily determining that the FAR unit is in contact with groundwater. As a consequence of this preliminary determination, EPA is also proposing to determine that Gavin has failed to meet the requirement to develop an adequate closure plan and to demonstrate that the performance standards will be achieved during closure of the FAR.

EPA also evaluated the Demonstration and closure-related information on Gavin's CCR website to determine whether Gavin has adequately explained how the closure performance standards will be achieved for the BAP. Gavin will implement a hybrid closure approach by leaving CCR in place and closing the remaining portion of the BAP by removal of waste. Following the removal of waste, Gavin explains that the new PWP will be constructed in this portion of the BAP footprint. Gavin did not provide enough detail in the Demonstration for EPA to determine whether the closure of this unit will meet the closure performance standard of 40 C.F.R. § 257.102(d)(1). Consequently, EPA is preliminarily determining that the proposed PWP potentially will impact the BAP's ability to meet the closure performance standard of 40 C.F.R. § 257.102(d)(1)(i).

(a) Intersection between FAR and Groundwater

The following information indicates that at least a portion of the CCR in the FAR is saturated with groundwater.

First, the static water levels measured in at least seven piezometers indicate that the groundwater elevation along the fly ash dam is above the base of the unit and is therefore high enough to be in contact with CCR in the unit. The FAR compliance documents indicate that the elevation of the base of the FAR (i.e., where the sluiced ash is stored) ranges from 600 to 657 feet above sea level. The groundwater was consistently measured in seven of eight wells at levels between 640 and 660 feet. The evidence for this is as follows.

The lowest elevation of the FAR is given as 600 feet.¹² This is consistent with Profile 3-G Dr. No. 12-3000F-1 of the History of Construction (October 2016),¹³ which shows the

¹² History of Construction, Stingy Run Flyash Pond, October 2016, section 10.0

¹³ History of Construction, Stingy Run Flyash Pond, October 2016, Design Drawings, Dam Raising, For Phase II, Stingy Run, Fly Ash Retention Pond, Dr. No. 12-3000F-1

elevation of the ash at 600 feet near where the piezometers are installed. Additionally, section 5.0 of the Dam & Dike Inspection Report (October 2016) indicates that the elevation of the base of the FAR varies from about 602 feet to 657 feet.¹⁴ EPA estimates that the average bottom elevation of the pond is 646 feet.¹⁵ Figure 10b of Appendix C of the Dam & Dike Inspection Report (October 2016)¹⁶ is a graphical depiction of the elevations of eight observation wells over time (the figure also shows the elevation of the impounded water). The wells are installed either along the crest of the dam or on the downstream edge of the dam (the observation well locations are shown on Figure 10a of Appendix C of the Dam & Dike Inspection Report (October 2016), DR. NO. 12-300B-1 of Attachment B of the History of Construction,¹⁷ and the following cross-sections from Attachment B of the History of Construction: DR. NO. 12-3000D-1, Dr. No 12-3000E-1). Figure 10b¹⁸ indicates that from April 1988 to November 2016, the groundwater elevations in the piezometers were fairly consistent. All, except for OB-29 and OB-36, show that groundwater was consistently above 640 feet. Four (OB-28, OB-31, OB-32, and OB-35) consistently measured above 660 feet. OB-29 consistently measured groundwater at around 630 feet. Therefore, if the elevation of the ash is presumed to range between 600 and 657 feet as shown in Profile 3-G DR. NO. 12-3000F-1 of the History of Construction (October 2016), all piezometers, except for OB-36, consistently indicated groundwater was above the level of the ash.

¹⁴ Dam & Dike Inspection Report, Bottom Ash Complex, Stingy Run Fly Ash Dam, November 2016, section 5.0

¹⁵ Closure Plan, Stingy Run Flyash Pond, Gavin Plant, Cheshire Ohio, October 2016, sections 5.0 and 6.0. Section 5.0 states that the maximum inventory of CCR material is "approximately 19,800 acre-ft" at a "maximum fly ash elevation of 725 feet." Section 6.0 states, "The largest CCR area requiring final cover is approximately 250 acres." Based on this, EPA estimated the average bottom elevation of the pond to be 646 ft.

¹⁶ Dam & Dike Inspection Report, Bottom Ash Complex, Stingy Run Fly Ash Dam, November 2016, Appendix C, Figure 10b

¹⁷ History of Construction, Stingy Run Flyash Pond, October 2016

¹⁸ 2016 Dam & Dike Inspection Report, Bottom Ash Complex, Stingy Run Fly Ash Dam, October 2016, Appendix C, Figure 10b

Additionally, Section 6.2.1 of the 2016 Dike and Dam Inspection Report indicates that the water levels in the observation wells installed on and around the crest of the dam are consistently high enough to be in contact with CCR in the impoundment:

“A historical plot of the observation wells water elevation is provided in Figure 10b. In the last 15 years, the static water levels are steady with very minor fluctuation...At present, the water level in the flyash pond (near the dam) is maintained at approximately 664 (+/-1) feet. Piezometer OB-28 is located at the crest of the dam on the north side and installed to the depth of the bottom ash drain. The static water elevation readings closely match the pond level.”

Therefore, these data and accompanying narrative indicate that the groundwater level near and across the dam is high enough to be in contact with CCR.

Second, descriptions of the site groundwater conditions indicate that there is a natural water table higher than the base of the unit in some areas. The FAR was constructed in the Stingy Run stream valley. The presence of surface water may indicate a high groundwater table; often, ground and surface water are hydrologically connected, and groundwater may directly supply (recharge) surface water. Further, groundwater conditions are described in Section 3.5 of the Proposed Dam Raising for Phase II Stingy Run Fly Ash Retention Pond (American Electric Power Service Corporation, March 1986).¹⁹ The report states, “In general, ground-water levels are found to be high in both the valley floor and in the reservoir rim. These levels are generally higher than the proposed maximum operating pool of el. 726 ft.” Additionally, during construction operations, water had to be managed using pumps and a coffer dam.²⁰ This means that at the time of construction, naturally occurring water was present in the stream valley above where the ash is currently stored. This is further indication that currently there may be

¹⁹ This document can be found within the History of Construction, Stingy Run Flyash Pond, October 2016, Attachment B.

²⁰ This is described in Chapter III, “Diversion and Care of Water” of the “Final Report, Gavin Fly Ash Dam and Fly Ash Line Support System, Volume I” done by Hazra Engineering (January 1975). This document can be found in the History of Construction, Stingy Run Flyash Pond, October 2016, Attachment B.

groundwater high enough to be in contact with ash. Additionally, section 2.1 of the FAR 2019 Annual GWMCA Report states: “Hydrogeology within the FAR is characterized by a shallow zone of saturation that overlies an upper aquifer system that consists of sandstone and interbedded clay and shale units.” Collectively, this information indicates that there is a high groundwater table in the vicinity of the FAR, and that the groundwater level is higher than the level of the ash.

Finally, although Gavin indicates in the FAR Annual GWMCA reports that there are layers of low permeability in between the uppermost aquifer and the base of the FAR, the History of Construction Report states that there is a possible hydraulic connection between the uppermost aquifer and the bottom of the FAR. As stated in Section 3.6 of the “Proposed Dam Raising for Phase II Stingy Run Fly Ash Reservoir” (American Electric Power Service Corporation, March 1986) from the History of Construction Report (October 2016):

“As discussed in the lithologic descriptions, water pressure test data show that the clay shales in the reservoir area are relatively impermeable. Thin beds of sandstone found in two rock units (5 and 7) contain open joints and are permeable, especially when the units are found at the bedrock surface. These may provide a path for potential seepage from the reservoir particularly in the areas of thin divides.”

Notably, the FAR is unlined,²¹ thus there is no engineered barrier installed between the uppermost aquifer and the ash in the bottom of the FAR. Based on the evidence of high groundwater elevations at and around the FAR, EPA is proposing to determine that there is hydraulic connection between the uppermost aquifer and the fly ash located on the bottom of the FAR and that at least a portion of the ash in the unit is saturated with groundwater.

(b) Compliance with the closure performance standards: FAR and BAP

Fly Ash Reservoir

²¹ Liner Design Certification (Fly Ash Pond), October 2016

EPA evaluated the Demonstration and closure-related information on Gavin's CCR website to determine whether Gavin has adequately explained how the closure performance standards will be achieved during closure of the FAR in light of the evidence that at least a portion of the impoundment appears to be in contact with groundwater. EPA's preliminary determination is that the explanation is inadequate. EPA is therefore proposing to determine that Gavin has failed to meet the requirement to develop an adequate closure plan and to demonstrate that the performance standards will be achieved during closure of the FAR. 40 C.F.R. § 257.102(b), (d)(1)-(2). In the case of the FAR, this is particularly important because closure of the unit is ongoing and planned to be completed in 2021.

The CCR closure requirements applicable to impoundments closing with waste in place include general performance standards and specific technical standards that set forth individual engineering requirements related to the drainage and stabilization of the waste and to the final cover system. The general performance standards and the technical standards complement each other, and both must be met at every site. The general performance standards under 40 C.F.R. § 257.102(d)(1) require that the owner or operator of a CCR unit "ensure that, at a minimum, the CCR unit is closed in a manner that will: (i) Control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere; and (ii) Preclude the probability of future impoundment of water, sediment, or slurry." The specific technical standards related to the drainage of the waste in the unit require that "free liquids must be eliminated by removing liquid wastes or solidifying the remaining wastes and waste residues" prior to installing the final cover system. 40 C.F.R. § 257.102(d)(2)(i). Finally, the regulations require facilities to develop a written closure plan that describes the steps necessary to close the

CCR unit, consistent with recognized and generally accepted good engineering practices. 40 C.F.R. § 257.102(b)(1). The plan must also include a written narrative describing how the unit will be closed in accordance with the section, or in other words, how the closure will meet the performance standards in the regulation. 40 C.F.R. § 257.102(b)(1)(i).

Neither the closure plan posted on Gavin's website nor the Demonstration describe the steps that will be taken to close the unit consistent with generally recognized good engineering practices, as required by 40 C.F.R. § 257.102(b). Nor does either document that the closure of the FAR meets the requirements of 40 C.F.R. § 257.102. For example, the Demonstration provides insufficient details on how free liquids were to be eliminated from the FAR, and the October 2016 closure plan for the FAR only states that "[a]s part of closure of the CCR unit, all free water will be removed."²² Such a summary discussion does not meet requirements for a closure plan as laid out in 40 C.F.R. § 257.102(b). And if EPA is correct that the base of the impoundment intersects with groundwater, the closure plan would need to have discussed the engineering measures taken to ensure that the groundwater had been removed from the unit prior to the start of installing the final cover system, as required by 40 C.F.R. § 257.102(d)(2)(i). This provision applies both to the freestanding liquid in the impoundment and to all separable porewater in the impoundment, whether the porewater was derived from sluiced water or groundwater that intersects the impoundment. The definition of free liquids in 40 C.F.R. § 257.53 encompasses all "liquids that readily separate from the solid portion of a waste under ambient temperature and pressure," regardless of whether the source of the liquids is from sluiced water or groundwater.

²² "Closure Plan, C.F.R. 257.102(b), Stingy Run Flyash Pond, Gavin Plant, Cheshire, Ohio." October 2016. Page 6.

Similarly, neither the Demonstration nor the closure plan document how the FAR will be closed in a manner that will “control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere.” 40 C.F.R. § 257.102(d)(1). EPA views the word “infiltration” as a general term that refers to any kind of movement of liquids into a CCR unit. That would include, for example, any liquid passing into or through the CCR unit by filtering or permeating from any direction, including the top, sides, and bottom of the unit. This is consistent with the plain meaning of the term. For example, Merriam-Webster defines infiltration to mean “to pass into or through (a substance) by filtering or permeating” or “to cause (something, such as a liquid) to permeate something by penetrating its pores or interstices.” Neither definition limits the source or direction by which the infiltration occurs. In situations where the groundwater intersects the CCR unit, water may infiltrate into the unit from the sides and/or bottom of the unit because the base of the unit is below the water table. In this scenario, the CCR will be in continuous contact with water. This contact between the waste and groundwater provides a potential for waste constituents to be dissolved and to migrate out of (or away from) the closed unit. In this case, the performance standard requires the facility to take measures, such as engineering controls that will “control, minimize, or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste” as well as “post-closure releases to the groundwater” from the sides and bottom of the unit. The Demonstration does not discuss how this performance standard will be achieved for the FAR, and the October 2016 closure plan for the FAR only addresses the permeability characteristics of the final cover system with respect to this performance standard.²³

²³ *Id.* Page 5.

In summary, based on available information, EPA cannot determine whether the closure performance standards will be met. This is a violation of 40 C.F.R. § 257.102(b), which requires facilities to develop a written closure plan that documents the steps that will be taken to complete closure and to ensure the performance standards are met. It may also demonstrate that Gavin has failed to comply with the performance standards for closure with waste in place in 40 C.F.R. § 257.102(d). EPA is therefore proposing to determine that Gavin has failed to comply with 40 C.F.R. § 257.102(b), and that Gavin has not demonstrated compliance with the performance standards applicable to the closure of the FAR in 40 C.F.R. § 257.102(d)(1)-(2). EPA is also proposing to find that Gavin's plans for closure are inconsistent with the plain language of the requirement that to obtain approval, a facility must demonstrate that it will maintain compliance with all the requirements of subpart D. 40 C.F.R. § 257.103(f)(1)(viii).

Bottom Ash Pond

EPA evaluated the Demonstration and closure-related information on Gavin's CCR website to determine whether Gavin has adequately explained how the closure performance standards will be achieved for the BAP. Gavin did not provide enough detail in the Demonstration for EPA to determine whether the closure of this unit will meet the closure performance standard of 40 C.F.R. § 257.102(d)(1). Specifically, based on the information presented in the Demonstration, it appears that Gavin may not meet the closure performance standards in 40 C.F.R. § 257.102(d)(1)(i): "The owner or operator ... must ensure that, at a minimum, the CCR unit is closed in a manner that will: Control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere." Gavin has chosen to implement a hybrid closure approach for the BAP. The Demonstration states that

approximately 37 acres will be closed by removal of CCR (and repurposed as the future PWP) and 17 acres will be closed by leaving CCR in place. The designs submitted with the Demonstration²⁴ and written descriptions in the Demonstration²⁵ indicate that an earthen berm will separate the impounded wastewaters in the PWP from the consolidated CCR in the closed BAP.

EPA understands that the designs submitted with the Demonstration are preliminary and that Gavin may not have completed its construction-level engineering designs for the PWP. However, no information was provided about the implementation engineering controls (e.g., liner system) that would prevent water from laterally infiltrating through the earthen berm from the PWP to the closed BAP. Based on the absence of any discussion, it appears that there will not be engineering controls installed in the PWP that would prevent this infiltration. Thus, EPA is concerned about the potential release of CCR constituents to groundwater should impounded non-CCR wastewaters in the new PWP migrate through the earthen berm into the consolidated CCR.

In summary, EPA cannot determine based on information available that the closure performance standards will be met. EPA is proposing to determine that Gavin has not met the standard of 40 C.F.R. § 257.102(b), which requires facilities to develop a written closure plan that documents the steps that will be taken to complete closure and to ensure the performance standards are met. Further, EPA is proposing to determine that Gavin has not demonstrated compliance with the performance standards applicable to the closure of the BAP in 40 C.F.R. § 257.102(d)(1). EPA is also proposing to find that the inclusion of the above plans for closure is inconsistent with the plain language of the requirement that, to obtain approval, a facility must

²⁴ Demonstration, Appendix A, Figure 6-1

²⁵ Demonstration, section 6.1.2

demonstrate that it will maintain compliance with all the requirements of subpart D. 40 C.F.R. § 257.103(f)(1)(viii).

(c) Requirement to Amend the Written Closure Plan- FAR

The regulations specify that a facility must amend the written closure plan whenever there is a change in the operation of the CCR unit that would substantially affect the written closure plan or whenever unanticipated events necessitate a revision of the written closure plan, whether such an event occurs before or after closure activities have commenced. In addition, the regulations require that the closure plan must be amended at least 60 days prior to a planned change in the operation of the facility or CCR unit, or no later than 60 days after an unanticipated event requires the need to revise an existing written closure plan. 40 C.F.R. § 257.102(b)(3)(ii) and (iii). Based on information in the Demonstration and its publicly accessible CCR website, Gavin has not amended its closure plan for the FAR as required.

As stated in the Demonstration and other closure-related documents, closure of the FAR began in 2015 and is nearly complete. While the October 2016 closure plan provided some information on the elements that must be addressed in the closure plan, additional information is needed or should have been updated. EPA would expect these details to be documented and available in a closure plan for an impoundment for which closure is nearly complete. For example, Gavin's closure plan does not document how the closure performance standards specified in 40 C.F.R. § 257.102(d)(1)-(2) are achieved based on site and unit characteristics. Another example is that the October 2016 closure plan states that the FAR "should be closed by 2020" but does not describe the sequential steps and major milestones that will be taken to close the FAR as required by 40 C.F.R. § 257.102(b)(1)(vi). In contrast, the Demonstration acknowledges that closure of the FAR is scheduled "to be completed no later than 2021" and a

separate document posted to the CCR website indicates that FAR closure was expected in March 2021 and that the date has changed from initial estimates.²⁶ EPA is therefore proposing to determine that Gavin has failed to amend the written closure plan to document the measures it has taken to meet the closure requirement and provide an updated, and accurate, schedule for completion of closure activities, and thus has failed to demonstrate that the facility is in compliance with the requirements of 40 C.F.R. part 257, subpart D, as required by 40 C.F.R. § 257.103(f)(1)(iii).

2. Groundwater Monitoring Compliance

The regulations require facilities to submit several groundwater monitoring compliance documents as part of their Demonstrations so that EPA can thoroughly evaluate the groundwater monitoring network and the site hydrogeology for every CCR unit at the facility.

(a) Groundwater compliance at the BAP

EPA evaluated the Demonstration and its appendices as well as the 2017 and 2019 BAP GWMCA Reports, the Groundwater Monitoring System P.E. Certification, the Safety Factor Assessment, and the History of Construction.

EPA is proposing to determine that the groundwater monitoring program for the BAP is inadequate for multiple reasons and therefore does not adequately demonstrate compliance with the regulations. First, design of the groundwater monitoring system at the BAP is not adequately supported by thorough characterization of groundwater flow direction. 40 C.F.R. § 257.91(b)(1). Second, the statistical comparisons between background and compliance well data have not been conducted in accordance with 40 C.F.R. §§ 257.93(a), 257.93(f)(3), or 257.94(c). Third, the Alternative Source Demonstrations (ASDs) in the 2019 Annual GWMCA Report fail to

²⁶ “Fly Ash Reservoir Demonstration.” September 9, 2020. Page 4.

these units meets the performance standards in 40 C.F.R. 257.102(d) is highly technical and extremely complicated. As explained in Section III.E.1, Gavin provided insufficient information for EPA to identify specific actions that would need to be taken at the site. Nor could EPA conclude that Gavin could implement the necessary measures before its requested deadline.

VI. Effective Date

EPA is proposing to establish an effective date for the final decision on Gavin's demonstration of 135 days after the date of the final decision (i.e., the date that the final decision is signed). EPA is proposing to align the effective date with the new deadline that EPA is proposing to establish for Gavin to cease receipt of waste. EPA is doing so for all of the reasons discussed as the basis for proposing to establish the new cease receipt of waste discussed in Section IV of this document.

January 11, 2022
Date


Barry N. Breen
Acting Assistant Administrator