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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

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

In Re:

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

Volume II

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Wednesday, May 25, 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 (By Zoom)
FITZ JOHSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
JASON SHAW, Commissioner

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

2 MADAM CHAIR PRIDEMORE: Good morning. We're
3 going to call the meeting to order. But before we
4 get started with today's business, I hope that you
5 will join me and my fellow Commissioners in a moment
6 of silence over the tragedy in Texas.

7 (A pause was taken.)

8 MADAM CHAIR PRIDEMORE: Amen. Thank you.

9 We will call this meeting to order. This is
10 Docket No. 44160, Georgia Power Company's 2022
11 application for approval of its integrated resource
12 plan, and Docket No. 44161, Georgia Power Company's
13 2022 application for approval of its Amended DSM plan
14 and certification and decertification of certain DSM
15 programs.

16 We are leaving off with what was final -- we
17 were at cross from Georgia Power Company, Mr. Alvarez
18 and Mr. Stephens.

19 Hi, Mr. Alvarez.

20 WITNESS STEPHENS: Good morning.

21 MADAM CHAIR PRIDEMORE: There's Mr. Stephens.

22 Are you ready, Mr. Hewitson?

23 MR. HEWITSON: I am, Chair. Thank you.

24 MADAM CHAIR PRIDEMORE: Okay. Go ahead.

25 MR. HEWITSON: Good morning, Mr. Alvarez.

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1 WITNESS STEPHENS: Good morning.

2 MR. HEWITSON: Good morning, Mr. Stephens.

3 WITNESS ALVAREZ: Good morning.

4 CROSS-EXAMINATION CONTINUED

5 BY MR. HEWITSON:

6 Q All right. Let's start this morning with a
7 new topic, the distribution and transmission investment
8 levels, the testimony that you had in your testimony.

9 Just to confirm, you did not make any
10 recommendations in this section, but rather foreshadowing
11 your anticipated review in the rate case. Is that a fair
12 assessment?

13 A (Witness Alvarez) We have not been engaged, but
14 yes.

15 Q Okay. So I guess let me ask it this way.
16 Your testimony in the IRP doesn't make any specific
17 recommendations regarding distribution and transmission
18 investment levels; is that correct?

19 A (Witness Alvarez) No, it does not.

20 Q Is it fair to say that through data requests
21 in the IRP you received extensive information and data on
22 the company's transmission and distribution investments?

23 A (Witness Alvarez) Extensive in the IRP? I
24 would not say that that's correct, no.

25 Q Okay. Do you believe that you received the
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1 information that you requested through data requests?

2 A (Witness Alvarez) Absolutely.

3 Q Okay. On page 19, lines 13 to 14 of your
4 testimony, you note that Georgia Power Company's
5 transmission investments in 2021 was almost double the
6 amount spent in 2018; is that right?

7 A (Witness Alvarez) That's correct.

8 Q Okay. 2018 represents the lowest amount
9 spent by Georgia Power Company on transmission investments
10 in the last ten years. Do you agree with that?

11 A (Witness Alvarez) Subject to check. I don't
12 doubt you.

13 Q Sure. Fair enough.
14 Georgia Power's transmission investments in
15 2021 was similar to investments that were made from 2013
16 through 2016; is that right?

17 A (Witness Alvarez) I don't recall.

18 Q Okay. Well, if you're looking at your chart
19 on page 19, the bars seem to be similar; right?

20 A (Witness Alvarez) Thank you. Yes.

21 Q And transmission in 2021 was down from 2019
22 and 2020; is that right?

23 A (Witness Alvarez) That's correct.

24 Q In 2018, are you aware that Georgia Power
25 Company sold a transmission asset worth \$140 million,

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1 which reduced the total transmission spend in that year by
2 that amount?

3 A (Witness Alvarez) I was not aware of that, no.

4 Q Did you review the response to your data
5 request STG-WG-3-1?

6 A (Witness Alvarez) I believe so, yes.

7 Q Okay. Well, do you recall seeing a negative
8 number in the transmission growth and load flow column in
9 the response to that for 2018?

10 A (Witness Alvarez) I do not recall that, no.

11 Q Okay. With that information in mind and
12 subject to check that I'm telling you the correct
13 information about the \$140 million sale, the transmission
14 spend in 2018 is actually closer to \$350 million; right?

15 A (Witness Alvarez) That would be about right,
16 yes.

17 Q And that would put it in line with spending
18 in 2013 through 2017; is that right?

19 A (Witness Alvarez) Yes.

20 Q Looking specifically at distribution
21 investment, those increases since 2018, aren't the 2020
22 and 2021 increases attributable to Georgia Power's grid
23 investment plan that was approved by the Commission in
24 2019?

25 A (Witness Alvarez) That may be true, yes.

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1 Q Okay. Do you agree that positive customer
2 and economic growth can lead to increased investment in
3 distribution?

4 A (Witness Alvarez) Yes.

5 Q Do you agree that customers now have
6 increased and evolving expectations related to reliability
7 than they did even just a few years ago?

8 A (Witness Alvarez) I would like to see the
9 market research on that before I could agree to that.

10 Q Population growth can also lead to things
11 like transportation improvements and other infrastructure
12 changes that may drive the need for distribution
13 investment; right?

14 A (Witness Alvarez) That's true.

15 Q On page 20 of your testimony, lines 6 to 8 --
16 6 through 8, you included a statistic on frequency and
17 duration of outages. Do you remember that?

18 A (Witness Alvarez) I do.

19 Q Okay. For duration you said Georgia Power's
20 service interruptions were 142 minutes per interruption on
21 average in 2020. Do you recall that testimony?

22 A (Witness Alvarez) I do.

23 Q Okay. Is that the SADIE statistic?

24 A (Witness Alvarez) That's correct.

25 Q SADIE represents the sum of durations of all

1 outages experienced by the average customer in a year;
2 right?

3 A (Witness Alvarez) That is correct.

4 Dennis, do you have any --

5 A (Witness Stephens) No. That's correct.

6 A (Witness Alvarez) Thank you.

7 Q So shouldn't that --

8 COMMISSONER McDONALD: Excuse me. Do those
9 interruptions -- what are the interruptions? Are
10 they nature interruptions? Are they a fault of
11 generation interruptions?

12 What is the class of interruptions that you're
13 having?

14 WITNESS ALVAREZ: I believe, Your Honor,
15 they're all interruptions from any source.

16 COMMISSONER McDONALD: Any source?

17 WITNESS ALVAREZ: Yeah.

18 Is that correct, Dennis?

19 WITNESS STEPHENS: That is correct.

20 COMMISSONER McDONALD: Well, I just -- you
21 know, I don't want it to -- as it reads here, you
22 know, that Georgia Power's responsible for all
23 interruptions. Well, they are the recipient of the
24 interruptions and the consumer is the recipient of
25 interruptions. But some of it is certainly not the

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1 fault of the company and it's the nature of the
2 situation or some drunk taking a pole out --

3 WITNESS ALVAREZ: That's correct.

4 COMMISSONER McDONALD: -- or something of that
5 nature.

6 WITNESS ALVAREZ: Yeah.

7 COMMISSONER McDONALD: So I just wanted to make
8 sure that we have a clarification on some of it.

9 WITNESS ALVAREZ: Yeah. And, actually, Your
10 Honor, now that I think about it, that chart is
11 without major event days. So that would be big
12 storms. Big storms are removed from that data.

13 But every other type of interruption, including
14 people hitting poles --

15 COMMISSONER McDONALD: I mean, that helps.

16 WITNESS ALVAREZ: -- are included, yeah. Yeah.

17 BY MR. HEWITSON:

18 Q Well, in the statement as is written in your
19 testimony, it says 142 minutes per interruption. If it is
20 the SADIE statistic -- easy for me to say -- is the SADIE
21 statistic, shouldn't that statement say 142 total minutes
22 of interruption on the average in 2020?

23 A (Witness Alvarez) Yes. That would be a
24 better -- a better description, yes.

25 Q Okay. You're aware that Georgia Power is in
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1 the third quartile for both SADIE and safety as compared
2 to other investor-owned utilities?

3 A (Witness Alvarez) Yes.

4 Q Are you also aware that the grid investment
5 plan approved in 2019 is aimed at improving reliability
6 for customers who fall at the lower end of the reliability
7 metrics?

8 A (Witness Alvarez) We had not reviewed that
9 plan, but --

10 Dennis, we had not reviewed that plan?

11 A (Witness Stephens) No, no. We have to accept
12 that.

13 Q Okay. I'm sorry. You did not review the
14 grid investment plan?

15 A (Witness Alvarez) No.

16 Q Okay. So you weren't aware that that grid
17 investment plan targets about 800 of the company's
18 worst-performing distribution feeders?

19 A (Witness Alvarez) I was not aware of that, no.

20 Q Do you agree that targeting improvements to
21 the worst-performing feeders could greatly improve overall
22 customer reliability?

23 A (Witness Alvarez) I think it could. I think
24 the question is: How do you do so most cost-effectively?
25 There are many ways to improve reliability and, you know,

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1 some are less costly than others. And so I think the
2 question is: Were the most cost-effective approaches chosen
3 to help address the issues on those feeders?

4 Dennis, do you have anything to add to that?

5 A (Witness Stephens) Yes. I want to add to that
6 that we would have to review the plan to determine whether
7 or not there was spending for reliability beyond the
8 worst-performing feeders and whether or not that was
9 cost-effective.

10 Q Okay. So did you understand that the company
11 performed an economic benefit study to evaluate and
12 determine the optimal investment range for the grid
13 investment plan?

14 A (Witness Alvarez) I was not aware of that, no.

15 MR. HEWITSON: Gentlemen, that's all the
16 questions I have for you. Thank you very much for
17 your time.

18 MADAM CHAIR PRIDEMORE: Mr. Thomas, redirect.

19 MR. THOMAS: Thank you.

20 REDIRECT EXAMINATION

21 BY MR. THOMAS:

22 Q All right, gentlemen. I want to ask a few
23 redirect questions about the Commission programs.

24 Have the commissions in states with the highest
25 adoption of DER-approved tariffs similar to what Georgia

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1 Power Company is requesting and why do you think that is?

2 A (Witness Alvarez) So unlike Wisconsin and
3 Florida and Minnesota and Colorado where we have not worked,
4 we worked extensively in California and in Hawaii, and I can
5 tell you those states with very high levels of adoption of
6 DER do not have such tariffs.

7 Q And why do you think that is?

8 A (Witness Alvarez) You know, I mean, we have
9 been here before, you know. This has all been addressed in
10 legislation. I think it was the Public Utility Holding
11 Company Act of 1935 or so that says that regulated utilities
12 can't own unregulated businesses. And that came from -- I
13 know of at least one example of how that occurred.

14 Why that legislation came to pass is that the
15 utilities were delivering or offering discounts to their own
16 owned streetcar companies. And then those streetcar
17 companies would offer lower rates. They would drive all of
18 the other streetcar companies out of business, at which
19 point those streetcar companies would raise their rates and
20 earn above-market returns.

21 And so that's what led to that legislation.
22 And I think that those were the right -- those were the
23 right laws to pass at that time. And I think a lot of
24 commissions will be concerned about that.

25 Q The company's unregulated side can and,
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1 according to Mr. Hewitson, does have a DER business. Is
2 there any reason why GPC would prefer to offer its DER
3 services under the regulated tariffs?

4 A (Witness Alvarez) Well, sure. It's all the
5 reasons, you know, I've noted in my testimony. They have
6 some competitive advantages when offering that kind of a
7 business through the regulated arm that they would not in an
8 unregulated business.

9 So, for example my testimony talks about
10 on-bill financing. That's a huge advantage. Economies of
11 scale in purchasing, potential bad debt risk reductions,
12 leverage in the labor pool. You know, they have many
13 different advantages they can leverage as an unregulated
14 business that they cannot -- as a regulated business that
15 they cannot as an unregulated business. So I would think it
16 would be better for shareholders.

17 Q Am I correct in saying that the company's
18 unregulated subsidiary with the DER business that you
19 learned of yesterday, they're not entitled to an
20 authorized rate of return set by this Commission; correct?

21 A (Witness Alvarez) That's correct.

22 Q Okay. And the unregulated business cannot
23 pass on bad debt or relocation cost onto regulated
24 customers; is that correct?

25 A (Witness Alvarez) I think that's the intention.

1 I'm not sure that that is necessarily what would happen. I
2 think the risk is that that would not happen. The
3 protection of the customers is not there. But, yes, I agree
4 with you.

5 Q Okay. So -- I'm sorry. A little confused
6 there.

7 The unregulated business you're -- you're
8 agreeing that they can't pass on bad debt to the regulated?

9 A (Witness Alvarez) Yes, yes. The unregulated
10 business cannot pass on bad debt, that's correct.

11 Q Okay. And staff's main concerns with the
12 company providing regulated DER services is primarily that
13 other customers will have to subsidize it or that it could
14 create an unfair competitive advantage against unregulated
15 businesses already in the industry; is that correct?

16 A (Witness Alvarez) That's correct.

17 Q Is there anything in the company's proposal
18 that would ensure that other customers won't subsidize
19 this proposed DER business?

20 A (Witness Alvarez) Well, not yet. I think, you
21 know, to be fair, there's -- the tariff has not been, you
22 know, offered. But I do -- we do believe that that's a
23 risk. That's a big risk.

24 Q Has the company guaranteed that it won't pass
25 on bad debt to other customers?

1 A (Witness Alvarez) That's not in the IRP, no.

2 Q Has Georgia Power guaranteed that it won't
3 pass on relocation costs to other customers?

4 A (Witness Alvarez) That is not in the IRP plan,
5 no.

6 Q If bad debt and relocation costs truly are
7 such a rare occurrence, why would the company refuse to
8 give the Commission a guarantee that they won't be passed
9 on to other customers?

10 A (Witness Alvarez) I think it's a great
11 question.

12 Q Mr. Hewitson passed out several tariffs
13 yesterday.

14 A (Witness Alvarez) Yes.

15 Q Do you remember that?

16 A (Witness Alvarez) I do.

17 Q And proposed tariffs --

18 A (Witness Alvarez) Yes, I do.

19 Q -- from a few states. And he said that they
20 are the same or similar as what the company as -- is
21 proposing. But the company hasn't actually proposed or
22 filed a proposed tariff in this case, have they?

23 A (Witness Alvarez) That's correct.

24 Q Okay. Without seeing a proposed tariff from
25 the company, is it possible to say that the tariffs they

1 were proposing is the same or similar to the tariffs that
2 were passed out yesterday?

3 A (Witness Alvarez) No, it's not.

4 Q One tariff that Mr. Hewitson passed out is
5 only a proposed tariff. That means it is proposed by a
6 utility company, but not adopted by a Commission; is that
7 correct?

8 A (Witness Alvarez) That's correct.

9 Q Has Georgia Power ever proposed tariffs that
10 this Commission has found inappropriate or has chosen not
11 to adopt?

12 A (Witness Alvarez) Not to my knowledge.

13 Q Okay. Well, how much weight should this
14 Commission give to a tariff that has been proposed by a
15 utility, but not adopted by any Commission?

16 A (Witness Alvarez) I think very little, if any.

17 Q Mr. Hewitson passed out a tariff that had
18 been adopted and then put on hold for review. Did he
19 explain to the panel why it had been put on hold for
20 review?

21 A (Witness Alvarez) No, he did not.

22 Q How much weight do you think this Commission
23 should give to a tariff that was put on hold for review by
24 a commission without knowing the circumstances that caused
25 that hold?

1 A (Witness Alvarez) I think very, very little.

2 Q Referring to the Xcel Energy handout that
3 Mr. Hewitson passed out to you yesterday that he has
4 PSC Reference No. 42194 stamped on it --

5 A (Witness Alvarez) Yes.

6 Q If you'd turn to the page --

7 MADAM CHAIR PRIDEMORE: Mr. Thomas, there were
8 two Xcel Energy. What state?

9 MR. THOMAS: It has 421914 stamped on it and it
10 is for Wisconsin.

11 MADAM CHAIR PRIDEMORE: Okay. We have one
12 that's not stamped. So Wisconsin?

13 MR. THOMAS: Yes, ma'am.

14 MADAM CHAIR PRIDEMORE: Thank you.

15 BY MR. THOMAS:

16 Q So if you can turn to the back side of the
17 third page that at the top says: Sheet No. E62-2.

18 Do you see that page?

19 A (Witness Alvarez) Yes, I do.

20 Q Okay. In the third paragraph, the document
21 states that the company reserves the right to require
22 customers to execute a contract with the company for a
23 definite character or period of service and otherwise
24 protect the company against possible losses in a manner
25 consistent with Section 5.89 of the Wisconsin Electric

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1 Rate Book.

2 Now, I'm not going to ask you to give me a
3 legal interpretation of this language. And I know that
4 you're just receiving these handouts yesterday. So you
5 haven't had time to thoroughly review the tariff.

6 But is this -- is this language documenting the
7 type of concerns that staff has surrounding customers having
8 to subsidize losses that the company might incur?

9 A (Witness Alvarez) I think it does.

10 Q Should the -- should the Georgia Commission
11 base its decisions regarding regulated DER tariffs on what
12 a small handful of other state commissions have approved
13 or have approved and then put on hold?

14 A (Witness Alvarez) I don't think so, no. I
15 think the Commission has to do what's best for Georgia.

16 Q And should this Commission adopt a proposal
17 without seeing the proposed tariff?

18 A (Witness Alvarez) No, it should not.

19 Q Did the company provide in its IRP or its
20 testimony any indication that the marginal experience
21 benefits of additional pilot locations were worth the
22 incremental cost of those additional locations?

23 A (Witness Alvarez) No. We did not see that, no.

24 Mr. Stephens, do you care to --

25 A (Witness Stephens) No, we did not see that.

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1 MR. THOMAS: All right. That concludes my
2 redirect. And I would just ask that --

3 MADAM CHAIR PRIDEMORE: Commissioner McDonald
4 has a question.

5 MR. THOMAS: Oh, I'm sorry.

6 COMMISSONER McDONALD: Sir, in your expertise,
7 do you favor an investor-owned utility or
8 deregulating a utility?

9 WITNESS ALVAREZ: I'm not sure that I have a
10 position on that, Your Honor. I think there are pros
11 and cons each -- either way. You know, I think in
12 some states, especially the larger customers, have
13 certainly gained, I think, some competitive benefit
14 to securing their supply, you know, their energy,
15 from various, you know, suppliers of power, power
16 generators.

17 But there are pros and cons both ways. I think
18 that's a -- that's a big question, Your Honor, to --
19 it requires a lot of study. It requires a lot of
20 study.

21 COMMISSONER McDONALD: Mr. Stephens, do you
22 have a response on that?

23 WITNESS STEPHENS: Yes, I do. When we analyzed
24 investor-owned utilities versus metro's
25 noninvestor-owned utilities, we find that the

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1 noninvestor-owned utilities are much more
2 conservative in their spending. I think they
3 understand the relationship between trying to be very
4 economical in -- in investment and the best interest
5 of their customers.

6 When we look at a lot of the investor-owned
7 utilities, we see an awful lot more -- just a lot
8 more spending in general. And I don't have a problem
9 with investor-owned utilities as long as they are
10 properly overseeing -- properly looked at such that
11 their investments are in the best interest of the
12 ratepayers, specifically that there is a risk-based
13 cost benefit analysis looked at all their
14 non-required work.

15 In other words, there's a lot of required work.
16 In other words, they have to serve their customers.
17 They have to keep their system working properly with
18 voltage and frequency and those kinds of things. But
19 there's an awful lot of others' work that's
20 associated with reliability, DER, those kinds of
21 things that are not necessarily required and require
22 a cost-benefit analysis, specifically a risk-based
23 cost-benefit analysis.

24 And in those cases we believe that if the -- if
25 the benefit -- the dollar value to the ratepayer is

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1 not in excess of the dollar cost to the ratepayer
2 that those projects should definitely not be
3 implemented. Though it is -- I guess my bottom line
4 is I don't have a problem with investor-owned units.
5 I worked for one for 35 years, but it definitely --
6 in the most recent years, I think a closer scrutiny
7 is warranted.

8 COMMISSONER McDONALD: Are you familiar with
9 the activity of Wall Street, as far as their ratings
10 concerned with investor-owned utilities versus
11 deregulated utilities?

12 WITNESS ALVAREZ: Not --

13 WITNESS STEPHENS: Not --just slightly heard
14 about it, you know.

15 MR. THOMAS: Madam Chair, I would just ask that
16 the witnesses be excused and that Staff Exhibits 55
17 through 63 be entered into the record.

18 MADAM CHAIR PRIDEMORE: So moved and so marked.

19 (Staff's Exhibits 55 through 63 were admitted
20 into evidence.)

21 MR. HEWITSON: May I also move our exhibits in,
22 Chair?

23 MADAM CHAIR PRIDEMORE: So moved.

24 (Georgia Power Exhibits 8-11 were admitted into
25 evidence.)

1 MADAM CHAIR PRIDEMORE: You're excused. Thank
2 you.

3 WITNESS ALVAREZ: Thank you, Your Honor.

4 MADAM CHAIR PRIDEMORE: You're excused,
5 Mr. Stephens.

6 Let's give the court reporter a moment and set
7 up for our next panel.

8 MR. THOMAS: Madam Chair, at this time I call
9 John W. Chiles and Jacob M. Thomas to the stand.

10 Would you both please raise your right hand.
11 Thereupon,

12 JOHN W. CHILES,
13 JACOB M. THOMAS,
14 having been duly sworn, testified as follows:

15 DIRECT EXAMINATION

16 BY MR. THOMAS:

17 Q Mr. Chiles, will you please state your name
18 full name, by whom you are employed, and your
19 responsibilities for the record.

20 A (Witness Chiles) Yes. My name is
21 John W. Chiles. I'm a principal at GDS Associates in
22 Marietta, Georgia. I serve in the transmission services
23 group and my responsibilities are transmission planning,
24 transmission policy, and wholesale energy market design.

25 Q Mr. Thomas, same question.

A (Witness J. Thomas) Yes. I am Jacob M. Thomas,
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1 a principal of GDS Associates in our distribution services
2 department. My responsibilities include load forecasting
3 and retail cost of service and rate design.

4 Q And, Mr. Chiles, on May 6 of this year, did
5 you file or -- prefile or caused to be prefiled 37 pages
6 of testimony in question-and-answer format, along with
7 three exhibits marked as JWC-1 through JWC-3?

8 A (Witness Chiles) Yes, I did.

9 Q And, Mr. Thomas, on May 6 of this year, did
10 you file or cause to be prefiled 12 pages of testimony in
11 question-and-answer format, along with four exhibits
12 marked as JMT-1 through JMT-4?

13 A (Witness J. Thomas) Yes.

14 Q And do either of you have any corrections you
15 need to make to either your prefiled testimony or your
16 exhibits at this time?

17 A (Witness Chiles) Yes, I do. On page 24,
18 line 7, we reference the Webb (APC) 15 kV line. That should
19 be 115 kV. And the same correction needs to be made on
20 page 27, line 10.

21 Q Is this all the corrections that you have?

22 A (Witness Chiles) This is.

23 Q Okay. And if I were to ask you the same --

24 A (Witness J. Thomas) I --

25 Q Oh, I'm sorry.

1 A (Witness Thomas) I have a -- one adjustment,
2 too, on mine. On page 7, line 2, where it reads
3 "residential consumption survey," that should read
4 residential energy consumption survey.

5 Q Okay.

6 A (Witness J. Thomas) That's it.

7 Q And with these changes, if I were to ask you
8 the same questions here under oath, would your answers be
9 the same?

10 A (Witness J. Thomas) Yes.

11 (Witness Chiles) Yes.

12 MR. THOMAS: Madam Chair, the court reporter
13 has been provided a copy of the prefiled testimony.
14 And I would ask that the direct testimony be copied
15 into the record as if given here today. And I would
16 ask that Exhibits JWC-1 through JWC-3 and JMT-1
17 through JMT-4 would be marked for staff
18 identification purposes as Staff Exhibit 64
19 through 71.

20 MADAM CHAIR PRIDEMORE: So moved. So marked.

21 (The documents referred to were marked for
22 identification as Staff Exhibits 64 through 71.)

23 (Whereupon, the prefiled direct testimonies
24 of Mr. Chiles and Mr. Thomas follows:)

25

1 **INTRODUCTION**

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

3 **A.** My name is John W. Chiles. I am a Principal at GDS Associates, Inc. My business address
4 is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

5 **Q. HAVE YOU INCLUDED SUMMARIES OF YOUR EXPERIENCE AND**
6 **QUALIFICATIONS IN THIS TESTIMONY?**

7 **A.** Yes. My resume is included herein as Exhibit JWC-1.

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

9 **A.** I am testifying on behalf of the Public Interest Advocacy Staff ("Staff") of the Georgia Public
10 Service Commission ("Commission"). The purpose of my testimony is to respond to certain
11 elements of Georgia Power Company's ("Company" or "Georgia Power") 2022 Integrated
12 Resource Plan ("IRP") filing. I will address issues pertaining to the Company's transmission
13 planning processes including the evaluation of the Company's Ten-Year Plan.

14 **SUMMARY OF RECOMMENDATIONS**

15 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

16 **A.** First, I have reviewed the Company's Ten-Year Transmission Plan and agree with the results
17 of the projects in that they meet NERC TPL requirements. Second, I support the
18 recommendations of the Company regarding the proposed retirement of Plant Wansley Units
19 1-2 and Unit 5A, Plant Boulevard Unit 1, Plant Gaston Units 1-4 and Unit A, Plant Bowen
20 Units 1-2 and Plant Scherer Units 1-3. I am recommending that the Company continue the
21 review of the required transmission facilities associated with the retirement of Plant Bowen

1 Units 3-4 prior to their planned retirement in 2035. Third, I am supportive of additional
2 reporting requirements associated with the proposed Energy Storage Systems to ensure that
3 the Company is achieving their goals with assessing ESS technologies. Lastly, I am
4 recommending that the Commission develop a Commission-led collaborative long-term
5 transmission planning process to identify the needs and solutions for North Georgia in light
6 of retirement challenges, unknown renewable generation siting needs and ESS requirements
7 prior to the 2025 Integrated Resource Plan.

8 **EVALUATION OF THE COMPANY'S TRANSMISSION PLANNING PROCESS**

9 **Q. HAS THE COMPANY PROVIDED A DESCRIPTION OF THEIR**
10 **TRANSMISSION PLANNING PROCESS?**

11 **A.** Yes, the Company has provided a description of their planning process in Section A of
12 Trade Secret Volume 3 of the 2022 Integrated Resource Plan.

13 **Q. WHAT TYPES OF MODELS DOES THE COMPANY USE WHEN PERFORMING**
14 **THE TRANSMISSION PLANNING FUNCTION?**

15 **A.** The Company uses both load flow models and stability models.

16 **Q. WHAT IS A POWER FLOW OR LOAD FLOW MODEL?**

17 **A.** A load flow model is a model of the electric power system. It contains representations of
18 substations, transmission lines, transformers, generators, loads, and other power system
19 components such as capacitor banks. The load flow model is used to model a system
20 condition, such a high demand period.

1 **Q. DOES THE COMPANY DEVELOP JUST ONE SET OF LOAD FLOW MODELS**
2 **FOR ALL STUDIES?**

3 **A.** No. The Company develops a base case load flow model that incorporates the existing
4 system plus all planned transmission additions up to a specified date. These include a
5 current year or "Year 0" case and a set of cases for the next ten years. Additionally, there
6 are multiple sets of base case load flow models that reflect various phases of the
7 Integrated Transmission System (ITS) coordinated planning process. The Company
8 creates a Version 1 set of models that reflect the input of data from all ITS Participants
9 and include planned transmission additions. There is also an error checking stage that the
10 models undergo to make sure the information is verified by multiple parties. The
11 Company also creates a Version 2 set of models in which some future transmission
12 additions are "stripped" from the model in order to create the final base case models.

13 **Q. WHAT FUTURE TRANSMISSION PROJECTS ARE LEFT IN THE MODEL FOR**
14 **THE VERSION 2 BASE CASES?**

15 **A.** The Company has stated that there are three reasons why a future project is kept in the
16 Version 2 models. They are: (1) if the project is far enough along in the engineering and
17 construction process, (2) if the projects are tied to contracted obligations for specific years,
18 or (3) if the projects are tied to certain assumptions, such as improvements associated with
19 new generation additions. These Version 2 cases represent the completed plan.

20 **Q. IN TERMS OF ASSESSING THE IMPACT ON THE TRANSMISSION SYSTEM**
21 **OF THE COMPANY'S PLANS FOR THE DECERTIFICATION AND**

1 **RETIREMENT OF GENERATION, IS IT THE VERSION 2 CASES THAT FORM**
2 **THE BASIS FOR THOSE DECISIONS?**

3 **A.** That is my understanding based on the Company's filing.

4 **Q.** **AT WHAT POINT IN THE TRANSMISSION PLANNING PROCESS DOES THE**
5 **EFFECT OF CHANGES TO THE GENERATION EXPANSION PLAN GET**
6 **INCLUDED?**

7 **A.** It appears that changes to the generation expansion plan are considered in the Project
8 Evaluation phase of the planning cycle (Technical Volume 3, Section A.6.d). Up to this
9 point, the set of solutions in the base cases remain constant. As solutions are evaluated, the
10 base case assumptions can vary and this includes the generation expansion plan
11 assumptions.

12 **Q.** **IN THE DEVELOPMENT OF THE POWER FLOW MODELS FOR THE TEN-**
13 **YEAR TRANSMISSION PLAN, DID THE COMPANY INCLUDE ANY PLANNED**
14 **GENERATION RETIREMENTS IN THE VERSION 1 OR VERSION 2 MODELS?**

15 **A.** Yes. The planned retirements of Plant Wansley Units 1-2 and Plant Boulevard Unit 1 were
16 included in the power flow base models.

17 **Q.** **DO THE TRANSMISSION PLANNERS GET TO MAKE DECISIONS**
18 **REGARDING THE TIMING, SIZE AND LOCATION OF FUTURE**
19 **GENERATION PLANTS?**

20 **A.** According to Technical Volume 3, Section A.6b, it is a "management decision" regarding
21 the timing, size and location of future generation plans.

1 **Q. WHY WERE SOME RETIREMENTS INCLUDED IN THE MODELS BEFORE**
2 **THEIR RETIREMENT WAS APPROVED BY THE COMMISSION?**

3 **A.** That is difficult to say.

4 **Q. IS THE TEN-YEAR TRANSMISSION PLAN THE ONLY STUDY PERFORMED**
5 **BY THE COMPANY TO ASSESS SYSTEM PERFORMANCE?**

6 **A.** No. The Company has several study efforts to address various needs on the transmission
7 system. These include Operating Studies, Loss Studies, System Interface Studies, and
8 Optimal Generation Siting Studies.

9 **Q. DOES THE COMPANY USE THE SAME ASSUMPTIONS FOR EACH STUDY**
10 **CONSISTENT WITH THE VERSION 1 AND VERSION 2 BASE CASE POWER**
11 **FLOW MODELS FROM THE TEN-YEAR TRANSMISSION PLAN?**

12 **A.** No, they do not. The near-term Operating Studies look at system conditions for the next
13 season (e.g., Summer 2022) to identify any unusual conditions that could arise based on
14 short-term load forecast changes, planned transmission and generation outages and new
15 generation changes. These models use different load and transmission topology
16 assumptions from the Ten-Year Plan. The System Interface Studies look at the impact of
17 regional flows from neighboring systems and how those flows impact the ability of the
18 Southern Company System to import or export electricity. These models include more
19 detailed representations of the neighboring systems, and also include base flows across the
20 various interfaces from long-term firm transmission commitments. Reductions in available
21 capacity are made to capture reliability margins associated with regional power delivery,
22 such as Transmission Reliability Margin and Capacity Benefit Margin. The Optimal

1 Generation Siting Study uses a separate power flow model to look at the high-voltage
2 busses on the Company transmission system that could potentially accommodate additions
3 of new generation.

4 **Q. DOES THE OPTIMAL GENERATION SITING STUDY INCLUDE THE IMPACT**
5 **OF PROPOSED RETIREMENTS IN THE ANALYSIS?**

6 **A.** The Company references that each year there are changes to load, generation and
7 transmission that could impact the results but the Company did not reference specific
8 assumptions regarding retirements.

9 **Q. HOW OFTEN DOES THE COMPANY PERFORM THIS ANALYSIS?**

10 **A.** The Company does not provide a specific timetable for performance of this study, but does
11 mention that it will be performed periodically going forward.

12 **Q. DID THE COMPANY EVALUATE ALL POTENTIAL BUSES IN THE**
13 **GEORGIA POWER SYSTEM FOR OPTIMAL SITING?**

14 **A.** Only buses located in North Georgia were published in the latest study. In STF-GDS-4-3,
15 the Company explained that North Georgia includes those counties located north of
16 Interstate 20 and those counties bisected by Interstate 20. Other sites were removed from
17 consideration due to the concentration of solar development in South Georgia and the
18 increases in south-to-north flows on the system.

19 **Q. WOULD THE COMPANY BENEFIT FROM PERFORMING THIS TYPE OF**
20 **ANALYSIS ON AN ANNUAL BASIS?**

1 A. Absolutely. The Company's goals related to increasing renewable generation penetration
2 in the State necessitate having a transmission system that can accommodate those goals.
3 Developers benefit from knowing where to target the system to maximize use of the
4 transmission system and where to minimize the need for costly upgrades that may make
5 their projects uneconomic. The consumers would benefit from having lower costs with an
6 optimized solution that neither overbuilds generation in undesirable locations or in
7 constructing transmission infrastructure that does not achieve reliability and resilience
8 goals. This type of transparency in planning would facilitate better decision-making instead
9 of the three year look the Commission gets in the IRP.

10 **THE RENEWABLE RFP AND TRANSMISSION**

11 Q. THE COMPANY HAS DISCUSSED A FUTURE RENEWABLE RFP AND THE
12 NEED FOR GENERATION IN NORTH GEORGIA TO ADDRESS RETIREMENT
13 CONCERNS AND THE GENERATION IMBALANCE BETWEEN RENEWABLE
14 RESOURCES IN SOUTH GEORGIA AND HIGHER LOADS IN NORTH
15 GEORGIA. HOW SHOULD THE COMPANY CONSIDER THE EFFECT OF
16 SITING DECISIONS FOR NEW RENEWABLE CAPACITY IN THE
17 RENEWABLE RFP IN THEIR PLANNING PROCESS?

18 A. There are two approaches that could be considered. The first approach, which appears to
19 be the Company's preference, is to encourage projects in North Georgia in the RFP. The
20 role of the transmission planner in this generation-centric approach is to designate preferred
21 sites or regions and then to build appropriate infrastructure to support the expected
22 generation once the total portfolio is known. The second is to develop the transmission

1 infrastructure first and then encourage developers to take advantage of the backbone
2 transmission expansion by siting generation in those locations. With all of the uncertainty
3 surrounding the generation portfolio in North Georgia with proposed retirements and new
4 generation, development of the backbone system may be the preferred direction for the
5 Company to consider. I recommend that Commission develop a collaborative transmission
6 planning process which has Commission oversight and includes all of the ITS Participants,
7 the Staff and the Company to wrestle with this issue and come up with a comprehensive
8 plan that considers the regional needs for a reliable, resilient and economic grid to support
9 the Company's transition to a clean energy future.

10 **Q. DO YOU SUPPORT THE IDEA OF THE COMPANY DESIGNATING NORTH**
11 **GEORGIA AS THE ONLY PLACES FOR NEW RENEWABLE GENERATION?**

12 **A.** I support the Company running their Renewable RFP to consider capacity throughout the
13 state, but maybe consider either a reduced value of capacity or a transmission cost adder to
14 proposals not sited in the North Georgia region.

15 **Q. HAS THE COMPANY PERFORMED ANY ANALYSIS OF POTENTIAL**
16 **GENERATION SITES FOR THE RENEWABLE RFP?**

17 **A.** To my knowledge, the Company has not provided any transmission studies related to the
18 requirements of the Renewable RFP.

19 **Q. WOULD YOU SUPPORT THE COMPANY PERFORMING AN OPTIMUM**
20 **GENERATING SITING STUDY AND MAKING THOSE RESULTS AVAILABLE**
21 **TO BIDDERS INTO THE RENEWABLE RFP?**

1 A. Yes, I would support the Company letting developers know locations that are the most
2 desirable from a transmission perspective prior to bid submittal.

3 **THE NORTH GEORGIA RELIABILITY AND RESILIENCE PROJECT**

4 **Q. IS THE COMPANY PROPOSING A NORTH GEORGIA RELIABILITY AND**
5 **RESILIENCE PROJECT IN THIS IRP?**

6 A. Chapter 12 of the IRP Main Document discusses the concept of the North Georgia
7 Reliability and Resilience Action Plan, but the Company is not proposing a specific set of
8 facilities that would make up a solution set.

9 **Q. WHAT DRIVERS WILL HAVE THE LARGEST IMPACT ON THE**
10 **TRANSMISSION SOLUTIONS THAT WILL MAKE UP THE NORTH GEORGIA**
11 **RELIABILITY AND RESILIENCE ACTION PLAN?**

12 A. The main drivers for serving load in North Georgia is the retirement of Plant Bowen Units
13 1-4, the high concentration of renewable resources in South Georgia and the location of
14 new generation that may be selected in the Renewable RFP.

15 **Q. HOW WILL THE NORTH GEORGIA RELIABILITY AND RESILIENCE**
16 **PROJECT IMPACT THE DECISIONS SURROUNDING FUTURE GENERATION**
17 **RETIREMENTS AND THE SITING OF GENERATION FOR THE RENEWABLE**
18 **RFP?**

19 A. The construction of transmission infrastructure to facilitate the delivery of existing
20 renewable resources from South Georgia to a generation-deficient North Georgia load sink,
21 due to the planned retirement of Plant Bowen Units 1-4, is critical to the ability to serve

1 the Company's load requirements. Not already having a transmission expansion plan that
2 is designed to facilitate new generation to feed North Georgia is a serious problem that
3 requires rapid decisions. The failure of the Company to have a long-term strategic plan in
4 place for the loss of Bowen generation is a flaw in the Company's planning process and
5 something that should have been addressed in a Commission-directed, transparent process
6 long before the 2022 Integrated Resource Plan. Many organizations conduct long-term
7 planning assessments beyond the ten-year horizon, and the Company and Commission
8 would benefit from such a collaborative long-term transmission planning process which
9 includes Staff, consultants, and ITS Participants.

10 **Q. HAS THE COMPANY PERFORMED ANY STUDIES RELATED TO THE**
11 **NORTH GEORGIA RELIABILITY AND RESILIENCE PROJECT?**

12 **A.** To date, the Company has not performed any specific studies although there appear to be
13 initial discussions with the ITS Participants regarding this topic based on the Company's
14 comments in the IRP Main Document in Section 12.1 ("To date, strategic projects remain
15 under development with ITS Participants.").

16 **Q. HAS THE COMPANY IDENTIFIED ANY SPECIFIC SOLUTIONS AT THIS**
17 **TIME?**

18 **A.** The Company has not identified any solutions at this time.

19 **Q. SHOULD THE COMMISSION STAFF HAVE ANY INPUT INTO THE**
20 **PROJECTS THAT WILL MAKE UP THE NORTH GEORGIA RELIABILITY**
21 **AND RESILIENCE PROJECT?**

1 A. The significant changes in the Company's generation mix and retirement/siting strategy
2 requires a long-term view and will likely require much analysis. Additionally, with
3 potentially large-scale and potentially expensive expansion of the transmission system, the
4 need for the Commission to fully understand the options, scope, costs and rate treatment
5 for future facilities will benefit Georgia consumers. Staff needs to understand the process
6 and the results. One of the best ways to do that is to be walking alongside the Company
7 and impacted stakeholders as the plan is developed. If the Company only identifies projects
8 for approval in the 2025 IRP, there will not be enough time to consider alternatives. This
9 is already the problem with the evaluation of the retirement of Plant Bowen Units 3-4 in
10 the 2022 IRP. The lead-time lead time for traditional transmission solutions, and the
11 apparent failure to not consider alternative solutions, limit the Commission's ability to
12 approve anything other than the Company's proposed solution.

13 **Q. IF THERE WERE MORE COORDINATION BETWEEN THE COMPANY'S**
14 **VARIED STUDY EFFORTS AND IMPACTED STAKEHOLDERS, DO YOU**
15 **BELIEVE THIS WOULD RESULT IN A MORE ROBUST PLANNING PROCESS?**

16 A. Yes, I do believe that more coordination and communication with staff and stakeholders
17 throughout the transmission expansion planning process would produce a plan that has
18 greater buy-in from regulatory bodies and the developer community.

19 **Q. HAVE YOU SEEN OTHER STATES WHERE THERE IS A JOINT**
20 **TRANSMISSION PLAN THAT IS PRODUCED THROUGH A STAKEHOLDER**
21 **PROCESS, THAT IS NOT PART OF A REGIONAL TRANSMISSION**
22 **ORGANIZATION?**

1 A. Yes, there are statewide transmission planning processes that are performed in both North
2 Carolina and Arizona, where the Commissions have oversight and a seat at the table in the
3 strategic evaluation of the regional transmission system.

4 Q. PLEASE DESCRIBE THE PROCESS IN NORTH CAROLINA.

5 A. From the North Carolina Transmission Planning Collaborative website
6 (<http://nctpc.org/nctpc>),

7 *"The major electric load-serving entities (LSEs) of North Carolina, including*
8 *Duke Energy Carolinas, Duke Energy Progress, ElectriCities of NC (municipals)*
9 *and the North Carolina Electric Membership Corporation (cooperatives), have*
10 *created the North Carolina Transmission Planning Collaborative (the "Process").*
11 *The Process was formed to enhance transmission planning by allowing all*
12 *stakeholders to participate in shaping the future transmission network in the*
13 *areas of North Carolina and South Carolina served by the LSEs. An*
14 *administrator has been selected to facilitate the Process and to ensure that the*
15 *interests of all stakeholders are fairly and meaningfully represented.*

16
17 *Specifically, the Process is intended to create an integrated long-term*
18 *transmission expansion plan that will result in a reliable (i.e., meets all*
19 *applicable reliability criteria) and cost effective (i.e., lowest overall cost to*
20 *consumers) transmission system. A Transmission Advisory Group ("TAG") will*
21 *provide advice and recommendations to the LSEs for consideration for*
22 *incorporation into the coordinated transmission expansion plan. The TAG*
23 *membership is open to all parties interested in the development of the Process."*

24
25 Q. PLEASE DESCRIBE THE PROCESS IN ARIZONA.

26 A. Generally, the Arizona Corporation conducts a Biennial Transmission Assessment of the
27 Ten-Year Plans for each utility in the state including hosting a series of public workshops
28 to review the adequacy of the transmission system to serve load, to address reliability
29 issues, assess the impact of changes from existing generation and integration of renewable
30 resources.

1 Q. SHOULD THE COMMISSION CONSIDER ADOPTING SUCH A PROCESS TO
2 AVOID SOME OF THE ISSUES THAT CONTINUE TO ARISE IN THE
3 COMPANY'S TRANSMISSION PLANNING PROCESS?

4 A. Yes, this would be consistent with my previous recommendations to develop a statewide
5 transmission planning collaborative approach which includes participation from Staff,
6 consultants and all of the ITS Participants to develop a long-term strategic transmission
7 plan as a stipulation of the approval of the Company's 2022 Integrated Resource Plan.

8 **EVALUATION OF TEN-YEAR TRANSMISSION PLAN**

9 Q. DID YOU PERFORM AN EVALUATION OF THE COMPANY'S TEN-YEAR
10 TRANSMISSION PLAN AS PART OF YOUR REVIEW OF THIS FILING?

11 A. Yes, I reviewed the results of the Ten-Year Transmission Plan as filed in Technical
12 Appendix Volume 3 Transmission Planning of the 2022 Integrated Resource Plan.

13 Q. WHAT WAS THE PURPOSE OF YOUR EVALUATION?

14 A. The purpose of the evaluation was to review and verify the results of the power flow
15 analysis, including an investigation of the following questions:

16 (1) Would an independent verification of the power flow models provided by the
17 Company identify the same system problems that the Company presented in Technical
18 Appendix Volume 3 Transmission Planning?

19 (2) Would the solutions provided by the Company to alleviate the respective system
20 problems?

1 **Q. WHAT MODELS DOES THE COMPANY USE TO PERFORM THE ANALYSIS**
2 **THAT SUPPORTS THE TEN-YEAR PLAN?**

3 **A.** The Company has developed a set of base case power flow models that can be run on the
4 Siemens PSS/E platform. The base cases test the performance of the transmission system
5 under differing load levels, solar facility dispatch, hydroelectric facility dispatch and
6 transfers between the MISO North and MISO South regions. The primary planning period
7 is related to the summer season as this tends to be the time when the transmission system
8 is the most stressed. The Company also develops base cases for other times of the year, but
9 in all of the non-summer and non-off-peak cases, the MISO flow is consistently a 1,000
10 MW transfer from MISO North to MISO South. Also, solar generation is modeled off-line
11 at the time of the winter peak, shoulder load level and during the spring minimum load
12 level. The Company also has developed a series of Unit Off cases, where certain units are
13 modeled as off-line under the different load levels for each base case. The list of Unit Off
14 cases is not performed for each generator in the Company service territory. The Company
15 also evaluates system performance under MaxGen cases, whereby generation in certain
16 parts of the system are fully dispatched to assess the ability of the transmission system to
17 move power from these areas to serve other parts of the system. The system performance
18 is assessed under certain contingency conditions, which include NERC Transmission
19 Planning (TPL-001-5) contingencies. Other Ten-Year Plan studies look at interface
20 performance (NERC FAC-013-2), nuclear unit performance (NERC NUC-001) and system
21 stability analyses.

22 **Q. PLEASE DESCRIBE THE VERIFICATION PROCESS YOU CONDUCTED TO**
23 **REVIEW THE COMPANY'S TEN-YEAR TRANSMISSION PLAN.**

1 A. My team received a series of power flow models, associated input files and output reports
2 from the Company as described in Technical Appendix Volume 3 of the Integrated
3 Resource Plan filing. The first part of the verification process is a review of the power
4 flow models to assess consistency in generation dispatch, load modeling, system topology,
5 interchange between regions and application of any outages on transmission system
6 elements. The second phase of the verification process involves running the power flow
7 models to verify that the transmission system issues identified by the Company and the
8 technical effectiveness of the solutions proposed by the Company are consistent with the
9 results of the power flow analysis.

10 Q. DID THE COMPANY'S ANALYSIS EVALUATE WHETHER THE PROJECTS
11 PROPOSED BY THE COMPANY WERE THE OPTIMAL SOLUTIONS WITH
12 RESPECT TO COST?

13 A. No. The Company did not provide any analysis that indicated the projects were the optimal
14 solutions with respect to cost. The power flow analysis only identifies possible solutions
15 to meet various system conditions but does not evaluate the costs of those solutions.

16 Q. DID YOUR ANALYSIS EVALUATE WHETHER THE PROJECTS PROPOSED
17 BY THE COMPANY WERE THE OPTIMAL SOLUTIONS WITH RESPECT TO
18 COST?

19 A. No. We only verified that the proposed solutions addressed the identified need. No cost
20 analysis was performed by the Company or by my team in an attempt to optimize the
21 transmission system plan with respect to cost. The power flow analysis only identifies

1 possible solutions to meet various system conditions, but does not evaluate the costs of
2 those solutions.

3 **Q. DOES THE ANALYSIS PERFORMED FOR THE TEN-YEAR PLAN APPEAR TO**
4 **COMPLY WITH NERC TRANSMISSION PLANNING STANDARDS?**

5 **A.** Without conducting a comprehensive review of all 12,000+ cases provided by Company,
6 I agree that the types of cases that are developed and the contingency analysis that is
7 performed is consistent with the NERC TPL standards.

8 **Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF THE INITIAL POWER**
9 **FLOW CASES AND FILES PROVIDED BY THE COMPANY?**

10 **A.** The summer peak power flow cases provided by the Company were reasonable with
11 respect to load modeling and generation dispatch, except for Scherer Unit 3. As the
12 Company noted,¹ the proposed Scherer Unit 3 retirement is not in the power flow cases
13 used for Ten-Year Plan due to the case building finishing prior to the Company's decision
14 to recommend retiring Scherer Unit 3. We did not note any issues with interchange, or
15 transmission system topology. The Company has assumed that all facilities are in service
16 for the Ten-Year Transmission Plan. This assumption is consistent with planning practices
17 in other parts of the United States.

18 **Q. WHAT WERE THE RESULTS OF THE SECOND PHASE OF THE**
19 **VERIFICATION PROCESS?**

¹ Hearing Transcript, volume 1, pp 258, ln 5-7

1 A. After verifying the consistency of the Company's summer peak power flow cases, we ran
2 a sample of the 12,000+ power flow models. We ran the power flow models to verify the
3 issues identified by the Company. Then we checked if the mitigation provided by the
4 Company addressed the issue.

5 Q. **WHAT WERE THE RESULTS OF YOUR ANALYSIS?**

6 A. I found that the summer peak load flow cases were reasonable with respect to generation
7 dispatch, load modeling, interchange and system topology. I was able to verify that the
8 problems identified by the Company in Technical Appendix Volume 3 were consistent
9 with the results of my analysis. I was also able to verify that the mitigation plans proposed
10 by the Company successfully mitigated the identified problems.

11 Q. **WHAT IS THE CONCLUSION OF YOUR ASSESSMENT OF THE COMPANY'S**
12 **TEN-YEAR TRANSMISSION PLAN?**

13 A. The Company has developed a Ten-Year Transmission Plan that appears to be reasonable
14 with respect to the modeling, methodology and solutions that were generated.

15 **EVALUATION OF THE COMPANY'S UNIT RETIREMENT STUDY**

16 **DECERTIFICATION OF PLANT BOULEVARD UNIT 1, PLANT WANSLEY UNITS 1-**
17 **2 AND UNIT 5A, PLANT GASTON UNITS 1-4 AND UNIT A**

18 Q. **WHAT IS YOUR CONCLUSION REGARDING THE PROPOSED**
19 **RETIREMENTS OF PLANT BOULEVARD UNIT 1, PLANT WANSLEY UNITS**
20 **1-2 AND 5A AND PLANT GASTON UNITS 1-4 AND UNIT A?**

1 A. I do not disagree with the Company's plans to retire these assets from a transmission
2 perspective.

3 **DECERTIFICATION OF PLANT BOWEN UNITS 1-2**

4 **Q. WHAT IS THE PROPOSED PLAN FOR PLANT BOWEN UNITS 1 AND 2 IN THE**
5 **2022 IRP?**

6 A. The Company anticipates retiring Plant Bowen Units 1 and 2 no later than December 31,
7 2027. The Company maintains that updated reliability assessments show that the earliest
8 Plant Bowen Units 1 and 2 can be retired is in 2027, as this will provide the Company
9 sufficient time to complete the necessary transmission system improvements to
10 accommodate retirement of these units (Main Document at 11-74).

11 **Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES**
12 **THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO**
13 **CHOOSE TO DECERTIFY PLANT BOWEN UNITS 1-2?**

14 A. In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset
15 Eval_URS_Steam_Units.xlsm" which contains the transmission projects assignable to
16 decertification request. It appears that a series of power flow models were developed
17 around a set of fleet scenarios that included combinations of retirement units. Fleet
18 Scenario 0 includes avoided transmission facilities associated with Plant Wansley Units 1-
19 2 and Plant Bowen Units 1-2.

20 **Q. WHAT TRANSMISSION FACILITIES ARE IN THAT TRANSMISSION**
21 **EXPANSION LIST?**

1 A. The following transmission projects are listed as being associated with the retirement of
2 Plant Bowen Units 1-2:

- 3 • Blakely Primary – Webb (APC) 115 kV (2026 need date) – This project is not listed in
4 Exhibit JWC-2 as being assignable to Plant Bowen Units 1-2 exclusively. It does appear to
5 be assigned to Plant Wansley 1-2 in Exhibit JWC-2.
- 6 • Capitol Heights – Carter Hill Road – Fisk Road 115 kV (2026 need date) – This project
7 only shows up in the aforementioned spreadsheet and is not included in Exhibit JWC-2
- 8 • Lagrange – North Opelika 230 kV new line (2027 need date) – This project is referenced
9 in both the aforementioned spreadsheet and in Exhibit JWC-2. The need for this facility is
10 tied to the combined retirement of Plant Wansley Units 1-2 and the retirement of Plant
11 Bowen Units 1-2.
- 12 • Bonaire Primary – Echeconnee 115 kV (2030 need date) – This project is not listed in
13 Exhibit JWC-2.

14 **Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINED THAT THESE**
15 **FACILITIES WERE NEEDED IF PLANT BOWEN UNITS 1-2 WERE**
16 **DECERTIFIED.**

17 A. The retirement analysis for Plant Bowen Units 1-2 was performed in 2020, according to
18 the company's response to STF-GDS-4-1 (TS). Subsequent studies have assumed
19 additional retirements, such as the retirement of Plant Wansley Units 1-2 and Plant Gaston
20 Units 1-4.

1 **Q. WHAT IS YOUR RECOMMENDATION REAGR Ding THE TRANSMISSION**
2 **FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT BOWEN**
3 **UNITS 1-2?**

4 **A.** I agree with the Company's assertion that Plant Bowen Units 1-2 can be retired by
5 December 31, 2027 without any adverse impacts on the transmission system, assuming the
6 timely completion of the transmission facilities listed above.

7 **DISCUSSION OF PLANT SCHERER UNITS 1-2**

8 **Q. WHAT IS THE COMPANY'S PROPOSED PLAN FOR PLANT SCHERER UNITS**
9 **1-2?**

10 **A.** At this time, the company has stated that the economics associated with Plant Scherer Units
11 1-2 are challenged (Main Document 11-75). In preparation for a potential retirement due
12 to worsening economics, transmission system upgrades are being proposed which will
13 permit the retirement of Plant Scherer Units 1-2 by December 31, 2028. This date is
14 consistent with the fixed retirement date for Plant Scherer Unit 3.

15 **Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES**
16 **THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO**
17 **CHOOSE TO DECETIFY PLANT SCHERER UNITS 1-2?**

18 **A.** In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset
19 Eval_URS_Steam_Units.xlsm" which contains the transmission projects assignable to
20 decertification request. It appears that a series of power flow models were developed
21 around a set of fleet scenarios that included combinations of retirement units. Fleet
22 Scenario 0+Scherer 3 includes avoided transmission facilities associated with Plant

1 Wansley Units 1-2, Plant Bowen Units 1-2 and Plant Scherer Unit 3. Fleet Scenario 1
2 includes avoided transmission investment associated with Fleet Scenario 0 + Scherer 3 and
3 Plant Scherer Units 1-2.

4 **Q. WHAT TRANSMISION FACILITIES ARE IN THAT TRANSMISSION**
5 **EXPANSION LIST?**

6 **A.** The following transmission projects are listed as being associated with the retirement of
7 Plant Scherer Units 1-2:

- 8 • Morrow – Yates Common 115 kV (2028 need date) – This project is listed in Exhibit JWC-
9 2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2
10 and Plant Bowen Units 1-2.
- 11 • South Coweta Bank A (change need date from 2030 to 2028) – This project is listed in
12 Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant
13 Wansley Units 1-2 and Plant Bowen Units 1-2.
- 14 • Bonaire Primary – Butler 230 kV (change need date to 2028 from 2030) – This project is
15 listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant
16 Wansley Units 1-2 and Plant Bowen Units 1-2.
- 17 • Hollingsworth Ferry – Yellow Dirt 230 kV (2028 need date) – This project is listed in
18 Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant
19 Wansley Units 1-2 and Plant Bowen Units 1-2.

- 1 • Dresden – Hollingsworth Ferry 230 kV (2028 need date) – This project is listed in Exhibit
- 2 JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units
- 3 1-2 and Plant Bowen Units 1-2.
- 4 • Gordon – Sandersville #1 115 kV (2028 need date) – This project is listed in Exhibit JWC-
- 5 2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2
- 6 and Plant Bowen Units 1-2.
- 7 • Eufala – George Dam (COE) – Webb (APC) 15 kV (2030 need date) – This project is not
- 8 listed in Exhibit JWC-2 but is included in TS Asset Eval URS Steam Units.xlsm, tab
- 9 Transmission Calc, Row 52.
- 10 • Hammond – Weiss Dam (APC) 115 kV (2030 need date) – This project is listed in Exhibit
- 11 JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units
- 12 1-2 and Plant Bowen Units 1-2.

13 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TRANSMISSION**

14 **FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT SCHERER**

15 **UNITS 1-2?**

16 **A.** I agree with the Company's assertion that Plant Scherer Units 1-2 can be retired by

17 December 31, 2028 without any adverse impacts on the transmission system, assuming the

18 timely completion of the transmission facilities listed above.

19 **DECERTIFICATION OF PLANT SCHERER 3**

20 **Q. WHAT IS THE PROPOSED PLAN FOR PLANT SCHERER UNIT 3 IN THE 2022**

21 **IRP?**

1 A. The Company has assumed that Plant Scherer Unit 3 will be retired on December 31, 2028
2 (Main Document 11-75).

3 **Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES**
4 **THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO**
5 **CHOOSE TO DECERTIFY PLANT SCHERER UNIT 3?**

6 A. The Company has stated that substantial transmission system upgrades will be required if
7 Plant Scherer Units 1-3 are retired. The completion of the identified upgrades will be
8 difficult to achieve prior to December 31, 2028 according to Company estimates. It does
9 not appear that the Company has provided any facilities associated with just the retirement
10 of Plant Scherer Unit 3.

11 **Q. WHAT TRANSMISSION FACILITIES ARE IN THAT TRANSMISSION**
12 **EXPANSION LIST JUST FOR UNIT 3 ALONE?**

13 A. In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset
14 Eval_URS_Steam_Units.xlsx" which contains the transmission projects assignable to
15 decertification request. It appears that a series of power flow models were developed
16 around a set of fleet scenarios that included combinations of retirement units. Fleet
17 Scenario 0+Scherer 3 includes avoided transmission facilities associated with Plant
18 Wansley Units 1-2, Plant Bowen Units 1-2 and Plant Scherer Unit 3. The following
19 transmission projects are listed in "TS Asset Eval_URS_Steam_Units.xlsx" as being
20 associated with the retirement of Plant Scherer Unit 3:

- 21 • Bremen (GPCO) – Crooked Creek 115 kV (2028 need date)
- 22 • Bonaire Primary – Butler 230 kV (2030 need date)

- South Coweta Bank A (2030 need date)

- Dresden – Lagrange Primary 230 kV (2031 need date)

This list is not the same as what the Company provided in Exhibit JWC-2. The following list shows the facilities the Company has attributed to the combined retirement of Plant Wansley Units 1-2, Plant Bowen Units 1-2 and Plant Scherer Units 1-3.

Q. WHAT TRANSMISSION FACILITIES ARE IN THE TRANSMISSION EXPANSION LIST FOR PLANT SCHERER UNITS 1-3 INSTEAD OF JUST UNIT 3 ALONE?

A. The following transmission projects are listed as being associated with the retirement of Plant Scherer Units 1-3, inclusive:

- Morrow – Yates Common 115 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

- South Coweta Bank A (change need date from 2030 to 2028) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

- Bonaire Primary – Butler 230 kV (change need date to 2028 from 2030) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

- 1 • Hollingsworth Ferry – Yellow Dirt 230 kV (2028 need date) – This project is listed in
2 Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant
3 Wansley Units 1-2 and Plant Bowen Units 1-2.
- 4 • Dresden – Hollingsworth Ferry 230 kV (2028 need date) – This project is listed in Exhibit
5 JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units
6 1-2 and Plant Bowen Units 1-2.
- 7 • Gordon – Sandersville #1 115 kV (2028 need date) – This project is listed in Exhibit JWC-
8 2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2
9 and Plant Bowen Units 1-2.
- 10 • Eufala – George Dam (COE) – Webb (APC) 15 kV (2030 need date) – This project is not
11 listed in Exhibit JWC-2 but is included in TS Asset Eval URS Steam Units.xlsm, tab
12 Transmission Calc, Row 52.
- 13 • Hammond – Weiss Dam (APC) 115 kV (2030 need date) – This project is listed in Exhibit
14 JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, along with Plant
15 Wansley Units 1-2 and Plant Bowen Units 1-2.

16 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TRANSMISSION**
17 **FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT SCHERER**
18 **UNIT 3?**

19 **A.** I agree with the Company's assertion that Plant Scherer Unit 3 can be retired by December
20 31, 2028 without any adverse impacts on the transmission system, assuming the timely
21 completion of the transmission facilities listed above.

DISCUSSION OF PLANT BOWEN UNITS 3-4

Q. WHAT IS THE COMPANY'S PROPOSED PLAN FOR PLANT BOWEN UNITS 3-4?

A. The current plan for Plant Bowen Units 3-4 assumes continued operation of the units with ELG controls until December 31, 2035 (Main Document 11-76). This is consistent with the modeling of Plant Bowen Units 3-4 in the power flow models for the Ten-Year Plan.

Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO CHOOSE TO DECEITIFY PLANT BOWEN UNITS 3-4?

A. The Company has not provided a list of transmission facilities that are required for the eventual retirement of Plant Bowen Units 3-4. The only references to transmission expansion related to this potential retirement is included as part of the North Georgia Reliability & Resilience Plan (Main Document 12-87 to 12-88) as well as the URS Steam Units workbook. There is a recognized need for additional transmission infrastructure in North Georgia due to the retirement of Plant Bowen Units 1-4, the need to deliver renewable resources from South and Central Georgia to the North Georgia load centers and to accommodate utility scale renewable procurements from North Georgia as part of the North Georgia Renewable RFP. However, no specific transmission plans have been developed by either the Company or the ITS Participants to address this identified need.

Q. WHAT IS THE PATH THE COMPANY IS USING TO DEVELOP THIS PLAN?

A. The Company is currently working with the ITS Participants to develop the North Georgia Reliability & Resilience Action Plan, which will hopefully consider transmission solutions,

as well as other alternatives. Given the complexity of this problem, I would encourage the Company to consider a more collaborative approach with Staff and the Commission in the study process.

Q. WHAT TRANSMISION FACILITIES ARE IDENTIFIED IN THE UNIT RETIREMENT STUDY?

A. In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset Eval_URS_Steam_Units.xlsx" which contains the transmission projects assignable to decertification request. It appears that a series of power flow models were developed around a set of fleet scenarios that included combinations of retirement units. By comparing the facilities from Fleet Scenario 2 to Fleet Scenario 1 a residual list of projects can be inferred. This residual list of transmission projects associated with the retirement of Plant Bowen Units 3-4 is:

- Arlington Primary – Greenhouse Road 115 kV (2028 need date)
- Corn Crib – Lagrange 115 kV (2028 need date) – This project is included in the Company's One-Year Plan.
- East Dalton – Oostanaula 115 kV (2028 need date) – This project is included in the Company's One-Year Plan.
- Dalton – Loopers Farm 230 kV interface (2028 need date)
- Dyer Road – South Coweta 115 kV (2030 need date)
- Hickory Level – Villa Rica Primary 230 kV (2030 need date)
- Union City – Yates (Black) 230 kV (2030 need date)

- 1 • Union City – Yates (White) 230 kV (2030 need date)
- 2 • Eufala – George Dam (COE) – Webb (APC) 115 kV (2030 need date)
- 3 • Barnesville Primary – South Griffin 115 kV (2030 need date)

4 **Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINED THAT THESE**
5 **FACILITIES WERE NEEDED IF PLANT BOWEN UNITS 3-4 WERE**
6 **DECERTIFIED.**

7 **A.** It does not appear that the Company performed any power flow analyses of just the
8 retirement of Plant Bowen Units 3-4. All studies that evaluated the retirement of Plant
9 Bowen Units 3-4 also assume the retirements of Plant Wansley Units 1-2 and Unit 5A,
10 Plant Gaston Units 1-4 and Unit A, Plant Bowen Units 1-2 and Plant Scherer Units 1-3.

11 The following is a copy of the transcript from the April 4 Hearing (Page 258, Lines 12-18):

12 Q. Are there reasons related to transmission projects that the company's position is that
13 Bowen 3 and 4 cannot be retired before 2035?

14 A. (Witness Robinson) Yes. So when we looked at the retirement of Bowen 3 and 4 on
15 top of the other units, in the rank order that we used to study those, we saw significant
16 transmission that needed to be completed.
17

18 **Q. DID THE COMPANY PERFORM ANY SENSITIVITY ANALYSES REGARDING**
19 **THE NEED FOR TRANSMISSION FACILITIES ASSOCIATED WITH THE**
20 **POTENTIAL DECERTIFICATION OF PLANT BOWEN UNITS 3-4?**

21 **A.** The Company evaluated multiple scenarios related to the retirement of Bowen Units 3-4.
22 Most of the scenarios evaluated local maximum generation output cases and several
23 generator off cases. These cases reflected various redispatch patterns and different
24 locations for proxy generation.

1 **Q. WHAT WERE THE RESULTS OF THAT SENSITIVITY ANALYSIS?**

2 **A.** The results of the sensitivity analysis revealed that the need for transmission was highly
3 dependent on the location of proxy generation and existing unit dispatch. This volatility in
4 the results showed that the feasibility of retiring the units earlier may have been technically
5 possible in some cases, but that the timing requirements surrounding construction of the
6 necessary upgrades may not be practical with respect to facility construction.

7 **Q. HAS THE COMPANY PROVIDED ANY DETAILS REGARDING THE TIMING**
8 **REQUIREMENTS ASSOCIATED WITH THE CONSTRUCTION OF**
9 **FACILITIES THAT ARE REQUIRED BY 2028?**

10 **A.** The Company did not provide any analysis to support the timing issue, but only generally
11 addressed the construction and outage schedules associated with transmission expansion.

12 **Q. DO YOU AGREE WITH THE COMPANY'S FILING THAT THE IDENTIFIED**
13 **FACILITIES ARE NECESSARY TO MAINTAIN SYSTEM RELIABILITY WITH**
14 **PLANT BOWEN UNITS 3-4 RETIRED?**

15 **A.** I generally agree with the assertion that Plant Bowen Units 3-4 will require some level of
16 transmission construction in order to be retired, however, I would support additional
17 analysis of the facilities required due to a lack of alternatives being included in this IRP.
18 The level of reliability is speculative depending on generation dispatch levels and the
19 location of proxy generation included in the cases in future years.

20 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TRANSMISSION**
21 **FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT BOWEN 3-**
22 **4?**

1 A. Although it is reasonable to consider retirement of Plant Bowen Units 3-4 by 2029 due to
2 the technical feasibility of implementing transmission solutions prior to 2028, it's not clear
3 the Company has sufficiently investigated transmission alternatives that would allow it to
4 avoid the required ELG compliance plan for Units 3-4. With ELG investments, the timing
5 of the retirement for Bowen 3-4 should be considered in the 2025 IRP or as part of an
6 integrated analysis to address the North Georgia reliability and resilience issues, including
7 results from the Renewable RFP. The Company's power flow analysis demonstrates that
8 the location and volumes of replacement capacity is a significant driver of the required
9 transmission system upgrades. Having better clarity from the Renewable RFP will result
10 in a transmission solution that is right-sized for North Georgia.

11 **BATTERY ENERGY STORAGE SYSTEM (BESS)**

12 **Q. PLEASE DESCRIBE THE COMPANY'S PLANS IN THE 2022 IRP RELATED TO**
13 **BATTERY STORAGE.**

14 A. The Company has proposed the addition of the McGrau Ford Battery Facility, which is a
15 265-MW, 2-hour lithium-ion facility. This facility is planned to be in service by 2026. This
16 project is in addition to two projects the Company is developing in response to the approvals
17 given in the 2019 IRP.

18 **Q. WHAT DID THE COMPANY PROPOSE REGARDING BATTERY STORAGE IN**
19 **THE 2019 IRP?**

20 A. The Company proposed the development of 80 MW of Company-owned and operated
21 Battery Energy Storage Systems (BESS) in the 2019 IRP. There are two demonstration projects

1 that make up this total. The first is the 65 MW, 4-hour lithium-ion project at the Mossy Branch
2 Battery Facility, which was approved by the Commission in an Order dated October 12, 2021.
3 This project is expected to go inter service in 2023. The remainder of the 2019 BESS volume
4 is the Fort Stewart BESS operating in conjunction with an existing solar facility at that location.
5 The in-service date for this facility is the second half of 2024.

6 **Q. HOW DID THE COMPANY SELECT THE MCGRAU FORD SITE AS THE**
7 **OPTIMAL LOCATION FOR A BATTERY STORAGE SYTSEM?**

8 **A.** The Company made their decision based on ease of interconnection, low interconnection
9 costs and other economic factors. The impact on local reliability does not appear to be one of
10 the factors the Company considered.

11 **Q. ARE THERE ANY OTHER PROJECTS PLANNED FOR THE MCGRAU SITE**
12 **THAT COULD IMPACT THE EVALUATION OF THE PROPOSED ENERGY**
13 **STORAGE PROJECT?**

14 **A.** Yes. In the Ten-Year Plan, the ITS has proposed the addition of a +/- 150 MVAR
15 STATCOM at the McGrau Ford 230 kV bus by December 1, 2023. This is a new project
16 and is the result of the Company's stability analysis. The addition of a STATCOM in
17 addition to an Energy Storage System may make it difficult to isolate the benefits of the
18 Energy Storage System, particularly with respect to the Ancillary Services benefits an ESS
19 can provide.

20 **Q. THE COMPANY HAS STATED THAT THE STATIC VAR COMPENSATOR**
21 **(STATCOM) IS NEEDED TO ADDRESS FIDVR IN NORTH GEORGIA. WHAT**

1 **IS IT ABOUT THE NORTH GEORGIA PORTION OF THE COMPANY'S**
2 **TRANSMISSION SYSTEM THAT MAKES IT SUSEPTICAL TO FIDVR?**

3 **A.** The addition of high levels of Distributed Energy Resources, particularly those that have
4 limited reactive support, can exacerbate the effects of FIDVR.

5 **Q. WHAT IS FIDVR?**

6 **A.** FIDVR or Fault-Induced Delayed Voltage Recovery refers to the unexpected delay in the
7 recovery of voltage to its nominal value following the normal clearing of a fault.

8 **Q. WHAT IMPACT DOES A HIGH PENETRATION OF SOLAR PV GENERATION**
9 **HAVE ON THE EFFECTS OF FIDVR?**

10 **A.** The addition of high levels of Distributed Energy Resources, particularly those that have
11 limited reactive support, can exacerbate the effects of FIDVR.

12 **Q. HAS THE COMPANY PROVIDED ANY INFORMATION ON HOW THEY PLAN**
13 **TO OPERATE THE PROPOSED STORAGE FACILITIES?**

14 **A.** The Company has not stated that the ESS facilities will be operated in a manner other than
15 to provide transmission system support, particularly when paired with solar facilities at the
16 same location.

17 **Q. SHOULD THE OPERATION OF THE PROPOSED FACILITIES HAVE A**
18 **POSITIVE IMPACT ON THE RELIABILITY OF THE COMPANY'S**
19 **TRANSMISSION SYSTEM?**

20 **A.** Yes.

1 Q. DOES THE COMPANY PLAN TO OPERATE THESE FACILITIES TO PROVIDE
2 ADDITIONAL SUPPORT TO THE COMPANY'S TRANSMISSION SYSTEM,
3 SUCH AS ANCILLARY SERVICES?

4 A. That is still to be determined.

5 **RECOMMENDATIONS AND STIPULATIONS**

6 Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE REVIEW OF
7 THE TEN-YEAR TRANSMISSION PLAN?

8 A. I recommend that Commission approve the results of the Ten-Year Transmission Plan as
9 being acceptable for meeting Company and NERC reliability standards.

10 Q. WHAT CONCLUSIONS HAVE YOU REACHED REGARDING THE
11 AVAILABILITY OF REQUIRED TRANSMISSION RESULTING FROM THE
12 DECERTIFICATION OF CERTAIN GENERATION FACILITIES REQUESTED
13 BY THE COMPANY?

14 A. Consistent with the Company's request, I conclude that there are no transmission-related
15 impediments to the retirement of Plant Wansley and Plant Boulevard retirements as
16 planned on August 31, 2022. Similarly, there are no transmission-related impediments to
17 the retirement of Plant Bowen Units 1-2 as planned on December 31, 2027, Plant Gaston
18 or Plant Scherer Units 1-3 as planned on December 31, 2028.

19 With respect to the retirement of Plant Bowen Units 3-4 I conclude that alternative
20 traditional transmission solutions were not fully explored by the Company. It's not clear
21 that the solutions proposed by the Company are the only solutions, and the Company did

1 not provide an analysis of whether these were optimal with respect to cost. It is not known,
2 and the Company did not investigate, whether transmission alternatives exist that would
3 allow the Company to retire Bowen 3-4 by December 2028 and avoid the required ELG
4 compliance plan. With ELG investments, the timing of the retirement for Bowen 3-4 should
5 be considered in the 2025 IRP or as part of an integrated analysis to address the North
6 Georgia reliability and resilience issues, including results from the Renewable RFP. I am
7 recommending the Company complete the assessment of transmission facilities associated
8 with this retirement, and the additions from the Renewable RFP by September 1, 2023, so
9 the Commission has time to properly evaluate the transmission solution prior to the 2025
10 Integrated Resource Plan.

11 **Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE APPROVAL**
12 **OF THE BATTERY STORAGE FACILITIES REQUESTED BY THE COMPANY?**

13 **A.** If the ESS facilities are approved by the Commission, the Company should be required to
14 provide annual feedback to the Commission regarding performance of the ESS facilities,
15 including performance during outages and use of the facilities to provide ancillary services.

16 **Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE NORTH**
17 **GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?**

18 **A.** Given that the Company has not proposed any projects related to the Action Plan, I
19 recommend that the Commission establish a collaborative transmission planning process
20 which includes Staff and consultants and all ITS Participants to meet on a quarterly basis
21 to follow the activities of the Georgia ITS as problems are identified and solutions are
22 developed to address the deliverability issues in North Georgia including the development

1 of the long-term North Georgia Reliability and Resilience Action Plan. I also recommend
2 that the Company be required to provide quarterly updates to the Commission on the
3 progress of the North Georgia Reliability and Resilience Action Plan and that the
4 Commission open a public proceeding to discuss the Company's plan prior to the 2025
5 Integrated Resource Plan Submittal.

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

7 **A.** Yes.

INTRODUCTION

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

A. My name is Jacob M. Thomas. I am a Principal at GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. HAVE YOU INCLUDED SUMMARIES OF YOUR EXPERIENCE AND QUALIFICATIONS IN THIS TESTIMONY?

A. Yes. My resume is attached as Staff Exhibit JMT-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the Public Interest Advocacy Staff ("Staff") of the Georgia Public Service Commission ("Commission"). The purpose of my testimony is to respond to certain elements of Georgia Power Company's ("Company" or "Georgia Power") 2022 Integrated Resource Plan ("IRP"). I will address issues pertaining to the Company's load and energy forecast.

Q. WHAT IS A LOAD FORECAST AND HOW DOES IT IMPACT RATEPAYER REVENUE REQUIREMENTS?

A. A load forecast is a projection of a utility's energy and peak demand requirements over a given time period. The peak demand load forecast, measured in megawatts, is a primary input in determining the amount of installed generation capacity (MW) a utility must have to reliably serve customers. Therefore, it is critical that the load forecast be as accurate as

possible so there is enough generation capacity installed to reliably serve customers but not excess generation capacity that would result in unnecessary cost to customers.

Q. WHAT ADJUSTMENTS TO GEORGIA POWER'S LOAD FORECAST ARE YOU RECOMMENDING?

A. I am not recommending any adjustments to the Company's load forecast in this proceeding. However, there are two recommendations regarding the Company's process for developing a load forecast that should be adopted in future load forecasts.

SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. I am making two recommendations related to the Company's load forecasting process:

1. The Company should update its Residential Consumer Survey to collect more recent information regarding end-use market saturations;
2. The Company should use a twenty-year normal for weather instead of the forty-one-year normal it currently employs and should be required to provide, going forward, a sensitivity forecast reflecting summer and winter climate trends in line with the Energy Information Administration ("EIA") methodology described below.

OVERVIEW OF LOAD FORECAST

Q. PLEASE SUMMARIZE THE COMPANY'S BUDGET 2022 LOAD AND ENERGY FORECAST.

1 A. The Budget 2022 forecast contains energy sales and peak demand projections for years
2 2022 to 2041.¹ The energy sales forecast is developed at the customer class level and
3 aggregated to produce projections at the system level. The sales forecast for years 2022
4 through 2025 is based on a series of econometric models; sales over the longer term are
5 based on end-use modeling techniques. Econometric models describe load as a
6 mathematical function of economic and weather variables. End-use models attempt to
7 project long-term load requirements based on modeling the number of electric end-use
8 appliances in use in the territory and the amount of annual energy those appliances
9 consume based on trends in efficiency and appliance size. The peak demand forecast is
10 based on class energy sales forecasts and class load profiles, which produce hourly
11 forecasts by customer class. The Budget 2022 forecast is generally based on the same
12 methods and software tools as the Budget 2019 load forecast, which support Georgia
13 Power's 2019 IRP. The Budget 2022 load forecast projects peak demand to start slightly
14 higher than the Budget 2021 forecast, but by 2041 is nearly the same. This is the first of
15 the last ten forecasts where peak demand projections were not lower than the prior vintage
16 forecast. Refer to Exhibit JMT-2, which presents graphically a history of the Company's
17 weather-normalized, long-term peak demand forecasts. The lowering of the Company's
18 forecasts over time is consistent with many other utilities across the United States and is
19 due primarily to greater than expected impacts of increasing appliance efficiencies, housing
20 stock efficiency, and overall conservation by electricity consumers.

21 **Q. PLEASE SUMMARIZE YOUR REVIEW OF THE LOAD FORECAST.**

¹ Georgia Power Company. Docket No. 44160, Volume 1.

1 A. I reviewed all aspects of the load forecast including the methods employed by the Company
2 to produce the load forecast, the assumptions made, the forecast inputs, and the forecast
3 outputs. As part of that review, Staff observed that the Company's residential end-use
4 saturation surveys have not been updated since 2016. I also reviewed the Company's
5 weather normalization approach, which uses forty-one years to compute normal weather
6 versus the sensitivity forecast based on twenty years to compute normal weather. My
7 review of the weather normalization informed my conclusions regarding these two
8 approaches as presented later in my testimony.

9 **RESIDENTIAL END-USE SATURATION SURVEYS**

10 **Q. WHAT VINTAGE IS THE COMPANY'S RESIDENTIAL SATURATION SURVEY**
11 **USED IN THE BUDGET 2022 LOAD FORECAST?**

12 A. It is from 2016, as indicated in Section 5 – pages 40-41 of the Budget 2022 Load and Energy
13 Forecast.

14 **Q. HOW DOES THE COMPANY USE THE RESIDENTIAL SATURATION SURVEY**
15 **IN ITS FORECASTING PROCESS?**

16 A. The residential saturation survey is useful in understanding appliance ownership, age, size,
17 and efficiency within the residential sector. The data from the survey informs the residential
18 long-term energy sales forecasting model.

19 **Q. DOES THE COMPANY USE ANY OTHER SOURCES OF INFORMATION FOR**
20 **THESE APPLIANCE CHARACTERISTICS?**

1 A. Yes. The Company also makes use of information from the EIA's Annual Energy Outlook
2 ("AEO") and the EIA's Residential Consumption Survey ("RECS") as sources of
3 information regarding appliance ownership, age, size, and efficiency. The EIA data sources
4 provide national and regional information.

5 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO GEORGIA POWER'S**
6 **RESIDENTIAL SATURATION SURVEY?**

7 A. I recommend that the Commission direct the Company to update its Residential Saturation
8 Survey as soon as possible and continue to update the survey every three years so the
9 Company's IRP filing is based on the most current information.

10 **Q. WHY DO YOU RECOMMEND REGULAR UPDATING OF THE RESIDENTIAL**
11 **SATURATION SURVEY?**

12 A. It is important to continue to collect primary data about appliance ownership in Georgia
13 Power's territory because this appliance information enables the Company to know if trends
14 in ownership of certain appliances begin to diverge from the EIA information and have the
15 intelligence to adjust its load forecast to reflect such divergence. The market share is a critical
16 factor in the residential end-use model and therefore the best efforts to include as much
17 relevant and system-specific information as can possibly be collected is important to ensuring
18 the best possible forecast accuracy.

19 **Q. DOES YOUR RECOMMENDATION IMPACT THE BUDGET 2022 LOAD AND**
20 **ENERGY FORECAST?**

21 A. No. It is not feasible to expect the Company to move forward with the process of developing,
22 executing, and summarizing an update to the Residential Saturation Study in time to adjust

1 the current load forecast. However, the Residential Saturation Study should be updated for
2 future IRPs.

3 WEATHER NORMALIZATION

4 **Q. WHAT IS WEATHER NORMALIZATION AND WHAT IS ITS PURPOSE?**

5 A. Weather normalization is the process of estimating what historical energy and peak demand
6 would have been had normal, or typical, weather had occurred. The process is useful for
7 understanding the underlying trends in historical loads. A weather normalized load forecast
8 assumes typical weather and does not include extreme weather events that would
9 significantly increase peak demand (MW). Using weather normalized load forecast allows
10 different load forecast to be compared on an apples-to-apples basis by removing the impact
11 of weather which may vary significantly from year to year.

12 **Q. WHAT WEATHER DATA DOES THE COMPANY USE IN DEVELOPING ITS** 13 **ENERGY SALES FORECAST?**

14 A. The Company uses heating degree hours ("HDH") and cooling degree hours ("CDH") in
15 development of the energy sales forecast. HDH and CDH are measures of temperature and
16 are computed as the absolute value of the difference between average daily temperature and
17 a defined base temperature. For example, if the average temperature was 35° on a given
18 winter day, the day would represent 10 HDH on a base 45° computation of HDH. HDH are
19 a measure of cold weather and CDH are a measure of hot weather. The relationship between
20 energy consumption and degree hours is positive, i.e., energy consumption increases with
21 increases in HDH and CDH.

1 **Q. HOW DOES THE COMPANY COMPUTE FORECASTED, OR NORMAL, HDH**
2 **AND CDH?**

3 A. In the Budget 2022 forecast, normal HDH and CDH are represented as their respective
4 averages for the 41 years beginning 1980 and ending 2020.

5 **Q. WHAT IS A SENSITIVITY FORECAST?**

6 A. The Company produces six sensitivity forecasts in addition to the base case load forecast.
7 The sensitivity forecasts are developed to evaluate the impact of changes to some key
8 assumptions and variables included in the load forecasting models. The sensitivities
9 produced by the Company include: 1) high economic growth; 2) low economic growth; 3)
10 no load growth; 4) load growth with no demand side management (DSM) program impacts;
11 5) load growth with aggressive DSM; and 6) a 20-year normal weather definition.

12 **Q. DID THE COMPANY PRODUCE A SENSITIVITY FORECAST REGARDING**
13 **NORMAL WEATHER?**

14 A. Yes. In the 2019 IRP, Docket No. 42310, Staff witness John Hutts recommended use of a
15 rolling 20-year normal for weather as opposed to a fixed average dating back to 1980. The
16 Company, as part of the Budget 2022 load forecast, prepared a sensitivity that uses the most
17 recent 20 years for normal weather as opposed to 41 years.

18 **Q. DID THE 20-YEAR NORMAL FORECAST SHOW A DIFFERENCE FROM THE**
19 **41-YEAR NORMAL FORECAST?**

20 A. The two versions of the forecast produce nearly identical energy projections, and the summer
21 and winter demand projections are similar but do show a difference. By 2041 the 41-year

1 normal forecast projects energy requirements of 101,813 GWh whereas the 20-year normal
2 forecast shows 101,870 GWh. Summer peak demand under the 41-year normal is 18,367
3 MW whereas the summer demand is 18,119 MW in the 20-year normal forecast.

4 **Q. WHAT DOES THE EIA USE FOR NORMAL WEATHER IN ITS ANNUAL**
5 **ENERGY OUTLOOK?**

6 A. The EIA, which is a source for many of the Company's input assumptions, uses a 30-year
7 normal for weather, but they also trend the weather to reflect the fact that heating and cooling
8 weather has generally shown a trend in the last thirty years. In the Company's base case
9 forecast (based on the 41-year normal) and in the 20-year normal forecast, the average
10 weather is held constant throughout the forecast horizon.

11 The EIA's "Assumptions to the Annual Energy Outlook 2022: Residential Demand Module"
12 (included as Exhibit JMT-3) indicates on page 8 that short-term projections are based on a
13 15-month forecast from the National Oceanic and Atmospheric Administration ("NOAA")
14 and that "State-level projections of degree days beyond that follow a linear trend using the
15 most recent 30 years of complete annual historical degree-day data." The EIA in its 2022
16 AEO projects heating degree days in the South Atlantic region to decrease by a compound
17 average growth rate of 0.6% per year from 2021 through 2050. Their trend approach projects
18 South Atlantic regional cooling degree days to increase by an average of 0.9% per year. Both
19 trends indicate a warming trend in weather.

20 **Q. WHAT FACTORS SHOULD BE CONSIDERED IN THE DEVELOPMENT OF THE**
21 **APPROPRIATE METHOD TO USE FOR NORMAL WEATHER?**

1 A. When selecting a historical record from which to draw normal weather, the forecaster is
2 trying to balance stability versus accuracy in the projected weather. A long-term and fixed
3 average will generally be more stable from one year to the next as new information carries
4 less weight in a long-term average. A shorter average will reflect changes in the underlying
5 trend more readily and, if there are indeed trends in the weather, will therefore be more
6 accurate but will produce less stability.

7 In the 2019 IRP, Staff witness Hutts recommended use of the 20-year normal as a means to
8 more readily capture observed trends in the weather data. The EIA has moved to using 30-
9 years of history but also consider climate trends for each year of the forecast horizon.

10 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO DEFINING NORMAL**
11 **WEATHER?**

12 A. I recommend use of the 20-year rolling average normal as the appropriate method. Historical
13 climate trends impact heating and cooling requirements, as evidenced in that 20-year history.
14 The trend can be observed from the following information, which represents average HDH
15 and CDH for the last 10, 20, 30, and 41 years. and from the charts of the annual HDH and
16 CDH for the 41-year period with trends in Exhibit JMT-4.

AVERAGE HDH AND CDH BY LENGTH OF AVERAGE

# of Years in Average	Average HDH ¹	Average CDH ²
41 Years	886	1,422
30 Years	854	1,431
20 Years	847	1,461
10 Years	766	1,543

1- billing cycle HDH (base of 54°F)

2- billing cycle CDH (base of 67°F)

1 The 20-year fixed normal approach captures any trends that may be occurring better than the
2 41-year normal used by the Company. The 20-year approach also helps establish stability
3 through maintaining a fixed normal assumption throughout the forecast horizon, as opposed
4 to adjusting both the level of the normal assumption and the rate of growth, which a 30-year
5 trend would involve. However, given the EIA and other utilities are beginning to investigate
6 trends in normal weather variables, I also recommend the Company be required to provide,
7 going forward, a sensitivity forecast reflecting summer and winter climate trends in line with
8 the EIA's methodology.

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

10 **A. Yes.**

1 MR. THOMAS: With your permission, I would ask
2 at this time that both Mr. Chiles and Mr. Thomas give
3 a brief summary of their testimonies.

4 MADAM CHAIR PRIDEMORE: Go ahead.

5 WITNESS CHILES: Once again, my name is John W.
6 Chiles. I'm a principal at GDS Associates and I'm
7 testifying on behalf of the Public Interest Advocacy
8 staff of the Georgia Public Service Commission.

9 The purpose of my testimony is to respond to
10 certain elements of the Georgia Power Company's 2022
11 integrated resource plan filing. I will address
12 issues pertaining to the company's transmission
13 planning process, including the evaluation of the
14 company's ten-year plan and other aspects of the IRP,
15 including the unit retirement study, the use of
16 battery energy storage, and the proposed
17 North Georgia reliability and resilience action plan.

18 In past reviews of the company's integrated
19 resource plan filings, I raised issues regarding the
20 lack of integration of the ten-year transmission plan
21 with other parts of the IRP process. Although the
22 company has made incremental improvements in this
23 area with respect to regional coordination, the 2022
24 filing demonstrates that the lack of coordination
25 between the development of the ten-year transmission

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1 plan with other requests by the company persists and
2 is impacting the ability of staff to conduct a
3 prudent review of how transmission decisions critical
4 to the implementation of the resource decisions the
5 company desires to make are reached.

6 In this IRP, the company provided over 200,000
7 power flow models, but those cases did not address
8 any long-term solution to the uncertainty surrounding
9 the impact of the retirement of Bowen 3 and 4, plus
10 the lack of infrastructure needed to accommodate the
11 6,000 megawatts of renewable capacity that will be
12 needed to be sited from a capacity IRP, plus other
13 reliability and resilience needs.

14 The company has referenced the North Georgia
15 reliability and resilience action plan, but has not
16 presented a plan yet for this Commission to approve.

17 In our evaluation of the company's ten-year
18 transmission plan, consistent with past practices, my
19 team conducted a review of the models, identified
20 issues and the effectiveness of the solutions in the
21 ten-year plan.

22 We confirmed that the models developed by the
23 company for the ten-year plan were consistent with
24 respect to load allocation, generation dispatch,
25 transmission facility modeling parameters, and

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1 interchange with neighboring utilities. We confirmed
2 that the contingencies evaluated by the company met
3 the requirements of the NERC transmission planning
4 standards.

5 In running the models, our team was able to
6 successfully replicate the problems the company
7 identified. The company proposed a series of
8 solutions to these issues. Our team verified that
9 mitigation plans did resolve the violations in the
10 power flow cases. The company did not provide any
11 analysis on the cost-effectiveness of the TND
12 projects listed in the 2022 transmission plan.

13 In the unit retirement study, the company
14 identified several transmission upgrades that would
15 be needed at Plant Wansley Units 1, 2, and 5A, Plant
16 Boulevard Unit 1, Plant Gaston Units 1 through 4 and
17 Unit A, Plant Bowen Units 1 and 2, and Plant Scherer
18 Units 1 through 3 were to be retired. I agree with
19 the company's findings regarding required
20 transmission upgrades that are needed for the
21 retirement of the aforementioned units. I am
22 concerned that the transmission upgrades were not
23 studied on a unit-by-unit basis but were studied on a
24 cumulative basis. Assuming the first tranche of
25 units was retired and then the evaluation of the next

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1 set of units include the impact of the first set.

2 The evaluation of Plant Bowen Units 3 and 4 is
3 somewhat murky due to the incremental evaluation of
4 the generation retirements and the technical
5 feasibility of completing construction of
6 transmission facilities by 2029 to avoid ELG
7 compliance plan expenses. This issue, along with
8 considering the other generation and transmission
9 issues in North Georgia, will need to be addressed in
10 the discussion of the North Georgia reliability and
11 resilience action plan.

12 The company has also requested funds for
13 multiple battery energy storage systems, which are to
14 be evaluated under differing operating scenarios. I
15 support the evaluation of BESS and am particularly
16 interested in how the company will communicate to
17 this Commission regarding the status of those
18 projects, particularly at a time when so much
19 renewable generation is contemplated for the
20 company's resource mix.

21 The company is looking at adding 1,000
22 megawatts of battery storage in the future and the
23 hope is that what the company is doing now with these
24 demonstration projects will maintain the same or
25 improved reliability that Georgia Power customers

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1 have historically enjoyed.

2 The company pays a great deal of attention to
3 the North Georgia reliability and resilience action
4 plan and has correctly identified the drivers of the
5 need for action. Significant generation retirements,
6 a lack of renewable generation in North Georgia, an
7 abundance of renewable energy in South Georgia, and
8 inadequate transmission systems to deliver the
9 generation in the south to the north, and other
10 reliability issues can occur with high penetrations
11 of resources are all reasons that there needs to be
12 action now on expanding the transmission system to
13 ensure that the reliability and resilience will be
14 maintained into the future.

15 The failure of the company's various planning
16 processes beyond the ten-year plan to take a long
17 look at system needs beyond ten years has led to
18 eleventh-hour decisions like what to do about ELG at
19 Bowen 3 and 4. This Commission cannot be expected to
20 prudently react to those changing requirements
21 without having a window into the long-term system
22 needs and the feasibility and cost-effectiveness of
23 potential solutions every three years.

24 I am recommending that the Commission require
25 the company to have more transparency in the planning

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1 process through a collaborative planning process that
2 includes all ITS participants and Commission staff.
3 Multiple states, such as North Carolina and Arizona,
4 have these processes and the Commission would benefit
5 by having more insight into these critical
6 infrastructure improvements on a consistent basis.

7 In short, the company has met the requirements
8 of the NERC planning standards in their ten-year
9 plan. Also, I'm supportive of retirement decisions
10 of all units recommended by the company in this IRP
11 with the exception of Plant Bowen Units 3 and 4,
12 which should be deferred, if possible, based on the
13 issues associated with the ELG decision.

14 The company still does not appear to have taken
15 a consistent integrated approach between transmission
16 planning and resource retirements or an
17 interconnection of new technologies. Additional work
18 needs to be done to ensure that initiatives which
19 could result in changes to power delivery patterns on
20 the company's transmission system are adequately
21 vetted in either future IRP proceedings or through a
22 collaborative transmission process with Commission
23 oversight.

24 WITNESS J. THOMAS: Okay. For my summary, my
25 name is Jacob M. Thomas. I am a principal of
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1 GDS Associates, Incorporated. And I am testifying on
2 behalf of the Public Interest Advocacy staff and the
3 Georgia Public Service Commission.

4 The purpose of my testimony is to make
5 recommendations based on my review of Georgia Power
6 Company's budget 2022 load and energy forecast, which
7 is an element of the company's 2022 integrated
8 resource plan filing.

9 I reviewed the input assumptions, methods, and
10 outputs of the company's long-term load forecast.
11 Based upon my review, I have made two recommendations
12 with respect to the company's load forecasting
13 process, neither of which I would recommend as
14 revisions to the 2022 budget forecast, but rather
15 recommendations for future forecasts.

16 My first recommendation regards the company's
17 residential saturation survey, which has not been
18 updated by the company since 2016. The saturation
19 survey is useful in understanding appliance
20 ownership, age, size, and efficiency within the
21 residential sector, and represents a source of
22 primary data collection or information specific to
23 the company's service territory customers.

24 Along with the saturation survey data, the
25 company relies upon information from the Energy

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1 Information Administration, including the annual
2 energy outlook and the residential energy consumption
3 survey which provide national and regional
4 information about appliances. I recommend that the
5 company conduct a new saturation survey and continue
6 to update the survey on a three-year basis going
7 forward.

8 Collecting the primary data for the residential
9 sector on a regular basis will allow the company to
10 know if trends and ownership of appliances begin to
11 diverge from the regional information that is
12 collected from the EIA. If such divergence becomes
13 evident, the company will be positioned to reflect
14 such changes in future iterations of the load
15 forecast.

16 With respect to this recommendation, I note
17 that the time and effort associated with conducting a
18 survey would preclude the company from incorporating
19 any such update in the revision of the budget 2022
20 load forecast, and, therefore, make the
21 recommendation for future load forecasts in IRPs.

22 My second recommendation regards the company's
23 computation of normal weather, which is used as a
24 basis for weather normalizing historical loads and
25 projecting future loads. Weather normalizing

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1 historical loads is the process whereby an analyst
2 estimates what peak demands and energy requirements
3 would have been had normal or typical weather
4 occurred.

5 A weather normalized load forecast that's
6 produced by Georgia Power is a forecast that assumes
7 the normal weather for each year into the future.
8 This process of weather normalizing historical load
9 and projecting load on a weather normal basis allows
10 for an apples to apples comparison of historical and
11 forecasted trends.

12 The company uses heating degree hours, or HDH,
13 and cooling degree hours, or CDH, as the measures of
14 weather which measure how cold or hot a day is by
15 comparing the average daily temperature to a basis
16 temperature. The company uses a 41-year average of
17 HDH and CDH to represent normal weather, including
18 1980 through 2020 inclusive.

19 In the 2019 IRP, Staff Witness John Hudson
20 recommended use of a 20-year rolling normal for
21 defining normal weather. In the current IRP, the
22 company generated a sensitivity forecast that uses
23 that 20-year normal to be reflective of Mr. Hudson's
24 prior recommendation. The company's base case
25 forecast using a 41-year normal is similar to the

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1 sensitivity case using a 20-year normal.

2 As a third possible approach, I noted that the
3 EIA uses a 30-year normal for weather and includes
4 trends in the weather variables in its latest annual
5 energy outlook.

6 In the south Atlantic region, the EIA's trends
7 indicate warming weather in both summer and winter
8 seasons. I recommend use of a 20-year normal that is
9 fixed during the forecast horizon, rather than
10 trending as done by the EIA. Trends are evident in
11 the weather data used by the company historically and
12 I conclude that an average based on a fewer years, 20
13 versus 41, will better reflect the historical
14 trending.

15 However, I also conclude that excluding trends
16 in future years will help with stability between
17 forecast vintages. I do recommend the company
18 produce a sensitivity forecast that does trend HDH
19 and CDH in a manner consistent with the EIA's
20 methodology.

21 MR. THOMAS: Thank you.

22 Madam Chair, the panel is available for
23 questions from Commissioners and cross-examination.

24 MADAM CHAIR PRIDEMORE: Commissioners.

25 (No response.)

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1 MADAM CHAIR PRIDEMORE: I guess, Mr. Chiles, I
2 have one question just to get us going.

3 So in your summary testimony you stated that
4 you agree with the closure of the coal plants as
5 proposed, even the ones that aren't even in this IRP,
6 the ones in the future.

7 I know that there's been conversation about
8 transmission risk relative to Plant Bowen and to
9 Plant Scherer. Talk me through your advice on
10 closure. Is it from simply just a transmission
11 perspective, or is your advice on closure at these
12 coal plants across the board for all reasons?

13 WITNESS CHILES: I'm only speaking to the
14 transmission perspective, Madam Chair. What I'm
15 looking at is: If the plant were to shut down, are
16 the transmission facilities proposed by the company
17 adequate to maintain system reliability?

18 I'm not dealing with the economics of the
19 transmission system, nor am I dealing with the
20 economics of that shutdown. I'm strictly looking at
21 from a power flow perspective: Is the system remain
22 stable and meet criteria with the loss of that plant
23 on the system?

24 MADAM CHAIR PRIDEMORE: So if Bowen Units 1 and
25 2 were to shut down, would that put the transmission

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1 system in North Georgia at risk?

2 WITNESS CHILES: I think in a long-term basis
3 it would, yeah. In the immediate, I think it is --
4 it's somewhat of a degradation of performance.

5 You know, the problem, of course, with
6 transmission systems is that it's not just those
7 plants being down. But, of course, at times of
8 outages, you know, we have multiple lines out of
9 service. We have multiple plants out of service.

10 And so transmission modelings are a one-hour
11 snapshot. You know, so we really have to deal with
12 an issue of an every-hour question because I can run
13 a power flow model and tell you summer peak 2027,
14 this makes sense, but that assumes all lines in
15 service and all generators in service. The operators
16 don't get that luxury.

17 So I would -- I would say that from a planning
18 perspective: Is the process reasonable? Yes. But I
19 would be concerned from an operational perspective
20 long term would we be able to maintain the system?
21 You know, as it stands, I would be concerned about
22 that.

23 MADAM CHAIR PRIDEMORE: Is there any negative
24 effect on the transmission system if the two coal
25 units and the one jump-starter CT at Wansley close?

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1 WITNESS CHILES: Not in the analysis that we
2 performed because I believe those are scheduled for
3 August of this year. So we did not see any issues
4 with that.

5 MADAM CHAIR PRIDEMORE: Okay. Is --
6 considering the change and sort of this transition
7 that our country's electric fleet is going through
8 right now, is a ten-year transmission planning cycle
9 enough time when we're writing 20- and 30-year solar
10 PPAs?

11 WITNESS CHILES: I would argue that for
12 long-term planning, for giving the energy
13 transmission, it's not. Right now a ten-year plan is
14 consistent with NERC standards. And so then the
15 company is meeting its requirement under NERC.

16 But if you look throughout the country, many
17 places are looking at a long-term 20-year
18 transmission plan. And the idea is that since they
19 know there's a lot of renewables coming, since they
20 know there's plants going to be shut down, what
21 they're looking at is an expansion of the grid to
22 accommodate that scenario out into the future.

23 And then they are working that plan as they
24 move forward. So I would recommend ultimately a
25 longer-term horizon for that type of strategic

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1 planning versus just a ten-year plan looking at what
2 you need for reliability and load serving.

3 MADAM CHAIR PRIDEMORE: Are we seeing the
4 plan -- the plan time frame match solar PPA awards in
5 the same time frames or --

6 WITNESS CHILES: Are you talking specifically
7 or just in general?

8 MADAM CHAIR PRIDEMORE: Just in general, across
9 the country.

10 WITNESS CHILES: Really we're not. Most of the
11 times we're behind. Because if you look at the
12 interconnection queues, not just here in Georgia, but
13 throughout the country, there are several gigawatts
14 that are in the queue, and even the larger RTOs who
15 have large planning processes are still struggling
16 with the idea of: How do we assimilate all of that
17 generation?

18 And so they are basically creating corridors
19 for: These are reasonable locations where building
20 transmission to accommodate, you know, that type of
21 an influx. And then hopefully the developers are
22 getting the signal to respond to that in what they
23 put out there.

24 MADAM CHAIR PRIDEMORE: Cybersecurity is
25 very -- is a very hot topic in our industry right

1 now, as you're aware. And it's something that we, as
2 Commissioners, receive updates and information on,
3 but we don't talk about it. The utilities, of
4 course, are active and the transmission planners are
5 active, as well as our government is active. What
6 advice would you give -- I'm sorry, our federal
7 government.

8 What advice would you give to the five of us
9 and any state utility regulator when it comes to
10 cybersecurity planning for transmission systems?

11 WITNESS CHILES: To be honest, that is not an
12 area where I am, you know, nearly as qualified to
13 speak to the transmission planning matters in
14 general. You know, I would say that, you know, we
15 have the NERC set of standards and I would be making
16 sure that we are auditing on a consistent basis, that
17 we are taking it seriously, and that we are moving
18 forward and looking at technologies which are going
19 to help improve that system.

20 But ultimately it's going to come down to, I
21 think, more regional coordination because one of the
22 big concerns is confidentiality of information, you
23 know, operation of units remotely. So we need to
24 have a system that is resilient enough that if an
25 event were to happen that there's not widespread

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1 cascading.

2 I don't think we're ever going to solve and
3 make sure there's not a cybersecurity incident, but
4 really the goal as planners is to make sure that if
5 an extreme event happens, whether that's
6 cybersecurity or a big weather event, that the system
7 is able to withstand and move forward such that we
8 don't have multi-state blackouts. So part of it is
9 how do we do better in terms of isolation of problems
10 knowing that we're never really fully, I think, going
11 to eliminate those because those threats will always
12 be there and people wanting to infiltrate that system
13 will always be active.

14 MADAM CHAIR PRIDEMORE: Very good.

15 Any questions from Commissioners?

16 (No response.)

17 MADAM CHAIR PRIDEMORE: All right.

18 Americans for Affordable Clean Energy.

19 MR. GALLOWAY: No questions.

20 MADAM CHAIR PRIDEMORE: Did you say no
21 questions?

22 MR. GALLOWAY: Yes, ma'am.

23 MADAM CHAIR PRIDEMORE: All right. I need you
24 all to speak up.

25 Commercial Group.

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1 MR. JENKINS: No questions.

2 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
3 for Georgia.

4 (No response.)

5 MADAM CHAIR PRIDEMORE: Cypress Creek
6 Renewables.

7 MR. STAIR: No questions.

8 MADAM CHAIR PRIDEMORE: Georgia Association of
9 Manufacturers.

10 MR. C. JONES: No questions.

11 MADAM CHAIR PRIDEMORE: Georgia Center for
12 Energy Solutions.

13 MR. HUBBARD: No questions.

14 MADAM CHAIR PRIDEMORE: You moved on me, Peter.
15 Bobbing and weaving up here.

16 Georgia Coalition of Local Governments.

17 MS. BROWN: No questions.

18 MADAM CHAIR PRIDEMORE: Thank you for sitting
19 in the same seat, Alicia. It's easier to find you
20 that way.

21 Georgia Interfaith Power & Light and the
22 Partnership for Southern Equity.

23 MS. KYSOR: Good morning.

24 MADAM CHAIR PRIDEMORE: There she is. Good
25 morning, Ms. Kysor.

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1 MS. KYSOR: I'll be brief.

2 CROSS-EXAMINATION

3 BY MS. KYSOR:

4 Q Good morning, gentlemen. I just have a few
5 questions and all of them relate to Mr. Thomas' testimony.

6 A (Witness J. Thomas) Okay.

7 Q Mr. Thomas, your recommendation that the
8 company update its residential saturation survey once
9 every three years, is that in line with industry standard?

10 A (Witness J. Thomas) I would -- yeah, I would
11 say it's in line with what you typically see.

12 Q And then a clarification question surrounding
13 your recommendation that Georgia Power use a 20-year
14 rolling average weather normal. Is your recommendation
15 that Georgia Power use a 20-year rolling weather normal
16 data set with sensitivities for summer and winter climate
17 trends?

18 A (Witness J. Thomas) Yes, that is correct. The
19 sensitivity would trend both heating and cooling weather
20 data.

21 Q And then referring to page 6 of your
22 testimony at the top there, lines 1 through 8, you list
23 the items that you reviewed in preparing your testimony.
24 Do you see that?

25 A (Witness Thomas) Yes.

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1 Q In preparing your testimony or conducting
2 this analysis, did you do any independent modeling of any
3 of the company's sensitivities?

4 A (Witness J. Thomas) I did not.

5 MS. KYSOR: That's all I have. Thank you.

6 MADAM CHAIR PRIDEMORE: Ms. Kysor is efficient
7 today.

8 Georgia Large Scale Solar Association and
9 Advanced Power Alliance.

10 MR. CARVER: No questions, Madam Chair.

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

14 MR. THOMASSON: No questions.

15 MADAM CHAIR PRIDEMORE: Georgia Watch.

16 MS. COYLE: No questions from the current
17 closet.

18 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

19 MR. CARVER: No questions, Madam Chair.

20 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
21 Coalition.

22 MR. S. JONES: No questions, Madam Chair.

23 MADAM CHAIR PRIDEMORE: Sierra Club.

24 MR. FABISH: No questions.

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

2 Good morning, Mr. Baker.

3 MR. BAKER: Good morning. Good morning, panel.

4 My questions are going to be directed to Mr. Chiles.

5 So, Mr. Thomas, you can take it easy.

6 WITNESS J. THOMAS: Sit back.

7 MR. BAKER: You're welcome.

8 CROSS-EXAMINATION

9 BY MR. BAKER:

10 Q All right. Mr. Chiles, at any point in your
11 review of the company's ten-year transmission plan, did
12 you see any project cost estimates associated with various
13 transmission projects selected for inclusion in the
14 ten-year plan?

15 A (Witness Chiles) There are project costs
16 included in the technical appendix Volume 3, but those are
17 trade secret numbers. But I did see those.

18 Q All right. Thank you.

19 Can you provide a rough estimate or an
20 approximation of the cost of projects included in the plan
21 that are being presented here for the Commission's approval?

22 A (Witness Chiles) I cannot. Because I feel that
23 summarizing those numbers would be giving away information
24 that was considered trade secret.

25 Q Even if it's an aggregate of the -- all the
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1 plans, not separating or identifying in any way any
2 transmission plan. You think an aggregate number is a
3 violation of trade secret?

4 A (Witness Chiles) If it was included in the
5 trade secret document, sir, then I really can't speak to
6 that. That would require a legal opinion. But I will defer
7 to counsel on that.

8 MR. BAKER: Madam Chairman, I'd ask for a
9 question. This is not trade secret information. I'm
10 asking for an aggregate number, an approximation.
11 Not identifying any particular project, number of
12 projects, or anything that could specifically
13 identify the cost associated with a transmission
14 project. It is not trade secret.

15 MADAM CHAIR PRIDEMORE: I have no objections
16 from either table to your left or to your right,
17 so...

18 BY MR. BAKER:

19 Q Mr. Chiles, can you answer the question?

20 MADAM CHAIR PRIDEMORE: Do you have an
21 aggregate number?

22 WITNESS CHILES: I do not have an aggregate
23 number for that. I do have an aggregate number for
24 those things I just stated with the retirement of
25 generation, but I do not have an aggregate for the

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1 entire ten-year transmission -- I mean, for the
2 entire ten-year plan.

3 BY MR. BAKER:

4 Q All right. Thank you.

5 Well, would you agree that a cost estimate is
6 important when estimating whether a transmission project is
7 the best option to pursue?

8 A (Witness Chiles) I agree it's one of the
9 factors. I think the first factor we have to deal with is
10 from a NERC reliability perspective: Does it meet criteria
11 and does it resolve, you know, a situation?

12 Cost is certainly part of that, but I think the
13 first piece is if you spend money and it doesn't solve the
14 problem, it doesn't matter what it costs.

15 Q So the first concern is the engineering?

16 A (Witness Chiles) I would say the first concern
17 is the engineering and the federal reliability standards.
18 And then the second concern would be the cost optimization.
19 And the siting feasibility of that -- of that solution.

20 Q At page 17 of your prefiled testimony you
21 indicate the company did not perform an economic analysis
22 of projects included in its ten-year plan; is that
23 correct?

24 A (Witness Chiles) That was not provided to me as
25 part of what was in the IRP filing, no, sir.

1 Q Okay. By any chance did staff submit a data
2 request for that information?

3 Was there any inquiry about that information?

4 A (Witness Chiles) Not to my recollection, sir.

5 Q Okay. How can the company and Commission
6 improve the current planning process with regard to
7 providing cost-effective, economic solutions?

8 Do you have any recommendations on that topic?

9 A (Witness Chiles) I would say part of that would
10 be -- as we -- as I discussed in my testimony, a
11 collaborative process between staff and the company to
12 evaluate and walk through this planning process such that
13 staff at least has insight into those discussions, I think
14 would be helpful.

15 Q Okay. And what role should economic planning
16 and evaluation of alternatives play in the collaborative
17 study that you're recommending?

18 A (Witness Chiles) I would say it's one of
19 several factors. If you look throughout the country at
20 transmission planning processes, economics is one of those
21 factors, but it's not the sole factor. So I would say it's
22 one factor that needs to be considered, but I would not rank
23 it higher than others.

24 Q But at a certain point, you know, if the cost
25 of a project is -- appears to be excessive or would place

1 a financial burden on the company or its other
2 transmission projects, wouldn't that be a factor that
3 should be considered?

4 A (Witness Chiles) That's part of the
5 optimization because you want to look at solutions which are
6 economic, but also, you know, you have to weigh: Is that a
7 Band-Aid solution? Are you going to have to do something
8 now and then three years from now? Are you looking for
9 long-term solution which costs more in the interim, but
10 provides greater benefits?

11 There are a whole host of things to consider.
12 So, once again, it's not just an economic decision.
13 Planning requires many factors and we need to consider all
14 of those. So that's part of the collaborative process is
15 those discussions. What are the factors you do to evaluate
16 projects and how do you weigh those things should be part of
17 that discussion.

18 Q Okay. You recommend the Commission --
19 Commission, integrated transmission system participants,
20 staff, and the company engage in a collaborative planning
21 process. At page 13 you further recommend that impacted
22 stakeholders should be involved in -- as the plan is
23 developed.

24 Do you recommend that independent power
25 producers, renewable project developers, consumers, and

1 other public interested stakeholders be included in this
2 collaborative process?

3 A (Witness Chiles) I would say there's a time for
4 that, depending upon how you structure that. My initial
5 thought would be that, you know, certainly we are dealing
6 with confidential energy infrastructure information
7 regarding power flow models and maps and that type of
8 information. So I would be concerned from a CEI
9 perspective.

10 Ultimately my goal would be that staff would
11 have greater insight into that entire process and that at
12 some point there would be, you know, a proceeding similar to
13 this where that plan would be shared and people could have
14 the opportunity to comment and participate at that level.

15 Q And would you agree that parties or entities,
16 such as independent power producers, renewable project
17 developers and experienced stakeholders could bring
18 valuable, unique information to the process that the other
19 parties would not have?

20 A (Witness Chiles) I think we see that throughout
21 the country in various plant -- transmission plant
22 processes. But, once again, you know, I think Georgia is in
23 a unique position with its arrangements with the ITS and
24 things like that. So I would defer to the Commission and
25 what they would want to consider as to who they would want

1 to include as part of that process.

2 Q Okay. Why is impacted stakeholder input
3 important to the success of the collaborative process you
4 recommend?

5 A (Witness Chiles) At the end of the day, the
6 transmission system is used to deliver resources to load and
7 impacted stakeholders are usually one of those two
8 categories. They're either resources or load.

9 So that input is important, but ultimately it's
10 the company has to make the decision on what's being built.
11 Because they have to go out and procure right-of-way, they
12 have to go out and spend the funds, they have to make
13 decisions, and they have to evaluate various generation
14 options. So, you know, that input is helpful, but I think
15 that it's the company's responsibility to -- to build those
16 upgrades and so they should carry the weight of that
17 decision.

18 Q Should public nongovernment organizations
19 with experience and knowledge regarding transmission
20 planning also be included?

21 A (Witness Chiles) Once again, it depends on the
22 structure of the process. I think if you look at the North
23 Carolina transmission planning collaborative, you would see
24 that they have multiple committees and in that there's
25 various levels of participation. There's an oversight

1 committee, there's a planning committee, there's a technical
2 committee. And there may be places where that could be
3 allowed, depending upon how we structure something here in
4 Georgia, if that's what the Commission so desires.

5 Q Okay. Well, at page 14 you mention the
6 statewide transmission planning processes used in North
7 Carolina and Arizona. Are you aware the North Carolina
8 collaborative transmission planning process allows all
9 interested public stakeholders to participate in the
10 process, as well as independent project developers?

11 A (Witness Chiles) I'm aware they're allowed to
12 participate in the process. I don't know if they are
13 allowed to participate in the actual technical analysis of
14 particular projects.

15 And I think that's really where I'm drawing a
16 distinction. It's one thing to provide input to say:
17 Here's a list of problems. What do you think?

18 It's another thing to be involved in the --
19 frankly, the nuts and bolts of actually conducting that
20 analysis and making those determinations.

21 So, you know, I'm sure they're allowed to
22 participate. But, once again, it's the level of that
23 participation, in terms of input versus actually letting
24 cases and evaluating. I think that's where I'm drawing a
25 distinction.

1 Q And you would recommend for Georgia to have
2 the more general participation by stakeholders and other
3 parties?

4 A (Witness Chiles) I would recommend that, you
5 know, primarily we need to be concerned with technically:
6 Does the system work? I think that's very important.

7 Once again, if you're a developer, you want to
8 know that the generation you're putting in, is it going to
9 get to the load. If you're the company, you're going to
10 want to know: Is the resource I have contracted with going
11 to be able to serve the load? Can it get there? So I think
12 the technical evaluation is critical for this.

13 There's other issues of stakeholder input. You
14 know, that's really for us to decide, you know, what that
15 looks like. But I think they do have to have a technical
16 group made up of the impacted participants who are
17 responsible for the grid to run those analyses and make
18 those decisions.

19 Q And I hear you. And what I am asking is
20 to -- not technical aspect, not the nuts and bolts, not
21 the engineering, but the collaborative process. That
22 should be open and -- to a broader audience and groups for
23 the other more general discussion?

24 A (Witness Chiles) Yeah. I think that's why I've
25 talked about possibly doing a proceeding where that plan is

1 presented and where a forum like this occurs because,
2 clearly, you're able to participate in the IRP process now
3 as an interested participant. I think staff, as the Public
4 Interest Advocacy staff, has a responsibility to reflect
5 some of those interests.

6 I would hope that staff, in its role, would be
7 able to reflect those on the technical side. So there's
8 probably places for input, but I -- once again, I would
9 distinguish between the development of a plan and that
10 review of the plan after the fact. I think that's where you
11 and I are maybe on different tracks.

12 Q No. I don't think we are that far off. I
13 think --

14 A (Witness Chiles) Okay.

15 Q I hear you and I understand what you're
16 saying.

17 A (Witness Chiles) Okay.

18 COMMISSONER McDONALD: Mr. Chiles, is that --
19 when you're talking about the development and the
20 public input, et cetera, does that include just
21 upgrading your transmission system, or redesigning,
22 or does that mean relocation whereby you have
23 property values involved in it and usually those
24 things are not really open for a lot of openness and
25 discussion? They are usually handled in a more

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1 private way.

2 WITNESS CHILES: In the forums in which I have
3 been involved, Commissioner, it has not gotten to the
4 level of the property values and all that. It's
5 mostly a case of where I have seen, you know, there's
6 a set of base case models that are developed. You
7 run the system, you identify the problems.

8 Solutions are then developed. You identify a
9 selected solution set. And then that's shared to the
10 stakeholders.

11 So there is no discussion of the right-of-way
12 acquisition, property values. None of that is
13 involved in that discussion. Mostly it's about
14 what's the technical basis and does the system work
15 with those upgrades in place.

16 But they don't get involved in that. The
17 only -- the cost allocation decisions that you get
18 into in a lot of those cases is usually based upon
19 either voltage level or function and it's not getting
20 into the property value side of the equation.

21 BY MR. BAKER:

22 Q Is that the way it works, say, for North
23 Carolina collaborative process?

24 A The North Carolina process, you know, I do not
25 know if they get into that level of detail. But I do know

1 that in Arizona, for instance, they're not getting into that
2 discussion.

3 I do know that in the various RTO proceedings
4 throughout the country, you know, they do not get into that
5 level. I do not know specifically about North Carolina and
6 any property value discussion.

7 Q Is there any collaborative process you're
8 aware of that you recommend as a potential model for this
9 Commission to look at?

10 A (Witness Chiles) I think we would probably be
11 best to look at the state and look at our needs and take
12 best practices from other parts of the country would be
13 where I start. I don't think there is one model that fits
14 everyone because I think every state has unique geography,
15 unique interconnections, you know, unique problems in its
16 transmission system. East versus west is a great example of
17 that.

18 You know, so I think you would have to design a
19 process that reflects the kind of characteristics of the
20 state, you know, to do that. I wouldn't recommend a single
21 off-the-shelf product to do that.

22 Q Thank you.

23 Regarding your recommendation that the
24 Commission lead a collaborative long-term transmission
25 planning process to identify the needs and solutions for

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1 North Georgia, how would this process interact with existing
2 Southeastern Regional Transmission Planning Process, SERTP?

3 A (Witness Chiles) That's really a two-edged
4 sword. You know, if the question is: Does -- do you use
5 SERTP to inform an internal process, or do you use the
6 internal process to inform SERTP, I think that's a decision
7 that would be made amongst the participants.

8 Q Okay. How would the projects from the
9 PSC-led collaborative effort you propose feed into or how
10 would you recommend feed into existing Southeastern
11 Regional Transmission Planning Process?

12 A (Witness Chiles) I would probably start with
13 interface-type projects first. And if there is anything
14 that comes out of that, that might be the first place to
15 start.

16 I don't think we get into any internal
17 constraints as much, but I would deal with the interface
18 side first because most of the SERTP is dealing with
19 cross-border transactions. So I think that would be a
20 natural -- natural touch point that we could begin to
21 address.

22 Q Would the Georgia process you are proposing
23 support development and evaluation of regional
24 transmission project solutions?

25 A (Witness Chiles) That really depends on the
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1 goals of the Commission and what they would desire. I mean,
2 certainly there are processes which do that. And I would
3 defer to the will of the Commission and the development and
4 structure of what that process looks like.

5 Q Okay. At page 12 you state: The failure of
6 the company to have a long-term strategic plan in place
7 for the loss of Bowen generation is a flaw in the
8 company's planning process and something that should have
9 been addressed long before the 2022 integrated resource
10 plan.

11 Can you be more specific in terms of the time
12 frame in which the company should have begun analysis of the
13 Plant's -- of Bowen's unit retirement?

14 A (Witness Chiles) I would -- it would be hard to
15 speculate on that. I would kind of give you a high-level
16 opinion in my view. Usually, given the time frame of
17 transmission development, that's usually a four- to six-year
18 process from concept to construction to energization,
19 depending on the type of project and the length of it and
20 the voltage level. So I would have been more in favor of
21 having this discussion back in a 2019 time frame, rather
22 than in 2022 for projects which need to be done in the 2025
23 to 2028 time frame.

24 Q Are you aware that public interest groups
25 requested within the SERTP transmission planning process

1 back in 2016 and 2017 that Southern Company transmission
2 planners evaluate transmission needs being driven by
3 public policy or requirements that are driving the closure
4 of Plant Bowen today?

5 A (Witness Chiles) I was not aware of that.

6 Q Did you evaluate whether the North Georgia
7 reliability planning effort would be necessary if the
8 company's winter target reserve margin is set at a lower
9 level, as many parties in this proceeding are
10 recommending?

11 A (Witness Chiles) I did not specifically address
12 that. I think the concern from a North Georgia perspective
13 is most of the factors, at least in my mind as a planner,
14 are uncertainty about generation, uncertainty about the
15 location of new generation. And I'm not really thinking
16 about it from a reserve margin standpoint. The reason why
17 is, as planners, we have to plan a system at the time of the
18 peak, that the sum of the generation equals the sum of the
19 load, plus losses.

20 So, therefore, the reserve margin piece to me
21 is not something which really impacts the power flow
22 modeling. It certainly impacts the economics of what plants
23 are running, but we would not be putting in 25 percent
24 greater generation and expect that to be online at the time
25 of the power flow modeling.

1 We would say: This is the load at the time.
2 What resources are going to serve that? Does the system
3 work?

4 Q Thank you.

5 Did your analysis include any evaluation of
6 sensitivity of transmission needs under various target
7 reserve margin levels or scenarios?

8 A (Witness Chiles) No, it did not. Once again,
9 for the reasons stated.

10 MR. BAKER: Okay. Thank you very much. Thank
11 you, Mr. Thomas, for being patient.

12 Thank you, Commissioners.

13 MADAM CHAIR PRIDEMORE: Southern Renewable
14 Energy Association.

15 MR. MAHAN: Good morning, Commissioners. Good
16 morning, panel.

17 WITNESS CHILES: Good morning.

18 MR. MAHAN: Simon Mahan for the Southern
19 Renewable Energy Association.

20 CROSS-EXAMINATION

21 BY MR. MAHAN:

22 Q My questions today, if everyone was paying
23 attention yesterday, are going to be directed towards
24 Mr. Chiles.

25 Were you able to listen, Mr. Chiles, to the
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1 panel Barber, Bower, and Cook yesterday?

2 A (Witness Chiles) I did.

3 Q And they instructed me to ask you these
4 questions.

5 A (Witness Chiles) I'm aware. And they will hear
6 about it later.

7 Q Yes.

8 Do you have experience with the Aurora model
9 the staff and company have referenced?

10 A Not with Aurora specifically, but I have worked
11 with several production cost models in my career.

12 Q Do you recall the discussion regarding the
13 locational value study that we were talking about
14 yesterday?

15 A (Witness Chiles) I do recall hearing about that
16 study.

17 Q Okay. Do you recall how staff said Aurora
18 could be used to conduct that study?

19 A (Witness Chiles) If you could refresh me, that
20 would be helpful.

21 Q They said that.

22 A (Witness Chiles) That's helpful.

23 Q Okay. It's coming back from yesterday.

24 Is Aurora designed to conduct locational
25 marginal pricing on a notable basis?

1 A (Witness Chiles) I am not aware of if it is or
2 not.

3 Q Okay. But you're aware that the proposal is
4 that the Aurora model could be so subdivided into subzones
5 to come up with effectively avoided costs in different
6 parts of the state. You're familiar with that?

7 A (Witness Chiles) Yes, sir. I am aware of that.

8 Q But effectively couldn't the company
9 gerrymander the zones to make the analysis less
10 transparent than locational marginal pricing?

11 A (Witness Chiles) There's a couple of options
12 you can look at in --

13 Q Yes or no?

14 A (Witness Chiles) -- most production cost
15 models. So I believe the answer is yes.

16 Q Okay.

17 A (Witness Chiles) I believe you could look at,
18 once again, a trading up model or a zonal model to give you
19 some --

20 Q Do regional -- thank you.

21 Do regional transmission organizations use
22 Aurora to run their market locational marginal pricing?

23 A (Witness Chiles) There may be some. I'm more
24 familiar with those they use provided use -- use PSLF and GE
25 MAPS.

1 Q Okay. So different models to conduct more
2 locational marginal pricing, instead of Aurora?

3 A (Witness Chiles) That's correct.

4 Q Okay. Moving on, you're familiar with the
5 North Georgia RFP proposal that the company has put
6 forward; correct?

7 A (Witness Chiles) Yes, I am.

8 Q Okay. And you're familiar that the staff
9 have recommended that Northern Georgia renewable -- that
10 instead, that the renewable RFP should be statewide and
11 that renewable projects that are located in the north
12 should instead be somehow compensated for not having
13 transmission service from the south.

14 Is that your understanding of that
15 recommendation?

16 A (Witness Chiles) That's my understanding, yes,
17 sir.

18 Q But projects in the north -- if projects do
19 bid in to this RFP, are they definitively negating the
20 need for transmission in the south?

21 A (Witness Chiles) Once again, it would depend
22 upon location and the contingency analysis run on a power
23 flow model for the entire state.

24 Q And so a northern project could
25 potentially -- instead of providing a transmission

1 benefit, it could actually provide a reliability benefit?

2 A (Witness Chiles) Once again, the power flow
3 model is agnostic to, you know, who provides what. You
4 know, it's a case of: Under contingency conditions, does
5 the sum of the generation and the sum of the load result in
6 overloads on the system?

7 So I'm sure, you know, multiple projects could
8 provide benefits in various locations, depending upon the
9 season, the contingency, and the time of day.

10 Q Yesterday Mr. Hewitson during
11 cross-examination of the same panel, he asked if ERCOT
12 uses locational marginal pricing. Did you catch that
13 question?

14 A (Witness Chiles) I did.

15 Q Does ERCOT use locational marginal pricing?

16 A (Witness Chiles) Yes, it does.

17 Q Did the use of locational marginal pricing
18 cause blackouts in Texas?

19 A (Witness Chiles) I sure hope not, no. But my
20 understanding is is that, you know, the energy market
21 construct and the use of pricing, once again, gives you a
22 price signal. But it's operation of the system and outages
23 of generation that, my understanding, has resulted in the
24 blackout situation.

25 Q Okay. And so --

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1 MADAM CHAIR PRIDEMORE: Mr. Chiles, isn't it --
2 isn't it fair to say that -- as even the people in
3 Texas like to say, it was the perfect storm. So it
4 was policy with the system and system reliability
5 from a generation and transmission side. It was all
6 things combined; right?

7 WITNESS CHILES: That's correct. If you look
8 at -- if you look at the system and look at the
9 number of outages, the types of outages, the location
10 of those --

11 MADAM CHAIR PRIDEMORE: Yeah.

12 WITNESS CHILES: -- the fuel supply. You know,
13 there were several factors that contributed to the
14 problems in Texas.

15 COMMISSONER McDONALD: Mr. Chiles, do you think
16 that the utility that this Commission regulates would
17 find any favor by being a part of an RTO?

18 WITNESS CHILES: I think that's a question for
19 this Commission to answer and not for me to answer.
20 The only thing I would say is, you know, from a
21 transmission perspective, my concern is: Do we have
22 a system where the resources that the company wants
23 to have can effectively serve the loads of the
24 customers of the state of Georgia?

25 Whether that's in an RTO construct or not, I am
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1 completely agnostic to that. I just want to make
2 sure that when mom and pop at the end of the line
3 turn the light -- hit the switch, do the lights come
4 on and do they stay on.

5 MR. MAHAN: That is a great answer.

6 COMMISSONER McDONALD: I can tell you this
7 Commission has a position on it.

8 MR. MAHAN: And, Chairwoman Pridemore, thank
9 you for pointing out the multiple factors that led to
10 the blackouts in Texas.

11 BY MR. MAHAN:

12 Q To be a little bit more specific on this, did
13 a lack of transmission connections outside of Texas
14 contribute to the blackouts and the extremity and the
15 length of time of the blackouts in Texas?

16 A (Witness Chiles) Well, certainly within this --
17 within ERCOT, given it's about, I think, 5- to 600 megawatts
18 of total capability across the three DC ties, that certainly
19 has a whole lot less interconnection capability than what we
20 have here in the state of Georgia. So I would argue yes.

21 Q And so does ERCOT build transmission projects
22 that cross U.S. state borders?

23 A (Witness Chiles) ERCOT does not do that.

24 Q Why don't they do that?

25 A (Witness Chiles) Because they made the decision

1 back in the '70s to sever the ties to -- to the rest of the
2 country in order to avoid the influence of the federal
3 government under the Interstate Commerce Act.

4 Q All right. So ERCOT is, in effect, a
5 single-state transmission planning entity?

6 A (Witness Chiles) It is a single-state
7 independent transmission planning entity. There's about 20
8 percent of the state of Texas that is served by customers in
9 the Eastern and Western Interconnect.

10 Q Single-state-based transmission planning
11 analysis or a collaborative might actually miss
12 larger-scale regional transmission solutions that could
13 help prevent things like blackouts?

14 A (Witness Chiles) Once again, it depends upon
15 the configuration of the system. You know, here in Georgia,
16 because we're an integrated system, you know, the models
17 which the company runs right now look at those things. The
18 company does interface planning. The company looks at that.

19 So I think it's already being addressed, in
20 terms of the other planning options that the company has.
21 So I think that's already being covered as the previous --

22 Q But your testimony in general is dissatisfied
23 with the way the company does transmission planning, isn't
24 it?

25 A (Witness Chiles) I wouldn't say I'm
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1 dissatisfied with the way they do planning, in terms of the
2 reliability planning. I think I'm more concerned from a
3 strategic planning long-term perspective, given the
4 significant changes in the generation mix, in the location
5 of that generation, you know, in the energy transition,
6 which the Chair recognized. I think you have to look beyond
7 our ten-year horizon and really decide, as my mother-in-law
8 would say: What do you want to be when you grow up?

9 And I think that's part of -- I think that's
10 part of the discussion, you know, of really: Where do we
11 want to be? You know, if we want to be a state that has
12 significant renewable generation, for example, then I think
13 you need to build a transmission and planning for that which
14 is going to accommodate that. Otherwise, you're chasing
15 your tail and you run into problems where the planning lags
16 behind the desire to move forward with generation.

17 Q And you think that's where we are right now?

18 A (Witness Chiles) I'm concerned that's where we
19 are right now.

20 COMMISSONER McDONALD: So you -- we referred to
21 blackouts and, of course, I think we were more
22 talking about Texas and California. Do you recall
23 blackouts in Georgia?

24 WITNESS CHILES: Not in the 18 years I have
25 been here.

1 COMMISSONER McDONALD: Thank you.

2 WITNESS CHILES: The last time I saw a blackout
3 was up in the northeast on August 14th of 2003, sir.

4 MADAM CHAIR PRIDEMORE: Where you were in the
5 northeast in 2014, are they part of an RTO?

6 WITNESS CHILES: That was part of the PJM
7 system. And along with MISO, and along with what was
8 happening in Canada and transferring off of
9 FirstEnergy system. So it was a confluence of events
10 that caused a great deal of regulate issues, which is
11 why we have the NERC reliability standards today.

12 BY MR. MAHAN:

13 Q On page 9 and 10 of your testimony you were
14 describing kind of these two separate concepts of
15 generation-centric planning or transmission-centric
16 planning. Do you recall that?

17 A (Witness Chiles) Yes. Yes, I do.

18 Q Am I correctly characterizing that generally?

19 A (Witness Chiles) Yes, sir.

20 Q Okay. So can comprehensive transmission
21 planning reduce overall generation costs?

22 Can a good transmission plan reduce costs of
23 generation?

24 A (Witness Chiles) I am going to ask you to be a
25 little bit more specific on that because the transmission

1 system, once again, is agnostic to the prime mover. If
2 you're talking about production costs, then I can't speak to
3 that. If you're talking about interconnection costs and
4 improved deliverability, I can speak to that.

5 Q Let me think about this a different way. So
6 if you had a generation-centric planning system, sort of
7 like what we have right now, it still requires
8 transmission upgrades?

9 A (Witness Chiles) That's correct.

10 Q But in your testimony you identify that we
11 could possibly optimize the transmission system to reduce
12 overall costs?

13 A (Witness Chiles) Correct.

14 Q Okay. Generally could a generation-centric
15 planning approach be concerned kind of like a bottom-up
16 transmission planning process?

17 A (Witness Chiles) I usually think about
18 bottom-up in the context of a regional transmission
19 organization where the members of that group submit a
20 project based upon their local needs and that gets rolled up
21 into a common plan. Yeah, what I'm thinking about is in
22 terms of generation.

23 The question is does the -- does the
24 transmission planner have the obligation to make the system
25 work when a company says: You're putting generation here.

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1 Go figure it out?

2 Or does the transmission planner have the
3 option to say: Based upon the grid and the needs of the
4 grid, these are viable locations for placing generation such
5 that the grid can accommodate that and the grid operates
6 more efficiently. So that's how I view those two things.

7 Q But there is a top-down approach?

8 A (Witness Chiles) There is top-down approach,
9 that's correct.

10 Q Okay. Would you describe Georgia Power's
11 current transmission planning process as a bottom-up
12 approach or a top-down approach?

13 A (Witness Chiles) Probably more of the
14 bottom-up, in terms of the -- I think the generation tends
15 to lead the transmission more than the transmission leading
16 the generation.

17 Q But they both have value, both the bottom-up
18 and the top-down?

19 A (Witness Chiles) Absolutely. And if you look
20 at most processes, most organizations have both a top-down
21 and bottom-up for that reason.

22 Q And when you say organizations, what do you
23 mean?

24 A (Witness Chiles) That -- it can mean utilities.
25 It can mean state commission planning processes. It can

1 mean regional transmission organizations. It really -- it
2 could even be within a single company.

3 Q Okay. On page 14 of your testimony, you give
4 Arizona and North Carolina as two examples of states that
5 do joint transmission planning through some sort of
6 stakeholder process where the commissions, quote, have
7 oversight and a seat at the table in the strategic
8 evaluation of the regional transmission system.

9 Do you believe that the Georgia Public Service
10 Commission staff currently have oversight and a seat at the
11 table regarding strategic evaluation of the regional
12 transmission system?

13 A (Witness Chiles) Only to the extent that they
14 participate in this integrated resource plan every three
15 years.

16 Q Have you participated in the North Carolina
17 Transmission Collaborative?

18 A (Witness Chiles) I have not, but I have clients
19 who have participated in that process.

20 Q Do you happen to know who leads that process?

21 A (Witness Chiles) I do not.

22 Q Is it possible that's a utility-lead process?

23 A I do know that utilities do have seats at the
24 table at that process. I do not know if there's an
25 independent evaluator or not.

1 Q Are you familiar that that North Carolina
2 Transmission Collaborative has a planning working group?

3 A (Witness Chiles) Yes, I am.

4 Q Did you know that the planning working group
5 requirements require a bachelor's degree in engineering to
6 participate?

7 A (Witness Chiles) Yes, I did.

8 Q Are there any nonutility members of that
9 planning working group?

10 A (Witness Chiles) I don't know the roster.

11 Q You also had mentioned that there's a
12 transmission advisory group?

13 A (Witness Chiles) That's correct.

14 Q Has the transmission advisory group ever
15 proposed an interregional transmission project?

16 A (Witness Chiles) I haven't reviewed the last
17 couple of plans.

18 Q Do you happen to know who bears the cost of
19 the additional transmission solutions and studies that are
20 recommended in that process?

21 A I do not.

22 Q Would it surprise you that it's the requester
23 that has to pay for those costs?

24 A (Witness Chiles) The requester of the project
25 pays for the entire project cost?

1 Q Of the study.

2 A (Witness Chiles) It wouldn't surprise me that
3 the requester pays for that study. That's similar to what
4 happens when we talk about interconnection service. If you
5 request interconnection service, you pay the deposit for the
6 study.

7 Q Don't you think it would be cost-prohibitive
8 for nonprofit organizations to request studies in that
9 process if they are the ones that are going to have to pay
10 for those studies?

11 A (Witness Chiles) I would think that depending
12 upon that cost and depending upon how you -- the type of
13 budgets you propose, I would suggest that those groups get
14 together and form a coalition to propose a project and share
15 those costs amongst its members.

16 Q Regard CEII, what is that?

17 A (Witness Chiles) Confidential energy
18 infrastructure information.

19 Q Can you give an example of some of those?

20 A (Witness Chiles) Maps of the power system,
21 power flow models would be a couple of examples.

22 Q And some of those things have been provided
23 in this integrated resource plan; correct?

24 A (Witness Chiles) They have been provided under
25 a confidentiality agreement and are shared.

1 Q Okay. So it's not uncommon for intervening
2 parties, for instance, to be granted access to CEII data
3 so long as they sign a nondisclosure agreement?

4 A (Witness Chiles) If they sign an NDA. Now, if
5 it's a federal situation, then you would have to go through
6 FERC and request, you know, that clearance and then the
7 utility would grant it.

8 Q Okay. Do you happen to know if the North
9 Carolina Transmission Collaborative performs both top-down
10 and bottom-up transmission analyses?

11 A (Witness Chiles) I would not. My understanding
12 is I think that the utilities present their plans and then
13 that rolls into what the North Carolina Collaborative
14 actually uses that as a foundation for evaluating other
15 projects.

16 Q Do you happen to know how many staff from the
17 North Carolina Utility Commission oversee that process?

18 A (Witness Chiles) I do not.

19 Q How many consultants from the utility
20 commission oversee that project?

21 A (Witness Chiles) I do not.

22 Q Is the IRP incorporated in that process?

23 A (Witness Chiles) I do not know.

24 Q But you still believe the North Carolina
25 process is better than the current Georgia process?

1 A (Witness Chiles) I believe the North Carolina
2 process gives a framework for which better transparency and
3 engagement exists, which ultimately, to me, it would be an
4 improvement over the current process where we see a plan
5 every three years.

6 Q Do states and regional transmission
7 organizations have significant oversight regarding
8 transmission planning and siting?

9 A (Witness Chiles) When you say states, are you
10 referring to state commissions?

11 Q Yes.

12 A (Witness Chiles) Okay. Yes, they do. Because
13 the -- I'll use MISO as an example. The MISO board, they
14 approve a transmission project, but that project will go
15 before the state commission, who will have the option to
16 review and determine whether or not that project is useful
17 and whether it's appropriate and prudent for the state.

18 Q And so state PSCs still have to approve the
19 transmission projects that the RTOs recommend; right?

20 A (Witness Chiles) That is correct.

21 Q And state public service commissions often
22 hire specific staff and consultants just to interact with
23 the RTO stakeholder processes; right?

24 A (Witness Chiles) That is correct.

25 Q Do you know what the Organization of MISO

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1 States is?

2 A (Witness Chiles) Yes, I do.

3 Q What is it?

4 A (Witness Chiles) The Organization of MISO
5 States is a collective of representatives of state
6 commissions of each of these states which are part of the
7 MISO footprint.

8 Q And they have considerable oversight in the
9 MISO process?

10 A (Witness Chiles) They do. They have their own
11 budget, they have their own staff of consultants. They also
12 have ability to file, you know, at FERC on various issues,
13 which MISO will make submittals to the federal commission
14 for.

15 Q Do you know what the Southwestern Power
16 Pool's regional state committee is?

17 A (Witness Chiles) It's a very similar
18 organization to OMS.

19 Q Okay. Does PJM have something similar?

20 A (Witness Chiles) I believe they have the
21 Organization of PJM States.

22 Q OPSI?

23 A (Witness Chiles) I believe that's correct.

24 Q I love the acronym.

25 So which RTOs are you heavily involved in?

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1 A (Witness Chiles) I'm most heavily involved in
2 the Midcontinent ISO and the Southwest Power Pool. I have
3 some involvement in ERCOT and limited involvement in PJM.

4 Q Do you have a favorite RTO?

5 A (Witness Chiles) That's like asking me if I
6 have one of my favorite children. The answer to that would
7 be no, in case they're listening.

8 Q But you love them all?

9 A (Witness Chiles) I appreciate the differences
10 between them.

11 Q Are those RTOs, in your opinion today, better
12 at transmission planning and stakeholder engagement than
13 the North Carolina process?

14 A (Witness Chiles) I would say they provide a
15 higher level of stakeholder participation.

16 Q And the North Carolina process is better than
17 the Georgia process?

18 A (Witness Chiles) Once again, from a
19 transparency standpoint, I would say that North Carolina
20 does provide opportunities for stakeholders where the
21 Georgia process doesn't.

22 COMMISSONER McDONALD: That's the second time
23 you've asked that same question.

24 MADAM CHAIR PRIDEMORE: And you also know that
25 North Carolina is 95 miles northeast of here.

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1 MR. MAHAN: Yes, ma'am.

2 MADAM CHAIR PRIDEMORE: Like, we're in Georgia
3 and this gentleman has filed this testimony about
4 Georgia.

5 MR. MAHAN: Yes, ma'am. He is the sole RTO
6 expert that we have had on any witness stand. And
7 considering the importance of transmission planning,
8 I'd really like to continue asking about transmission
9 planning and --

10 MADAM CHAIR PRIDEMORE: But you do recognize
11 that you're in the state of Georgia. Georgia's not
12 in an RTO. Whether or not to be in an RTO or even
13 repeat the acronym isn't even in this IRP, so --

14 MR. MAHAN: Yes. Which I agree with that.

15 MADAM CHAIR PRIDEMORE: You've been given a lot
16 of leeway here, but -- but let's keep it centered.
17 I'm sure Mr. Chiles has a lot of opinions on a lot of
18 important things. And let's keep it centered here on
19 his testimony.

20 MR. MAHAN: Yes, ma'am.

21 BY MR. MAHAN:

22 Q Would it be valuable to incorporate
23 surrounding states in a transmission planning analysis,
24 like Alabama and Tennessee?

25 A (Witness Chiles) I believe that already happens
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1 as part of the SERTP.

2 Q But do you think the SERTP is adequate in
3 addressing Georgia's problems?

4 A (Witness Chiles) I can't speak to that. I'm
5 not engaged in the day-to-day activities of the SERTP.

6 Q On page 17 of your testimony, line 13,
7 regarding the ten-year transmission plan, you state: The
8 company did not provide any analysis that indicated the
9 projects were the optimal solutions with respect to cost.

10 Do you recall saying the exact same thing in
11 the 2019 IRP?

12 A (Witness Chiles) Yes, I do.

13 Q How do you define optimal?

14 A (Witness Chiles) Optimal with respect to cost?

15 Q Yes.

16 A (Witness Chiles) It is a combination of the
17 economic factors and the reliability factors. Once again, I
18 can spend very little on a transmission upgrade and it may
19 solve the problem, but it may not solve the problem for 20
20 years. It may solve the problem for two years.

21 I can spend a whole lot more money, I can have
22 a great reliability solution, but I may have such limited
23 flow on that line that really the line is not used and
24 useful for other than maybe a few hours of the year. So
25 that's what I mean by optimization with respect to cost.

1 Q Why would the company not automatically
2 select the optimal transmission solution?

3 A (Witness Chiles) I think the company would
4 select the optimal transmission solution. I think it's in
5 the best interest to do so. I'm just saying in my testimony
6 that they did not provide that analysis to us. They
7 provided what they provide in Appendix 3 of their IRP and
8 that's what he reviewed.

9 Q Is it possible that expanding the
10 transmission system could provide more opportunities for
11 competitors to compete against Georgia Power's existing
12 generation?

13 A (Witness Chiles) That's a hypothetical. I
14 think any time you expand the grid and you change power
15 flows, that creates opportunity.

16 Q So it's possible the company may have an
17 incentive to not find the optimal transmission solution on
18 their own?

19 A (Witness Chiles) I'm not going to speak to
20 that, sir.

21 Q That's fine.

22 So how would you recommend for the Commission
23 and staff to be able to determine if a solution is actually
24 optimal?

25 A (Witness Chiles) I think what would help, you
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1 know, from an evaluation standpoint is understanding better
2 the criteria by which the company uses to define the optimal
3 solution. And just getting an understanding of the why
4 behind the number I think would be very helpful.

5 Q Would it be helpful to have some sort of
6 independent transmission analysis completed by a third
7 party?

8 A (Witness Chiles) In lieu of a process by which
9 staff is engaged --

10 Q In addition to?

11 A (Witness Chiles) Depends on the quality of that
12 analysis and it depends on what are the goals of that
13 analysis. You know, I think, once again, the people that
14 are most interested in and understanding that are probably
15 the Commission, the staff, you know, and the company.

16 You know, primarily, in terms of the rates,
17 reliability, all of that, you know, I think that, you know,
18 those folks need to understand very clearly what are the
19 drivers behind the selection of one project over another.

20 Q But there are non-RTO consulting firms that
21 could perform this type of analysis for the Commissioners?

22 A (Witness Chiles) There --

23 MADAM CHAIR PRIDEMORE: Was that a question?

24 MR. MAHAN: Yes.

25 WITNESS CHILES: I can guarantee you there are

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1 consulting firms all over this country that can
2 perform all types of things and would be more than
3 happy to do so.

4 BY MR. MAHAN:

5 Q On page 18, line 10, you stated that the
6 summer peak power flow cases provided by the company were
7 reasonable. Did you only evaluate the power flow cases
8 for the summer?

9 A (Witness Chiles) No. We evaluated some
10 different seasonal cases, as well.

11 Q Did you evaluate all the cases provided?

12 A (Witness Chiles) We received over 200,000
13 cases. So I don't think that it would have been prudent or
14 timely for us to evaluate every single case that the company
15 provided. We did do a selected number of cases in our
16 evaluation consistent with what we thought would be the ones
17 primary for making determinations in this proceeding.

18 Q At the end of your testimony, or page 28 --
19 sorry. At the end of page 28, and to page 29 of your
20 testimony, you stated that you hope -- or that hopefully
21 that the company would include transmission alternatives
22 in the North Georgia reliability and reliance action plan.

23 Are you aware that you have previously
24 requested this annual -- an assessment of nontransmission
25 solutions in the earlier IRPs?

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1 A (Witness Chiles) I am aware of that, sir.

2 Q And the company still hasn't done it;
3 provided those nontransmission alternatives to you?

4 A (Witness Chiles) I have not -- I mean, I have
5 seen -- you know, I mean, obviously the battery storage
6 projects at this point I would say are fully into that. But
7 I don't think there has been large-scale deployment of
8 nonwire solutions yet on the company's transmission system.

9 MADAM CHAIR PRIDEMORE: Can I ask you that
10 question in a more forthright way?

11 WITNESS CHILES: Absolutely.

12 MADAM CHAIR PRIDEMORE: Did you supply this
13 recommendation and make a data request to the company
14 for that?

15 WITNESS CHILES: We supplied the recommendation
16 as part of the 2019 IRP.

17 MADAM CHAIR PRIDEMORE: Okay.

18 BY MR. MAHAN:

19 Q If the Commission hired an independent
20 consultant to conduct an independent transmission
21 analysis, the Commission could theoretically require that
22 consultant to conduct its analysis that you recommended,
23 though; right?

24 A (Witness Chiles) I can't speak to what the
25 Commission would require. That's their call, sir.

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1 Q Okay. On page 32 of your testimony, line 9
2 and 10, you said: Having better clarity from the
3 renewable RFP will result in a transmission solution that
4 is right-sized for North Georgia.

5 Which RFP are you talking about? Are you
6 talking about the staff-proposed statewide renewable RFP
7 next year?

8 A (Witness Chiles) Yeah. It would include that,
9 yes, sir. Because as part of the problem is when you deal
10 with power flow modeling, location is very important in
11 terms of power flow models. So until you know what
12 resources at what locations, then you're making a
13 guesstimation on what you think is the appropriate
14 transmission system.

15 You know, unfortunately, transmission models
16 are not very forgiving. They really expect to have loads in
17 the right spots, lines in the right spots, and generation in
18 the right spots, and dispatched at the right setting to get
19 the answer you want.

20 Q On page 8, lines 14 through 18 of your
21 testimony, you explain that buses or substations or
22 locations in North Georgia that were provided by the
23 company north of I-20 were used to evaluate renewable
24 interconnection locations.

25 Do you recall that component of your testimony?

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1 A (Witness Chiles) Yes, I do, sir.

2 Q Did you evaluate each one of those sites
3 specifically to see if they could actually host a
4 300-megawatt solar farm?

5 A (Witness Chiles) We did not evaluate every one
6 of those sites.

7 Q Did you evaluate any of those sites?

8 A (Witness Chiles) Subject to check, I'd have to
9 go back. I don't recall if we evaluated any of those or
10 not.

11 Q Do you recall the company calling those the
12 optimal sites, though?

13 A (Witness Chiles) I do you recall that, yes,
14 sir.

15 Q If you call something optimal, but if -- even
16 though it's not, is it truly optimal?

17 A (Witness Chiles) I think we're talking about an
18 absolute versus an incremental discussion here. And,
19 obviously, optimal would be a copper sheath. And we're not
20 dealing with that in this case.

21 If it's optimal as related to other positions
22 on the system, then I think, you know, there is a case for
23 that.

24 MR. MAHAN: Okay. I appreciate it. Thank you
25 for you patience.

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1 MADAM CHAIR PRIDEMORE: You're welcome.

2 Do we have anybody else from the appearance
3 list that would like to question this witness panel
4 that was not present yesterday?

5 (No response.)

6 GA Solar. Resource Supply Management.

7 (No response.)

8 MADAM CHAIR PRIDEMORE: No. Everybody else has
9 checked in.

10 All right. Very good. Georgia Power.

11 MS. PRYOR: Good morning, Mr. Chiles and
12 Mr. Thomas. Allison Pryor for Georgia Power Company.

13 CROSS-EXAMINATION

14 BY MS. PRYOR:

15 Q I'm going to start with a couple of follow-up
16 questions.

17 Mr. Chiles, did you participate in the 2019
18 IRP?

19 A (Witness Chiles) Yes, I did.

20 Q Do you recall at that time the company was
21 looking into transmission requirements needed to support
22 the future coal retirements, including Bowen 1 and 2?

23 A (Witness Chiles) Yes, I do.

24 Q Okay. And in response to a question of
25 Commissioner Pridemore, as well as Mr. Mahan, you were

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1 discussing the difference between transmission build-out
2 and generation build-up. Do you recall that?

3 A (Witness Chiles) Yes, I do.

4 Q And you mentioned that there's a lag in
5 transmission build-out. Are you recommending that
6 transmission precede generation build-out?

7 A (Witness Chiles) Well, I think that ultimately
8 what we would love to see is that those things operate in
9 parallel. And right now we are behind. So to catch up, you
10 would have to have transmission leading generation a little
11 bit until they caught up. But ultimately you want things to
12 proceed in a truly integrated process, rather than operating
13 independently and then coming together at the last minute.

14 Q Okay. And just to clarify what we're talking
15 about today, you'd agree that the transmission system as
16 it exists today is not inadequate and that we are just
17 talking about future additions and potential inadequacies
18 that may occur if anticipated constraints are not
19 addressed?

20 A (Witness Chiles) I'm agreeing that the system
21 today as constructed meets NERC TPL planning requirements
22 and that it operates appropriately for the contingencies and
23 solution sets that are needed. Future plans depends, once
24 again, upon new transmission projects, new generation
25 projects, retirements, additions and other changes in system

1 conditions.

2 Q And you would agree that there are major
3 transmission challenges for delivering additional
4 renewable energy from the south to the North Georgia
5 region?

6 A (Witness Chiles) I believe the company
7 identified that there is a deficit of generation in
8 North Georgia which would require power flow movement from
9 south to north, yes.

10 Q And you'd agree that the continued high
11 concentration of renewable resources in South Georgia is a
12 primary driver of that need?

13 A (Witness Chiles) I would say it's one of two
14 primary drivers. I think there's two parts to that that we
15 have to consider. One is an increase in generation in that
16 part of the system, but also you have a deficit in the
17 northern part.

18 So basically what you're creating is a sink in
19 the northern part that has to be filled. And that's going
20 to come from multiple locations. As we know, there's
21 interface ties between Georgia and multiple other states.

22 So those electrons are flowing from somewhere
23 to that load sink. I wouldn't say that a hundred percent of
24 that is flowing from South Georgia through North Georgia,
25 though.

1 Q Okay. And I think you just addressed a
2 little bit of this. But if additional renewable projects
3 are not sited in North Georgia, what type of transmission
4 projects are necessary to move potential energy from South
5 Georgia to North Georgia?

6 A (Witness Chiles) Well, I think what we need to
7 do ultimately is to do an evaluation of that, looking at --
8 there's either one of two ways to do that. One is to look
9 at establishing -- I'll call it a planning zone, for lack of
10 a better term, to look at what it means to transfer power
11 from planning zones in the south to planning zones in the
12 north and to identify what level of transfer is required and
13 what transmission upgrades are needed. I would suspect
14 those would be higher voltage transmission upgrades, not
15 your lower-voltage 69 kV right there by a generator. I
16 would suspect it would be more volt transmission.

17 Q Okay. And in your experience, what is the
18 typical time frame for building major transmission
19 infrastructure like those you just described?

20 A (Witness Chiles) Well, as I mentioned earlier,
21 four to six years is not uncommon. And when you talk
22 about -- if you're talking about 500 kV running hundreds of
23 miles through the state, that's certainly going to take a
24 lot longer just because of the requirements to, you know,
25 deal with landowners, right-of-way, the siting issues,

1 alternate routing, and all that.

2 But, once again, we won't know the true answer
3 to that until we identify a set of projects and see, you
4 know, what those needs are. It's very possible those needs
5 could be made with multiple shorter lines and lower
6 voltages, which solve underlying problems at a lower cost to
7 building major EHV facilities. But we wouldn't know that
8 until there's a study done which actually identifies that
9 list of upgrades.

10 Q Okay. And is it possible that new South
11 Georgia solar projects could be delayed, curtailed, or
12 even canceled before those new transmission improvements
13 are constructed?

14 A (Witness Chiles) Could you repeat the question,
15 please?

16 Q Sure. I will restate it.

17 So, for example, if it's going to take four to
18 six years for these transmission infrastructure projects to
19 be constructed, is it possible that any solar projects
20 located in South Georgia in the meantime could be delayed,
21 curtailed, or canceled until that generation -- that
22 transmission infrastructure is completed?

23 A (Witness Chiles) Well, the curtailment piece,
24 that's really an operational decision the company would
25 make. So that wouldn't be anything that a transmission

1 planner would be engaged with.

2 In terms of delay, that's going to depend upon
3 the contract that's established between the company and that
4 solar provider. If it's affirmed in the contract that they
5 can provide from another resource, then the arrangement
6 between the company and that provider may still move
7 forward. But it doesn't necessarily mean they can watch
8 over the flow from that solar facility.

9 Q But you would agree those are possible
10 outcomes?

11 A (Witness Chiles) There are many possible
12 outcomes, yes.

13 Q And in your experience, can geographic
14 diversity of generation help transmission constraints?

15 A (Witness Chiles) It can help, but it can also
16 harm.

17 Q How does reliance on generation from distant
18 geographic regions negatively impact transmission system
19 reliability and resiliency?

20 A (Witness Chiles) That's really going to depend
21 upon the configuration of the transmission system. For
22 example, when you look out the Western Interconnect, there
23 are hundreds and hundreds of miles between generation
24 sources and very limited transmission. And that system
25 seems to work pretty well for the most part.

1 Obviously, you know, people prefer central
2 station being closer to, you know, the load, as long as it's
3 not in their backyard. But, you know, once again, it
4 depends upon the configuration of the system and the
5 operational parameters by which that system is run.

6 Q Thank you.

7 Now I have a couple of questions for
8 Mr. Thomas.

9 A (Witness J. Thomas) Okay.

10 Q Generally speaking, do you agree that the
11 more accurate the load forecast the better?

12 A (Witness J. Thomas) Yes. Generally.

13 Q And do you agree that a load forecast is only
14 as good as the data included as input in that analysis?

15 A (Witness J. Thomas) Yes.

16 Q On page 7 of your testimony you recommend
17 that the company update its residential energy consumption
18 survey to collect more recent information on end-use
19 market saturations; is that correct?

20 A (Witness J. Thomas) That's correct.

21 Q And why do you believe an update of this
22 self-reported saturation survey is needed?

23 A (Witness J. Thomas) Well, I believe that -- so
24 the company uses a couple of different sources. They use
25 regional information from the EIA, which the EIA collects

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1 through a survey process as well. And then the
2 system-specific data, which is self-reported.

3 And it is my understanding through informal
4 discussions with Georgia Power staff that the two sources
5 are fairly similar right now. My recommendation is to
6 continue to collect that information to see if it diverges
7 from the regional EIA information. I think it's just good
8 practice to try to measure that and keep track of that in
9 case there are divergences.

10 Q Do you object to the company's use of the EIA
11 data?

12 A (Witness J. Thomas) I do not.

13 Q Okay. Do you expect the data for Georgia and
14 Georgia Power's service territory to be that different
15 than the national regional end-use information available
16 from the EIA?

17 A (Witness J. Thomas) It is possible. One
18 example I could give, in a recent project in another state,
19 we did a survey in 2021 and found that the share of
20 standalone freezers had doubled from a prior survey and it
21 was attributed to COVID activity. Customers going out and
22 buying standalone freezers and then it not getting -- you
23 know, it had not made it into the EIA information yet.

24 So I think there are instances where you might
25 find a divergence depending on a specific population and the

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1 behavior of your residential customers relative to the
2 region.

3 Q And would you agree that self-reported
4 information is less accurate than non?

5 A (Witness J. Thomas) It depends on the
6 information. I think ownership of electric appliances can
7 be fairly reliably reported on, but, for instance,
8 efficiency information is probably less reliable.

9 Q Do you agree that the load forecast estimates
10 and captures projected energy use over the forecast
11 horizon?

12 A (Witness J. Thomas) Could you repeat that?

13 Q Sure. Do you agree that the load forecast
14 estimates and captures projected energy use over the
15 forecast horizon?

16 A (Witness J. Thomas) Yes.

17 Q And one of the major drivers of energy use is
18 weather?

19 A (Witness J. Thomas) Yes.

20 Q It's also true that utilities use weather
21 normal data to neutralize the impact of extreme weather on
22 the load forecast?

23 A (Witness J. Thomas) That's correct.

24 Q Is it -- would you agree that extreme weather
25 years have a greater impact on a single budget cycle using

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1 a 20-year definition compared to the company's 41-year
2 definition?

3 A (Witness J. Thomas) Yes. I would agree that a
4 20-year average, a single extreme year would have a greater
5 impact on that average, yes.

6 Q And do you agree that trends shown in the
7 20-year forecast are also seen in the company's 41-year
8 weather normal forecast, which is less pronounced?

9 A (Witness J. Thomas) Yes.

10 Q Is it fair to say that using longer weather
11 normal definition results in less variability and fewer
12 year-to-year swings?

13 A (Witness J. Thomas) I would agree with that,
14 yes.

15 Q And isn't it true that a longer weather
16 normal definition provides greater stability in the load
17 forecast?

18 A (Witness J. Thomas) When -- I would agree with
19 that when the historical period is trending in one direction
20 or the other, then a longer forecast would be more stable.
21 If the underlying history has no trend, then both would be
22 very stable.

23 Q And greater stability produces a more
24 accurate load forecast; do you agree?

25 A (Witness J. Thomas) I do not agree. Again, if
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1 the historical period is trending in a certain direction,
2 then a shorter period is going to pick up that trend and
3 should be more accurate over time.

4 Q But you do agree that the trend would appear
5 in both a 20-year forecast and a 41-year forecast, just
6 less pronounced?

7 A (Witness J. Thomas) Yes.

8 MS. PRYOR: No further questions. Thank you.

9 MADAM CHAIR PRIDEMORE: Redirect.

10 MR. THOMAS: Thank you.

11 REDIRECT EXAMINATION

12 BY MR. THOMAS:

13 Q If the Commission were to establish a
14 collaborative planning process, could the Commission set
15 rules governing things like who participates, who pays for
16 different activities, and what the scope of the process
17 would look like?

18 A (Witness Chiles) Absolutely.

19 Q And the Commission, if they established such
20 a process, they could contain control over what
21 transmission projects are approved for cost recovery, as
22 well; is that right?

23 A (Witness Chiles) I would believe that would be
24 correct. Depends what's included in the rate base, yes.

25 Q Okay. And for Bowen 1 and 2 retirement, does
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1 the company have a plan to address and upgrade the
2 transmission system to accommodate that retirement?

3 A (Witness Chiles) Yes, it does.

4 Q And is the issue of transmission planning,
5 and in context of Bowen 3 and 4 retirement, due to the
6 company not having a long-term strategic plan for the
7 transmission system, in your opinion?

8 A (Witness Chiles) I would think it's a
9 combination of factors. I think you were dealing with
10 timing while on ELG. You were dealing with tagalong
11 transmission upgrades being constructed. And so there's
12 multiple factors with that.

13 Q Okay. And could a collaborative process help
14 with that long-term planning process?

15 A (Witness Chiles) To the extent you perform
16 scenario planning and look at, you know, other options, look
17 at -- you know, for example, you know, there are regions
18 where we look at advanced technology acceptance, where you'd
19 look at statewide mandates, we look at policy cases. So in
20 those type of situations, I think there would be benefit to
21 that.

22 Q And is the issue regarding transmission plan
23 for Bowen 3 and 4 retirement due to the need to approve
24 the projects without enough adequate time for Commission
25 review?

1 A (Witness Chiles) I believe that's the -- I
2 believe that is the issue, yes, sir.

3 MR. THOMAS: Chair Pridemore, I would ask that
4 this panel be excused and that Exhibits -- Staff
5 Exhibits 64 through 71 be entered into the record.

6 MADAM CHAIR PRIDEMORE: So moved, so marked,
7 and you're excused.

8 (Staff Exhibits 64 through 71 were admitted
9 into evidence.)

10 MADAM CHAIR PRIDEMORE: Let's give a moment for
11 the court reporter to reset and our panelists.

12 All right. Everyone is ready. You can go
13 ahead, Alex.

14 MR. DAVIS: Thank you. Madam Chair, at this
15 time I'd call Jamie Barber, Nick Cooper, and Richard
16 Spellman to the stand.

17 Would you each please raise your right hand.
18 Thereupon,

19 JAMIE BARBER,
20 NICK COOPER,
 RICHARD SPELLMAN,

21 having been duly sworn, testified as follows:

22 DIRECT EXAMINATION

23 BY MR. DAVIS:

24 Q On May 6 of this year, did you file or cause
25 to be filed 64 pages of testimony in question-and-answer

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1 format, along with 17 exhibits marked as BCS-1 through 17?

2 A (Witness Cooper) We did.

3 Q Do you have any corrections you need to make
4 to that prefiled testimony or exhibits at this time?

5 A (Witness Cooper) Yes. Three relative minor
6 corrections. On page 44, lines 16 through 19, the exhibit
7 cited should say Staff Exhibit_BCS-15, not BSC-14. The
8 numbers cited in the additional sum should be updated as
9 follows: As shown in Staff Exhibit BCS-15, the company has
10 earned an average of 9.82 million overall in addition sum
11 over the previous five years, from '17 to '21. For the
12 residential portfolio, the average was 2.16 million per
13 year. And for the commercial portfolio, the average was
14 7.66 million per year.

15 Second, Staff Exhibit BCS-13 should be labeled
16 as commercial prescription -- prescriptive budget analysis,
17 not commercial behavioral budget analysis. The testimony
18 correctly identifies the program be considered in the
19 exhibit. And all data in the exhibits are correct.

20 And, last, on page 61, line 21, it should
21 reference the commercial behavioral program, not commercial
22 behavior program.

23 Q And noting these corrections, if I were to
24 ask you the same questions today under oath, would your
25 answers be the same as set forth in these -- in this

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1 prefiled direct testimony?

2 A (Witness Cooper) Yes, they would.

3 MR. DAVIS: Madam Chair, the court reporter has
4 been provided with a copy of the prefiled direct
5 testimony and I would ask that the direct testimony
6 be copied into the record as if given here today.
7 And I would ask that Exhibits BCS-1 through 17 be
8 entered into the record and marked as Staff
9 Exhibits 72 through 79.

10 MADAM CHAIR PRIDEMORE: So moved. So marked.

11 (The documents referred to were marked for
12 identification as Staff Exhibits 72 through 79.)

13 (Whereupon, the prefiled direct testimony
14 of Ms. Barber, Mr. Cooper, and Mr. Spellman follows:)

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1 **I. QUALIFICATIONS**

2 **Q. MS. BARBER, PLEASE STATE YOUR NAME, TITLE, AND BUSINESS**
3 **ADDRESS.**

4 A. My name is Jamie Barber, and I am the Director of the Energy Efficiency and Renewable
5 Energy Unit for the Georgia Public Service Commission ("Commission"). My business
6 address is 244 Washington Street SW. Atlanta, GA 30334.

7 **Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
8 **EXPERIENCE.**

9 A. My educational background and work experience are provided in my resume, which is
10 attached as Staff Exhibit_BCS-1.

11 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?**

12 A. Yes. I testified in each of the 1998 through 2009 United Cities Gas Company (now known
13 as Atmos Energy Corporation) Gas Supply Plan Proceedings. I have also testified in
14 Docket No. 10270, GPSC Determination of Lack of Market Constraints on Atlanta Gas
15 Light Company's Commodity Sales; Docket No. 11114, Rule Nisi Against United Gas
16 Management of Georgia, Inc.; Docket No. 14311, Earnings Review to Establish Just and
17 Reasonable Rates for Atlanta Gas Light Company; Docket No. 15296 Service Quality
18 Standards for Certified Marketers and Regulated Provider; Docket No. 18638-Atlanta Gas
19 Light Company's 2004/2005 Rate Case; Docket No. 20298 Atmos Energy Corporation's

1 2005 Rate Case; Docket No. 27163 Atmos Energy Corporation's 2008 Rate Case; Docket
2 No. 30442 Atmos Energy's 2010 Rate Case; Docket No. 36498 Georgia Power Company's
3 2013 IRP Filing; Docket No. 36499 Georgia Power Company's 2013 Demand Side
4 Program Certification; Docket No. 37854, Georgia Power Company's Application for the
5 Certification of the Power Purchase Agreements for Wind Resources from the Blue
6 Canyon II and Blue Canyon VI Wind Farms; Docket No. 38877, Georgia Power
7 Company's Application for the Certification of the 2015 and 2016 Advanced Solar
8 Initiative Prime Power Purchase Agreements and Request for Approval of the 2015
9 Advanced Solar Initiative Power Purchase Agreements, Docket No. 36989 Georgia Power
10 Company's 2013 Rate Case, Docket No. 40161 Georgia Power Company's 2016 IRP
11 Filing, 40162 Georgia Power Company's 2016 Demand Side Program Certification,
12 Docket No. 41596, Georgia Power Company's Application for the Certification of the
13 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase
14 Agreements, Docket No. 41734, Georgia Power Company's Application for the
15 Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale
16 Power Purchase Agreements for the Commercial and Industrial Program, Docket No.
17 43210 Georgia Power's 2019 IRP Filing, and Docket No. 43211 Georgia Power
18 Company's 2019 Application for the Certification, Decertification, and Amended
19 Demand-Side Management Plan, and Docket No. 42516 Georgia Power's 2019 Rate Case.

20 **Q. MR. COOPER, PLEASE STATE YOUR NAME, TITLE, AND BUSINESS**
21 **ADDRESS.**

1 A. My name is Nick Cooper, and I am a Utilities Engineer for the Commission. My business
2 address is 244 Washington Street SW. Atlanta, GA 30334.

3 **Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
4 **EXPERIENCE.**

5 A. My educational background and work experience are provided in my resume, which is
6 attached as Staff Exhibit_BCS-2.

7 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?**

8 A. Yes. I have testified in Docket No. 40162 Georgia Power Company's 2016 Demand Side
9 Program Certification and Docket No. 43211 Georgia Power Company's 2019 Application
10 for the Certification, Decertification, and Amended Demand-Side Management Plan.

11 **Q. MR. SPELLMAN, PLEASE STATE YOUR NAME, TITLE AND BUSINESS**
12 **ADDRESS.**

13 A. My name is Richard F. Spellman, and I am an Executive Consultant at GDS Associates,
14 Inc. ("GDS"), an engineering and management consulting firm which specializes in energy
15 supply, energy efficiency and demand response planning and analysis issues with clients
16 in the US and Canada. In addition to providing energy efficiency and demand response
17 program planning and evaluation services, GDS is implementing energy efficiency and
18 demand response programs for clients in several states. My business address is Suite 800,
19 1850 Parkway Place, Marietta, Georgia 30067.

1 Q. DOES GDS PROVIDE SERVICES TO BOTH GOVERNMENT AND UTILITY
2 CLIENTS?

3 A. Yes. GDS provides engineering and energy consulting services to electric and natural gas
4 utilities, government agencies, non-profit organizations, commercial organizations, other
5 consulting firms, and homeowners.

6 Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK
7 EXPERIENCE.

8 A. My educational background and work experience are provided in my resume, which is
9 attached as Staff Exhibit_BCS-3.

10 Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

11 A. Yes. I have testified before the Commission in twenty prior dockets including Docket No.
12 5601, Georgia Power's 1995 Integrated Resource Plan; Docket No. 5602, Savannah
13 Electric & Power Company's 1995 Integrated Resource Plan; Docket No. 6315, Georgia
14 Power Application for Certification of the Residential Load Management Program; Docket
15 No. 6325, Georgia Power Application to Establish a Customer Controlled Load
16 Management Rate; Docket No. 8708, Savannah Electric & Power Company's 1998
17 Integrated Resource Plan; Docket No. 8709, Georgia Power 1998 Integrated Resource
18 Plan; Docket No. 13305, Georgia Power Company's Application for Approval of the 2001
19 Integrated Resource Plan; Docket No. 13306, Savannah Electric and Power Company's
20 Application for Approval of the 2001 Integrated Resource Plan; Docket No. 17687,
21 Georgia Power Company's 2004 Integrated Resource Plan; Docket No. 17688, Savannah

1 Electric and Power Company Company's 2004 Integrated Resource Plan; Docket No.
2 4822, Capacity and Energy Payments to cogenerators under PURPA; Docket No. 19279,
3 Biomass Gas & Electric, LLC's Petition to Establish Docket Regarding Forsyth County
4 Renewable Energy Plant; Docket No. 31081, Georgia Power Company 2010 IRP Filing;
5 Docket No. 31082, Georgia Power's 2010 Demand Side Program Certification; Docket
6 No. 36498 Georgia Power Company 2013 IRP Filing; Docket No. 36499 Georgia Power
7 Company's 2013 Demand Side Program Certification; Docket No. 40161 Georgia Power
8 Company 2016 IRP Filing; Docket No. 40162 Georgia Power Company's 2016 Demand
9 Side Program Certification, Docket No. 43210 Georgia Power Company's 2019 IRP
10 Filing; and Docket No. 43211 Georgia Power Company's 2019 Application for the
11 Certification, Decertification, and Amended Demand-Side Management Plan.

12 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

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

15 **II. SUMMARY**

16 **Q. PLEASE PROVIDE THE RECOMMENDATIONS THAT STAFF IS MAKING**
17 **FOR THE COMMISSION TO CONSIDER.**

18 A. Based on our review of the Georgia Power Company's ("Georgia Power" or "Company")
19 filing, testimony, data request responses, and other pertinent information for this case, we
20 have the following recommendations for the Commission's consideration:

- 1 1. Staff recommends approval of the Company's Demand Side Plan as modified by Staff's
2 recommendations contained in this testimony.
- 3 2. Staff recommends requiring the Company to include an additional scenario in its 2025 IRP
4 development and resource optimization process where Demand Side Management
5 ("DSM") is allowed to compete head-to-head with supply-side options in the Company's
6 Integrated Resource Plan ("IRP") model. This modification should also be included in the
7 DSM Program Planning Approach as shown in Staff Exhibit_BCS-4.
- 8 3. Staff recommends that the Company's DSM Program Planning Approach be approved for
9 use going forward with the modification as proposed by Staff.
- 10 4. Staff recommends that the Demand Side Management Working Group ("DSMWG")
11 continue in its current form and be involved in the development of future DSM programs.
- 12 5. Staff recommends approval of the Company's request for decertification of the Residential
13 Power Credit and Commercial Midstream Programs.
- 14 6. Staff recommends approval of the certification of the HopeWorks Program.
- 15 7. Staff recommends approval of the Company's request for waiver of Commission Rule 515-
16 3-4-.04(4)(a)3 for the Thermostat Demand Response Program.
- 17 8. Staff recommends approval of the amended certificates for the Residential Behavioral,
18 Residential Home Energy Improvement, Residential Refrigerator Recycling, Residential
19 Specialty Lighting, Residential Home Energy Efficiency Assistance, Commercial Custom,
20 Commercial Prescriptive, Commercial Small Commercial Direct Install, and Commercial
21 Behavioral Programs.

- 1 9. Staff recommends that the Company pause the Commercial Behavioral Program pending
2 decertification, if the upcoming 2024 Evaluation, Measurement, and Verification
3 (“EM&V”) does not show the program to be cost effective.
- 4 10. Staff recommends the continuation of the Residential Investment to Save Energy (“RISE”)
5 pilot.
- 6 11. Staff recommends that the Automated Benchmarking Tool (“ABT”) continue for the 2023-
7 2025 program cycle as approved in the 2019 IRP.
- 8 12. Staff recommends that the Home Energy Improvement Program (“HEIP”) be expanded to
9 include the proposed Manufactured Homes Program, with the exception of “whole home
10 replacement” measures, as outlined in the DSMWG Advocacy Case.
- 11 13. Staff recommends approval of Staff’s recommended DSM energy savings targets as
12 provided in Staff Exhibit_BCS-9.
- 13 14. Staff recommends approval of Staff’s recommended DSM program budgets as provided in
14 Staff Exhibit_BCS-10. This recommendation includes a reduction of non-incentive costs
15 for certified programs by a total of \$6 million over the three-year program cycle.
- 16 15. Staff recommends the inclusion of a per building cap for the Commercial Custom Program
17 of \$75,000 in the Final Program Plans.
- 18 16. Staff recommends a continuation of the Education Initiative-Learning Power budget at \$4
19 million for 2023-2025.
- 20 17. Staff recommends a continuation of the Residential and Commercial Energy Efficiency
21 Consumer Awareness budgets at \$4.5 million and \$1.1 million, respectively for the 2023-
22 2025 program cycle.

- 1 18. Staff recommends a continuation of the pilot budgets of \$3 million per year, to be split
2 evenly between Residential and Commercial pilots and that Staff has input regarding any
3 proposed pilots before they are implemented by the Company and throughout the course
4 of the pilot.
- 5 19. Staff recommends that the current, Commission-approved, DSM Additional Sum
6 mechanism remain in place.
- 7 20. Staff recommends that the Company's Additional Sum continue to be based on net energy
8 savings, as opposed to the Company's request to use gross energy savings.
- 9 21. Staff recommends that once a program implementer is selected and program plans are
10 drafted that these plans be provided to Staff for review and approval prior to the
11 implementation of the programs. The Company should provide Staff at least 15 days for
12 review of the Final Program Plans.
- 13 22. Staff recommends continuation of the current DSM True-Up process, including not
14 allowing the rollover of unspent annual budget dollars or unrealized savings targets.
- 15 23. Staff recommends that the Commission approve the continuation of a three-year program
16 EM&V cycle.
- 17 24. Staff recommends that the Company continue to utilize the Commercial lighting HOU
18 reflected in Staff Exhibit_BCS-17, and used in the Company's program planner, for
19 reporting gross savings during the 2023-2025 program cycle.
- 20 25. Staff recommends that the Company plan to evaluate income-qualified savings in a manner
21 consistent with the remainder of the Residential sector to confirm whether this NTG
22 assumption is appropriate.

26. Staff recommends using the valid 2021 EM&V results and using the 2018 EM&V results in all other instances as outlined in the EM&V and requested by the Company.

27. Staff recommends the continuation of current policy to implement the EM&V results in the first year of the next IRP cycle in 2026.

28. Staff recommends continuation of current Commission policy that requires the Company to provide detailed evaluation plans for each of the approved DSM programs within 90 days of the selection of Program Implementers for each of the certified programs.

29. Staff recommends the upcoming EM&V include a new in-situ metering study for the Refrigerator Recycling Program.

III. CURRENT COMMISSION DSM POLICY

Q. PLEASE DESCRIBE THE COMMISSION'S CURRENT DSM POLICY.

A. The Commission's Order issued in Docket No. 31082 on July 13, 2010 updated and clarified the Commission's DSM policy. The Commission's current DSM policies are set forth in that Order, including:

1. The adoption of Standard 16 of the 2007 Federal Energy Independence and Security Act ("EISA") that recognizes cost effective energy efficiency as a priority resource.
2. The continued use of "the Nine-Step DSM Planning Process".¹

¹ The Company now refers to this as the DSM Program Planning Approach.

- 1 3. The Commission Staff's role as the administrator of the Demand-Side Management
- 2 Working Group and its obligation to seek input from Working Group participants in
- 3 setting the agenda for each meeting of the Working Group.
- 4 4. The Company's duty to prepare and file with the Commission a new energy
- 5 efficiency potential study one year in advance of every IRP filing.
- 6 5. The use of the Total Resource Cost ("TRC") test to evaluate DSM programs
- 7 included in the Company's proposed DSM Plan. While the Rate Impact Measure
- 8 ("RIM") test should be considered in conjunction with other tests, such as the TRC
- 9 test, the Societal test, the Program Administrator test and the Participant test, a ratio
- 10 of above 1.0 for the RIM test should not be deemed mandatory. The RIM test is not
- 11 a test of economic efficiency. Rather, the RIM test is a test of equity or fairness.
- 12 Because the RIM test only indicates whether electric rates may increase if an energy
- 13 efficiency program is implemented, and not whether the impact may lower a
- 14 participant's overall electric bill, this test will screen out energy efficiency measures
- 15 that can save significant amounts of electricity and can lower customer electric bills.

16 **Q. HAS GEORGIA POWER COMPLIED WITH EISA STANDARD 16?**

17 A. No. EISA Standard 16 requires electric utilities to "(A) integrate energy efficiency

18 resources into utility, State and regional plans and (B) adopt policies establishing cost-

19 effective energy efficiency as a priority resource" (Energy Independence and Security Act,

20 121 Stat., Public Law 110-140-DEC. 19, 2007, SEC. 532(a) (16). UTILITY ENERGY

21 EFFICIENCY PROGRAMS). The Company did not allow demand side resources to

22 compete directly with supply-side resources in the Aurora modeling used to develop the

1 Company's resource expansion plan proposal in this IRP. Company Witness Andy Phillips
2 testified that while integrated modeling is technically possible, as shown in the DSM White
3 Paper, the Company chose not to complete fully integrated modeling and decided to
4 continue with previous methods (Transcript (Tr.) at 655).

5 The Company prepared a static forecast of the impact of its base case energy efficiency
6 plan, and then subtracted those impacts from the Company's load forecast. While the
7 Company has included a defined amount of energy efficiency programs in its IRP, it has
8 not used an integrated approach to determine the optimal level of cost-effective energy
9 efficiency that should be included in its proposed expansion plan. Without using an
10 integrated approach, it is unclear whether there are more cost-effective DSM resources
11 available than what is currently included by the Company in its resource expansion plan.
12 Therefore, the proposed expansion plan will not represent the most cost-effective plan for
13 customers leading to higher electric bills.

14 **Q. DID THE COMPANY FILE A WHITE PAPER TO INVESTIGATE**
15 **METHODOLOGIES TO MODEL DSM RESOURCES ALONGSIDE**
16 **TRADITIONAL SUPPLY-SIDE OPTIONS AS REQUIRED BY THE 2019**
17 **IRP/DSM STIPULATION?**

18 **A.** Yes. The Company's DSM White Paper was filed under Docket No. 42311 in April 2021.

19 **Q. WHAT ARE THE FIRST TWO CONCLUSIONS STATED IN THE COMPANY'S**
20 **DSM WHITE PAPER?**

1 A. The first conclusion of the DSM White Paper stated that "Evaluating EE (energy
2 efficiency) as a resource alongside supply resources in the Company's existing resource
3 planning processes is possible". The second conclusion states "Aurora, the Company's
4 planning software system, is capable of evaluating EE alongside supply resources".

5 **Q. DOES STAFF BELIEVE THAT THE WHITE PAPER DEMONSTRATED THAT**
6 **ENERGY EFFICIENCY RESOURCES CAN BE ACCURATELY MODELED BY**
7 **AURORA?**

8 A. Yes. Staff agrees with those conclusions of the DSM White Paper and found the modeling
9 to be reasonable.

10 **Q. DOES STAFF BELIEVE THAT DSM AND DEMAND RESPONSE RESOURCES**
11 **SHOULD BE ALLOWED TO COMPETE IN FUTURE ALL SOURCE**
12 **PROCUREMENTS?**

13 A. Yes. DSM and Demand Response resources could be the most cost-effective way to
14 address future system energy and demand needs. The DSM White Paper showed that DSM
15 resources can be effectively modeled as selectable resources and that there is significant
16 remaining potential for cost-effective DSM. Future Requests for Proposals ("RFPs")
17 should include DSM and Demand Response as potential resource options to fill energy and
18 demand needs.

19 **Q. IS STAFF PROPOSING ANY MODIFICATIONS TO THE COMMISSION'S**
20 **CURRENT DSM POLICY?**

1 A. Yes. Staff recommends requiring the Company to include an additional scenario in its 2025
2 IRP development and resource optimization process where DSM is allowed to compete
3 head-to-head with supply-side options in the Company's IRP model. This modification
4 should also be included in the DSM Program Planning Approach as shown in Staff
5 Exhibit_BCS-4. This change would provide the Commission with valuable information on
6 the level of DSM resources that would be selected using an integrated modeling approach
7 ensuring the system is developed and managed at the optimal economic efficiency and least
8 cost for customers.

9 **IV. DSMWG AND THE DSM PROGRAM PLANNING APPROACH**

10 **Q. PLEASE DESCRIBE STAFF'S ROLE WITH THE DSMWG.**

11 A. Staff continued to serve as the facilitator of the DSMWG for the 2022 DSM planning
12 meetings. This was accomplished by working collaboratively with both the Company and
13 the other DSMWG members. As the facilitator of the group, Staff was responsible for
14 coordinating meetings, ensuring that members received pertinent materials prior to
15 meetings, and preparing the minutes of each meeting. Staff also served as a liaison to get
16 questions answered and issues resolved for the other DSMWG members. Staff was also
17 responsible for ensuring that the Company was in compliance with the DSM Program
18 Planning Approach.

19 **Q. PLEASE DESCRIBE THE DSM PROGRAM PLANNING PROCESS.**

1 A. The DSM Program Planning Approach is used by the Company when developing its
2 program plans for future IRP and DSM Certification filings. The purpose of using this
3 approach for DSM program development is to ensure that the process is robust and
4 transparent allowing for Staff and other stakeholders the opportunity to assist the Company
5 in its DSM program planning process.

6 **Q. IN THIS DOCKET, IS THE COMPANY PROPOSING ANY CHANGES TO THE**
7 **DSM PROGRAM PLANNING APPROACH?**

8 A. No. In this IRP Filing, the Company has not requested any changes to the current DSM
9 Program Planning Approach. However, Staff is recommending a modification to the DSM
10 Program Planning Approach as discussed earlier in our testimony. The DSM Program
11 Planning Process with Staff's recommended modification is provided in Staff
12 Exhibit_BCS-4.

13 **Q. DOES STAFF BELIEVE THAT THE COMPANY COMPLETED ALL OF THE**
14 **STEPS INCLUDED IN THE DSM PROGRAM PLANNING APPROACH?**

15 A. Yes. Staff agrees that the Company completed all the steps of the current DSM Program
16 Planning Approach.

17 **Q. DOES STAFF HAVE A RECOMMENDATION REGARDING CONTINUATION**
18 **OF THE DSMWG?**

19 A. Yes. Staff recommends that the DSMWG continue in its current form and be involved in
20 the development of future DSM programs. The DSMWG serves an important role in

1 assisting the Company in the development of its energy efficiency programs and ensures
2 that current and pertinent information is being considered by the Company.

3 **Q. PLEASE DESCRIBE THE PROGRAM IDEAS SUBMITTED BY THE DSMWG**
4 **MEMBERS.**

5 A. At the DSM Program Ideation meeting held on February 22, 2021, various members of the
6 DSMWG submitted new programs and additions to the current DSM programs. These
7 ideas included a program focused on manufactured homes, agricultural measures,
8 industrial offerings, new homes, and funding expansion for tariff-based financing
9 programs.

10 **Q. DID ANY OF THE PROGRAM IDEAS SUBMITTED BY THE DSMWG**
11 **MEMBERS PASS THE REQUIRED ECONOMIC SCREENING?**

12 A. Yes. The Manufactured Home Retrofit and Replacement Program passed the TRC test in
13 all years that were modeled. The other stand-alone program ideas were submitted as pilots
14 and did not pass the TRC test as modeled.

15 **Q. DID THE COMPANY INCLUDE ANY OF THESE PROGRAM IDEAS IN ITS**
16 **PROPOSED DSM PLAN?**

17 A. Yes. However, the Company did not include any as stand-alone programs. The Company
18 did incorporate several of the program suggestions into the current portfolio of programs.
19 During the Direct Hearing, Company Witness Jeff Smith stated that the Company included
20 six of the eleven proposals into current programs (Tr. at 640-641).

1 **V. GEORGIA POWER'S CURRENT CERTIFIED ENERGY EFFICIENCY**
2 **PROGRAMS**

3 **Q. PLEASE DESCRIBE THE COMPANY'S CURRENT CERTIFIED DSM AND**
4 **DEMAND RESPONSE PROGRAMS.**

5 A. Currently, the Company has eleven certified DSM Programs and one Residential Demand
6 Response ("Power Credit") Program. The DSM Programs were certified either in Docket
7 Nos. 31082, 36499, 40162, or 43211 and include six Residential energy efficiency
8 programs, one Residential Demand Response program and five Commercial DSM
9 programs. The Power Credit program was originally certified in Docket No. 6315 and has
10 been reauthorized in several IRP/DSM proceedings.

11 **Q. DID THE COMPANY MEET ITS ENERGY SAVINGS GOALS FOR YEARS 2020**
12 **AND 2021 WHICH WERE APPROVED IN THE 2019 IRP AND DSM**
13 **CERTIFICATION DOCKETS?**

14 A. No. For 2020 and 2021, the Company did not meet its approved energy savings goals due
15 to the impacts of the Pandemic, which created significant barriers to the implementation of
16 several of the Company's DSM programs. In 2021, all DSM programs were affected, with
17 several of the programs being halted completely due to Covid-19 restrictions. In addition,
18 Georgia Power decided to limit marketing in 2020 in order to present a clear health and
19 safety message. Staff was aware and supported the Company's efforts to limit the spread
20 of Covid-19 in 2020.

1 For the 2020 Residential portfolio, Georgia Power achieved 90.5% of their overall savings
2 target while spending 65.5% of the overall budget. For the 2020 Commercial portfolio,
3 Georgia Power achieved 45.9% of the overall savings target while spending 59.2% of the
4 overall budget. For 2021, Georgia Power did exceed the overall Residential savings goal
5 by achieving 107.3% of the target while spending 72.2% of the overall Residential budget.
6 For the 2021 Commercial portfolio, Georgia Power achieved 59.9% of the overall savings
7 target while spending 67.9% of the overall budget.

8 **Q. CAN YOU PROVIDE A SUMMARY OF HOW THE COMPANY'S ENERGY**
9 **SAVINGS FOR 2020 AND 2021 WERE ACHIEVED?**

10 A. Yes. As shown in Staff Exhibit_BCS-5, the Company's energy savings for 2020 were
11 achieved mostly through the Commercial Prescriptive program (47%), Commercial
12 Custom program (15%), and the Residential programs which contributed a combined 36%
13 of total savings. As shown in Staff Exhibit_BCS-6, the Company's energy savings for 2021
14 were achieved mostly through the Commercial Prescriptive program (41%), Commercial
15 Custom program (19%), and the Residential programs which contributed a combined 34%
16 of total energy savings.

17 **Q. DOES STAFF EXPECT GEORGIA POWER TO MEET ITS ENERGY SAVINGS**
18 **TARGETS IN 2022?**

19 A. Yes. All of the Company's DSM programs are fully operational and both the Residential
20 and Commercial portfolios are on track to achieve their savings targets for 2022. Staff

1 meets with the Company on a monthly basis to discuss the status of the current programs
2 and other pertinent DSM issues.

3 **VI. COMPANY'S PROPOSED CHANGES TO THE CURRENT AND PROPOSED**
4 **DSM PROGRAMS**

5 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED DSM PLAN.**

6 A. In its Proposed DSM Plan, the Company requests a Certificate of Public Convenience and
7 Necessity ("certificate") for one new DSM program, decertification of two of its currently
8 certified DSM programs, amendments to the certificates of eight currently certified DSM
9 programs, and amendments to the certificate and waiver of Commission Rule 515-3-4-
10 .04(4)(a)3 for one currently certified DSM program presented in the Company's 2022 DSM
11 Application.

12 **Q. HAS STAFF IDENTIFIED ANY CHANGES IN FOCUS REGARDING THE**
13 **COMPANY'S PROPOSED DSM PLAN?**

14 A. Yes. Several of the Company's proposed certified Residential programs include an
15 increased focus on the income-qualified sector. Staff supports programs that address this
16 historically underserved customer segment. However, Staff does have concerns about how
17 these programs will be evaluated in the determination of the Additional Sum. That issue
18 will be addressed later in our testimony.

19 **Q. UNDER WHAT GEORGIA STATUTE AND COMMISSION RULE IS THE**
20 **COMPANY MAKING THESE REQUESTS?**

1 A. The Company is making its request to amend the current DSM programs pursuant to
2 O.C.G.A § 46-3A-3 through 46-3A-5 and Commission Rule 515-3-4-.09(01) and 515-3-4-
3 .10.

4 **Q. FOR WHICH PROGRAMS IS THE COMPANY REQUESTING**
5 **DECERTIFICATION?**

6 A. The Company is requesting to decertify the Residential Power Credit and Commercial
7 Midstream Programs. The current equipment for the Power Credit will remain active with
8 the ability to be called upon in case of a demand reduction need. The Company requested
9 \$15,000 per year, for a total of \$45,000 for the 2023-2025 time period, in order to maintain
10 these existing capabilities.

11 **Q. WHY IS THE COMPANY ASKING FOR DECERTIFICATION OF THE POWER**
12 **CREDIT PROGRAM?**

13 A. On page 8-47 of the IRP Main Document, the Company stated that the reason for its
14 decertification request for this program is due to having the Residential Thermostat
15 Demand Response Program which can focus on the winter and summer seasons where the
16 Power Credit Program can only serve summer peak events.

17 **Q. WHY IS THE COMPANY REQUESTING DECERTIFICATION OF THE**
18 **COMMERCIAL MIDSTREAM PROGRAM?**

19 A. In the IRP Main Document Page 8-48, the Company stated that market transformation has
20 occurred with Midstream distributors over the previous IRP cycle. This conclusion was

1 confirmed in the 2021 EM&V Report. The measures previously offered by the Midstream
2 Program were moved to the Commercial Prescriptive Program.

3 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S**
4 **DECERTIFICATION REQUESTS?**

5 A. Yes. Staff recommends approval of the Company's request for decertification of the Power
6 Credit and Commercial Midstream Programs.

7 **Q. FOR WHICH PROGRAM IS THE COMPANY REQUESTING A NEW**
8 **CERTIFICATE?**

9 A. The Company is seeking to certify one new Residential program, HopeWorks.

10 **Q. PLEASE DESCRIBE THE PROPOSED HOPEWORKS PROGRAM.**

11 A. The HopeWorks Program will promote energy efficiency improvements in existing single-
12 family homes that are primarily owned by income-qualified senior citizens. HopeWorks is
13 a 501(c)(3) nonprofit that provides weatherization and energy efficiency services at no cost
14 for income-qualified seniors.

15 **Q. AS PROPOSED BY THE COMPANY, WILL THE HOPEWORKS PROGRAM**
16 **REPLACE THE CURRENT FUNDING THAT IS MADE AVAILBLE TO**
17 **HOPEWORKS?**

18 A. Yes. The proposed HopeWorks Program will replace the current funding made available
19 to HopeWorks for weatherization efforts. The funding to HopeWorks will be increased
20 from \$400,000 per year to \$700,000 per year.

1 Q. DID STAFF HAVE ANY CONCERNS REGARDING THE PROPOSED
2 HOPEWORKS PROGRAM?

3 A. Yes. Staff was originally concerned that by changing the funding made available to
4 HopeWorks as a certified program, it would cause HopeWorks to have to complete more
5 rigorous reporting requirements. During the Direct Hearing, Company Witness Jeff Smith
6 stated that the Company has had several discussions with HopeWorks regarding the
7 certification and that HopeWorks is supportive of the program certification and has not
8 raised any significant concerns (Tr. at 643). This alleviates any concerns that Staff had
9 regarding the certification of this program.

10 Q. IS THE COMPANY REQUESTING TO RECEIVE AN ADDITIONAL SUM FOR
11 THE SAVINGS REALIZED FROM THE HOPEWORKS PROGRAM?

12 A. Yes. Since the Company is requesting that this program be certified, it has requested an
13 Additional Sum based on the realized savings from the program.

14 Q. DOES STAFF RECOMMEND APPROVAL OF THE CERTIFICATION OF THE
15 HOPEWORKS PROGRAM?

16 A. Yes. Staff recommends certification of the HopeWorks Program.

17 Q. PLEASE DESCRIBE THE COMPANY'S REQUESTED WAIVER OF THE
18 TOTAL RESOURCE COST REQUIREMENTS FOR THE THERMOSTAT
19 DEMAND RESPONSE PROGRAM.

1 A. On pages 3-4 of the Company's DSM Application Filing, the Company is requesting a
2 waiver of the TRC cost effectiveness requirement within Commission Rule 515-3-4-
3 .04(4)(a)3 in order to continue the Thermostat Demand Response Program. This program
4 does not show positive TRC test results until the year 2031.

5 **Q. DID THE COMPANY EXPLAIN WHY IT SEEKS TO CONTINUE THE**
6 **THERMOSTAT DEMAND RESPONSE PROGRAM DESPITE FAILING THE**
7 **ECONOMIC TEST?**

8 A. Yes. The Company explains in the DSM Application on pages 3-4 that the program has
9 previously passed the TRC test and wants to avoid market interruption, which will allow
10 the technology to remain active in the event of an unplanned system need.

11 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S**
12 **COMMISSION RULE WAIVER REQUEST?**

13 A. Yes. Staff agrees that maintaining the Thermostat Demand Response Program for
14 unplanned summer and winter peak system needs is a benefit to Georgia Power's system.
15 While the economic screening of the program may not show energy benefits to customers
16 in the near term, the demand benefits are significant enough to warrant the program and if
17 avoided costs rise, the economics could pass screening sooner than modeled by GPC in
18 this IRP. Staff recommends approval of the Company's request for waiver of Commission
19 Rule 515-3-4-.04(4)(a)3 for the Thermostat Demand Response Program.

1 **Q. FOR WHICH PROGRAMS IS THE COMPANY REQUESTING AMENDED**
2 **CERTIFICATES?**

3 A. The Company is requesting to amend the certificates for the Residential Behavioral,
4 Residential Home Energy Improvement, Residential Refrigerator Recycling, Residential
5 Specialty Lighting, Residential Home Energy Efficiency Assistance, Commercial Custom,
6 Commercial Prescriptive, Commercial Small Commercial Direct Install, and Commercial
7 Behavioral programs.

8 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE**
9 **RESIDENTIAL BEHAVIORAL PROGRAM.**

10 A. The Company is proposing to amend the certificate of the Residential Behavioral Program
11 to update the delivery methods to have an increased focus on electronic home energy
12 reports. This program provides customer specific information through digital or paper
13 Home Energy Reports to help the customer understand their energy usage, how they could
14 save energy and reduce their bills, and promote participation in other Company DSM
15 programs.

16 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE**
17 **HEIP.**

18 A. The Company is proposing to amend the certificate of the HEIP by updating available
19 measures and shifting the projected quantity of installed measures. The updated measure
20 mix is expected to achieve 70% of savings from smart thermostats and 30% of savings

1 from whole-home and individual measures. The program also includes a carve-out for
2 Multi-Family housing.

3 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE**
4 **RESIDENTIAL REFRIGERATOR RECYCLING PROGRAM.**

5 A. The Company is proposing to amend the certificate of the Refrigerator Recycling Program
6 to adjust the participation levels downward because there are fewer older inefficient
7 secondary refrigerators and freezers available to recycle. One of the reasons for this decline
8 in the stock of older refrigerators and freezers is because the Company has offered this
9 program for many years.

10 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE**
11 **RESIDENTIAL LIGHTING PROGRAM.**

12 A. The Company is proposing to amend the certificate of the Residential Lighting Program to
13 only include specialty lighting. Regular lighting has been excluded due to EISA Code
14 changes. This program is being renamed as the Specialty Lighting Program. The residential
15 lighting market is undergoing a rapid transformation that will likely decrease the cost
16 effectiveness of this program over the next few years. Staff will closely monitor the
17 economics of this program during the program cycle to ensure it continues to deliver
18 benefits for customers.

19 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE**
20 **RESIDENTIAL HOME ENERGY EFFICIENCY ASSISTANCE PROGRAM.**

1 A. The Company is proposing to amend the certificate of the Residential Home Energy
2 Efficiency Assistance Program ("HEEAP") to change the energy savings targets and
3 update the available measures to now include energy efficiency kits. The program will
4 continue to allow for members of the community to join in charitable contributions to assist
5 other income-qualified customers that could not otherwise afford energy efficiency
6 upgrades.

7 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE**
8 **COMMERCIAL CUSTOM PROGRAM.**

9 A. The Company is proposing to amend the certificate of the Commercial Custom Program to
10 update the available measures and change the energy savings targets. The savings targets
11 for the program are about 10% less than the savings target approved in the 2019 IRP and
12 will provide a pathway for a variety of measures that are not specifically included in the
13 Commercial Prescriptive Program.

14 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE**
15 **COMMERCIAL PRESCRIPTIVE PROGRAM.**

16 A. The Company is proposing to amend the certificate of the Commercial Prescriptive
17 Program to update the available measures and change the energy savings targets. The
18 savings targets for the program are slightly higher when compared to those savings targets
19 approved in the 2019 IRP. Lighting measures comprise the vast majority of the projected
20 savings for this program.

1 Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE
2 SMALL COMMERCIAL DIRECT INSTALL PROGRAM.

3 A. The Company is proposing to amend the certificate of the Small Commercial Direct Install
4 Program to update the available measures, slightly decrease the energy savings targets, and
5 reduce the budget.

6 Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED AMENDMENT TO THE
7 COMMERCIAL BEHAVIORAL PROGRAM.

8 A. The Company is proposing to amend the certificate of the Commercial Behavioral Program
9 to update per participant energy savings expectations, program budgets, and an increased
10 focus on digital reports.

11 Q. DOES STAFF HAVE ANY CONCERNS REGRDING THE COMMERCIAL
12 BEHAVIORAL PROGRAM?

13 A. Yes. The current Commercial Behavioral Program has not achieved its expected savings,
14 reaching 15.5% of goal in 2020 and 25.7% of goal in 2021. Staff recognizes that some of
15 this shortfall is likely due to the expected ramp-up time for behavioral programs and the
16 delayed launch of the program due to the Pandemic. The 2021 Commercial EM&V report
17 found that there was no statistically significant treatment effect detected from the program
18 after the first twelve months of implementation. The evaluation compared the treatment
19 group that received reports to a control group that did not receive reports thereby mitigating
20 energy savings effects of the Pandemic. The Company's modeling shows expected savings
21 per participant to be 152 kWh annually. Even using the Company's modeled savings level,

1 the TRC is barely positive for all three years. In addition, the Company's Commercial
2 Behavior pilot did not produce significant savings impacts.

3 **Q. DUE TO THE THESE CONCERNS, WHAT IS STAFF'S RECOMMENDATION**
4 **REGARDING THE COMMERCIAL BEHAVIORAL PROGRAM?**

5 A. Staff recommends the continuation of the Commercial Behavioral Program to allow the
6 program and energy savings to mature. Staff expects an EM&V study to be completed no
7 later than 2024. At that time, Staff recommends that the Company pause the Commercial
8 Behavioral Program pending decertification, if the upcoming 2024 EM&V does not show
9 the program to be cost effective.

10 **Q. DOES STAFF RECOMMEND APPROVAL OF THE AMENDED CERTIFICATES**
11 **AS REQUESTED BY THE COMPANY?**

12 A. Yes. Staff recommends approval of amended certificates for the Residential Behavioral,
13 Residential Home Energy Improvement, Residential Refrigerator Recycling, Residential
14 Specialty Lighting, Residential HEEAP, Commercial Custom, Commercial Prescriptive,
15 Commercial Small Commercial Direct Install, and Commercial Behavioral programs.

16 **Q. IS THE COMPANY REQUESTING TO CONTINUE THE RISE PILOT?**

17 A. Yes. The Company is requesting approval to continue the RISE pilot, formerly called the
18 Income-Qualified Tariff Based Financing Pilot. This pilot promotes energy efficiency
19 improvements in existing, income-qualified single-family homes as well as Multi-Family
20 properties. This pilot will serve up to five hundred (500) income-qualified residential

1 customers, with an income level less than or equal to 200% of the federal annual poverty
2 level, in select targeted areas of the state with the goal of saving 25% of their baseline
3 household electric energy with an investment of an average of \$7,500 per household. The
4 Company will cover the upfront cost of eligible energy efficiency measures installed. The
5 customer at the premises, regardless of a change in tenancy, will repay the cost of the
6 energy efficiency upgrades installed through the IQTBEE-1 tariff charge which is included
7 on the customer's bill. The customer will repay these costs over the lesser of 10 years or
8 the average measure life of the measure installed.

9 **Q. PLEASE DESCRIBE THE PERFORMANCE OF THE RISE PILOT TO DATE.**

10 A. The RISE pilot has been slow in finding eligible participants and participants that are
11 interested in moving forward with the pilot. Several factors have limited participation
12 including the Pandemic and difficulties identifying homes that are able to provide the
13 required bill savings. As of March 2022, only seventeen participants have completed
14 tariffed installations. Over two hundred customers have been contacted through the pilot
15 with over one-hundred fifty receiving direct install measures.

16 **Q. HAS THE COMPANY MADE ANY SIGNIFICANT CHANGES TO THE RISE**
17 **PILOT SINCE ITS APPROVAL IN 2020?**

18 A. Yes. The Company, along with Staff's support, has made several significant changes to the
19 design of the RISE pilot. The savings and spending per home were adjusted to save 25%
20 of baseline household electric energy usage, up from 20%, and the per-home spending was
21 changed to be an average of \$7,500 per home rather than a cap of \$7,500 per home. The

1 pilot was expanded to include gas savings in addition to electric savings to encourage
2 participation of customers with a natural gas furnace as well as customers with an electric
3 heat pump.

4 **Q. WHAT CONCERNS DOES STAFF HAVE REGARDING THE RISE PILOT?**

5 A. Staff is concerned that the pilot may not be able to find enough eligible participants to reach
6 the goal of 500 customers despite the changes that have already been made to increase
7 participation. Staff's research indicates that tariff-based financing programs are not
8 typically limited to only income-qualified customers.

9 **Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S REQUEST TO**
10 **CONTINUE THE RISE PILOT?**

11 A. Yes. Staff recommends approval of the Company's request to continue the RISE pilot.
12 With the changes that have been made, Staff expects to see an increase in participation
13 leading to a successful pilot.

14 **Q. IN ITS FILING, DID THE COMPANY REQUEST THE CONTINUATION OF THE**
15 **ABT?**

16 A. No. The Company did not request to continue the ABT.

17 **Q. IN THE IRP FILING, DID THE COMPANY PROVIDE A REASON THEY DID**
18 **NOT REQUEST TO CONTINUE THE ABT?**

19 A. No. The Company's IRP and DSM Certification filings did not discuss the ABT. During
20 the Direct Hearing, Company Witness Jeff Smith stated that the evaluation of the ABT did

1 not show that use of the tool led to any energy efficiency installations or participation in
2 any Company offered programs. Therefore, the Company does not believe that continued
3 spending on the ABT is warranted (Tr. at 674-675).

4 **Q. DOES STAFF BELIEVE THAT THE ABT SHOULD BE CONTINUED FOR THE**
5 **2023-2025 CYCLE?**

6 A. Yes. Staff has reviewed the evaluation of the ABT and agrees with the Company that there
7 are few direct savings attributable to the Tool. However, Staff believes that ABT provides
8 benefits for building owners to be able to access their aggregated whole building electricity
9 usage data without significant barriers or costs. The ABT provides building owners and
10 property managers with aggregated energy consumption data for buildings with more than
11 five tenants or where property managers secure participation from buildings with fewer
12 than five tenants. For buildings for which no single account comprises over 50 percent of
13 the building energy usage, energy usage data will be automatically aggregated. For
14 buildings where one account comprises over 50 percent of the building energy usage,
15 building owners or property managers will need to get and submit consent and
16 authorization from each of the tenants.

17 **Q. WHAT IS THE ESTIMATED ANNUAL COST TO CONTINUE THE ABT?**

18 A. The costs for the ABT costs were approximately \$500,000 for the 2020-2022 three-year
19 cycle with an annual cost between \$150,000 and \$200,000 per year according to Company
20 Witness Jeff Smith (Tr. 675). Staff expects the annual cost to be similar to maintain the
21 ABT for the next 3 years.

1 **Q. DOES STAFF RECOMMEND THE CONTINUATION OF THE ABT?**

2 A. Staff recommends the continuation of the ABT for the 2023-2025 program cycle.

3 **Q. WHAT ENERGY AND DEMAND SAVINGS ARE PROJECTED TO RESULT**
4 **FROM THE COMPANY'S PROPOSED DSM PLAN?**

5 A. In the Company's IRP/DSM Certification filing, the proposed energy efficiency programs
6 will result, on average, in approximately 113 megawatts ("MW") of peak demand
7 reductions and 431 gigawatt hours ("GWh") of incremental annual energy reductions for
8 the period of 2023 to 2025 for a 3-year cumulative energy savings of 1.29 GWh and 340
9 MW of demand savings (DSM Application, Appendix D-1). These savings targets are
10 nearly identical to the kilowatt hours ("kWh") and kilowatt ("kW") savings targets that
11 were approved in the 2019 IRP/DSM Order.

12 **Q. IN ITS 2022 IRP FILING, DID THE COMPANY ALSO PROVIDE**
13 **INFORMATION FOR ANY DSM SENSITIVITY CASES?**

14 A. Yes. In this filing, the Company provided information for two alternative DSM sensitivity
15 cases, "DSMWG Advocacy Case" and "Aggressive Case Sensitivity".

16 **Q. PLEASE DESCRIBE THE TWO DSM SENSITIVITY CASES.**

17 A. The DSMWG Advocacy Case includes a set of DSM programs designed around the
18 recommendations from some DSMWG members to build upon the Company's Proposed
19 Case, with a ramp up of the energy savings target with the addition of new programs. This
20 case is designed to achieve 3-year cumulative energy savings of 2.33 GWh and 550 MW

1 of demand savings (IRP Filing, Technical Appendix Vol 2, 3 2022 IRP DSM Case
2 Summary Data MGO, DSMWG Advocacy Case Tab).

3 The Aggressive Sensitivity Case achieves 3-year cumulative energy savings of 2.48 GWh
4 and 568 MW of demand savings and includes programs from the Company's Proposed
5 Case, but with customer participation at higher penetration levels and higher budgets as
6 well as additional programs, measures, and the associated budgets (IRP Filing, Technical
7 Appendix Vol 2, 3 2022 IRP DSM Case Summary Data MGO, Aggressive Case Tab).
8 These two sensitivity cases were discussed with DSMWG members at a DSMWG meeting
9 held on December 9, 2021.

10 **Q. PLEASE DESCRIBE HOW THE COMPANY'S PROJECTED KWH SAVINGS**
11 **FOR THE 2023 TO 2025 TIME PERIOD COMPARES TO PREVIOUSLY**
12 **APPROVED KWH SAVINGS TARGETS AND ACTUAL LEVELS OF KWH**
13 **SAVINGS DURING THE 2019 TO 2021 TIME PERIOD.**

14 **A.** Staff Exhibit_BCS-7 shows a comparison of the projected incremental annual kWh savings
15 for the Company's DSM programs for the 2023 to 2025 time-period to the actual
16 incremental annual kWh savings achieved by the Company's programs for the 2014 to
17 2021 time-period. Staff obtained the historical kWh savings data for 2014 to 2021 from the
18 Company's annual DSM reports filed under Docket Nos. 36499, 40162 and 42311. The
19 2023-2025 proposed kWh savings in the Company's Proposed Case were obtained from
20 Docket No. 44161, DSM Application. As shown in this exhibit, the Company exceeded
21 the projected kWh savings targets every year from 2014-2019. However, the DSM

1 programs for 2020 and 2021 were severely hindered by the Pandemic limiting the kWh
2 and kW savings achieved.

3 **Q. PLEASE PROVIDE THE PERCENT OF THE ACHIEVABLE COST-EFFECTIVE**
4 **ENERGY EFFICIENCY POTENTIAL FOUND IN THE COMPANY'S**
5 **POTENTIAL STUDY THAT IS INCLUDED IN THE COMPANY'S PROPOSED**
6 **DSM PLAN FOR THE YEAR 2032.**

7 **A.** The Company's Proposed DSM Case includes energy efficiency program cumulative
8 annual megawatt hours ("MWh") savings of 4,284 GWh by the end of 2032 as shown in
9 the DSM Application Appendix D-1. The Company's 2021 Technical, Economic,
10 Achievable Potential ("TEAPOT") study filed in Docket No. 43040 on February 1, 2021,
11 found that the energy efficiency cumulative annual achievable potential MWh savings by
12 2032 is 7,728 GWh, assuming incentives to program participants are set at 100% of the
13 incremental measure cost. Thus, the percent of the total achievable potential identified in
14 the Company's potential study that is included in the DSM Proposed Case by 2032 is only
15 55.4% of the 2032 cost effective energy efficiency achievable potential included in the
16 Company's 2021 energy efficiency potential study.

17 **Q. PLEASE DESCRIBE HOW THE COMPANY'S PROJECTED DSM SPENDING**
18 **FOR THE 2023 TO 2025 TIME PERIOD COMPARES TO ACTUAL AND**
19 **PROJECTED LEVELS OF DSM SPENDING OVER THE PRIOR YEARS.**

20 **A.** As shown in Staff Exhibit_BCS-8, the Company's proposed DSM spending for the 2023
21 to 2025 time period is an increase of \$3.1 million dollars per year compared to the approved

1 2020-2022 budgets. The Company has consistently spent significantly less than approved
2 on the overall DSM portfolio. For the 2017-2019 time period, the Company only spent an
3 average of 76% of its approved budget. For the 2020-2021 period, the Company spent only
4 61% of its approved budget, though these two years were significantly impacted by the
5 Pandemic.

6 **Q. DOES STAFF HAVE CONCERNS WITH THE COMPANY'S PROPOSED DSM**
7 **BUDGET?**

8 **A.** Yes. Over the past several years, the Company's approved DSM budgets have consistently
9 been millions of dollars higher than its actual spending. After conducting a detailed
10 analysis of budgets and spending, Staff developed budget reduction recommendations that
11 will be discussed in the next section.

12 **VII. STAFF'S RECOMMENDED CHANGES TO THE COMPANY'S PROPOSED**
13 **PROGRAM PLANS AND BUDGETS**

14 **Q. IS STAFF RECOMMENDING MODIFICATIONS TO THE COMPANY'S**
15 **PROPOSED DSM PLAN AND BUDGET?**

16 **A.** Yes. Staff has recommendations to modify Company's Proposed DSM Plan and associated
17 DSM budget.

18 **Q. WHAT ARE STAFF'S RECOMMENDATIONS TO MODIFY THE COMPANY'S**
19 **PROPOSED DSM PLAN AND ASSOCIATED ENERGY SAVINGS TARGET?**

1 A. Staff recommends that the HEIP be expanded to include the proposed Manufactured
2 Homes Program, with the exception of “whole home replacement” measures, as outlined
3 in the DSMWG Advocacy Case. This recommendation would increase the energy savings
4 targets for HEIP by 3 GWh per year to an average savings level of 21.5 GWh per year.
5 With this modification, the demand savings would increase by an average of 0.55 MW per
6 year to an average level of 5.14 MW per year. With Staff’s recommended modification to
7 the Company’s Proposed DSM Plan, the total portfolio savings for all program increases
8 to 433 GWh per year for a total of 1,300 GWh for the 2023-2025 program cycle on a
9 cumulative annual basis. Staff’s recommended DSM savings targets are outlined in Staff
10 Exhibit_BCS-9

11 **Q. WHAT ARE STAFF’S RECOMMENDATIONS REGARDING THE BUDGETS**
12 **FOR CERTAIN COMPANY PROPOSED DSM PROGRAMS?**

13 A. Staff recommends that the non-incentive budget for the Residential Behavioral Program be
14 reduced by a total of \$1,494,303 for the 2023-2025 program cycle. Staff also recommends
15 that the HEIP budget be increased to incorporate the addition of Manufactured Homes
16 Program, with the exception of “whole home replacement” measures. Staff further
17 recommends that the non-incentive budget for the Commercial Prescriptive Program be
18 reduced by \$2,000,000 per year for 2023-2025 for a total reduction of \$6,000,000 over the
19 three-year program cycle. Staff Exhibit_BCS-10 provides Staff’s recommendations for
20 revised budgets for 2023 to 2025 for the certified DSM programs.

1 **Q. PLEASE EXPLAIN STAFF'S RECOMMENDED BUDGET IMPACT DUE TO**
2 **STAFF'S RECOMMENDED MODIFICATION TO INCLUDE A PORTION OF**
3 **THE MANUFACTURED HOMES PROGRAM IN THE RESIDENTIAL HEIP.**

4 A. Staff recommends the inclusion of the measures that were included in the proposed
5 Manufactured Homes Program as outlined in the DSMWG Advocacy Case, excluding the
6 whole home measures. For this budget modification, Staff has included the costs for the
7 Manufactured Home Program incentives, marketing, and evaluation. Staff did not include
8 an increase in Contracting Costs or Program Admin Costs as the inclusion of a few
9 additional measures that are substantially the same as the Company's DSM Proposed Case
10 HEIP should not result in an increase in these areas. As shown in Staff Exhibit_BCS-11,
11 the overall increase to the HEIP budget averages \$498,101 per year for a total of \$1.49
12 million for the 2023-2025 program cycle.

13 **Q. PLEASE DESCRIBE STAFF'S RECOMMENDED BUDGET MODIFICATIONS**
14 **TO THE RESIDENTIAL BEHAVIORAL PROGRAM.**

15 A. Staff recommends the reduction of the non-incentive costs for the Residential Behavioral
16 Program budget by \$1.49 million. As shown in Staff Exhibit_BCS-12, the Company's
17 proposed Residential Behavioral Program budget increased from \$3.72 million for 2020-
18 2022 as approved in the 2019 IRP to \$5.61 million for 2023-2025, an increase of over
19 \$630,000 annually. Historical spending for this program has averaged less than one million
20 dollars per year which was only 70% of the approved budget. Staff finds the projected
21 budget of nearly double the actual prior spending for this program to be excessive and

1 recommends a reduction to an average of \$0.498 million annually for a total of \$1.49
2 million for the 2023-2025 program cycle.

3 **Q. PLEASE EXPLAIN WHY STAFF IS RECOMMENDING THE BUDGET**
4 **REDUCTION FOR THE COMMERCIAL PRESCRIPTIVE PROGRAM.**

5 A. The Commercial Prescriptive Program non-incentive costs have been consistently
6 overestimated by an average of approximately \$4 million each year for the previous several
7 years, as shown in Staff Exhibit_BCS-13. Staff recommends a reduction of \$2 million per
8 year. Staff's recommended budget of \$7.2 million annually is still well above the
9 Company's prior year spending and also allows for inflation adjustments.

10 **Q. HOW DOES STAFF'S RECOMMENDED DSM CASE COMPARE TO THE DSM**
11 **CASE PROPOSED BY THE COMPANY?**

12 A. For Staff's recommended DSM Plan, the MWh savings are increased for the Residential
13 programs by 3 GWh per year when compared to the Company's Proposed DSM Case.
14 Staff's Recommended DSM Plan will cost a yearly average of \$2 million less than the
15 Company's Proposed DSM Plan and will have a higher TRC ratio.

16 **Q. WHAT IS THE COST-EFFECTIVENESS OF STAFF'S RECOMMENDED DSM**
17 **PORTFOLIO?**

18 A. The TRC and RIM benefit/cost ratios for Staff's revised DSM portfolio for the 2023 to
19 2025 period are provided below.

	Staff's Recommended Plan	Company Proposed Plan
TRC	1.54	1.52
RIM	0.43	0.43

Q. DID STAFF PREPARE REVISED ENERGY SAVINGS TARGETS AND BUDGETS BASED ON ITS RECOMMENDATIONS?

A. Yes. Staff recommends that the Commission approve the revised DSM energy savings targets provided in Staff Exhibit_BSC-9. Staff recommends that the Commission approve the revised DSM program budgets as provided in Staff Exhibit_BCS-10.

Q. DOES STAFF HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S PROPOSED DSM PLANS?

A. Yes. The Company has not included incentive caps for financial incentives paid to program participants as part of the program design of its Commercial Custom program plans. Staff is concerned that a small group of customers will use the entire incentive budget. Staff recommends that an incentive cap of \$75,000 per building be included as part of the Final Program Plans.

VIII. GEORGIA POWER PROPOSED OTHER DSM RELATED ACTIVITIES

Q. HAS THE COMPANY PROPOSED CHANGES TO ITS CURRENTLY APPROVED DSM AND RELATED ACTIVITIES?

1 A. No. The Company is proposing the same budgets as approved in the 2019 IRP Order for
2 several DSM related activities including the pilot budgets, the Education Initiative-
3 Learning Power, and the Energy Efficiency Consumer Awareness. The spreadsheet model
4 includes an escalation rate for all Pilot and Learning Power line items as shown in the DSM
5 Application Appendix C-2.

6 **Q. PLEASE DISCUSS THE EDUCATION INITIATIVE LEARNING POWER**
7 **PROGRAM AND ENERGY EFFICIENCY CONSUMER AWARENESS THAT IS**
8 **INCLUDED IN THE COMPANY'S BUDGET.**

9 A. The Learning Power program began in July 2011 and is an energy efficiency education
10 program for students in grades K-12. In the 2016 IRP and DSM Certification Final Order,
11 an annual budget of \$3 million was approved. In the 2019 IRP and DSM Certification Final
12 Order, the annual budget for the Learning Power program was increased to \$4 million. In
13 the 2019 IRP and DSM Certification Final Order, the annual budgets for the Residential
14 and Commercial Energy Efficiency Consumer Awareness budgets were approved at \$4.5
15 million and \$1.1 million, respectively.

16 **Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE PROPOSED**
17 **EDUCATION INITIATIVE LEARNING POWER PROGRAM AND THE**
18 **RESIDENTIAL AND COMMERCIAL ENERGY EFFICIENCY CONSUMER**
19 **AWARENESS BUDGETS?**

20 A. Staff recommends a continuation of the Education Initiative-Learning Power Program at
21 \$4 million for each year for 2023-2025. Staff recommends a continuation of the Residential

1 and Commercial Energy Efficiency Consumer Awareness at \$4.5 million and \$1.1 million,
2 respectively, for the 2023-2025 program cycle.

3 **Q. PLEASE DESCRIBE THE COMPANY'S REQUEST FOR A PILOT BUDGET.**

4 A. The Company has proposed a budget of \$1.5 million for Residential pilots and \$1.5 million
5 for Commercial pilots for 2023 resulting in a total pilot budget request of \$3 million. Both
6 of these annual budgets increase slightly for 2024 and 2025. The proposed budgets are the
7 same as approved in the 2019 IRP.

8 **Q. DID THE COMPANY SPEND THE ENTIRE PILOT BUDGET FOR THE YEARS**
9 **2020 AND 2021?**

10 A. No. The Company spent \$371,640 for the Residential pilots and \$377,582 for the
11 Commercial pilots in 2020. The Company spent \$1,458,753 for the Residential pilots and
12 \$575,655 for the Commercial pilots in 2021. The total spent for the Residential and
13 Commercial pilots for these years was \$749,222 and \$2,034,408, respectively.

14 **Q. HAS THE COMPANY IDENTIFIED SPECIFIC PROJECTS FOR WHICH THE**
15 **PILOT BUDGET WILL BE USED?**

16 A. No. In Docket No. 44161, DSM Application, the Company provided limited details on
17 potential pilots and is currently not required to allow Staff to have input regarding proposed
18 pilots before implementation. Each pilot does include, as part of the proposed budget,
19 significant spending for evaluations.

1 **Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE PROPOSED**
2 **PILOT BUDGET?**

3 A. Staff recommends that the Commission approve a total annual pilot budget of \$3 million
4 to be divided evenly between the Commercial and Residential pilots for each year for 2023-
5 2025. Staff further recommends that it has input regarding any proposed pilots before they
6 are implemented by the Company and throughout the course of the pilot.

7 **IX. ADDITIONAL SUM**

8 **Q. IS THERE A GEORGIA STATUTE THAT ADDRESSES ADDITIONAL SUM?**

9 A. Yes. While we are not attorneys, we understand that Official Code of Georgia ("OCGA")
10 § 46-3A-9 states that "The approved or actual cost, whichever is less, of any certificated
11 demand-side capacity option shall be recovered by the utility in rates, along with an
12 additional sum as determined by the commission to encourage the development of such
13 resources. The commission shall consider lost revenues, if any, changed risks, and an
14 equitable sharing of benefits between the utility and its retail customers."

15 **Q. DOES THE COMMISSION'S IRP RULE ALLOW GEORGIA POWER TO**
16 **REQUEST AN "ADDITIONAL SUM" RELATING TO THE ENERGY**
17 **EFFICIENCY AND DEMAND RESPONSE PROGRAMS FOR WHICH IT IS**
18 **SEEKING CERTIFICATION BY THE COMMISSION?**

19 A. Yes. Commission IRP Rule 515-3-4-.11(3)(b) states that "The certified or actual cost,
20 whichever is less, of any certificated demand-side capacity option shall be recovered by

1 the utility in rates, along with an Additional Sum as determined by the Commission to
2 encourage the development of such resources. The Commission shall consider lost
3 revenues, if any, changed risks, and an equitable sharing of benefits between the utility and
4 its retail customers.”

5 **Q. DOES STAFF AGREE THAT THE COMPANY SHOULD RECEIVE AN**
6 **ADDITIONAL SUM FOR IMPLEMENTING THE ENERGY EFFICIENCY**
7 **PROGRAMS PROPOSED IN THE COMPANY’S 2022 IRP?**

8 A. Yes. Staff believes that an Additional Sum or performance incentive continues to be an
9 essential component of the regulatory framework. It is essential for providing the Company
10 a clear financial interest in the success of energy efficiency and demand response programs
11 in the Company’s service area. Staff believes that the Additional Sum incentive plays a key
12 role in the Company’s decision making and planning processes relating to the IRP.

13 **Q. PLEASE DESCRIBE THE CURRENT DSM ADDITIONAL SUM**
14 **METHODOLOGY.**

15 A. Under the Additional Sum methodology approved by the Commission in the 2016 and
16 2019 IRP Orders, Georgia Power Company receives an Additional Sum equal to 8.5% of
17 actual net benefits based on net energy savings from the Program Administrator Cost Test
18 (“PACT”) per program. Once the Additional Sum amount as calculated exceeds the annual
19 program costs, the portion of the Additional Sum that exceeds the program cost shall be
20 calculated based on 4% of the actual net benefits based on net energy savings from the
21 PACT.

1 **Q. PLEASE EXPLAIN THE PRINCIPLES LISTED BY THE NATIONAL ACTION**
2 **PLAN FOR ENERGY EFFICIENCY FOR DSM INCENTIVE MECHANISMS.**

3 A. Chapter 3 of the November 2007 National Action Plan for Energy Efficiency report titled
4 "Aligning Utility Investments with Investment in Energy Efficiency"² lists several
5 principles for DSM incentive mechanisms:

- 6 1. Strike an appropriate balance of risks and rewards between utilities and customers
- 7 2. Promote stabilization of customer bills and rates
- 8 3. Stabilize utility revenues
- 9 4. Administrative simplicity and managing regulatory costs

10 **Q. DOES THE CURRENT DSM ADDITIONAL SUM MECHANISM MEET THESE**
11 **PRINCIPLES?**

12 A. Yes. The current Additional Sum mechanism shares the net present value ("NPV") of the
13 dollar savings of the Company's DSM programs between the Company and its customers
14 and helps the Company recoup lost revenues. The current mechanism considers program
15 costs and benefits and provides a signal to the Company to be vigilant about how much
16 money it spends to implement DSM programs that incentivize energy efficiency actions
17 and technologies in which customers would not otherwise invest. The current mechanism
18 helps the Company recoup lost revenues due to the implementation of DSM programs and
19 to receive a financial incentive for developing and implementing programs. A major feature
20 of the current Additional Sum mechanism is that it pays a higher Additional Sum amount

² National Action Plan for Energy Efficiency, "Aligning Utility Investments with Investment in Energy Efficiency", November 2007 (available at <https://www.epa.gov/sites/default/files/2015-08/documents/incentives.pdf>).

1 for energy efficiency measures with longer useful lives and a smaller Additional Sum
2 amount for measures with short useful lives.

3 **Q. PLEASE DESCRIBE THE ADDITIONAL SUM MECHANISM THAT GEORGIA**
4 **POWER COMPANY HAS REQUESTED TO RECEIVE FOR ITS ENERGY**
5 **EFFICIENCY PROGRAMS.**

6 A. In its 2022 IRP Filing as described in the DSM Application on page 5, the Company
7 requested an Additional Sum equal to \$.04 per first-year kWh saved based on gross verified
8 savings of the certified energy efficiency programs. If the Company's reported energy
9 savings grow higher than 120% of certified energy goals by class, or as portfolio during
10 any year within the IRP cycle, the Additional Sum on the reported savings beyond 120%
11 would increase to five cents per first-year kWh saved. The Company proposal to use gross
12 savings is a significant change from current policy of using net savings which include
13 market effects, such as free ridership and spillover.

14 **Q. PLEASE COMPARE HOW MUCH THE COMPANY EARNED IN ADDITIONAL**
15 **SUM OVER THE PREVIOUS FIVE YEARS TO THE PROPOSED METHOD.**

16 A. As shown in Staff Exhibit_BSC-14, the Company has earned an average of \$10.13 million
17 overall in Additional Sum over the previous five years (2017-2021). For the Residential
18 portfolio, the average was \$2.28 million per year and for the Commercial portfolio, the
19 average was \$7.86 million per year. As shown in the DSM Filing Appendix F, the
20 Company proposes to earn on average \$17.29 million per year, with \$3.85 million from
21 the Residential portfolio and \$13.41 million from the Commercial portfolio.

1 **Q. HOW DOES THE ADDITIONAL SUM REQUESTED BY GEORGIA POWER**
2 **COMPARE TO THE TOTAL AMOUNT THAT THE COMPANY PLANS TO**
3 **SPEND ON IMPLEMENTING THE PROPOSED ENERGY EFFICIENCY**
4 **PROGRAMS FOR THE PERIOD 2023 TO 2025?**

5 A. The Company's Proposed DSM Plan has a nominal value of DSM program expenditures
6 of \$211.3 million and a requested Additional Sum of \$51.7 million for the three-year period
7 from 2023 through 2025 as shown in DSM Filing Appendix G. The Company's proposed
8 Additional Sum represents additional costs to customers that will increase the DSM
9 expenditures by twenty-five percent each year for the 2023 to 2025 time-period.

10 **Q. DOES STAFF BELIEVE THAT THE COMPANY'S PROPOSED ADDITIONAL**
11 **SUM REQUEST IS REASONABLE?**

12 A. No. The Commission's IRP rule already provides the Company with 100% cost recovery
13 for prudently incurred expenditures on energy efficiency programs. Staff finds that
14 providing an Additional Sum that will increase DSM program budgets by an additional
15 25% is excessive. This is equivalent to granting the Company a 25% rate of return on DSM
16 program expenditures.

17 **Q. DOES STAFF HAVE OTHER CONCERNS WITH THE PROPOSED**
18 **ADDITIONAL SUM METHODOLOGY?**

19 A. Yes. As described in the DSM Application on page 5, the Company has proposed changing
20 from using net savings to gross savings for the Additional Sum calculation. According to
21 research conducted by eSource and listed in Staff Exhibit_BCS-14, for the states that allow

1 utilities to earn receive a performance incentive for shareholders, twenty-seven out of
2 thirty-one states use a percent of net savings approach to calculate an Additional Sum of
3 shareholder incentive. The use of gross savings as proposed by the Company is flawed due
4 to allowing a return on investment for measures that customers would have installed
5 without a program. Staff recommends maintaining the current practice of using net savings
6 for the calculation of the Additional Sum and gross savings for setting and tracking savings
7 targets.

8 **Q. HAS STAFF PREPARED AN ESTIMATE OF WHAT THE ADDITIONAL SUM**
9 **WOULD BE FOR 2023 TO 2025 WITH USING THE CURRENT COMMISSION**
10 **APPROVED METHODOLOGY FOR CALCULATING THE ADDITIONAL SUM?**

11 A. Yes. Staff Exhibit_BCS-15 provides Staff's estimate of the Additional Sum for the
12 Company's Proposed DSM Plan for the years 2023 to 2025 using the current Additional
13 Sum methodology. Using the current Additional Sum methodology, the DSM Additional
14 Sum for 2023 to 2025 would be \$29.6 million in total over this three-year period.

15 **Q. WILL THE COMPANY'S PROPOSED ADDITIONAL SUM METHODOLOGY**
16 **RESULT IN A HIGHER ADDITIONAL SUM THAN THE CURRENTLY**
17 **APPROVED METHODOLOGY WILL PRODUCE?**

18 A. Yes. The Additional Sum amount using the Company's proposed methodology results in
19 an increase on average of \$7.37 million per year for the years 2023 to 2025 compared to
20 the current Additional Sum methodology, as shown on Staff Exhibit_BCS-15. The
21 Company's proposal is to collect an Additional Sum of approximately \$17.2 million per
22 year for the years 2023 through 2025, or \$51.7 million in total over the three years 2023 to

1 2025. This is 74% percent higher than with the Additional Sum methodology that is
2 currently approved by the Commission.

3 **Q. DOES STAFF HAVE OTHER CONCERNS WITH THE COMPANY'S**
4 **PROPOSED DSM ADDITIONAL SUM MECHANISM?**

5 A. Yes. The Company's proposed Additional Sum mechanism would not share the NPV
6 savings of program net benefits fairly with the Company's customers. For example, if
7 electric avoided costs decrease by 25% and program net benefits decrease significantly, the
8 Company's Additional Sum would remain the same as it would be with higher avoided
9 costs, significantly reducing the net benefits shared with customers. The Company's
10 Additional Sum amount would be unrelated to decreases in electric avoided costs.
11 Likewise, if the Company's spending on its DSM programs doubles, all other things held
12 constant, and program net benefits shrink, the Company's Additional Sum will be the same
13 as it would be with lower program spending, causing the net benefits shared with customers
14 to decline significantly. The Company's proposed methodology eliminates any incentive
15 for the Company to control or reduce program delivery costs.

16 **Q. DOES THE COMPANY'S PROPOSED ADDITIONAL SUM METHODOLOGY**
17 **ALSO INCENTIVIZE THE COMPANY TO IMPLEMENT ENERGY**
18 **EFFICIENCY MEASURES THAT HAVE A SHORT USEFUL LIFE?**

19 A. Yes. The Company's proposed Additional Sum methodology, for example, would pay the
20 same Additional Sum amount for a measure that saves 10,000 kWh for one year and a
21 different measure that saves 10,000 kWh each year for 30 years. As such, the Company

1 may be incentivized to focus its efforts on implementing measures with a short useful life,
2 such as behavioral programs and lighting measures. The Company would receive a
3 significant Additional Sum incentive based only on first-year kWh savings, and then have
4 significantly reduced electricity savings and lost revenues, over the long-term, due to the
5 focus on measures with short useful lives. If that happened, most of the achievable energy
6 efficiency potential in the Company's service area would never be realized.

7 **Q. HAS STAFF RESEARCHED ADDITIONAL SUM MECHANISMS FOR ENERGY**
8 **EFFICIENCY PROGRAMS USED IN OTHER JURISDICTIONS?**

9 A. Yes. Staff Exhibit_BCS-14 provides up-to-date information recently collected by Staff for
10 DSM Shareholder Incentive Mechanisms that exist in the United States. The information
11 provided in this exhibit describes the general methodology currently in place for
12 calculating the level of DSM shareholder rewards or penalties in each state. There are many
13 states that do not have a policy for offering an Additional Sum for energy efficiency
14 programs.

15 **Q. DOES STAFF AGREE WITH THE COMPANY'S TESTIMONY THAT SOME**
16 **UTILITIES IN THE STATE OF MINNESOTA USE THE COMPANY'S**
17 **PROPOSED METHOD FOR CALCULATING DSM PERFORMANCE**
18 **INCENTIVES?**

19 A. No. During the Direct Hearing, Company Witness Jeff Smith stated that the proposed
20 method is similar to one used by a utility in Minnesota (Tr. at 648). Minnesota is not a good
21 example of a state where some utilities utilize a DSM incentive mechanism that is similar

1 to the Company's proposal. Minnesota allows for a maximum of \$0.08 per kWh saved.
2 The actual methodology used by Xcel Energy in Minnesota, for example, is based on
3 receiving 0.75% of net benefits per 0.1% of savings achieved as a total of Company sales
4 with a maximum of 1.7% annual savings with a cap of 40% of total expenditures. The
5 Company's proposed methodology does not include achieving specific targets for
6 electricity savings in order to earn the DSM shareholder incentive. Using the Additional
7 Sum methodology in effect for Xcel Energy, Georgia Power would only receive 3% of the
8 net benefits of DSM programs. The Additional Sum methodology proposed by Georgia
9 Power is not the same as the one used by Xcel Energy in Minnesota.

10 **Q. BASED ON STAFF'S REVIEW OF ENERGY EFFICIENCY INCENTIVE**
11 **MECHANISMS USED IN OTHER STATES, WHAT HAS STAFF FOUND**
12 **REGARDING PERFORMANCE INCENTIVES?**

13 **A.** According to the studies that we have reviewed and our collective experience in the energy
14 efficiency industry, the three major types of performance mechanisms that have been most
15 prevalent are the following:

- 16 1. Performance target incentives
- 17 2. Shared savings incentives
- 18 3. Rate of return incentives

19 The key finding from our analysis of incentive mechanisms is that numerous other states
20 with less costly incentive mechanisms have been able to achieve actual kWh and kW
21 savings far higher, as a percent of annual retail kWh sales, than the percentage reduction
22 in kWh sales projected by the Company in this case for the 2023 to 2025 time period. Our

1 research also indicates that the kWh and kW savings levels, as a percent of annual electric
2 sales, being achieved by numerous other program administrators are being achieved with
3 incentive mechanisms that are much less costly than the performance incentive proposed
4 by the Company for the 2023 to 2025 time period.

5 **Q. PLEASE PROVIDE EXAMPLES OF STATES THAT HAVE ACHIEVED HIGH**
6 **KWH AND KW SAVINGS FROM ENERGY EFFICIENCY PROGRAMS WITH**
7 **INCENTIVE MECHANISMS IN PLACE THAT ARE LESS COSTLY THAN THE**
8 **ADDITIONAL SUM PROPOSED BY THE COMPANY.**

9 A. Staff has the following examples which illustrate less costly incentive mechanisms than
10 the approach proposed by the Company in addition to the Arizona example provided
11 above:

- 12 • For electric utilities in Connecticut, the shareholder incentive, referred to as a
13 “management fee,” can be from 2.5-6.5% of the program costs before taxes. The
14 threshold for Connecticut utilities for earning the minimum incentive (2.5%) is
15 achieving 75% of the electricity savings goal. At 100% achievement of the
16 electricity savings goal, the incentive would be 5%. At 115% achievement of the
17 electricity savings goal, it would be 6.5%. Using Connecticut’s calculation
18 methodology and applying it to the Company’s DSM Proposed Case, the
19 Company’s Additional Sum for the 2023 to 2025 period would be 5% of \$211
20 million (total Georgia Power program costs for 2023 to 2025), or \$10.6 million, not
21 \$51.7 million as the Company has proposed.

- 1 • In Michigan, no Additional Sum is paid unless a utility reaches 115% of the target
- 2 annual kWh savings goal and the Utility Cost Test (“UCT”) benefit/cost ratio is
- 3 equal to or greater than 1.25. If Georgia Power Company used the calculation
- 4 method used in Michigan and achieved 100% of the proposed electricity savings
- 5 each year from 2023 to 2025, the Company would not earn any DSM shareholder
- 6 incentive.
- 7 • In Ohio, electric utilities receive only 7.5% of the net benefits if 100% to 110% of
- 8 the target savings goal is met. This is one percentage point lower than the 8.5%
- 9 used in the Commission’s current Additional Sum methodology.
- 10 • There are several states where no shareholder incentive is allowed.

11 **Q. DOES STAFF RECOMMEND THAT THE COMMISSION RETAIN THE**

12 **CURRENT ADDITIONAL SUM METHODOLOGY?**

13 A. Yes. Staff recommends that the current, Commission approved, Additional Sum

14 methodology remain in place. The current methodology provides for an equitable sharing

15 of the net benefits of the Company’s DSM portfolio and properly considers the costs,

16 benefits, and useful lives of the Company’s programs. All data needed to calculate the

17 Additional Sum using the current Commission-approved methodology is readily available

18 from the existing data tracking and reporting done for the Company’s DSM programs. The

19 current Additional Sum methodology properly pays no Additional Sum if the net benefits

20 of the Company’s DSM programs are zero.

1 Q. WILL THE ADDITIONAL SUM RECOMMENDED BY STAFF BE AN
2 ADEQUATE INCENTIVE TO THE COMPANY?

3 A. Yes. The Additional Sum amount as a percentage (8.5%) of net benefits as recommended
4 by Staff for the 2023 to 2025 time period is identical to what the Company has received in
5 the past two IRP cycles. In addition, the Company can earn a larger DSM Additional Sum
6 by implementing programs at a cost lower than the Company budgeted for its Proposed
7 Plan.

8 X. MARKET EFFECTS - FREE RIDERSHIP AND SPILLOVER

9 Q. IS THE COMPANY PROPOSING TO CHANGE ITS PROGRAM EVALUATION
10 AND ADDITIONAL SUM CALCULATION PROCEDURES REGARDING THE
11 MEASUREMENT OF FREE RIDERSHIP AND SPILLOVER?

12 A. Yes. For its 2023 to 2025 energy efficiency programs, the Company proposes to base the
13 calculation of its proposed Additional Sum on verified gross energy savings instead of net
14 savings. This proposed change is a significant departure from current Commission policy.

15 Q. PLEASE EXPLAIN HOW THE NET SAVINGS OF THE COMPANY'S
16 PROGRAMS ARE CURRENTLY CALCULATED BASED ON THE MOST
17 RECENT EM&V REPORT.

18 A. The gross energy savings from the Company's programs operated in 2021 have been
19 adjusted to net savings to allow for such factors as free ridership and spillover. Gross
20 savings are defined as the estimated savings from energy efficiency measures adopted by

1 program participants, before adjustments for free ridership, spillover, and other factors.
2 The free ridership adjustment accounts for program participants who would have
3 implemented a measure in the absence of a program. The spillover adjustment accounts for
4 households or businesses who learn about the Company's energy efficiency programs
5 through information provided by the Company, program participants or program allies, but
6 who then install a measure without applying for a rebate or financial incentive from the
7 Company. These savings calculation procedures were adopted by this Commission in the
8 stipulation approved during the 2013, 2016, and 2019 IRP proceedings.

9 **Q. DOES STAFF AGREE THAT THE ADDITIONAL SUM CALCULATION**
10 **SHOULD BE BASED ON VERIFIED GROSS ENERGY SAVINGS OF THE**
11 **COMPANY'S PROGRAMS?**

12 **A.** No. First, the Company's 2021 EM&V Report found that several of the energy efficiency
13 programs administered during 2020 and 2021 had high free ridership. Staff Exhibit_BCS-
14 16 provides a summary of the free ridership rates for the Company's energy efficiency
15 programs for 2020 and 2021. Because several of the Company's programs continue to
16 exhibit high free ridership, it is imperative that the Additional Sum mechanism provide a
17 signal to the Company that it is important for the Company to minimize free ridership.
18 Changing the basis of the Additional Sum calculation to verified gross savings will remove
19 any financial incentive or signal for the Company to focus on minimizing free ridership
20 and maximizing participant spillover.

21 Second, there are many program design features that the Company controls that can be
22 implemented to limit the number of free riders. Third, Staff does not believe that the

1 Company should receive an Additional Sum payment for kWh and kW savings that would
2 have occurred in the absence of the Company's programs. Changing the basis of the
3 Additional Sum calculation to verified gross savings from net savings is a step in the wrong
4 direction and will minimize the Commission's policy signal to the Company to focus on
5 and minimize free ridership.

6 **Q. DOES THE COMPANY HAVE THE CAPABILITY TO CONTROL AND REDUCE**
7 **FREE RIDERSHIP OCCURRING IN ITS PROGRAMS?**

8 A. Yes. It is Staff's position that the Company can implement program design modifications
9 to minimize free ridership. However, in the Company's DSM-DER Forecasting Direct
10 Testimony in Docket Nos. 44160 and 44161, page 22 lines 13-14, Company Witness Jeff
11 Smith stated that the Company does not have control over free riders and does not have the
12 ability to structure programs in such a way to limit free riders. In previous IRP proceeding
13 Staff has identified several ways the Company has already acted to reduce overall free
14 ridership such as in requesting to decertify the EarthCents New Home Program, as high
15 free ridership had a negative impact on program economics. The 2018 EM&V Report from
16 the Company's consultant, Nexant, also indicated that ongoing programs, such as the
17 Commercial Custom Program, have reduced free ridership as they have matured. Company
18 Witness Jeff Smith agreed that the Company has made changes to programs to limit free
19 ridership and has control over several aspects of the programs that could impact free
20 ridership including incentive levels, program eligibility, and the measure mix (Tr. at 651-
21 652).

1 Q. DOES STAFF HAVE ANY SUGGESTIONS ON HOW THE COMPANY CAN
2 MINIMIZE FREE RIDERSHIP IN THE COMPANY'S ENERGY EFFICIENCY
3 PROGRAMS?

4 A. Yes. Staff suggests proactive oversight of the ongoing DSM implementation to ensure that
5 incentives go towards motivating customers who would otherwise not implement energy
6 efficiency measures. The Company should continue to use its online Marketplace and
7 market intelligence to track pricing to provide the optimal discounts for economic nudges
8 to customers. The marketing of programs towards low and moderate income Residential
9 customers and small and medium sized Commercial customers in need of financial
10 opportunities may serve to help DSM program incentives to best influence
11 participation. The Company can also direct resources towards regions of the state or
12 economic sectors that have seen lower interest and participation levels in prior program
13 years to open the programs to customers who might have otherwise missed out on DSM
14 options. Advanced analytics and strategic planning using energy consumption and other
15 market data can help the Company find the customers most receptive to meaningful
16 program participation.

17 Q. WHAT IS STAFF'S RECOMMENDATION FOR THE USE OF MARKET
18 EFFECTS?

19 A. Staff recommends that the Company's Additional Sum be based on net, not verified gross,
20 energy savings. The use of net savings would include the effects of spillover and free
21 ridership.

1 **XI. APPROVAL/NOTIFICATION PROCESS**

2 **Q. ARE THE PROGRAM PLANS PROVIDED IN THE COMPANY'S**
3 **CERTIFICATION FILING FINAL?**

4 A. No. The plans filed are not final and in fact each program plan description, found in the
5 DSM Filing Appendix A, has a footnote which states "Final program delivery mechanisms
6 will be developed jointly by Georgia Power and its selected program implementer, which
7 may include modifications to the program delivery steps and processes".

8 **Q. ONCE A PROGRAM IMPLEMENTER IS SELECTED AND THE PROGRAM**
9 **PLANS ARE FINALIZED, DOES STAFF RECOMMEND THAT THE COMPANY**
10 **PROVIDE THE PLANS TO STAFF FOR REVIEW AND APPROVAL?**

11 A. Yes. Staff recommends that once a program implementer is selected and plans are drafted
12 that these plans should be provided to Staff for review and approval prior to the
13 implementation of the programs. The Company should provide Staff at least 15 days for
14 review of the Final Program Plans.

15 **XII. DSM TARIFF AND TRUE UP PROCESS**

16 **Q. CURRENTLY, IS THERE AN APPROVED TRUE UP MECHANISM FOR THE**
17 **DSM TARIFF?**

18 A. Yes. As part of the 2013 IRP/DSM Stipulation, the Company agreed that the Company's
19 DSM revenues and expenses will be trued-up on an annual basis to ensure that revenues
20 collected from the Company's customers for DSM related activities are spent on DSM

1 related activities. Staff and the Company worked on finalizing a True-Up process which
2 was filed in Docket No. 36499 on October 18, 2013.

3 **Q. HAS A TRUE-UP TAKEN PLACE OVER THE LAST PROGRAM CYCLE?**

4 A. Yes, a true-up occurs annually. Staff is currently reviewing the 2021 DSM True-Up which
5 was filed on March 15, 2021, under Docket No. 42311.

6 **Q. DOES STAFF RECOMMEND THAT THE COMPANY BE ALLOWED TO**
7 **ROLLOVER UNSPENT BUDGET DOLLARS AND UNACHEIVED SAVINGS**
8 **TARGETS TO THE FOLLOWING YEAR?**

9 A. No. Historically, the Company has achieved its approved energy savings targets every year
10 prior to 2020 and 2021, which were severely affected by the Pandemic. Staff expects the
11 Company to be able to achieve their savings targets within the approved budget. Due to
12 Company's prior performance of meeting its approved savings targets and because the
13 currently approved True-Up process addresses what happens to remaining budget dollars,
14 Staff recommends continuation of the current DSM True-Up process, including not
15 allowing the rollover of unspent annual budget dollars or unrealized savings targets.

16 **XIII. PROGRAM EVALUATIONS**

17 **Q. HAS THE COMPANY COMPLETED PROGRAM EVALUATIONS FOR THE**
18 **ENERGY EFFICIENCY PROGRAMS APPROVED BY THE COMMISSION IN**
19 **THE 2019 IRP DOCKET?**

1 A. Yes. The Company filed the Residential and Commercial EM&V Reports with the
2 Commission on October 29, 2021. The Residential evaluation was performed by Illume
3 Advising, LLC. The Commercial evaluation was performed by Brightline Group. These
4 reports covered the eleven Residential and Commercial DSM programs that were certified
5 by the Commission in the 2019 IRP proceeding. This evaluation report covered activities
6 for the 2020 and 2021 program years.

7 **Q. HAS THE STAFF COMPLETED ITS REVIEW OF THE EM&V REPORT?**

8 A. Yes. Staff completed its initial review and provided its recommendations to the Company
9 in December 2021. However, due to the limited amount of time that Staff had to review
10 the EM&V report and responses to questions that Staff had sent to the Company prior to
11 the 2022 IRP and DSM Certification Filings, there are a few remaining concerns that Staff
12 planned to review during these dockets and are addressed in detail below.

13 **Q. PLEASE DESCRIBE THE IMPACTS OF THE PANDEMIC ON THE EM&V**
14 **PROCESS AND REPORT.**

15 A. The programs approved in the 2019 IRP were set to launch in early 2020 just as the
16 Pandemic began. In response, the Company temporarily delayed the launch or disrupted
17 the activities of several DSM programs. Other programs continued but saw tempered
18 participation levels compared to pre-Pandemic levels. The delay and lack of participation
19 had a direct impact on the EM&V process. For some DSM programs, there were not
20 enough completed projects to be able to provide an adequate sample size for the program's
21 evaluation. Staff agreed to delay the filing of the EM&V reports to October of 2021 to

1 allow for more program activity and help evaluation efforts. However, not all programs
2 were able to return statistically viable results.

3 **Q. WHAT IS THE CURRENT COMMISSION POLICY REGARDING HOW**
4 **EVALUATION RESULTS SHOULD BE APPLIED?**

5 A. Per the stipulation approved in the 2019 IRP Order, evaluation results are used
6 prospectively for program planning, future year reported energy savings and the Additional
7 Sum Calculations, starting in the first year of the next program cycle.

8 **Q. DOES THE COMPANY PROPOSE TO DEVIATE FROM THIS POLICY FOR**
9 **ANY OF THE PROGRAMS?**

10 A. Yes. In the EM&V reports, Illume Advising and Brightline Group/Cadmus, the evaluators
11 for the Residential and Commercial programs, respectively, recommended to use the prior
12 2018 EM&V results for certain programs, or parts of programs, for the Company's DSM
13 Proposed Case. The recommendations from Illume Advising and Brightline
14 Group/Cadmus are summarized as:

- 15 • The Residential portfolio, the Behavioral, Specialty Lighting, HEIP – marketplace
16 portion, and Refrigerator Recycling Programs all completed successful evaluation
17 and will be used to inform the 2022 IRP proposed programs.
- 18 • The Residential HEEAP and HEIP – Whole Home and Individual improvements
19 pathways were determined to not be statistically valid, and the evaluators
20 recommended using the energy and demand savings as filed in the 2019 IRP.

- The Commercial Behavioral program evaluation, filed on March 20, 2022, under Docket No. 43040, was not statistically valid and the evaluators recommended maintaining the same energy and demand savings as filed in the 2019 IRP.
- The EM&V process for the Commercial Prescriptive, Custom, and Small Business Direct Install Programs was successful and will be used to inform the 2022 IRP proposed programs.

Q. DOES STAFF AGREE WITH THE COMPANY'S REQUEST TO USE OF THE 2018 EM&V RESULTS FOR THE PROGRAMS RECOMMENDED BY THE EVALUATORS?

A. Yes. Staff recognizes that the disruptions to program activity created unique challenges for the Company and their evaluators, and that the atypical participation levels limited the ability to produce statistically valid EM&V results for select programs. The statistically valid 2021 EM&V results will be used for the programs approved in this IRP and DSM Certification proceeding. The 2018 EM&V results will continue to be used for all areas not properly addressed by the 2021 EM&V reports.

Q. HAVE ALL OF STAFF'S RECOMMENDATIONS REGARDING THE COMPANY'S EM&V REPORT BEEN ADDRESSED AND FINALIZED?

A. No. Staff has a few remaining concerns regarding the findings and recommendations of the 2021 EM&V Report.

1 Q. PLEASE SUMMARIZE STAFF'S REMAINING CONCERNS AND
2 RECOMMENDATIONS FOR RESOLVING EM&V ISSUES THAT ARE STILL
3 PENDING FROM THE COMPANY'S 2021 PROGRAM EVALUATION REPORT.

4 A. Staff maintains the following concerns regarding the 2021 EM&V:

- 5 • The 2021 EM&V results regarding Commercial lighting hours of use ("HOU")
6 were more highly variable across building types when compared to prior evaluation
7 cycles. In many high impact building types, the hours of use derived from the 2021
8 evaluation cycle were significantly higher than the values used in the initial
9 reported savings. However, in response to a Staff data request STF-GDS-6-5, as
10 shown in Staff Exhibit_BCS-17, the Company has used an alternative set of
11 assumptions for commercial lighting HOU for program planning purposes. Staff
12 recommends that the Company continue to utilize the Commercial lighting HOU
13 reflected in Staff Exhibit_BCS-17, and used in the Company's program planner,
14 for reporting gross savings during the 2023-2025 program cycle.
- 15 • The underlying assumptions used in the algorithm to calculate measure savings
16 from the Refrigerator Recycling Program are based on primary market research
17 conducted in 2011. Staff recommends that the Company conduct an updated in-site
18 study that properly accounts for the current stock of secondary
19 refrigerators/freezers in the Company service area.
- 20 • As noted earlier in our testimony, Staff also recommends that the Company
21 continue to monitor the Commercial Behavior program, given its
22 underperformance and statistically uncertain savings reflected in the 2021 EM&V

1 report, and be prepared to make mid-cycle changes to the program if the next
2 evaluation does not demonstrate an improved and cost-effective program.

3 **Q. DOES STAFF HAVE ANY RELATED EM&V CONCERNS AND**
4 **RECOMMENDATIONS REGARDING THE EM&V OF PROSPECTIVE**
5 **PROGRAMS?**

6 A. Yes. Several of the Company's proposed certified Residential programs include significant
7 focus on the income-qualified sector. Historically, the Company has assumed a default net-
8 to-gross assumption ("NTG") of 1.0 for income-qualified sector savings. Staff
9 recommends that the Company plan to evaluate income-qualified savings in a manner
10 consistent with the remainder of the Residential sector to confirm whether this NTG
11 assumption is appropriate. This recommendation applies to the HEEAP and HopeWorks
12 programs and the Food Bank focused portion of the Specialty Lighting Program.

13 **Q. WHAT IS THE CURRENT COMMISSION POLICY REGARDING THE**
14 **FREQUENCY OF DSM PROGRAM EVALUATIONS?**

15 A. The current Commission policy is that impact, process, and other evaluations of the
16 Company's certified DSM programs are to be conducted every three years.

17 **Q. WHAT ARE STAFF'S RECOMMENDATIONS REGARDING THE**
18 **EVALUATION OF THE DSM PROGRAMS?**

19 A. Staff recommends using the valid 2021 EM&V results and using the 2018 EM&V results
20 in all other instances as outlined in the EM&V and requested by the Company. Staff

1 recommends the continuation of current policy to implement the EM&V results in the first
2 year of the next IRP cycle in 2026. Staff recommends continuation of current Commission
3 policy that requires the Company to provide detailed evaluation plans for each of the
4 approved DSM programs within 90 days of the selection of Program Implementers for each
5 of the certified programs. Staff recommends the upcoming EM&V include a new in-situ
6 study for the Refrigerator Recycling Program.

7 **XIV. COMPLIANCE FILINGS**

8 **Q. PLEASE DESCRIBE THE COMPANY'S CURRENT REPORTING**
9 **REQUIREMENTS AND WHETHER THE COMPANY IS IN COMPLIANCE**
10 **WITH THESE REQUIRMENTS.**

11 **A.** The Company is required to file quarterly progress reports on its Certified Demand Side
12 Programs. These reports include the major activities and accomplishments of each DSM
13 program including participation levels, energy savings, demand savings, and program costs
14 for the current quarter, year to date, and program to date. The Company is in compliance
15 with this reporting requirement.

16 **Q. DOES STAFF MEET WITH THE COMPANY TO DISCUSS THE QUARTERLY**
17 **REPORTS?**

18 **A.** Yes. Staff meets with the Company on a monthly basis to discuss energy goals, program
19 costs, and any other DSM issues that may have arisen since the last meeting between Staff
20 and the Company has been held.

1 Q. DOES THIS CONCLUDE STAFF'S TESTIMONY?

2 A. Yes.

1 MR. DAVIS: With your permission, Madam Chair,
2 I would like to ask that the witnesses give a summary
3 of their prefiled testimony.

4 MADAM CHAIR PRIDEMORE: Go ahead.

5 WITNESS COOPER: Good morning, Commissioners.

6 In our testimony we address --

7 THE STENOGRAPHER: Slow down.

8 WITNESS COOPER: Okay. Sorry.

9 In our testimony we address Georgia Power
10 Company's proposed demand side management plan.
11 Staff and our consultant, GDS Associates, have
12 reviewed the company's proposed DSM and recommended
13 approval of the demand side plan as modified by
14 staff's recommendations contained in staff's
15 testimony covering Docket Nos. 44160 and 44161.

16 The development of the company's proposed DSM
17 plan is a lengthy process that is outlined by the DSM
18 program planning approach. The DSM program planning
19 approach outlines the work of the DSM working group
20 and the modeling approach for the DSM programs.
21 Staff recommends that the DSM program planning
22 approach be modified to include a new scenario that
23 allows DSM resources to be selectable by the Aurora
24 modeling and compete head-to-head on a level playing
25 field with supply-side resources.

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1 This will allow staff, the company, and
2 interested stakeholders to understand the optimal
3 amount of DSM savings that should be included as part
4 of the lowest cost plan. Staff recommends that
5 future requests for proposals should include DSM and
6 demand response as potential resource options to fill
7 energy and demand needs. Staff recommends that the
8 DSM working group continue in its current form to
9 allow for interested parties to participate in the
10 development of future programs.

11 In the IRP and DSM certification filings, the
12 company requested and staff recommends approval of
13 the decertification of the Commercial Midstream
14 Program and the Power Credit Program. The company is
15 seeking to certify the HopeWorks program, which staff
16 supports.

17 The company requested a waiver of Commission
18 Rule 515-3-4.04(4)(a)3 for the thermostat demand
19 response program due to the program failing the TRC
20 in the near term. Staff recommends approval of this
21 request.

22 The company also requests that five current
23 residential programs: Behavioral, home energy
24 improvement, refrigerator recycling, specialty
25 lighting, home energy -- and the home energy

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1 efficiency assistance programs, and four current
2 commercial programs: Custom, prescriptive, small
3 commercial direct install, and behavioral programs be
4 approved with amended certificates. Staff recommends
5 approval of the programs proposed with adjustments
6 described in our testimony.

7 The commercial behavioral program has struggled
8 to pass economic screening and the recent EM&V for
9 the program showed minimal savings. Staff has
10 concerns that this program will not deliver value to
11 customers. As such, staff recommends that the
12 program be paused pending decertification if the
13 upcoming 2024 EM&V does not show the program to be
14 cost-effective.

15 Staff reviewed the proposed programs provided
16 by members of the DSM working group as modeled as
17 part of the advocacy case. The manufactured homes
18 program passed economic screening and is focused on a
19 portion of customers that have been underserved by
20 DSM programs historically. Staff recommends that the
21 measures included in the manufactured home program as
22 modeled in the advocacy case, except for the whole
23 home measures, be included in HEIP, along with a
24 total budget increase of 1.49 million for the
25 three-year time period.

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1 When analyzing the proposed budgets, staff
2 determined that the company has consistently
3 overstated the nonincentive costs for the commercial
4 prescriptive program and the residential behavior
5 program. Staff recommends a reduction of the costs
6 for the three-year time period totaling yearly
7 1.49 million for the residential behavior program,
8 and 6 million for the commercial prescriptive
9 program.

10 There are several aspects of the DSM nonprogram
11 spending that the company requested to continue at
12 the same budgets as approved in the 2019 IRP. Staff
13 recommends approval of the proposed budgets for the
14 Education Initiative, Learning Power, of \$4 million
15 annually, the Residential and Commercial Energy
16 Efficiency Consumer Awareness of 4.5 million and
17 1.1 million annually, respectively, and the pilot
18 budget of \$3 million to be split evenly between the
19 residential and commercial portfolios.

20 The 2019 IRP DSM order approved an
21 income-qualified tariff base financing pilot that is
22 now named the Residential Investment to Save Energy
23 or RISE pilot. Participation in this pilot has been
24 slow to date and staff and the company are continuing
25 to work to find ways to improve performance. And

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1 staff recommends continuation of this pilot.

2 In its filing, the company did not propose the
3 continuation of the Automated Benchmarking Tool.
4 Staff believe the tool provides a vital service to
5 customers and recommends continuation of the ABT at
6 the same funding as approved in the 2019 IRP.

7 The company proposed a new method for
8 calculating the additional sum of four cents per
9 kilowatt-hour saved based on gross savings. The
10 current Commission-approved methodology provides the
11 company 8.5 percent of net benefits and uses net
12 savings.

13 Staff finds the company-proposed methodology
14 will lead to an excessive additional sum with a
15 method that does not incentivize the company to
16 deliver the most cost-effective programs due to
17 elimination of market effects and eliminating of net
18 benefits. Staff recommends the continuation of the
19 current approved additional sum methodology that was
20 approved in the 2019 IRP DSM case.

21 All DSM spending is subject to a true-up
22 process to ensure that customers only pay for the
23 actual spending for each customer class. The true-up
24 has been an effective oversight tool for the
25 Commission and staff recommends continuing the

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1 process, which includes not allowing the rollover of
2 unspent annual budget dollars.

3 In between the IRP cycles, all certified
4 programs undergo a robust EM&V, evaluation,
5 measurement, and verification process, to help the
6 staff and the company understand how programs are
7 performing. The evaluation covers both the process
8 of implementing the programs and the determination of
9 savings that the measures and programs are actually
10 achieving. Staff recommends continuing the current
11 EM&V process with an updated in situ metering study
12 for the refrigerator recycling program and several
13 other detailed recommendations as stated in our
14 testimony.

15 Last, staff has two recommendations to ensure
16 the Commission has proper oversight of the process of
17 executing the approved programs. Staff recommends
18 that detailed plans for all programs be provided for
19 staff before final program plans are approved, and
20 that the detailed evaluation plans be provided for
21 review by staff for each program.

22 This concludes staff's testimony. Thank you.

23 MR. DAVIS: Madam Chair, the witnesses are now
24 available for questions from the Commissioners and
25 cross-examination.

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1 MADAM CHAIR PRIDEMORE: Questions from the
2 Commission.

3 (No response.)

4 MADAM CHAIR PRIDEMORE: Well, it will be me
5 again.

6 All right. In the Georgia Power testimony that
7 was delivered on the DSM portion of their filing,
8 page 20, in particular of the Ball, Phillip, Smith,
9 and Evans testimony, Georgia Power's requested an
10 additional \$3 million payment for DSM pilots in this
11 IRP. And I recognize in your testimony you approve
12 that on line 1 of page 8. You say that they should
13 go ahead and get the \$3 million.

14 Talk me through staff's recommendation for
15 that, in light of the fact that the DSM programs have
16 been woefully undersubscribed in the last three
17 years.

18 WITNESS COOPER: Well, the pilots, the budgets
19 are -- we believe it should continue on. They run
20 several different pilots there and the process of
21 running many that will carry over from the current
22 programs into the future.

23 The undersubscribing I don't think has much to
24 do with the pilots. I think that is mostly due to
25 COVID impacts. If you look before 2020, the company

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1 has achieved their savings targets every single year,
2 and while be under budget. The pilots allow them to
3 explore new options and seek, you know, novel ways
4 to, you know, hit those targets and make sure that
5 they are keeping up with the industry.

6 MADAM CHAIR PRIDEMORE: In light of COVID
7 impacts, what data requests has staff made of the
8 company in light of the fact that the DSM programs
9 have been woefully undersubscribed over the last
10 three years?

11 WITNESS SPELLMAN: Let me take a stab at that.
12 The company has performed rigorous evaluations of the
13 programs during 2019, '20, and '21. And the staff
14 participated in the design of the evaluation plans.

15 In short, where there was a comprehensive
16 analysis of every program and the company hired an
17 independent contractor to perform these rigorous
18 evaluations and there was overwhelming evidence that
19 the slowdown in participation was due to the impacts
20 of COVID.

21 For example, during a large part of that IRP
22 cycle, 2019 -- well, 2020 and '21, the company had
23 policies and procedures that wouldn't allow company
24 staff or their contractors to enter into customer
25 premises. So the company couldn't perform a lot of

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1 the DSM activities. Now that has come to an end and
2 the company is back doing the regular procedures for
3 its programs. But it was very clear from those
4 extensive evaluations, hundreds of pages of
5 evaluations, that not only did COVID have a big
6 impact, but it also made it more difficult to do the
7 evaluations.

8 But the staff was very closely involved with
9 all the evaluation activities, the design of the
10 evaluations, monitoring the progress of the
11 evaluations, talking with the company or the
12 contractors about the progress of the programs. And
13 we expect now that with COVID more in the rearview
14 mirror, but still around, that the participation
15 won't be -- you know, from COVID won't be a problem
16 in the future.

17 MADAM CHAIR PRIDEMORE: Besides construction of
18 the survey, what did the staff due to evaluate the
19 shortcomings of COVID impacts and how COVID impacted
20 it?

21 What else did you do?

22 WITNESS SPELLMAN: I would just add a couple of
23 things. We -- you know, we had regular monthly
24 meetings with the company to talk about the issues
25 with COVID. The company staff were very timely in

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1 reporting to us about some of the difficulties they
2 were encountering, especially with the company's
3 policies that affected what their staff and their
4 contractors could do. So we were talking with the
5 company on a monthly basis, making suggestions about
6 how they could deal with the impacts of COVID and,
7 you know, trying to understand what the company
8 policies were for their employees and contractors.

9 We also were designed -- involved in the design
10 of the evaluations, the design of the survey
11 instruments, the sample selection procedures. We
12 were involved with reviewing draft evaluation
13 reports, going through them line by line, hundreds of
14 pages of statistical and engineering calculations to
15 make sure that the evaluation results were robust and
16 rigorous. And in those evaluations, the evaluation
17 contractors made recommendations on what should be
18 done to improve the programs going forward.

19 MADAM CHAIR PRIDEMORE: Did staff make those
20 recommendations or did staff reset those goals,
21 Mr. Spellman, or was it done by the third party?

22 I mean, I recognize --

23 WITNESS SPELLMAN: Right.

24 MADAM CHAIR PRIDEMORE: -- and applause to
25 staff for working on the evaluation and survey,

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1 that's great, but in terms of goal attainment, seeing
2 how short the company was from meeting their goals --

3 WITNESS SPELLMAN: There were two things --
4 okay.

5 WITNESS BARBER: Well, one thing I want to
6 point out is on Staff Exhibit BCS-7. If you look,
7 prior to COVID, which was 2020, the company met or
8 exceeded their savings targets.

9 But 2020 was kind of like the perfect storm.
10 Not only COVID, but the company was -- I think the
11 week that COVID hit was about to implement programs
12 from the 2019 IRP. They had new implementation
13 contractors.

14 And so that was also part of the issues with
15 the implementation or launch of those programs. I
16 know that you had asked -- what was your most recent
17 question about staff?

18 MADAM CHAIR PRIDEMORE: My question was: Did
19 staff give advice to the company directly on how to
20 attain these goals, seeing how short they were in
21 attaining them?

22 WITNESS BARBER: Well, staff and the company
23 worked together. As soon as COVID hit, we started
24 talking about how they had planned to meet their
25 goals.

1 And all throughout 2020, we met. We actually
2 worked with the company about different ways of them
3 trying to reach their targets through food banks,
4 other things. And so, yes, we had numerous
5 discussions with the company.

6 Our position is -- and, plus, too, the
7 Commission had approved a 15 percent increase in the
8 most -- in the 2019 IRP. And that also got factored
9 in for 2020.

10 And so, yes, we had continuous discussions with
11 the company. We worked with them trying to see ways.
12 But Georgia Power took a very strict position, which
13 was appropriate, is that they were not going to enter
14 any homes. They were not going to allow third
15 parties to do it for awhile. I can't remember
16 specifically when -- when that occurred.

17 But, no, we -- we definitely worked. We feel
18 very strongly that the company will meet their goals
19 for this year.

20 MADAM CHAIR PRIDEMORE: Remind me, Ms. Barber,
21 what was the staff exhibit number that you gave?

22 WITNESS BARBER: BCS-7.

23 WITNESS COOPER: And I would like to point out
24 the 2022 programs that we just got a monthly update
25 on. The residential programs are tracking to hit
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1 their targets and the commercial programs are doing
2 significantly better than they had in the past.

3 The commercial programs tend to -- you know,
4 have most of their savings later in the year. So
5 hopefully as the economy continues to show signs of
6 improvement and steadiness, then that -- the
7 commercial will hit their targets, as well.

8 And Georgia Power indicated to us that they are
9 confident that they will achieve their targets this
10 year.

11 MADAM CHAIR PRIDEMORE: And staff has no
12 reservation -- my question is: Does staff have any
13 reservation about continuing to improve the quantity
14 of spending for DSM programs, in light of the goal
15 attainment not being reached during the last cycle?

16 WITNESS COOPER: We expect Georgia Power to be
17 able to hit their targets under budget as they have
18 done --

19 MADAM CHAIR PRIDEMORE: This time?

20 WITNESS COOPER: -- historically.

21 WITNESS BARBER: Plus, too, we have a true-up
22 process where any unspent dollars go back anyway. So
23 we're comfortable with their budgets as we modify.
24 We have a couple of modifications for their budgets.
25 So we are comfortable.

1 MADAM CHAIR PRIDEMORE: So I have a data
2 request in front of Georgia Power right now asking
3 for a percentage or a rough number of their
4 customers -- ratepayers that are identified as
5 income-qualified for these new DSM pilot programs
6 under this IRP who have not paid an electric bill at
7 some point during COVID. And what is the cor- -- the
8 correlation or trying to determine if there is a
9 correlation between not paying a bill and signing up
10 for a DSM program during this time period.

11 Has staff asked the company that question?

12 WITNESS COOPER: I don't believe we asked
13 specifically that question. We have asked about
14 participation. And they are focused on low-income
15 programs.

16 I know when we ask -- you know, the company
17 doesn't specifically track who is low income in the
18 participation across every aspect, but in certain --
19 you know, programs are focused on that area, so...

20 WITNESS SPELLMAN: Just --

21 MADAM CHAIR PRIDEMORE: But has staff asked in
22 particular then if they have done the analysis
23 internally to determine the percentage of customers
24 that needed income qualification barrier?

25 WITNESS SPELLMAN: Commissioner, I believe you
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1 asked that question. I was reading through the
2 transcript.

3 MADAM CHAIR PRIDEMORE: That's right. I have a
4 data request in front of me and now I'm asking if
5 staff has asked that question.

6 WITNESS SPELLMAN: So --

7 WITNESS COOPER: We have in the past. The
8 company has indicated they don't have -- carry income
9 per each individual customer to us. It's not
10 something that Georgia Power tends to track.

11 For most of income-qualified programs that we
12 use larger census data to identify areas, but in the
13 RISE pilot it was focused on certain ZIP codes in
14 order to likely, you know, focus on those kind of
15 communities.

16 And then when individuals do come to
17 participate in those, you know, programs with
18 specific requirements, then they will ask them if
19 they participate in other aspects. But Georgia Power
20 tends not to try to specifically identify customers
21 who are income-qualified for the programs.

22 WITNESS SPELLMAN: Let me add to that. We
23 actually did ask the company in a data request to
24 tell us how many low-income customers that they have
25 that would fit within the definition of

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1 income-qualified.

2 And they sent back an answer saying they didn't
3 have that information. So we did ask that type of
4 information, but the company didn't have it. But, as
5 Nick said, we can figure it out from other data
6 sources with the assistance of the company.

7 MADAM CHAIR PRIDEMORE: Then, Mr. Spellman, how
8 is the company going to determine income
9 qualification for these new programs as they are
10 presenting in this IRP?

11 WITNESS SPELLMAN: I have a suggestion. Again,
12 we haven't talked -- we haven't talked about this.
13 But there are other utilities doing this. And, for
14 example, it may have come up during the
15 cross-examination back on April 5th.

16 But there are indicators available, like: Is
17 the customer participating in the home energy
18 assistance program or other income-qualified
19 programs? As Nick said, we can use the data from
20 other agencies that would have that information.

21 Community action program agencies that identify
22 income-qualified people. And those are the details,
23 I guess, that would have to be worked out. But those
24 are the types of things we talked about as possible.

25 WITNESS COOPER: There is also likely funding
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1 that can be an indication of someone who is qualified
2 for the federal assistance. So, you know, we can
3 corroborate that. That won't capture every single
4 person, but that is a way of identifying customers.

5 MADAM CHAIR PRIDEMORE: Has staff asked the
6 company how they are going to determine income
7 qualification to fully subscribe these programs as
8 proposed?

9 WITNESS COOPER: Yeah. If you're talking about
10 the RISE pilot, then, yeah, we have. I've made sure
11 that there is a process in place to ensure that
12 they -- you know, the customers we are trying to
13 identify are the ones actually participating in that
14 pilot.

15 MADAM CHAIR PRIDEMORE: Okay. So DSM programs
16 are -- and not just income qualifying, but all of
17 these programs -- the cost of these programs, the
18 company comes back and seeks to recover the cost of
19 these programs in the rate case?

20 WITNESS COOPER: They are trued-up every year.
21 And, yes, there is a specific tariff that is
22 recovered in the rate case.

23 MADAM CHAIR PRIDEMORE: So the cost of these
24 programs as they're continuing to rise and continuing
25 to get approved, not only the number of programs, but

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1 also the approval -- or staff's recommendation on the
2 approval of the size of these programs, that
3 continues to get socialized across the rest of the
4 rate base; correct?

5 WITNESS COOPER: Per customer class, yes. The
6 residential customers take care of the programs. And
7 the commercial customers pay for the commercial
8 programs, yes.

9 MADAM CHAIR PRIDEMORE: So some ratepayers are
10 paying for DSM programs for others; is that true?

11 WITNESS COOPER: At the current level of
12 participation, I do not believe every residential
13 customer has probably participated, though they can.
14 Or commercial. So they are available to all, but not
15 every customer has likely participated, but...

16 MADAM CHAIR PRIDEMORE: But those that
17 participate, the cost of that participation is being
18 covered by those that pay their bills; right?

19 WITNESS COOPER: Correct.

20 WITNESS SPELLMAN: And, Commissioner, that's
21 true for supply-side investments, too. The customers
22 who don't --

23 MADAM CHAIR PRIDEMORE: So who is in the DSM
24 working group?

25 WITNESS COOPER: It could be any interested
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1 intervenor. It's a collection of, you know,
2 interested parties who are -- you know, advocate for,
3 you know, various things. I mean, several are in
4 this room. They can identify themselves.

5 MADAM CHAIR PRIDEMORE: They're not on the
6 stand, Mr. Cooper.

7 WITNESS COOPER: I mean, so --

8 WITNESS BARBER: Well, I'll get -- staff
9 facilitates the group. Of course, Georgia Power,
10 Southern Alliance for Clean Energy, Georgia Watch,
11 GIPL, Partnership for Southern Equity. We had Kroger
12 on the working group. I think they've left.

13 Who else?

14 WITNESS COOPER: We had some other, like
15 Walmarts.

16 WITNESS BARBER: Jim Clarkson.

17 WITNESS COOPER: Resource Supply Management.

18 WITNESS SPELLMAN: Retail Group.

19 WITNESS COOPER: Yeah. The Commercial Group
20 used to participate. Now, I'm not sure if he has in
21 this last cycle.

22 MADAM CHAIR PRIDEMORE: So the participants are
23 not determined through Commission action?

24 WITNESS BARBER: Participate -- the
25 participants, I guess, staff administers who

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1 participates. Generally, we allow with coordination
2 with Georgia Power people that can participate. We
3 generally don't let implementor -- energy efficiency
4 programs, somebody that doesn't have a vested energy
5 in the design and development of energy efficiency
6 programs in Georgia.

7 If they're looking at it for, we want to sell
8 you a product, we generally don't allow them to join.
9 But if someone has a vested interest -- like the City
10 of Atlanta has participated in the past.

11 So it's not a Commission -- it's a Commission,
12 staff and Georgia Power decision about who can
13 participate if they have an interest.

14 MADAM CHAIR PRIDEMORE: Would you mind getting
15 me a list of the DSM working group participants and
16 the rules by which that they are or are not allowed
17 to participate? I would like to look at that.

18 WITNESS BARBER: Okay.

19 WITNESS COOPER: Okay.

20 MADAM CHAIR PRIDEMORE: Commissioners, any
21 other questions from Commissioners?

22 COMMISSONER SHAW: I want to kind of move away
23 from talking about the goals and the -- you know, the
24 issues with COVID, as far as participation, and talk
25 about the total net benefits in terms of the program

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1 itself. Are y'all also looking at those?

2 I know there's tests of programs,
3 administrative cost tests. And how often -- how
4 often are those done?

5 WITNESS COOPER: Those are filed in the IRP.
6 There's certainly -- in the true-up process we can
7 look at those because we have the data and we can
8 build that up as needed. But they're looked at in
9 this IRP cycle.

10 COMMISSONER SHAW: So, in your opinion, what
11 are you -- what is your opinion on those -- is it
12 what type of benefit is it -- I've looked at one of
13 these cost tests. One from the 2017 DSM year which
14 showed a 6.1 net benefit. So a six-to-one return.

15 And then I have seen something from the '21
16 test year, which combined commercial and residential,
17 which showed a 3.2.

18 Is that accurate, in your opinion?

19 WITNESS COOPER: Yeah. Certainly the totals
20 are accurate. Most of it's a reflection of what it
21 costs going down and some of the programmatic shift,
22 especially away from lighting, which delivered much
23 higher benefits. And as LEDs have come into, you
24 know, the market that lighting benefit has diminished
25 slightly.

1 So we kind of expect those numbers to, you
2 know, tighten and get less. And that's been
3 indicated over the course of IRPs since -- we have
4 kind of a continuing trend, so...

5 COMMISSONER SHAW: And, Madam Chair, I'm sorry
6 because I'm going to ask a question here that has to
7 do with another statement.

8 Have you also looked and compared the success,
9 in terms of the return, the net benefit in Georgia,
10 in comparison to other states and other utilities?

11 WITNESS COOPER: We have looked around to make
12 sure, you know, our programs are, you know, as
13 beneficial as others. Georgia Power programs tend to
14 be pretty in line with the benefits you see.

15 Because a lot of the states that do very robust
16 energy efficiency programs tend to have other metrics
17 they use. So they have a renewable portfolio
18 standard or the EE standard or things like -- or
19 they're using, you know, different metrics than we
20 use to make sure that customers are getting benefits.

21 The numbers don't always line up, but other
22 utilities that run similar programs tend to have
23 similar type of benefit. And Georgia Power's do
24 provide significant benefits for customers. Those
25 operations are, you know, generally quite good.

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1 COMMISSONER SHAW: Would you agree with me when
2 I tell you that -- isn't it true that the majority of
3 the co-op electric providers in the state do not
4 offer the same level of DSM-type programs, energy
5 efficiency programs that Georgia Power does.

6 WITNESS COOPER: We don't regulate those so --
7 I mean, we really don't have a great reporting system
8 for that. But I know that -- there's a few that do.
9 Some of the larger ones run some programs, but, yeah,
10 I don't think most of them run robust programs.

11 WITNESS BARBER: Well, I will add to that. I
12 tend to agree they don't have the structured
13 programs, but also Georgia -- ACEEE used to do
14 rankings of states. It's been a couple of years
15 since they've stopped.

16 Georgia is not ranked -- we were pretty low on
17 the amount of energy efficiency that we do as a
18 state. They've kind of went away from that. But
19 Georgia, you know, does have a good program.

20 I know that somebody in their testimony talked
21 about how well ran the programs are from a cost of
22 saved energy. Georgia Power's commercial programs
23 are very inexpensive for the cost of saved energy.
24 And so, I mean, we do support the company's plan, you
25 know, as proposed with a few modifications.

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1 WITNESS SPELLMAN: Yeah. The cost of saved
2 energy as reported by the company for the DSM base
3 case that they propose is two cents per kilowatt per
4 lifetime kilowatt hour saved. So the resource is
5 very economical and that's why on these benefit cost
6 tests it's showing very high benefit cost ratios.

7 COMMISSONER SHAW: Okay. Thank you.

8 MADAM CHAIR PRIDEMORE: Any other questions
9 from the Commissioners?

10 (No response.)

11 MADAM CHAIR PRIDEMORE: Okay. Very good.
12 Americans for Affordable Clean Energy.

13 MR. GALLOWAY: No questions, Madam Chair.

14 MADAM CHAIR PRIDEMORE: Commercial Group.

15 MR. JENKINS: No questions.

16 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
17 for Georgia.

18 MR. PRENOVITZ: No questions.

19 MADAM CHAIR PRIDEMORE: Good to see you.

20 MR. PRENOVITZ: And you.

21 MADAM CHAIR PRIDEMORE: Cypress Creek
22 Renewables.

23 MR. STAIR: No questions.

24 MADAM CHAIR PRIDEMORE: Georgia Association of
25 Manufacturers.

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1 MR. JONES: No questions.

2 MADAM CHAIR PRIDEMORE: Georgia Center for
3 Energy Solutions.

4 MR. HUBBARD: No questions.

5 MADAM CHAIR PRIDEMORE: Georgia Coalition for
6 Local Governments.

7 MS. BROWN: Yes, ma'am.

8 I am definitely not that tall.

9 CROSS-EXAMINATION

10 BY MS. BROWN:

11 Q Good morning, Commissioners. I hope it's
12 still morning. I didn't really look at the clock.

13 And, witnesses, I'm going to direct you to
14 page 29. I have some questions about the RISE pilot,
15 starting with the question on line 4.

16 Let me know when you get there.

17 A (Witness Cooper) Ready.

18 Q Okay. So there's some concerns that that
19 pilot will not find the 500 participants that are
20 currently budgeted for. It's only been about 17 so far.
21 And you mentioned that in your research one reason that
22 might be is because most other programs are not limited to
23 income-qualified customers.

24 Can you explain why you think that might be a
25 reason that the program is not as successful as intended?

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1 A (Witness Cooper) So while low-income customers
2 often have a high energy burden, they may not have high
3 absolute bills. And the program requires a 25 percent --
4 20 to 25 percent reduction in their overall bills and then
5 have to pay back the investments over time.

6 So often you need a significant amount of
7 savings to pay for that investment. And if you --
8 while an \$80.00 bill may be very burdensome to that
9 individual, it may not cause enough savings to pay
10 that back over time.

11 Q So if I'm a low-income customer, would there
12 be any situation where RISE would offer benefits over the
13 home energy efficiency assistance program?

14 A (Witness Cooper) Well, with -- with just, like,
15 the upfront cost because it would -- those costs would then
16 be, you know, put into an account by Georgia Power and you'd
17 pay that over time.

18 So if you couldn't afford several thousand
19 dollars to replace your air-conditioning, say, then
20 you have that opportunity to make, you know, those
21 improvements and pay it off over time.

22 Q Can you remind us what the difference in
23 budget is between the RISE pilot and the HEEAP program
24 with the double?

25 A (Witness Cooper) I don't actually think I have
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1 that offhand. I know -- the RISE pilot I think is about \$7
2 million I think overall in it's potential budget.

3 Q I'm sorry. I mean per home.

4 A (Witness Cooper) Oh, per home. Well, it would
5 be -- well, it's the -- I think the average home -- there is
6 no actual cap, but I think the average expected spend is
7 about \$7,500 per home. Depending on, you know, the
8 participation level in the HEEAP program, it's -- I think
9 it's less. It's closer to 3,000 is what it currently is.

10 Q So based on your research of other programs,
11 would you say that the average investment per home is
12 about the same as other pay as you save programs, higher,
13 lower?

14 A (Witness Cooper) It's intended to be about the
15 same. They tend to be roughly in that \$7,000 range. Some
16 have caps, some don't. But, yeah, it's kind of the spending
17 you see.

18 Q And the length of the term, it's currently
19 capped at ten years; is that correct?

20 A (Witness Cooper) It is.

21 Q Is that standard for other programs, as well?

22 A (Witness Cooper) Yes.

23 Q So the cooperative programs that really
24 pioneered this model, they don't allow 12-year terms?

25 A (Witness Cooper) Some may. But I believe ten

1 years is the standard base model.

2 Q And for something expensive like a heat pump,
3 would it be more likely to be affordable if you financed
4 it over a longer period of time or a shorter period of
5 time?

6 A (Witness Cooper) Ten years is usually close to
7 the lifetime of that installation. So there may be a
8 possibility for 12 years, but, you know, the most heat pumps
9 tend to say they have a 10 to 12 year life span. So I don't
10 know if there's a whole lot available there.

11 Q If this program did not meet the 500
12 participant threshold, would you recommend that program
13 being expanded to non-income qualified customers,
14 recognizing that many middle class families are also
15 struggling with energy bills at this time?

16 A (Witness Cooper) Well, at this time we have
17 worked with a company to make other improvements to try to
18 look at increasing participation. And I think there is
19 other avenues we'd pursue before we do that.

20 You know, we do have issues of identifying
21 those customers and making sure that -- that the
22 intended participants are actually still
23 participating. If needed, then I think that's a
24 discussion we can have with Georgia Power in the
25 future, but not currently.

1 A (Witness Barber) Yeah. I'll just supplement.
2 That is definitely a policy call because this was approved
3 as a low income. Staff would be generally supportive of
4 that, but it's not currently approved that way.

5 And so, you know, we'll just to have to see how
6 the pilot progresses and whether 500 customers are
7 identified.

8 Q And if I can direct you to page 33, starting
9 with a question on line 3. You talk about what is call a
10 TEAPOT study, which measures the technical, economic and
11 achieved potential for energy efficiency. I believe that
12 is through the year 2032; is that correct?

13 A (Witness Cooper) Yeah. Usually that's 10 to
14 12 years out from when it was performed.

15 Q What percentage of that potential is proposed
16 to be covered through that time period with the energy
17 efficiency investments?

18 A (Witness Cooper) So of the 12-year here, you
19 know, we approve three year. But, yeah, so you have a
20 little bit of mismatch. But it's, you know, a relatively --
21 relatively small portion. I don't know the exact --

22 A (Witness Spellman) I can add to that. For the
23 next program cycle, which is 2023, '24, '25, 29 percent.

24 Q What percentage was listed in your testimony?

25 A (Witness Spellman) That's a good question.

1 A (Witness Barber) 55.4.

2 A (Witness Spellman) Oh, that's by --

3 A (Witness Barber) That's through -- 55.4 percent
4 through 2032.

5 Q We just heard testimony from Mr. Spellman
6 about how this is a very low-cost resource, about two
7 cents per kilowatt hour, which is extremely competitive.

8 With that in mind, why would we not be pursuing
9 100 percent of that achievable potential or something far
10 above half?

11 A (Witness Cooper) So the -- part of the reason
12 why we wanted to in other parts of our testimony suggest to
13 do -- include a DSM and EE as a selectable resource is that
14 we want to know what the actual optimal amount is for the
15 system. So while the TEAPOT may indicate there are
16 cost-effective potential energy efficiency, it may not
17 actually be the most efficient way to go. It may be solar.
18 And some of those might actually be more effective.

19 So, secondly, the COVID impacts of the current
20 programs have been significant. And so we think in
21 this current environment, increasing the savings by a
22 vast amount because you would be roughly doubling or
23 more, the programs may not be, you know, prudent
24 because we just want to make sure that the company
25 can actually achieve the level of savings of those

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1 who are ready before we, you know, would push for an
2 extreme, you know, advancement of that.

3 Q Recognizing that we haven't done a
4 co-optimized analysis, do you think that what's being
5 proposed right now is the optimal mix of demand- and
6 supply-side resources, in your opinion?

7 A (Witness Cooper) It's hard to speak without,
8 you know, an actual study. It seems like there are probably
9 more DSM and EE savings that would be available to the
10 company in an optimized scenario.

11 Q Okay. There's some concerns, too, about
12 impacts on rates that are mentioned throughout the IRP and
13 throughout these filings. Just as a matter of
14 clarification, do we use measures like the ratepayer
15 impact measure where we're looking at supply-side
16 resources or do we only subject demand-side resources to
17 that?

18 A (Witness Cooper) It is a metric for the
19 demand-side and energy efficiency measures.

20 A (Witness Barber) But just like Mr. Spellman
21 said, all resources have great impact. It's not just energy
22 efficiency resources.

23 MS. BROWN: All right. Thank you.

24 MADAM CHAIR PRIDEMORE: All right.

25 Georgia Interfaith Power & Light and
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1 Partnership for Southern Equity.

2 MS. KYSOR: No questions.

3 MADAM CHAIR PRIDEMORE: Georgia Large Scale
4 Association and Advanced Power Alliance.

5 MR. CARVER: No questions.

6 MADAM CHAIR PRIDEMORE: Georgia Solar Energy
7 Industries Association, Solar Energy Association and
8 Vote Solar.

9 MR. THOMASSON: No questions, Madam Chair.

10 MADAM CHAIR PRIDEMORE: Interstate Gas Supply?

11 MR. CARVER: No questions, Madam Chair.

12 MS. COYLE: Georgia Watch.

13 MADAM CHAIR PRIDEMORE: Georgia Watch.

14 MS. COYLE: Thank you.

15 MADAM CHAIR PRIDEMORE: Sorry. You had an X
16 next to you yesterday.

17 MS. COYLE: But then I popped in through the
18 side door to make my presence known.

19 MADAM CHAIR PRIDEMORE: Correct. You're over
20 in the permanent backstage.

21 MS. COYLE: That's right.

22 CROSS-EXAMINATION

23 BY MS. COYLE:

24 Q Well, good almost afternoon everyone. I'm

25 Liz Coyle for Georgia Watch. I have a few questions for

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1 the panel, which I think if any of you -- just answer
2 whoever you think is appropriate.

3 I wanted to start by addressing a question that
4 Chairman Pridemore asked you a little bit ago about whether
5 some customers might be paying for the DSM programs, but not
6 taking advantage of the DSM programs.

7 Do you recall that?

8 A (Witness Cooper) Yes.

9 Q Okay. But do DSM and demand response
10 programs also benefit all customers, whether someone
11 participates in them in or not?

12 A (Witness Cooper) Yes. If the programs pass the
13 total research cost, thus the overall system will be less
14 expensive to run, so all customers will benefit.

15 Q So, as I said, they will lower the needs on
16 the system for costly supply-side resources; is that --
17 what would you agree with that?

18 A (Witness Cooper) Yeah.

19 Q Thank you.

20 Now, in your testimony you recommend reducing a
21 non-incentive budget for certain DSM programs; right?

22 A (Witness Cooper) Yes.

23 Q Are non-incentive budgets the same as
24 administrative costs?

25 A (Witness Cooper) They include -- there a few
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1 other categories, but that is the -- yeah.

2 Q Primarily they're an administrative cost?

3 A (Witness Cooper) Yeah. And -- yeah.

4 Q Are you proposing that the companies
5 non-incentive budgets be lower to allow consistent actual
6 spending in prior years?

7 Have you been able to look at how much they
8 have budgeted, but not spent?

9 A (Witness Cooper) That has certainly informed
10 our recommendation, but if we allow for escalation costs, of
11 course, because, you know, inflation is a thing. So, you
12 know, we want to make sure that we're kind of in line with
13 historical spending, yes.

14 Q So you're not -- you're not going to exact
15 match your previous levels, but that informed your
16 recommendation about how much of the budget to cut?

17 A (Witness Cooper) Yes.

18 Q And if the budgets are lowered, would that
19 improve the economics of the programs and
20 cost-effectiveness tests?

21 A (Witness Cooper) Yes.

22 Q And might additional DSM programs be added to
23 the mix that previously were found uneconomic in part
24 because of high admin costs?

25 A (Witness Cooper) I guess it's possible, but the
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1 modeling -- as long as the modeling of those programs show
2 that they pass the TRC test, they could be added and be
3 cost-effectively, yeah.

4 Q Now, you're also recommending the Commission
5 require the company to allow demand-side management
6 programs to compete head to head with supply-side options
7 in the 2025 IRP; correct?

8 A (Witness Cooper) Yes.

9 Q Do you believe this could benefit ratepayers
10 because programs that lower electric use are likely to
11 cost less than supply-side options?

12 A (Witness Cooper) Yes. As the current programs
13 do.

14 Q And do you believe the company has failed in
15 this current IRP to adequately identify the optimal level
16 of cost-effective energy efficiency programs which could
17 keep electric bills higher than they need to be?

18 A (Witness Cooper) I don't think that the energy
19 efficiency is modeled in a way that could show what, you
20 know, the objective model would choose. I don't know.
21 Optimal is -- for energy efficiency can mean a lot of
22 different things to people that --

23 Q Ms. Barber, did you want to --

24 A (Witness Barber) Well, I mean, we're -- I mean,
25 staff has supported the approach the company has done in the

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1 past with subtracting out their proposed case before they do
2 their modeling -- Aurora modeling.

3 But in this case we are taking it to the next
4 step where they should do the integrated approach so
5 that we can see what is the amount of the
6 cost-effective energy efficiency is. So, you know,
7 we -- I mean, we have in our testimony about whether
8 the company, you know, has considered energy
9 efficiency as a priority resource or not.

10 A (Witness Cooper) Uh-huh.

11 Q Is it your opinion that the company could
12 have done more to potentially identify DSM and demand
13 response measures that could put downward pressures on
14 rates?

15 A (Witness Barber) Well, I think up until -- this
16 is the first year the company has switched to Aurora
17 modeling. And so it was not a Commission recommendation
18 last year that they do anything outside of the white paper.

19 So I think this is the first time we've seen
20 renewables and batteries modeled. So I think this is
21 the time to put energy efficiency into that mix.

22 Q And you anticipated my next question. In
23 previous staff testimony, I believe in the Hayet/Newsome
24 panel, staff is recommending that the company be required
25 to include utility-scale solar paired with battery storage

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1 in future resource mixed studies; is that correct?

2 A (Witness Barber) Yes.

3 Q And aside from what you just told me is that
4 this is -- prior to their selection of Aurora they did not
5 have the capability to do either of those things?

6 A (Witness Barber) That's correct.

7 Q The resources mix and --

8 A (Witness Barber) Yeah.

9 Q And -- okay. That helps. So I guess my next
10 line of questioning is really in the realm of possibility.

11 So if the company has not included solar plus
12 storage in the resource mix -- if they have not optimally
13 analyzed savings potential from energy efficiency programs,
14 is it -- and your testimony is talking about an IRP three
15 years from now. Is it possible for the company to go ahead
16 in this three-year cycle, the '23 to '25 time frame, to
17 include more utility-scale solar paired with battery storage
18 in the resource mix in their RFPs, for example?

19 A (Witness Barber) Now, are you saying
20 prospectively or are you asking if they could redo what just
21 got filed?

22 Q Well, yeah.

23 A (Witness Barber) I don't -- I'm not sure about
24 that. I mean, I'm sure they could. That's not our
25 recommendation though.

1 Q Okay. And then, finally, I have just a few
2 questions related to the company's request to change -- to
3 change the methodology for calculating additional sum.

4 Do you believe the company's proposal could
5 increase the costs of DSM and DR programs leading to
6 potentially higher electric billion?

7 A (Witness Barber) Yes.

8 A (Witness Spellman) Yes.

9 Q Will the company earn more profits on those
10 programs without generating increased savings for
11 customers?

12 A (Witness Spellman) Yes.

13 MS. COYLE: Thank you. No more questions.

14 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

15 MR. CARVER: No questions.

16 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
17 Coalition.

18 MR. S. JONES: No questions, Madam Chair.

19 MADAM CHAIR PRIDEMORE: Sierra Club?

20 MR. FABISH: No questions.

21 MADAM CHAIR PRIDEMORE: Southern Alliance for
22 Clean Energy and Southface Energy Institute.

23 CROSS-EXAMINATION

24 BY MR. BAKER:

25 Q Good afternoon, panel.

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1 A (Witness Barber) Good afternoon.

2 Q My name is Robert Baker. I represent the
3 Southern Alliance for Clean Energy and Southface Energy
4 Institute. I have a few questions for you.

5 Referring to page 9 of your prefiled testimony,
6 you state a ratio of above 1.0 for the RIM test should not
7 be deemed mandatory.

8 Why shouldn't it be deemed mandatory?

9 A (Witness Spellman) Actually, this was a quote
10 from the -- I think it's from the Commission order in the
11 IRP case in 2010. And there was quite a bit of testimony in
12 2010 on that issue.

13 And in the Commission order they wrote in the
14 order it shouldn't be considered mandatory. And the
15 reason is that the RIM test, just in short, is not a
16 test of economic events. It's a test of equity or
17 fairness.

18 And what it does is it -- the RIM test itself
19 tells you whether rates will go up or down, but it
20 doesn't tell you --

21 MADAM CHAIR PRIDEMORE: Sir, would you speak
22 into the mic for us.

23 WITNESS SPELLMAN: (Witness Spellman) Sorry.

24 The reason that the Commission decided that the
25 RIM test should not be a mandatory test was because
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1 it's not a test of economic efficiency. It doesn't
2 tell you whether a resource is cost-effective. It
3 doesn't tell you whether DSM is less expensive than
4 supply.

5 It just tells you whether or not rates will go
6 up or down. So it's a test of equity or fairness.
7 And in that IRP, the Commission decided that it
8 should not be a mandatory test.

9 BY MR. BAKER:

10 Q Thank you. Thank you.

11 General question for you, Mr. Spellman. Have
12 you been involved in every DSM case since the beginning?

13 A (Witness Spellman) Well, at least since 1995.

14 Q Okay.

15 A (Witness Cooper) Yes.

16 A (Witness Spellman) I guess, yes.

17 A (Witness Cooper) That's when the programs
18 initially started, yes.

19 A (Witness Spellman) That's why I get so many
20 calls for Medicare benefits.

21 Q Because the RIM test screens out energy
22 efficiency measures that can save significant amounts of
23 electricity, should Georgia Power and the Commission move
24 away from using the RIM test or be less dependent upon --

25 A (Witness Cooper) To be clear, the RIM test is
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1 not used for any screening of measures or programs. It is
2 used to inform the Commission whether or not rates could go
3 up or down and what that event might be. But it's not used
4 for screening of --

5 Q Okay. But due to the fact that it screens
6 out energy efficiency or it has a -- it doesn't screen
7 out. It indicates -- it makes it difficult for energy
8 efficiency programs to be accepted; is that accurate?

9 A (Witness Cooper) I think in our testimony we
10 indicated that it should not be used as a primary indication
11 of whether or not energy efficiency should be selected or
12 how much should be used. Or required rather.

13 Q Thank you. Because the proposed expansion
14 plan will not represent the most cost-effective plan for
15 customers leading to higher electric bills, what do you
16 recommend the Commission do?

17 A (Witness Cooper) Well, I don't know if we know
18 that 100 percent. But we do want the energy efficiency and
19 DSM to be demand-side -- or demand response to be modeled
20 alongside supply-side to understand your -- if your question
21 is actually correct. Right now we don't have that
22 knowledge.

23 A (Witness Spellman) We want DSM and demand
24 response to be selectable by the IRP planning model. To be
25 priority resources that are selectable by the model --

1 A (Witness Cooper) I think we --

2 A (Witness Spellman) -- going forward.

3 A (Witness Cooper) There's an assumption that
4 more is probably better, but right now we just don't know.
5 So it could -- it's within the possibility they're actually
6 choosing the perfect amount.

7 Q So have it available to compete against other
8 supply-side resources or -- and let the best resource win?

9 A (Witness Spellman) Yes.

10 A (Witness Cooper) Correct.

11 Q Could a measure program with a RIM score of
12 less than 1.0 result in lower total utility costs and
13 lower costs for customers?

14 A (Witness Cooper) Yes.

15 Q By allowing DSM and demand response resources
16 to compete in future all-source procurements, does that
17 mean for them to be selected they would have to be the
18 best choice for system energy and demand needs to be
19 selected against all other options considered?

20 A (Witness Barber) Yes.

21 Q At page 35 of your prefiled testimony you
22 note a carve-out for manufactured housing in the
23 AGIP program. Was this done to ensure that a certain
24 amount of spending and savings actually reach manufactured
25 housing residents?

1 A (Witness Cooper) Yes.

2 Q Is it possible that despite inclusion of new
3 services for manufactured homes in the HEEAP program that
4 the 3 megawatt hours of additional savings in the HEEAP
5 program would not go to manufactured housing residents?

6 A (Witness Cooper) The intent of the carve-out is
7 similar to the carve-out for a multifamily in HEIP in that
8 we would have a reported structure and would look at where
9 those measures are installed. So my expectation -- our
10 expectations as a panel is that the carve-out would be
11 effective and they would -- those measures would go to the
12 manufactured homes.

13 Q So you would be monitoring to make sure that
14 the benefits are going to the residents of manufactured
15 homes?

16 A (Witness Cooper) Yes.

17 MR. BAKER: All right. Thank you all very
18 much.

19 Thank you, Commissioners.

20 MADAM CHAIR PRIDEMORE: Thank you, Mr. Baker.
21 Southern Renewable Energy Association.

22 MR. MAHAN: No questions, ma'am.

23 MADAM CHAIR PRIDEMORE: Okay. Georgia Power,
24 how much time do you need --

25 MS. PRYOR: Twenty minutes.

1 MADAM CHAIR PRIDEMORE: -- for a cross?

2 Twenty minutes?

3 PSC/PIA Staff Attorneys, do you have redirect
4 for this panel?

5 MR. DAVIS: That depends on the next
6 20 minutes.

7 MADAM CHAIR PRIDEMORE: Okay. That's a really
8 good -- good way of putting it, Alex.

9 All right. We're going to go ahead and break
10 for lunch in just a minute.

11 But before we go -- and we can let you guys
12 come back and do your -- do your redirect, I want to
13 ask the panel one more question.

14 So in three separate occasions in the testimony
15 that Georgia Power filed, the Valle, Phillips, Smith,
16 Evans testimony, which is the bulk of the DSM
17 testimony, they talk about their residential lighting
18 programs. They do it on page 13, page 15, page 28.

19 Does the staff recommend to this Commission to
20 approve those energy efficiency home lighting
21 programs for LED lights?

22 WITNESS COOPER: Yes. The focus of the
23 programs moving forward are away from standard bulbs.
24 They're focused on specialty bulbs.

25 So it's hitting a portion of the market that
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1 has not shifted as much due to regulation and just
2 sort of natural market forces. So it's not your
3 standard, you know, bulb you see. It's like your
4 reflectors and things that are -- have not seen that
5 LED update.

6 MADAM CHAIR PRIDEMORE: Define a standard bulb.

7 WITNESS COOPER: A round one that you would put
8 in, like, a normal lamp, rather than --

9 COMMISSONER McDONALD: Incandescent.

10 MADAM CHAIR PRIDEMORE: Are you talking about
11 an incandescent bulb?

12 WITNESS COOPER: Well, I mean, previously, yes.

13 But, you know, or like then the market went to
14 a CFO, you know, the squiggly bulbs, and now it's
15 into LEDs. But they look like the old incandescents,
16 yes.

17 WITNESS BARBER: And I want to also add on
18 page 24 of our testimony we talk specifically about
19 the lighting program. And on lines 14 through 18, we
20 say the market is undergoing a rapid transformation
21 that will likely decrease the cost-effectiveness of
22 this program over the next few years. Staff will
23 closely monitor the economics of this program during
24 the cycle to ensure it continues to deliver benefits
25 to customers.

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1 So we are definitely aware of this
2 transformation in the lighting industry.

3 WITNESS COOPER: I would also like to point out
4 that the expected savings from the specialty lighting
5 program as filed by Georgia Power to decline over the
6 course, which is rare for programs. It's because a
7 lot of those -- the bulbs are more commonly LEDs.

8 MADAM CHAIR PRIDEMORE: The market has changed?

9 WITNESS COOPER: Yes.

10 MADAM CHAIR PRIDEMORE: The market has changed.
11 We're post transition at this point.

12 I just -- while you were talking, I did a quick
13 search on Home Depot.com. So I cannot get a standard
14 incandescent bulb at Home Depot.com. You can't get
15 one.

16 I can get a modified halogen hybrid that is
17 available in a standard light bulb size. I can get
18 globes, candles and diamonds, but not a standard
19 bulb.

20 I do, on the other hand, have 2,365 varieties
21 of LED bulbs that I can get in every size.

22 WITNESS COOPER: Yes.

23 MADAM CHAIR PRIDEMORE: Should this Commission
24 allow this utility to recover costs from other
25 ratepayers for a lighting program that the market has

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1 already managed?

2 WITNESS COOPER: So the program as designed
3 moving forward shifts away entirely from the bulbs
4 that you're seeing in Home Depot into specialty areas
5 where that market has not fully shifted. The
6 expectation also is is that those opportunities are
7 declining, but they are -- by our evaluations and
8 what we see in the market, there are still
9 opportunities available.

10 But we agree that they are declining and expect
11 the -- as these programs mature and move forward,
12 there will be less and less residential lighting.

13 WITNESS BARBER: Yes. Those lighting -- those
14 bulbs have been removed from this program going
15 forward.

16 MADAM CHAIR PRIDEMORE: Excellent.

17 All right. Let's take a lunch and let's come
18 back at 1:00.

19 (A recess was held from 12:14 p.m. until 1:00 p.m.)

20 MADAM CHAIR PRIDEMORE: We're going to get
21 started in one minute.

22 Okay. Miss Pryor, if you'd like to begin your
23 cross.

24 MS. PRYOR: Hi, panel. I hope y'all had a nice
25 lunch.

1 WITNESS COOPER: Good afternoon.

2 CROSS-EXAMINATION

3 BY MS. PRYOR:

4 Q Allison Pryor for Georgia Power Company. The
5 company completed each of the nine steps in the
6 Commission's DSM program planning approach; correct?

7 A (Witness Cooper) Yes.

8 Q And the company's approach and resulting DSM
9 portfolio are consistent with prior DSM portfolios the
10 company has presented to this Commission; correct?

11 A (Witness Cooper) Yes.

12 Q And you note in your testimony that the
13 company's proposed plan did not comply with the Energy
14 Independence and Securities Act, Standard 16, because it
15 did not model demand-side resources alongside supply-side
16 resources within the Aurora model; is that correct?

17 A (Witness Spellman) Let me --

18 A (Witness Cooper) That is a correct statement
19 of our testimony, yes.

20 A (Witness Spellman) But what the company told
21 us was that they did not do that type of modeling in the
22 data response GDS -- I mean, Staff GDS-1-9. So that's what
23 we meant was that because the company didn't use an
24 integrated model to model -- let energy efficiency and
25 demand response compete head-to-head with supply-side

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1 resources, that they didn't comply with that standard that
2 says that the plan -- DSM should be integrated into
3 integrated resource plan.

4 Q But the ISA standard only uses the word
5 "integrate." Correct? It does not require that a utility
6 model demand-side resources and supply-side resources
7 alongside each other; correct?

8 A (Witness Spellman) Not nec- -- I don't think I
9 agree with that. In fact, I brought the standard with me,
10 but as our testimony says -- let's go to that -- what page
11 is that on my testimony?

12 A (Witness Barber) 10. 10.

13 A (Witness Spellman) Okay. I think I've got the
14 language there. Okay. Okay. I'm trying to find where that
15 is.

16 Well, maybe you can show me the ISA standard
17 where that --

18 Q Well, I believe you stated that, as you
19 quoted it, that electric utilities are required to
20 integrate energy efficiency resources into utility plans.

21 A (Witness Spellman) Yes.

22 Q So the standard itself does not require
23 modeling demand-side resources with supply-side resources.
24 Those words don't appear in the standard. Correct?

25 A (Witness Spellman) It says, "Integrate energy
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1 efficiency resources into utility, state, and regional
2 plans."

3 So the word "integrate" is in line 17.

4 Q Correct.

5 A (Witness Spellman) And what I mean by
6 integrate is where it -- energy efficiency and
7 demand-response resources are allowed to compete
8 head-to-head in the model with supply-side resources. So
9 based on that definition, I said it didn't comply with that
10 term "integration."

11 And to me, integration means that you allow
12 energy efficiency and demand response to be selectable
13 resources, and the company responded in the data response
14 that it did not do that.

15 Q So you would agree that -- so your testimony
16 is that the company's plan fails to meet staff's
17 interpretation of ISA Standard 16; correct?

18 A (Witness Spellman) Well, it's really
19 two things. One, the standard says that it requires
20 electric utilities to integrate energy efficiency resources
21 into the utility, state, and regional plans. And my
22 testimony is that the company -- our testimony, excuse me --
23 is that the company did not model energy efficiency in
24 demand response resources as a selectable resource in the
25 modeling process.

1 Q But ISA also doesn't define the word
2 "integrate," does it?

3 A (Witness Spellman) I don't know. It may, in
4 the definition section. I just don't know that off the top
5 of my head.

6 Q Did the company's prior DSM plans model DSM
7 resources alongside supply-side resources?

8 A (Witness Spellman) No. In fact, I pointed
9 that out in our testimony in 2019. That was one of the
10 things that we recommended was that the company ought to do
11 that, and then in the last IRP in the Commission order and
12 the stipulation, it was agreed that the company would do the
13 DSM white paper to perform that type of integration, and the
14 company did do that and completed the white paper, I
15 believe, in 2021.

16 Q And the Commission approved each of the
17 company's last DSM plans as modified by stipulation?

18 A (Witness Spellman) Yes. Yes.

19 Q Regardless of your position on the ISA
20 standard, I understand your testimony to recommend that
21 the company model DSM along supply-side resources.

22 Would you be supportive of modeling DSM in the
23 Aurora model and recommending that this Commission approve a
24 smaller DSM target if that was the resulting output of what
25 the Aurora model came out with?

1 A (Witness Spellman) The answer to that is that
2 what we are proposing is that the Commission have that
3 information -- and the staff and the stakeholders -- have
4 the information available to it to see what the results are.
5 I think that the Commission staff would want to be sure that
6 the integration of energy efficiency and demand-response
7 resources was done in a proper way so that the -- you know,
8 the costs and benefits of energy efficiency are -- and
9 demand response are modeled fairly and correctly.

10 Q So to interpret your recommendation, use of
11 the model, the model DSM with supply-side resources, would
12 be to inform the Commission's decision as opposed to
13 directing it; correct?

14 A (Witness Barber) Yes, that's correct.

15 A (Witness Cooper) I think in all scenarios, you
16 know, Georgia Power doesn't take, you know, the output of
17 one particular model run and say, this is exactly what we're
18 going to do for every -- it's -- you know, you make
19 decisions and then come to the Commission for, you know,
20 your proposals and such. So we'd expect a similar process.

21 Q I'm going to move on to additional sum.

22 Do you agree that the purpose of the additional
23 sum for DSM programs is to incent the company to propose DSM
24 programs and work to achieve the savings targets approved by
25 the Commission as permitted by state statute?

1 A (Witness Cooper) Yes.

2 Q And you agree that the company should earn an
3 additional sum on certified programs; correct?

4 A (Witness Cooper) Yes.

5 Q And so the only unresolved additional sum
6 issue is the appropriate methodology to use; correct?

7 A (Witness Cooper) Correct.

8 Q And you testified that one of the additional
9 sum goals is to encourage the company to control or reduce
10 program delivery cost; correct?

11 A (Witness Cooper) Yes.

12 Q But you'd agree that the company has not
13 exceeded its DSM budgets in any of the prior DSM cycles;
14 right?

15 A (Witness Cooper) Correct. And that could be
16 contributable to how we calculate the additional sum which
17 may encourage Georgia Power to do exactly that.

18 Q And at the same time, excluding the two COVID
19 years, the company has not failed to meet any of its
20 savings targets; correct?

21 A (Witness Cooper) Correct.

22 Q Are you aware that if the current additional
23 sum methodology that staff supports continuing is
24 approved, four of the residential programs would offer
25 zero additional sum, and a fifth program that only

1 averages -- would only average less than 19,000?

2 A (Witness Cooper) Yes. As currently modeled,
3 we are looking at the extreme of benefits and that. That's
4 what that shows now. Historically, what we've seen is that
5 the company modeling the IRP has shown that, but the actual
6 programs when they're run show something different.

7 So if you look at the actual additional sums,
8 over the residential programs, say, like the previous IRP,
9 you would have expected a much lower return than they've
10 actually got of -- you know, I think the actual return has
11 been over 2 million in residential programs, and I think all
12 but one of them have had additional sum attached to them.
13 But that was not the modeling.

14 So I think that, you know, our expectation may
15 not be 100 percent that the model will -- that the -- yeah,
16 that benefits may not exactly align with what the modeling
17 is showing.

18 Q So do you think a zero additional sum is a
19 sufficient and fair incentive?

20 A (Witness Cooper) Our expectation is that the
21 company will earn additional sum with the -- if the current
22 additional sum mechanism moves forward.

23 Q And if there were in actuality a zero
24 additional sum, would that cause the Commission staff any
25 concern about the additional sum methodology?

1 A (Witness Cooper) More it would be a concern
2 about the net benefits delivered to the programs, so we
3 would need to look at the programs to make sure that we're
4 designing them to deliver as many benefits to customers as
5 possible.

6 So, you know -- so, yes. But not -- probably
7 not because the amount that the company earns or not.

8 Q Do you have a copy of Staff Exhibit BCS-15?

9 A (Witness Cooper) Yes, I do.

10 Q And this exhibit purports to show that the
11 additional sum projected for 2023 through 2025 is -- as
12 staff proposes it -- is consistent with the average
13 additional sum the company collected over the last
14 five years; is that correct?

15 A (Witness Cooper) Yes.

16 Q And how did you select the years 2017 through
17 2021?

18 A (Witness Cooper) They were the most recent
19 viable option, so the methodology -- well, the program's
20 kind of shifted, and the amount of targets are more similar
21 from '17 to now than they were previously. The programs
22 were much smaller and had a much different mix. Also, most
23 of those programs relied on lighting in the early stages, so
24 the amount of benefits are much higher, and the programs are
25 much cheaper to run than they are now. So we thought this

1 was a more representative forward.

2 Q But you would agree that your proposed
3 average includes the two COVID years 2020 and 2021?

4 A (Witness Cooper) Yes.

5 Q And you would also agree that in 2020 and
6 2021, the additional sum received was less because the
7 company did not achieve their savings targets; correct?

8 A (Witness Cooper) Yes. And that's reflected in
9 the table, so you can see that.

10 Q In preparing your exhibit, did you consider
11 all 10 years provided to the staff in response to
12 STF-GDS-123?

13 A (Witness Cooper) You mean, we modeled the
14 future years beyond 2025 --

15 Q No.

16 A (Witness Cooper) -- to do -- or the history?

17 Q So a data request that requested 10 years of
18 additional sum data and the company's exhibit only chose
19 to use five of those years.

20 A (Witness Cooper) Yes. We looked at the data,
21 historical data, but like I said, there was a rather large
22 shift in program delivery and the amount of DSM acquired at
23 about that 2017 time range.

24 Q So are you aware that the average additional
25 sum earned from 2012 through 2021 was actually closer to

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1 13.8 million rather than the 9 that you cited in your
2 exhibit?

3 A (Witness Cooper) Yes. One of those years, I
4 believe, 2014 or 2015, the additional sum was somewhere in
5 the range of like 25 million. So there's one particular
6 year that really boosted up that average, and I don't think
7 that aligns with what the kind of programs we would see
8 moving forward. So, you know, yeah. That outlier was
9 eliminated.

10 Q So the staff considered an outlier too high
11 because it didn't align with the rest of the years, but
12 yet you included the years that were too low?

13 A (Witness Cooper) No. The outlier, it does not
14 look like future programs, so, you know, while I understand
15 that the COVID impacts of the last two years, you know, are
16 there, if you look at the average that we had presented,
17 it's roughly 10 million.

18 If you average the 2017, '18, and '19, it's
19 only about 1 million more. So it's much more closer to what
20 we've seen over the last five years regardless of COVID or
21 not. But if you look historically back, it would be more
22 like '18, '19 are, you know, a million which is
23 significantly higher than what we've seen for the last
24 several years.

25 A (Witness Spellman) And what I would add to
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1 that is that in the earlier years, my recollection is that
2 avoided costs were higher back in those early years, and the
3 way that the additional sum mechanism is currently approved
4 by the Commission, the way it works, is that the net present
5 value savings from the programs are shared between the
6 company and customers.

7 So what happens is when -- if avoided -- if
8 everything else stays equal and avoided costs drop, which my
9 recollection is that they have, then the additional sum
10 would go down. Under the company's proposal, that's not the
11 case.

12 MS. PRYOR: And I'd like to show you an
13 exhibit.

14 Madam Chair, may I approach?

15 MADAM CHAIR PRIDEMORE: Yes, you may.

16 MS. PRYOR: Actually, Mr. Hewitson is going to
17 approach.

18 MADAM CHAIR PRIDEMORE: Well, okay. He can,
19 too.

20 MR. HEWITSON: Thank you.

21 MS. PRYOR: And I'd like to introduce this as
22 GPC Exhibit 12.

23 (The document referred to was marked for
24 identification as GPC Exhibit 12.)

25

1 BY MS. PRYOR:

2 Q So in this chart -- do you each have a copy
3 of it?

4 A (Witness Cooper) Yes.

5 Q Okay. In this chart, the first of three
6 listed, the first one identifies increasing savings over
7 time. Now, this represents the increasing trend in
8 projected energy savings from 2013; is that correct?

9 A (Witness Cooper) Yes.

10 Q Okay. In the second chart, it then shows the
11 declining trend in the company's projected additional
12 sum -- is that correct? -- over the same time period?

13 A (Witness Cooper) Yes. I assume some of these
14 numbers are projected, because the 2020 one --

15 Q Correct. They're all projected, just to keep
16 it on an even playing field.

17 A (Witness Cooper) Okay.

18 Q They're all projected numbers.

19 A (Witness Cooper) Just wanted to make sure.

20 Q And then the third chart layers the first
21 two charts over each other to see them combined. Would
22 you agree?

23 A (Witness Cooper) That seems to be the case.

24 Q Okay. Now, would you agree that based on
25 this information that the company's additional sum

1 methodology or -- a separate question first.

2 Would you agree that the company's additional
3 sum methodology has been the same since 2013?

4 A (Witness Cooper) Yes.

5 Q And as this chart shows, the additional sum
6 has gone down approximately 52 percent since 2013 even
7 though the methodology has stayed the same?

8 A (Witness Cooper) Yes. The projected amount.
9 This is --

10 Q Right, as projected.

11 A (Witness Cooper) -- as Mr. Spellman said, it
12 was largely because of avoided costs, not because of, you
13 know, other factors determined by the Commission or
14 anything.

15 Q And -- but while the additional sum is going
16 down, the projected energy saved from the company's
17 programs continue to increase. Would you agree?

18 A (Witness Cooper) Yes.

19 Q And the company's programs are saving
20 48.6 percent more energy in gigawatt hours than the
21 program saved in 2013?

22 A (Witness Cooper) I'll trust your math.

23 Q So just to compare, the more the company's
24 programs saved, the less incentive currently the
25 company -- the company currently earns under the existing

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1 methodology.

2 A (Witness Spellman) No. That isn't -- that
3 isn't correct. I mean, maybe historically, but if avoided
4 costs go up going forward, which they may, the additional
5 sum will go back up. And that's why it's very important to
6 understand the principle.

7 The statute that authorizes the additional sum
8 says that the Commission needs to consider the sharing of
9 the costs and savings between the company and customers.
10 The existing methodology approved by the Commission does
11 that. So it's meant to do that. It was designed that way
12 in order to have an equitable sharing of the costs and
13 benefits between the company and the customers.

14 So if -- going forward, if avoided costs go up,
15 the company's additional sum will go up.

16 A (Witness Cooper) I'll also point out that
17 because these are projections, the actuals bounce around
18 very differently than shown on these charts.

19 Q But the trend line would be generally the
20 same, even if the actuals differed?

21 A (Witness Cooper) Yes. Yeah. You'd see a much
22 different inflexion point and you might understand the
23 reasons why it's happening more clearly than the projections
24 show.

25 Q And, Mr. Spellman, to your point about
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1 declining additional sum -- or declining avoided cost --
2 excuse me -- staff's testimony criticizes the company
3 proposed additional sum methodology for failing to be tied
4 to avoided cost; correct?

5 A (Witness Spellman) Not exactly. It criticizes
6 the company because it -- it doesn't share the net present
7 value savings which includes costs and benefits to calculate
8 the savings. We are not criticizing avoided costs. We're
9 just saying that the company's methodology doesn't consider
10 it sharing the net present value savings between customers
11 and the company, which is one of the principles listed in
12 the statute.

13 In fact, the company's methodology, if there's
14 a measure that saves 1,000 kilowatt hours for one year and a
15 measure that saves 1,000 kilowatt hours for 100 years, the
16 company would get the same additional sum, so there are many
17 flaws in the company's proposed methodology.

18 Q But you would agree that the -- as you
19 understand it -- because I know you're not an attorney --
20 the DSM additional sum statute also requires or permits
21 the Commission to consider lost revenues and changed risks
22 as well. It's not solely shared savings. Is that
23 correct?

24 A (Witness Spellman) And I think that's in my
25 testimony.

1 Q On pages 50 and 51, your testimony highlights
2 three states where you claim utilities have achieved
3 greater savings with incentives that are less costly than
4 that proposed by the company; is that correct?

5 A (Witness Cooper) Yes.

6 Q Are you aware that the states of Connecticut,
7 Michigan, and Ohio, the three to which you compare, have
8 all been subject to currently or in the past energy
9 efficiency resource standards?

10 A (Witness Cooper) I mean, yes. I'm aware that
11 that's common in, you know, in the northeast, in those
12 areas, yeah.

13 A (Witness Spellman) The exact structure I'm not
14 familiar with at this moment.

15 Q Okay. Are you aware that Ohio statutorily
16 requires that energy efficiency savings in the peak demand
17 reduction be countered on a gross savings basis?

18 A (Witness Cooper) I am not aware of that,
19 but...

20 A (Witness Spellman) No.

21 MS. PRYOR: Okay. No further questions. Thank
22 you.

23 MADAM CHAIR PRIDEMORE: Redirect?

24 MR. DAVIS: Just a few points.

25 REDIRECT EXAMINATION

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1 BY MR. DAVIS:

2 Q You were asked about the -- about the
3 benefits of getting data from running DSM programs side by
4 side with supply side inputs in Aurora. Could you touch
5 on why that data would be useful?

6 A (Witness Cooper) Well, right now we don't
7 know -- we don't have the modeling system that optimizes the
8 future, you know, stream to include DSM and DR resources,
9 and there's a possibility that you could deflect the, you
10 know, a build-out or, you know, acquire, you know, the whole
11 system at a less expensive level.

12 You know, energy efficiency is -- over the
13 course of all these programs has delivered a very low cost
14 per -- you know -- the acquisition cost is very, very low,
15 much lower than pretty much any resource available. So
16 without a modeling, we just don't know what level would be
17 optimal.

18 Q And does staff have any reason to believe
19 that the current additional sum methodology will result in
20 insufficient incentives for the company to implement DSM
21 programs in the coming years?

22 A (Witness Cooper) No. It's -- the company's
23 earned a reasonable rate on return. If you look on a
24 percentage level, it's quite robust, even at the lower
25 levels over the last few years, so we expect it to be

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1 encouraging.

2 A (Witness Barber) And just to add to that, just
3 as we were just crossed on, the avoided cost could go back
4 up. It's just at this point it has dropped over the recent
5 years, and so this methodology shares the savings based on
6 what the current avoided costs are.

7 Q In fact, if you look at the exhibit that you
8 were just asked about, would you also -- a takeaway from
9 this could also be that these best fit lines show that the
10 current methodology was at least somewhat effective in
11 incentivizing, increasing savings from DSM despite a
12 decreasing additional sum?

13 A (Witness Cooper) I guess you could interpret
14 it that way.

15 MR. DAVIS: Thank you. And there is one
16 last -- at the beginning, I did not elicit their
17 titles and responsibilities. Should I --

18 MR. HEWITSON: It's in their testimony.

19 MADAM CHAIR PRIDEMORE: It's in the record in
20 their pre-sworn, prefiled testimony.

21 Okay. All right. Very good.

22 MR. DAVIS: I believe I --

23 MADAM CHAIR PRIDEMORE: Would you like to put
24 your exhibits in the record?

25 MR. DAVIS: I believe I already requested that
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1 in the beginning, but that -- yes, please.

2 MADAM CHAIR PRIDEMORE: Would you like to
3 excuse your witnesses?

4 MR. DAVIS: Please allow the witnesses to be
5 excused.

6 MS. PRYOR: May I ask that our exhibit also be
7 admitted into the record?

8 MADAM CHAIR PRIDEMORE: So moved, Ms. Pryor.

9 (GPC Exhibit 12 was admitted into evidence.)

10 MADAM CHAIR PRIDEMORE: Witnesses, you are
11 excused.

12 Give the court reporter a moment to reset.

13 MADAM CHAIR PRIDEMORE: Staff, by my count,
14 this is the final panel for you; correct?

15 MR. THOMAS: That's correct.

16 MADAM CHAIR PRIDEMORE: Well, happy Wednesday.
17 Go ahead, Alex.

18 MR. DAVIS: Madam Chair, at this time I call
19 Marcus Jackson, Harold Judd, and Phillip Layfield to
20 the stand.

21 MADAM CHAIR PRIDEMORE: Nicholas Wintermantel?

22 MR. DAVIS: I'm sorry. Nicholas Wintermantel
23 is --

24 WITNESS JUDD: If I might, Madam Chairwoman,
25 because of a preexisting obligation, Nick actually is
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1 upstairs in the electric division on a Zoom call with
2 a different Commission. Unfortunately, he was not
3 able to move that obligation, which was established
4 well over a month ago.

5 And if you had only asked some more questions
6 of Jamie's panel, perhaps we could have gotten him
7 into the room. But unfortunately, he is not in the
8 hearing room with us at the moment.

9 MADAM CHAIR PRIDEMORE: Well, sir, I ran out of
10 lightbulb questions, so I couldn't run it for you any
11 longer there. Okay.

12 WITNESS JUDD: We're prepared to proceed.

13 MADAM CHAIR PRIDEMORE: He's committed. So are
14 we.

15 WITNESS JUDD: Thank you.

16 MADAM CHAIR PRIDEMORE: Go ahead and swear in
17 your witnesses.

18 MR. MARZO: Madam Chair, we have no objection,
19 by the way.

20 MADAM CHAIR PRIDEMORE: You have no objections.

21 MR. MARZO: We've already been informed of
22 Mr. Wintermantel's situation.

23 MADAM CHAIR PRIDEMORE: A little executive
24 secretary birdie told me this, so it's good.

25 Go ahead, Alex.

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1 Thereupon,

2 HAROLD T. JUDD,
3 MARCUS JACKSON,
4 having been duly sworn, testified as follows:

5 Thereupon,

6 DIRECT EXAMINATION

7 BY MR. DAVIS:

8 Q Would you each please say your full name, by
9 whom you are employed, and your responsibilities for the
10 record?

11 A (Witness Judd) Yes. Harold Judd. I am with
12 the Accion Group. I am the president of the Accion Group.

13 A (Witness Jackson) I am Marcus Jackson. I am
14 with the Accion Group.

15 COMMISSIONER McDONALD: Pull up that
16 microphone, please, sir. Thank you.

17 A (Witness Jackson) Marcus Jackson with the
18 Accion Group, and I'm a senior consultant for Accion.

19 MADAM CHAIR PRIDEMORE: Joining us on video.

20 MR. DAVIS: And Mr. Layfield?

21 MADAM CHAIR PRIDEMORE: IT, please unmute
22 Mr. Layfield's mic.

23 WITNESS LAYFIELD: I should be unmuted.

24 MR. DAVIS: Yes. You're on, Mr. Layfield.

25 WITNESS LAYFIELD: Can you hear me?

MR. DAVIS: Yes.

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1 WITNESS LAYFIELD: Good.

2 BY MR. DAVIS:

3 Q Would you please state your full name, by
4 whom you are employed, and your responsibilities for the
5 record?

6 A (Witness Layfield) Phillip Layfield. I am
7 with Accion Group, and I was responsible for overseeing the
8 transmission analysis group.

9 Q Thank you. And on May 6 of this year, did
10 you file or cause to be prefiled seven pages of testimony
11 in question and answer format along with one exhibit
12 marked "20220224 GPC Capacity Report" with a public
13 version and a trade secret version?

14 A (Witness Judd) Yes, we did.

15 MADAM CHAIR PRIDEMORE: Mr. Davis, for the
16 purposes to assist the chair, did you swear your
17 witnesses in? Including your witness on-line?

18 COMMISSIONER McDONALD: No.

19 MADAM CHAIR PRIDEMORE: We need you to swear
20 your witnesses in.

21 COMMISSIONER McDONALD: He was not sworn in.
22 They were, but he wasn't.

23 MR. HEWITSON: He was on mute.

24 MR. DAVIS: Oh. Would you each please raise
25 your right hand.

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1 WITNESS LAYFIELD: I do.

2 Thereupon,

3 PHILLIP LAYFIELD,

4 having been duly sworn, testified as follows:

5 MR. DAVIS: Thank you.

6 MADAM CHAIR PRIDEMORE: Thank you, Mr. Davis.

7 Go ahead.

8 DIRECT EXAMINATION

9 BY MR. DAVIS:

10 Q Do any of you have any corrections you need
11 to make to your prefiled testimony or exhibit at this
12 time?

13 A (Witness Judd) If we could, Counsel and the
14 Commission, on page 5 of our prefiled testimonies starting
15 at line 15, for Mr. Jackson, we understated his experience
16 as a witness. He also appeared with Accion before the
17 Oregon Public Utility Commission as well as this Commission
18 in -- I'm sorry, Commissioner.

19 COMMISSIONER McDONALD: Thank you.

20 WITNESS JUDD: I didn't realize it was that --

21 I will speak up and speak more closely to the mic.

22 A (Witness Judd) Also, he has appeared before
23 this Commission. In addition, he appeared before the Kansas
24 Corporation Commission.

25

1 BY MR. DAVIS:

2 Q And noting that correction, if I were to ask
3 you the same questions today under oath, would your
4 answers be the same as set forth in your prefiled direct
5 testimony?

6 A (Witness Judd) Yes, sir.

7 MR. DAVIS: Madam Chair, the court reporter has
8 been provided with a copy of the prefiled direct
9 testimony, and I would ask that the direct testimony
10 be copied into the record as if given here today, and
11 I would ask that Exhibit 20220224 GPC Capacity Report
12 be marked as Staff Exhibit 80. Yes. 80.

13 MADAM CHAIR PRIDEMORE: So moved. So marked.

14 (The document referred to was marked as Staff
15 Exhibit 80.)

16 (Whereupon, the prefiled direct testimony of
17 Harold Judd, Marcus Jackson, and Phillip Layfield was
18 entered into the record.)

19

20

21

22

23

24

25

1 **DIRECT TESTIMONY OF ACCION GROUP, LLC., INDEPENDENT**
2 **EVALUATORS FOR THE GEORGIA POWER COMPANY**
3 **ON BEHALF OF THE GEORGIA PUBLIC SERVICE COMMISSION**

4
5 **In Re: 2022-2028 CAPACITY**
6 **REQUEST FOR PROPOSALS**

7
8 **DOCKET NO. 44160**

9
10 **Q. Please state your name and business address.**

11 **A. My name is Harold T. Judd. I am the President of Accion Group, LLC**
12 **(Accion Group). Accion Group served as the Independent Evaluator for the**
13 **2022-2028 Capacity (Capacity) RFP. Accion Group's business address is**
14 **244 North Main Street, Concord, NH 03301.**

15
16 My name is Phillip Layfield. I am a Senior Consultant with Accion Group.

17
18 My name is Marcus Jackson. I am a Senior Consultant with Accion Group.

19
20 My name is Nicholas Wintermantel. I am a Consultant with Accion Group.

21
22 **Q. Please discuss your educational background.**

23 **A. Mr. Judd:** I graduated from the University of Wisconsin at Madison in 1974
24 with a B.A. Degree. In 1978, I received a law degree from the University of
25 New Hampshire School of Law, formerly the Franklin Pierce Law Center.
26 Since then, I have continued my education through professional education
27 courses.

28
29 **Mr. Layfield:** I graduated from the George Washington University in 1964
30 with a Bachelor of Business Administration degree, and in 1971 with a
31 Master of Business Administration degree.

1 **Mr. Jackson:** I graduated from Southern Illinois University in 1974 with a
2 B.S. in Mechanical Engineering Technology, and graduated from Rockhurst
3 University, Kansas City, Missouri with a Master's in Business Administration
4 in 1991. My education includes Nuclear Engineering course work at the
5 University of Missouri as well as course work at the United States Air Force
6 Academy in Colorado Springs, Colorado.

8 **Mr. Wintermantel:** I graduated from the University of Alabama in 2003 with
9 a B.S. Degree in Mechanical Engineering and graduated from the University
10 of Alabama at Birmingham with a Master of Business Administration in
11 2007.

12 **Q. Please discuss your professional experience.**

13 **A. Mr. Judd:** I began my career in 1978 in New Hampshire as the Deputy
14 Consumer Advocate for the Legislative Utilities Consumer Counsel. I left
15 that office as Acting Consumer Advocate in 1979 to become the Deputy
16 General Counsel and Energy Advisor to the Special Assistant to President
17 Carter in the White House Office of Consumer Affairs. In 1981, I was
18 appointed an Assistant Solicitor for the Department of Energy. From 1985
19 through 1987, I served as the Economic Development Advisor to the
20 Congress of the Federated States of Micronesia (FSM), and as Special
21 Counsel to the President of the FSM. From September 1989 until January
22 1994, I served in the Office of the Attorney General for the State of New
23 Hampshire, first as an Assistant Attorney General and later as a Senior
24 Assistant Attorney General. Since then, I have represented regulators, and
25 utilities in the electric, telephone and water utility industries, with issues
26 ranging from deregulation, siting and decommissioning nuclear power
27 plants, and bankruptcies. Since 2003 I have served as an Independent
28 Evaluator for multiple procurements in Arizona, California, Colorado,

1 Florida, Georgia, Hawaii, North Carolina, Montana, Oregon, Puerto Rico
2 and South Carolina. I co-founded Accion Group, LLC in 2001.

3
4 **Mr. Layfield:** I began my career in 1964 at Potomac Electric Power. I was
5 able to specialize in electric system modeling and was responsible for the
6 adaption and implementation of the Philadelphia Electric load flow model
7 on the PEPCO system. While at PEPCO I helped implement compatible
8 units and unit costing programs. I designed and implemented the first-
9 generation maintenance scheduling program within the Pennsylvania New
10 Jersey Maryland interconnection. As a member of the System Control
11 Implementation Team, I designed and implemented the first automated
12 trouble call analysis system, which has become a standard for the industry.
13 Following my employment at PEPCO I was hired by the Ernst and Ernst
14 Utility Consulting Group, where I stayed until I became an independent
15 consultant completing electric and gas utility consulting engagements,
16 working with several different consulting firms on renewable resource
17 evaluation, regulatory support, performance management, business
18 process improvement and system operation and maintenance projects. For
19 the last five years I have been working with Accion Group serving as
20 Independent Evaluator in Arizona, Georgia, Hawaii, Oregon, Colorado and
21 Montana, evaluating supplies from those states and Canada, Washington,
22 California, Utah, New Mexico and Wyoming.

23
24 **Mr. Jackson:** Immediately before joining Accion Group I was Chairman of
25 the Board, President and CEO of SEMCO Energy Gas Company with
26 headquarters in Michigan, a firm with diversified business lines including
27 gas pipelines and pipeline construction companies. For much of my career
28 I was with Kansas City Power and Light, where I began as a Plant
29 Maintenance Engineer, eventually rising to Executive Vice President and

1 President of KCPL Power. I served in a variety of position, including Chief
2 Financial Officer of KCP&L and Senior Vice President of Power Production.
3 Also, I served as Chief Operating Officer for KCP&L, with responsibility for
4 power generation, transmission and distribution, customer service and
5 human resources. During a break in my tenure with KCP&L I was the
6 Project Engineer for Gibbs & Hill Engineering – Dravo Arabia for the
7 construction of power generation in Alkhobar, Saudi Arabia.

8
9 **Mr. Wintermantel:** I began my career in 2000 at Southern Company as a
10 co-op student working within Southern Nuclear. In 2003, I was hired as an
11 engineer within the resource planning functions of Southern Company and
12 served in a number of roles including integrated resource planning,
13 structuring of wholesale power contracts, system model development, and
14 asset management. From 2009 to present, I have served as a consultant
15 for Accion Group, serving as Independent Evaluator for multiple
16 procurements in Georgia, Arizona, Oregon, California, and Colorado,
17 evaluating supplies from those states and surrounding regions. As a
18 consultant, I have also performed multiple system reliability and economic
19 evaluations for regulators, utilities, and Regional Transmission
20 Organizations (RTOs), including entities such as the Federal Energy
21 Regulatory Commission (FERC), the Electric Reliability Council of Texas
22 (ERCOT), the Midcontinent Independent System Operator (MISO), the
23 Tennessee Valley Authority (TVA), and the Public Service Company of New
24 Mexico.

25
26 **Q. Have you ever testified before any regulatory agencies?**

27 **A. Mr. Judd:** Yes. I have testified before this Commission, the Arizona
28 Corporation Commission, the New Hampshire Public Utilities Commission,
29 the Vermont Public Service Board, the Oregon Public Utilities Commission,

1 The North Carolina Utilities Commission, the Public Service Commission of
2 South Carolina, the Public Service Commission of Montana and legislative
3 bodies or regulatory bodies in Maine, New Hampshire, Pennsylvania,
4 Massachusetts, and New York. I have also presented reports to regulatory
5 bodies in California, Hawaii, Colorado, and Florida for dockets where
6 testimony was not required.

7
8 **Mr. Layfield:** Yes, I have testified before this Commission and before the
9 Connecticut Public Utilities Regulatory Authority, the Guam Public Utilities
10 Commission, the Kentucky Public Service Commission, the Nevada Public
11 Service Commission, the Indiana Utility Regulatory Commission, the
12 Colorado Public Utilities Commission and the Oregon Public Utilities
13 Commission.

14
15 **Mr. Jackson:** Yes, I frequently appeared before the Missouri Public Service
16 Commission concerning plant operation issues.

17
18 **Mr. Wintermantel:** Yes, I have testified before this Commission, the North
19 Carolina Utilities Commission, the Public Service Commission of South
20 Carolina, and the New Mexico Public Regulation Commission. I have
21 prepared presentations, reports, and filed comments to regulated bodies
22 including the Federal Energy Regulatory Commission (FERC) where
23 testimony was not required.

24
25 **Q. Would you please describe your role in this proceeding?**

26 **A. Mr. Judd:** Accion Group was selected by the Commission to be the
27 Independent Evaluator for the Capacity Request for Proposals (RFP). In
28 that role we were involved in all major activities in the RFP, including the
29 development of the RFP process, the drafting of RFP related documents,
30 the receipt of bids, the evaluation of bids and post-selection discussions

1 with the successful Bidders. I participated in the Bidders Conference and
2 participated in all meetings between Georgia Power and any Bidder, as
3 required by the Rules of the Commission. In addition, Accion Group created
4 and maintained the website through which the RFP was conducted. I
5 directed the evaluation and analysis performed by Accion consultants,
6 which is documented in the report prepared for the Commission.

7
8 Mr. Layfield was responsible for the transmission and distribution impact
9 analysis performed by Accion as part of the evaluation of bids. Mr. Jackson
10 was responsible for reviewing the Asset Purchase Sale Agreement (APSA)
11 bids. Mr. Wintermantel was responsible for reviewing the Company's
12 evaluation methodology, conducting a mock bid process, and performing a
13 parallel evaluation of bids submitted for the Capacity RFP.

14 **Q. What is the purpose of your testimony?**

15 **A. Mr. Judd:** The Final Report of the Independent Evaluator Re: Georgia
16 Power Company's Capacity Request for Proposals Process dated February
17 24, 2022, was prepared by me or under my direction. The Report was
18 prepared in two versions, the public version and the non-public, Trade
19 Secret version. The Trade Secret version was prepared for the Commission
20 and contains commercially sensitive or proprietary and confidential
21 information, as determined by Georgia Power. The public version is
22 Attachment 1 to this testimony. We appear to sponsor the report.

23
24 **Q. Does your report detail the activities and findings of the Independent**
25 **Evaluator?**

26 **A. Mr. Judd:** Yes it does.
27

- 1 Q. Does this conclude your testimony and that of Mr. Layfield, Mr.
2 Jackson, and Mr. Wintermantel?
3 A. Mr. Judd: Yes it does.

1 MR. DAVIS: Madam Chair, with your permission,
2 I would like to ask that the panel be allowed to give
3 a summary of their prefiled testimony.

4 MADAM CHAIR PRIDEMORE: Go ahead.

5 WITNESS JUDD: Thank you very much. First off,
6 let me say, I appreciate you letting Mr. Layfield
7 participate remotely. Because of COVID concerns, it
8 was not possible for him to travel. So we appreciate
9 the courtesy of that.

10 Also, I want to say it's great to be back.
11 It's been probably three years since I've appeared
12 before you in person, and while y'all look great on
13 Zoom, it's nice to see that you are able to get folks
14 back together again.

15 Accion Group serves as your independent
16 evaluator. And indeed, we have for 28 RFPs over the
17 years. In addition to that, we have conducted over
18 100 RFPs across the country. And I also want to note
19 that the standards you established, we have taken
20 across the country and that basically they're adopted
21 as the gold standard.

22 And we agree with that approach because all
23 bidders are treated fairly. They have access to the
24 same information. There is never a question about
25 additional information being provided that isn't

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1 provided to all.

2 In the RFPs, and specifically in the 2022,
3 2028 Capacity RFP, we enforced the terms and
4 conditions approved by this Commission. In effect,
5 we are the traffic cops. You guys set the rules, and
6 we make sure they are followed. And we experienced
7 no violations of that, of any of those terms or
8 conditions in this RFP.

9 We view the RFP as being quite successful. We
10 had sought between 1,000 and 3,000 megawatts, and as
11 you know, we ended up with Georgia Power having
12 contracts for over 2,300 megawatts.

13 In the course of the RFP, we received 70 bids
14 with 6,000 megawatts bid in for consideration during
15 evaluation. Pardon me. In addition to the process
16 of actually evaluating the bids, we have a program
17 that was approved by this Commission. Indeed,
18 encouraged by this Commission, where we seek input
19 from stakeholders before the RFP documents are
20 presented to you for approval.

21 It's a comment period, and we specifically
22 request bidders to help us make the documents better
23 so they can give us their most robust bids.

24 Specifically, we give them the opportunity to
25 present red line comments to the RFP documents that

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1 includes the PPA, as well as the RFP itself, and to
2 provide their recommendations for improving the
3 documents.

4 In addition, we held a stakeholder session
5 where we got input, received questions, got written
6 responses that were provided so that all
7 participants, whether they participated in that
8 webinar or not, had access to all of the questions
9 and all of the answers.

10 Similarly, the comments were posted for all
11 participants to be able to have their knowledge
12 enhanced as to what was sought and the final RFPs
13 that were presented to you for approval.

14 With that process, we refined materials with
15 the staff and the company; and again, we think it was
16 a very successful RFP in seeking the capacity needs
17 of the company, and I believe those are the contracts
18 that were presented to you for approval.

19 Thank you. That concludes my opening
20 statement.

21 MR. DAVIS: Madam Chair, the panel is now
22 available for questions from the commissioners and
23 cross-examination.

24 MADAM CHAIR PRIDEMORE: Questions from
25 commissioners?

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1 (No response.)
2 MADAM CHAIR PRIDEMORE: Okay. Take it from the
3 top. Americans for Affordable Clean Energy?
4 MR. GALLOWAY: No questions.
5 MADAM CHAIR PRIDEMORE: Commercial Group?
6 MR. JENKINS: No questions.
7 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
8 for Georgia?
9 (No response.)
10 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
11 for Georgia?
12 (No response.)
13 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
14 for Georgia?
15 (No response.)
16 MADAM CHAIR PRIDEMORE: There's three times.
17 Cypress Creek Renewables?
18 MR. STAIR: No questions.
19 MR. PRENOVITZ: Madam Chair, I was in the other
20 room.
21 MADAM CHAIR PRIDEMORE: Do you have questions
22 for this panel?
23 MR. PRENOVITZ: No questions, ma'am.
24 MADAM CHAIR PRIDEMORE: There we go.
25 Cypress Creek Renewables?

1 MR. STAIR: No questions.

2 MADAM CHAIR PRIDEMORE: Nice job. Okay.

3 Georgia Association of Manufacturers?

4 MR. CHARLES JONES: No questions, Madam Chair.

5 MADAM CHAIR PRIDEMORE: Georgia Center for

6 Energy Solutions?

7 MR. HUBBARD: No questions.

8 MADAM CHAIR PRIDEMORE: Georgia Coalition of

9 Local Governments?

10 MS. BROWN: No questions.

11 MADAM CHAIR PRIDEMORE: Georgia Interfaith

12 Power & Light and Partnership for Southern Equity?

13 MS. KYSOR: No, thank you.

14 MADAM CHAIR PRIDEMORE: Okay.

15 MR. WALSH: I was starting to feel ignored, so

16 thank you for stepping up.

17 MS. RAKPANICHMANEE: You're welcome.

18 Good afternoon, Commissioners. Good afternoon,

19 panel. Nicha Rakpanichmanee on behalf of Georgia

20 Interfaith Power & Light and Partnership for Southern

21 Equity. I'll let the panel decide who is best to

22 answer each question.

23 WITNESS JUDD: Thank you.

24 CROSS-EXAMINATION

25

1 BY MS. RAKPANICHMANEE:

2 Q Referring to Staff Exhibit 80, the Capacity
3 RFP Report that you filed. Section 9-A under the
4 "Evaluation Process" and the "RFP Bid Data Requested,"
5 under Subsection N, among the bid data requested was
6 information about energy price; is that correct?

7 A (Witness Judd) I'm sorry. Do you have a page
8 number?

9 Q Page 29.

10 A (Witness Judd) Thank you. I could have found
11 it, but you made it a little quicker.

12 Q Page 29, Subsection N. It refers to RFP bid
13 data requested, and among the bid data that was requested
14 was information about energy price; is that correct?

15 You may refer back to the heading of that
16 section, too. It's on page 26.

17 A (Witness Judd) Yes. You have read that
18 correctly. Thank you.

19 Q Okay. And the energy -- the energy price
20 information requested included fuel costs; is that
21 correct?

22 A (Witness Judd) Yes.

23 Q And on page 30 of that same report, you
24 listed four scenarios under which the variable cost
25 components were analyzed. The four scenarios being too

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1 low gas price, too moderate gas price, and too moderate
2 gas price forecasts?

3 A (Witness Judd) Yes, ma'am.

4 Q So in the bid evaluation process, no high
5 gas-price scenario was considered; is that correct?

6 A (Witness Judd) That is -- it is as presented
7 here. That is correct.

8 MS. RAKPANICHMANEE: Okay. That is all. Thank
9 you.

10 MADAM CHAIR PRIDEMORE: Georgia Large Scale
11 Solar Association?

12 MR. CARVER: Thank you, Madam Chair. Brad
13 Carver on behalf of the Georgia Large Scale Solar
14 Association and Advanced Power Alliance.

BY MR. CARVER: (CROSS-EXAMINATION)

15 Q Thank you, panel members. Glad to have you
16 here today. Just a little context, we -- we -- we fully
17 100 percent support a competitive bid procurement format
18 for utility scale procurement in Georgia, and so we
19 applaud you for what you do as part of that process.

20 A (Witness Judd) Thank you.

21 Q The only thing I want to ask you is, one
22 thing that's come to light with several of our bids, bid
23 RFPs, is that we -- there's collective issues that the
24 market finds, and to the extent that we -- because again,

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1 we -- not all market participants are members of our
2 association, and so we understand that.

3 And we certainly will engage on behalf of our
4 membership, but we also want to make sure we keep a level
5 competitive market, and so to the extent -- do you foresee
6 that there's opportunities that we can have a bidders
7 conference to maybe address some of these issues going
8 forward so that all bidders would have equal access to that
9 information?

10 MR. MARZO: Madam Chair, I'm just going to
11 object to lack of foundation. What are the issues?
12 Issues is he referring to?

13 MR. CARVER: I'm sorry.

14 BY MR. CARVER:

15 Q Let me phrase it this way: There is not any
16 issues with the current RFP. I'm saying, going -- this is
17 for going forward. Not any existing RFPs that you are
18 dealing with.

19 Do you foresee there's an opportunity if issues
20 come -- arise that we can identify, that we can have a
21 bidders conference to have those issues raised and clarified
22 for all bidders?

23 WITNESS JUDD: Madam Chair, I'm prepared to
24 answer that, but it's the will of the chair.

25 MADAM CHAIR PRIDEMORE: Go ahead.

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1 WITNESS JUDD: Thank you.

2 A (Witness Judd) As I stated before, the RFP
3 process designed by this Commission provides for stakeholder
4 sessions, bidders conference, if you will, and the comment
5 period on the draft documents. And in all -- both of those
6 processes, we invite, indeed, encourage questions,
7 suggestions.

8 I'll also remind you, because some of your
9 members did participate in this and other RFPs, that we've
10 conducted for Georgia. On our website, there's a Q and A
11 feature, and we encourage folks to use that.

12 In addition, for those who submit bids, we have
13 a confidential message board where concerns about their
14 project-specific issues can be explored and discussed.
15 Those are, again, done confidentially, because, perhaps,
16 they don't want their competitors to know the specifics of
17 their project.

18 So we try to have a process where we get the
19 feedback during the process and so that we -- when we come
20 before the Commission here, they are -- we have gone through
21 concerns, addressed them, and are able to present them,
22 either in our report, or indeed, we've resolved them on the
23 website.

24 So, yes. We encourage your members -- and good
25 luck on getting everyone else to sign up with your

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1 organization -- that they come to us, participate fully in
2 the stakeholder session, bidders conference, if you will, as
3 well as use these other platforms that the Commission had us
4 design so we do get their input and factor it into the
5 process and the RFP documents that are presented to the
6 Commission.

7 BY MR. CARVER:

8 Q Thank you very much. I appreciate your
9 answer.

10 A (Witness Judd) Well, thank you for the
11 question.

12 MADAM CHAIR PRIDEMORE: Moving on, Georgia
13 Solar Energy Industries Association, Solar Energy
14 Association and Vote Solar?

15 MR. THOMASSON: No questions.

16 MADAM CHAIR PRIDEMORE: Georgia Watch?

17 MS. COYLE: No questions. Thank you.

18 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

19 MR. CARVER: No questions, Madam Chair.

20 MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge
21 Coalition?

22 MR. STEVEN JONES: No questions.

23 MADAM CHAIR PRIDEMORE: Sierra Club?

24 MR. FABISH: No questions.

25 MADAM CHAIR PRIDEMORE: Southern Alliance for
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1 Clean Energy and Southface Energy Institutes?

2 CROSS-EXAMINATION

3 BY MR. BAKER:

4 Q Good afternoon, gentlemen. A few questions
5 for you. And my first question is kind of a broad
6 question to you, Mr. Jackson, Mr. Judd.

7 Based on your experience, how could the process
8 for future capacity RFPs be improved? Do you see areas
9 where there could be some improvements and changes to make
10 it a better process?

11 A (Witness Judd) Great question. And we do
12 evolve. We are certainly different today than we were in
13 the process here of the Commission rules since 2002. It has
14 been a lot of improvement.

15 First and foremost, is encouraging the
16 participation of stakeholders from the outset. It is
17 challenging when we go through a process, whether in this
18 jurisdiction or elsewhere, and folks come in after the fact
19 and -- I'll put it in terms of offer suggestions on how
20 things could have been better.

21 We do everything, as I've stated before, to
22 encourage participation from the outset. So the first and
23 foremost is, perhaps we could do a better outreach to
24 encourage that. I will say that, when we launched this RFP,
25 we sent out a notice to approximately 5,000 potential

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1 bidders from a list that we keep of participants in Georgia
2 and elsewhere to try to make sure that there is broad
3 knowledge of the RFP.

4 And, again, we send out -- anyone who registers
5 on the site, they are then notified when the stakeholder
6 sessions are available, when the comment period is open. I
7 think that'd be the best way, because things change over
8 time. Not just in the process but in perceptions as well as
9 technology and opportunities.

10 So the people in the marketplace are in an
11 excellent position to help us refine the process as well as
12 the content of RFPs. So that would be my recommendation to
13 your membership and others, is to get engaged at the front
14 end of the process.

15 Q Mr. Jackson, do you have anything you would
16 like to suggest?

17 A (Witness Jackson) I don't have anything to
18 add, no.

19 Q Let me just ask for clarification. Do you
20 have to be a bidder to be able to make inquiries about the
21 RFP?

22 A (Witness Judd) No, sir.

23 Q Okay. So I could -- I could be an interested
24 bidder -- I can be an interested bidder, but I haven't
25 paid -- I haven't paid a fee or anything like that to --

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1 A (Witness Judd) That's a great question, so --
2 and I fully appreciate it and understand where you're coming
3 from. So let me try this again.

4 I was doing kind of high level, so let me try
5 to make sure that I'm understood. The process that we've
6 set up, again, we'd notify a broad category of potential
7 bidders. I said bidders. That actually includes interested
8 parties.

9 And on our website platform, we have set it up,
10 as approved by the Commission, where someone can register as
11 a bidder. They can also register as an interested party, a
12 nonbidder. They have -- nonbidders have access to
13 everything except for the bid form. So the Q and A feature,
14 being notified when there are the stakeholder sessions,
15 being invited to the stakeholder sessions, providing
16 comments on the documents. All of those opportunities
17 exist.

18 Bidding, actually, again, is for people who
19 want to bid. And when I said before that there is a
20 confidential message board, again, that is for bidders about
21 their project-specific issues that might arise. All other
22 questions from bidders and nonbidders are managed through
23 the Q and A feature, and folks are invited to present their
24 questions.

25 When the questions are answered, they are

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1 released on the site and a notice sent out to folks who are
2 registered. So all participants, stakeholders, of all --
3 bidders and nonbidders, have access to all the Q and A.
4 They have access to all the documents. They have access to
5 all the announcements that are posted. Everything right up
6 to submitting a bid. All interested parties are encouraged
7 to help us make it a better process.

8 Q Okay. Thank you.

9 A (Witness Judd) You're welcome.

10 Q And you indicated that in this latest RFP you
11 received or the Commission received or the company
12 received 70 bid proposals for a total of -- cumulative
13 total of 6,000 megawatts of capacity; is that correct?

14 A (Witness Judd) Yes. Those are, of course,
15 received through the website. Not directly to the company.

16 Q Right.

17 A (Witness Judd) But yes.

18 Q And did you get inquiries from parties or
19 comments from parties other than the 70 -- the bidders who
20 actually bid on those 70 contracts or 70 proposals to --
21 did you get more participation than just the 70 bidders or
22 70 -- companies representing those 70 bidders?

23 A (Witness Judd) Here's what I'm trying to be
24 responsive. I understand your question to be the questions
25 that we received, of the 244 registered potential bidders,

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1 did any of those provide us with comments or Q and A in
2 addition to the ones that were submitted by the actual
3 bidders?

4 Is that your question, sir?

5 Q Yes, sir. Yes, sir.

6 A (Witness Judd) The answer is yes.

7 Q Okay. And were those -- and were those
8 questions that they were asking about the -- the
9 qualifications necessary to be able to bid into the
10 process?

11 A (Witness Judd) I don't remember the specifics
12 of the Q and A's. Again, they're all released and published
13 on the site. I'm sorry I can't be more -- it was some time
14 ago. I don't remember exactly.

15 Q Thank you. So all of those questions were --
16 are publicly available so anybody could review them?

17 A (Witness Judd) Yes.

18 Q Okay. And do you agree with the PSC staff's
19 recommendation that demand-side resources should be
20 included as an eligible resource in the future capacity
21 RFPs?

22 A (Witness Judd) I am going to say that that's a
23 policy call for the commissioners. And I think that's above
24 my pay grade. If the Commission chooses to have DSM in a
25 future solicitation and we continue to be their dependent

1 evaluator, of course, that will be included, and they will
2 have a level playing field.

3 Q And you indicate that you do. You handle
4 more than just RFPs coming from Georgia Power Company and
5 the state of Georgia. In any of those other cases where
6 you are the independent evaluator, have there been bids or
7 RFPs where demand-side resources were included as eligible
8 resources?

9 A (Witness Judd) Yes.

10 Q Is that a common feature now of most RFPs for
11 capacity -- or most RFPs? I am not going to restrict it
12 to capacity.

13 A (Witness Judd) Of the RFPs that we conduct --

14 Q Correct.

15 A (Witness Judd) -- it is not standard, but it
16 is included in some. I will also say, many of the RFPs
17 we're conducting now are for energy, not capacity, given the
18 way the marketplace is going.

19 But, again, we -- to answer your question, we
20 have conducted RFPs. In fact, we are conducting one right
21 now in another jurisdiction where DSM by a different name
22 will be included.

23 Q Would you say that is an industry trend that
24 you're seeing?

25 A (Witness Judd) I won't say it quite that way.

1 I will say that, as you can tell, I've got more than a
2 couple of gray hairs now. I've been at this for some time.
3 And we've been doing DSM in one fashion or another since --
4 this is going to sound like my grandfather -- since before
5 the turn of the century.

6 So DSM is an established and recognized
7 approach to be used in some circumstances. And can it be
8 included in the competitive solicitation? If the Commission
9 so directs, yes, of course.

10 Q And you can compare a DSM -- you have the
11 ability to evaluate a DSM bid against other
12 capacity-related bids or bids such as a solar storage bid
13 and things like that? So you can compare them fairly on
14 an apples-to-apples basis; correct?

15 A (Witness Judd) Within the confines and the
16 structure established in each of the jurisdictions where we
17 do that, yes. And I am -- please understand, I'm not trying
18 to be evasive. Each jurisdiction sets standard for each
19 RFP. And there are criteria sometimes of specific goals
20 that are being sought, and that is a component of an RFP.

21 And I'm afraid I'm not going to be able to say
22 it's apples to apples because there may be different
23 criteria established by the regulators for a specific RFP.
24 So I hope that's responsive to your question.

25 Q It is. Thank you.

1 And just to -- hypothetically. Hypothetically,
2 if the Commission or a commission were to say, I want the
3 RFP to be an all-source-bid format. That can be done easily
4 and have -- it be evaluating the bid solicitations fairly?

5 A (Witness Judd) Well, if could --

6 MS. PRYOR: Objection.

7 A (Witness Judd) I see counsel, I'll be quiet.

8 MS. PRYOR: Objection. This is beyond the
9 scope of their testimony.

10 COMMISSIONER McDONALD: Mr. Baker?

11 MR. BAKER: I mean, it's in regard to -- we're
12 talking about the evaluation they did of the last
13 RFP. This -- they've been discussing the fact that
14 all-source bidding requirements are becoming more
15 common among utilities throughout the country.

16 So I was just asking if it was -- if this
17 Commission, and he indicated, Mr. Judd indicated,
18 that it's the Commission decision, whether an
19 all-source criteria would be applied to in a future
20 RFP. I'm just asking hypothetically, if that were
21 the case, would they do a fair evaluation.

22 MS. PRYOR: This panel's testimony is about the
23 2022 to 2028 capacity RFP. It doesn't include future
24 RFPs.

25 COMMISSIONER McDONALD: I agree with that. But
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1 the witness can say "I don't know" or "That's none of
2 my business" or whatever --

3 WITNESS JUDD: Thank you, Commissioner.

4 A (Witness Judd) I need to make a correction. I
5 didn't say -- you used the term "all source" and not in the
6 way I used in any of my responses. So let me address that.

7 Just like I stated before about the
8 jurisdiction will establish criteria and parameters, the
9 term "all source" is used in different jurisdictions to mean
10 different things. We've conducted all-source solicitations
11 that were all fossil fuel. Limited to fossil fuel, but they
12 still called it all source.

13 So I -- I caution you on the use in applying to
14 us of saying "all source." Specifically on the question of
15 how we conducted RFPs with DSM, sure. Could it be included?
16 As I stated before, the Commission will establish what is to
17 be included as products and technology to be bid, and we
18 will conduct that RFP accordingly.

19 BY MR. BAKER:

20 Q So the Commission would define what an
21 all-source bid is?

22 A (Witness Judd) Yes, sir.

23 Q Are the PPAs that are being presented to the
24 Commission for approval dependent upon one another?

25 A (Witness Judd) I'm sorry. I've got to -- I
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1 don't quite understand.

2 Are you saying if one fails, they all fail? Is
3 that your point?

4 Q Yes, sir.

5 A (Witness Jackson) I believe not, but I think
6 that would be the Commission -- the company would have to
7 decide how much of the portfolio would survive. Our process
8 and our involvement was conducting a fair RFP and the
9 evaluation of the bids received. And the disposition of
10 those RFPs and which ones are approved to go forward is for
11 this Commission to decide.

12 Q Thank you. And do all PPAs have to be
13 approved together in order for the offer to be accepted,
14 or can the Commission approve each PPA separately?

15 A (Witness Judd) Each PPA is separate and will
16 be addressed, I believe, as in the past practice by the
17 Commission.

18 MR. BAKER: All right. Thank you very much,
19 gentlemen. Thank you, Commissioners.

20 COMMISSIONER McDONALD: Thank you, Mr. Baker.
21 Southern Renewal Energy?

22 MR. MAHAN: No questions, sir.

23 COMMISSIONER McDONALD: Georgia Power?

24 MS. PRYOR: No questions.

25 COMMISSIONER McDONALD: Redirect?

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1 MR. DAVIS: No redirect. I would just like to
2 ask that Staff Exhibit No. 80 be entered into the
3 record and that the witnesses be excused.

4 COMMISSIONER McDONALD: So marked.

5 MR. DAVIS: Thank you.

6 (Staff Exhibit 80 was admitted into evidence.)

7 COMMISSIONER McDONALD: Commissioners, do you
8 have any questions to the witnesses?

9 (No response.)

10 COMMISSIONER McDONALD: You are excused. Thank
11 you very much.

12 WITNESS JUDD: Thank you.

13 WITNESS JACKSON: Thank you.

14 COMMISSIONER McDONALD: All right. We will
15 take a minute for the next panel to come forth.

16 MR. JENKINS: Thank you. I believe we're up
17 first.

18 Commercial Group calls Steve W. Chriss.

19 COMMISSIONER McDONALD: Would you swear your
20 witness.

21 MR. JENKINS: Yes.

22 Thereupon,

23 STEVE W. CHRISS,
24 having been duly sworn, testified as follows:

25 DIRECT EXAMINATION

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1 BY MR. JENKINS:

2 Q Mr. Chriss, by whom are you employed?

3 A I am employed by Walmart, Incorporated, or
4 Walmart, Inc.

5 Q Did you cause to be prefiled in these
6 proceedings 24 pages of direct testimony in question and
7 answer format and one exhibit consisting of your work
8 experience that was premarked SWC-1?

9 A Yes.

10 Q Do you have any corrections?

11 A I do have two corrections. So on page 19,
12 line 11, the word --

13 Q This is of your testimony?

14 A Of the testimony, yes. I'm sorry.

15 On page 19, line 11, of the testimony, the word
16 "sever" should read "severe."

17 And then on page 20, line 21, the phrase that
18 came out "same the" should be "the same."

19 Q Good. With those corrections, if I were to
20 ask you the same questions today as are contained in that
21 prefiled testimony, would your answers be the same?

22 A Yes.

23 MR. JENKINS: I ask that the direct testimony
24 of Steve W. Chriss be read into the record as if
25 given orally by -- from the stand and one Exhibit

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SWC-1 be marked as Commercial Group Exhibit 1.

COMMISSIONER McDONALD: Moved and marked.

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

(Whereupon, the prefiled direct testimonies
of Mr. Steve W. Chriss follows:)

1 **Introduction**

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

3 A. My name is Steve W. Chriss. My business address is 2608 SE J St., Bentonville,
4 AR 72716-0550. I am employed by Walmart Inc. as Director, Energy Services.

5 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?**

6 A. I am testifying on behalf of The Commercial Group. The Commercial Group is an ad
7 hoc association of large customers of Georgia Power Company ("GPC" or "the
8 Company").

9 **Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.**

10 A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State
11 University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the
12 Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My
13 duties included research and analysis on domestic and international energy and
14 regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility
15 Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties
16 included appearing as a witness for PUC Staff in electric, natural gas, and
17 telecommunications dockets. I joined the energy department at Walmart in July 2007
18 as Manager, State Rate Proceedings. I was promoted to Senior Manager, Energy
19 Regulatory Analysis, in June 2011. I was promoted to my current position in October,
20 2016. My Witness Qualifications Statement is attached as Exhibit SWC-1.

1 **Q. DO YOU HOLD ANY MEMBERSHIPS THAT ARE RELEVANT TO THE**
2 **ISSUES BEFORE THE COMMISSION FOR CONSIDERATION IN THIS**
3 **DOCKET?**

4 A. Yes. I am a member of the Edison Electric Institute National Key Accounts Program
5 Customer Advisory Group and the Clean Energy Buyers Alliance Advisory Board.

6 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE**
7 **GEORGIA PUBLIC SERVICE COMMISSION ("COMMISSION")?**

8 A. Yes. I submitted testimony in Docket Nos. 31958, 36989, 40161, 42310, and 42516.

9 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER**
10 **STATE REGULATORY COMMISSIONS?**

11 A. Yes. I have submitted testimony in 250 proceedings before 40 other utility regulatory
12 commissions. I have also testified or submitted written testimony before legislative
13 committees in Kansas, Missouri, North Carolina, and South Carolina. My testimony
14 has addressed topics including, but not limited to, cost of service and rate design, return
15 on equity, revenue requirements, ratemaking policy, large customer renewable
16 programs, qualifying facility rates, telecommunications deregulation, resource
17 certification, energy efficiency/demand side management, fuel cost adjustment
18 mechanisms, decoupling, and the collection of cash earnings on construction work in
19 progress.

20 **Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?**

21 A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

1 **Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS IN GEORGIA.**

2 A. As shown on Walmart's website, Walmart operates 214 retail units and seven
3 distribution centers and employs over 70,000 associates in Georgia. In fiscal year
4 ending 2021, Walmart purchased \$24.7 billion worth of goods and services from
5 Georgia-based suppliers, supporting over 205,000 supplier jobs.¹

6 **Q. PLEASE BRIEFLY DESCRIBE WALMART'S OPERATIONS WITHIN THE**
7 **TERRITORY OF THE COMPANY.**

8 A. Walmart is a large customer of GPC, with 127 stores, three distribution centers, and
9 related facilities that take electric service from the Company.

10 **Q. PLEASE DESCRIBE THE GENERAL POSITION OF THE COMMERCIAL**
11 **GROUP MEMBERS TOWARDS RENEWABLE ENERGY ISSUES.**

12 A. The Commercial Group members are national and international businesses that have
13 committed to the use of renewable energy as a key operational and policy goal of their
14 operations. The Corporate Renewable Energy Buyer's Principles, published by World
15 Resources Institute and World Wildlife Fund and to which Walmart is a signatory,
16 provides more detail around corporate customer renewable energy needs.²

17 **Q. HAS WALMART ESTABLISHED CORPORATE RENEWABLE ENERGY**
18 **GOALS?**

19 A. Yes. Walmart has long had aggressive and significant company-wide renewable
20 energy goals, and on September 21, 2020, we announced new targets, including: (1) to

¹ <http://corporate.walmart.com/our-story/locations/united-states#/united-states/georgia>

² <http://buyersprinciples.org/about-us/>

1 be supplied 100 percent by renewable energy by 2035 and (2) zero carbon emissions
2 in our operations, including our transportation fleet vehicles, without the use of offsets,
3 by 2040. We have also set a goal to transition to low-impact refrigerants for cooling
4 and electric equipment for heating by 2040.³ To date, Walmart has contracted for or
5 currently takes electricity from one or more renewable resources in at least 29 states,
6 including Georgia, and Puerto Rico. Walmart currently participates in GPC's
7 Renewable Energy Development Initiative program, authorized by the Commission as
8 part of the 2016 Integrated Resource Plan ("IRP") docket, and has entered into an
9 agreement with 14 municipal utility members of the Electric Cities of Georgia to be
10 supplied by 26 MW of solar from a new 80 MW project located in Georgia.⁴

11 **Q. TO PROVIDE AN EXAMPLE OF A CORPORATE CUSTOMER WHO**
12 **ACTIVELY ENGAGES IN RENEWABLE ENERGY OPPORTUNITIES, CAN**
13 **YOU PROVIDE INSIGHT INTO WALMART'S GENERAL FRAMEWORK**
14 **FOR EVALUATING RENEWABLE OPPORTUNITIES?**

15 **A.** Yes. Walmart's desire for renewable energy resources must be balanced against its
16 business needs. As a general rule, Walmart does not enter into premium structures or
17 programs that only result in additional costs to our facilities. Rather, Walmart seeks
18 renewable energy resources that deliver industry-leading cost, including renewable and
19 project specific attributes such as renewable energy credits ("RECs"), within structures
20 where the value proposition allows the customer to receive any potential benefits

³ <https://corporate.walmart.com/newsroom/2020/09/21/walmart-sets-goal-to-become-a-regenerative-company>

⁴ <https://ecoga.org/wp-content/uploads/2021/11/Walmart-Solar-Press-Release.pdf>

1 brought about by taking on the risk of being served by that resource instead of, or in
2 addition to, the otherwise applicable resource portfolio. Additionally, Walmart does
3 not enter into programs with contract terms in excess of 15 years.

4 **Q. WHAT CHANNELS DOES WALMART UTILIZE TO SECURE RENEWABLE**
5 **ENERGY RESOURCES?**

6 **A.** To meet our renewable energy goals, Walmart utilizes three primary channels to secure
7 renewable energy resources:

8 • **Contracting for off-site resources:** These products are typically structured to
9 replace other energy, both physically and on the bill. This mechanism allows
10 Walmart to leverage its scale to drive the best project economics while
11 simultaneously minimizing transaction time and costs. To date, Walmart has
12 contracted for these resources in deregulated markets through Texas Retail Energy,
13 LLC, a competitive electric supplier wholly owned by Walmart that serves as our
14 electric supplier in most deregulated retail markets, to directly serve our load. We
15 have also entered into "Virtual Power Purchase Agreements" in deregulated
16 wholesale markets, which do not directly serve our load but allow us to bring new
17 large scale renewable resources to the market.

18 • **Contracting for on-site resources:** Walmart contracts for on-site, behind the
19 meter resources through power purchase agreements ("PPAs") and leases that allow
20 performance guarantees. These resources replace grid energy and are priced with
21 the expectation that the operating costs for the site are reduced.

- 1 • **Utility partnerships:** Walmart works with its utility partners to develop useable
2 commercial and industrial programs and economic structures targeted to function
3 within the confines of the regulatory compact and with minimal impact to non-
4 participating customers. When this option is pursued, Walmart works to ensure
5 that programs it assists to develop can be used by the broader group of large
6 commercial and industrial customers, not merely Walmart. Walmart is unique in
7 the large commercial space because we have significant in-house rate and
8 regulatory expertise that we are willing to leverage to create opportunities to move
9 the entire industry forward. The partnerships include the development of and
10 participation in Florida Power & Light Company's SolarTogether Program
11 ("SolarTogether"), Georgia Power Company's Renewable Energy Development
12 Initiative program, as noted above,⁵ and Alabama Power Company's 72 MW solar
13 farm in Alabama.⁶ While Walmart assisted in developing these opportunities, the
14 opportunities are open to other interested large customers, not just Walmart.

15
16 **Purpose of Testimony and Summary of Recommendations**

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

18 A. The purpose of my testimony is to address aspects of GPC's integrated resource plan
19 ("IRP") and demand side management ("DSM") filing, focusing primarily on the
20 Company's proposed programs.

⁵ <https://www.greenbiz.com/article/how-google-and-walmart-work-utilities-procure-clean-power>

⁶ <http://www.alabamane.wscenter.com/2018/01/02/chambers-county-solar-project-now-serving-alabama-power-customers/>

1 Q. PLEASE SUMMARIZE THE COMMERCIAL GROUP'S
2 RECOMMENDATIONS TO THE COMMISSION.

3 A. The Commercial Group's recommendations to the Commission are as follows:

- 4 1) The Commercial Group supports approval of the Clean and Renewable Energy
5 Subscriptions ("CARES") Program, subject to approval of the Commercial Group's
6 proposal to first offer the portions of Existing, New, or Municipalities, Universities,
7 Schools, and Hospitals ("MUSH") renewable procurements not subscribed by
8 participating customers within each subset to other CARES program subsets before
9 being shifted to all customers.
- 10 2) The Commercial Group recommends that the Commission require GPC to work
11 with interested commercial and industrial customer stakeholders throughout the
12 CARES program design process.
- 13 3) The Commercial Group does not oppose Commission approval of GPC's proposed
14 Resilience Asset Service Tariff ("RAST-1"). However, because much of the
15 program structure has yet to be defined, the Commercial Group recommends that
16 the Commission require GPC to work with interested commercial and industrial
17 customer stakeholders throughout the program design process.
- 18 4) The Commercial Group does not oppose Commission approval of GPC's proposed
19 Demand Response Credit ("DRC-1") program, subject to the program being
20 available to all distributed energy resources ("DER"), regardless of ownership, that
21 qualify per the operational parameters of the program. Similar to RAST-1, the
22 Commercial Group recommends that the Commission require GPC to work with

1 interested commercial and industrial customer stakeholders throughout the program
2 design process.

3 5) For the purposes of this docket and to limit bill increases to residential and
4 commercial customers, the Commercial Group recommends the Commission
5 approve an additional sum for successful DSM measures that, at 100 percent
6 achievement of estimated results, does not increase the resulting revenue
7 requirement from the average of 2020 and 2021 additional sum earned by the
8 Company, or approximately \$7 million per year.

9 **Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR**
10 **POSITION ADVOCATED BY THE COMPANY INDICATE THE**
11 **COMMERCIAL GROUP'S SUPPORT?**

12 **A.** No. The fact that an issue is not addressed herein or in related filings should not be
13 construed as an endorsement of, agreement with, or consent to any filed position.
14

15 **Clean and Renewable Energy Subscription Program**

16 ***Program Description***

17 **Q. WHAT IS YOUR GENERAL UNDERSTANDING OF THE PROPOSED**
18 **CARES PROGRAM?**

19 **A.** My general understanding is that the Company proposes to contract for energy from up
20 to 2,100 MW of utility scale resources for subscription by commercial and industrial
21 customers. Customers will be able to subscribe to portions of the resources procured
22 through the CARES program subsets as described below. *See Direct Testimony of*

1 Jeffrey R. Grubb, A. Wilson Mallard, Michael B. Robinson, and Jeffrey B. Weathers,
2 pages 42-43.

3 **Q. WHAT IS YOUR UNDERSTANDING OF THE PROPOSED CARES**
4 **PROGRAM SUBSETS?**

5 **A.** My understanding is that the Company proposes the following CARES program
6 subsets:

- 7 • **CARES Existing Load:** GPC proposes that existing customers with a minimum
8 annual peak of 3 MW at one or more accounts under common ownership and
9 control have access to a 900 MW portfolio of generation, up to 100 percent of its
10 preceding year total annual energy consumption for participating accounts. If
11 customer interest exceeds available capacity, GPC proposes to allocate available
12 capacity on a pro-rata basis to customers who complete the notice of intent ("NOI")
13 process.
- 14 • **CARES New Load:** GPC proposes to offer 500 MW of generation to customers
15 with additional new load of 15 MW or greater on a first-come, first-served basis.
- 16 • **CARES Municipalities, Universities, Schools, and Hospitals ("MUSH"):** GPC
17 proposes to offer 50 MW of generation for subscription by MUSH customers with
18 an aggregate annual peak demand of 1 MW to 3 MW. If customer interest exceeds
19 available capacity, GPC proposes to allocate available capacity on a pro-rata basis
20 to customers who complete the NOI process.
- 21 • **CARES Carbon Free Energy-Around the Clock ("CFE-ATC"):** GPC proposes
22 to offer renewable resources paired with battery storage to optimize delivery of

1 renewable energy during all hours of the day. GPC proposes to offer up to a 100
2 MW block for subscription, supplied by energy from up to 650 MW of renewable
3 resources in addition to the supporting battery storage resources. GPC proposes
4 that customers receive both energy and capacity credits based on their subscription
5 level. The proposed minimum annual peak for participation is 25 MW at one or
6 more accounts under common ownership and control, up to 100 percent of their
7 preceding year's total annual energy consumption. If customer interest exceeds
8 available capacity, GPC proposes to allocate available capacity on a pro-rata basis
9 to customers who complete the NOI process.

- 10 • **CARES Economic Development:** GPC proposes to offer this subset as
11 incremental to the New Load subset for customers adding new load 50 MW or
12 greater. *See* IRP 14.4, page 14-106 to page 14-108.

13 **Q. WHAT SUBSCRIPTION OPTIONS DOES THE COMPANY PROPOSE?**

14 A. The Company proposes two subscription options: 1) a monthly subscription in which
15 the customer pays a \$/MWh customer participation charge and receives hourly energy
16 credits based on the actual production of the resources supplying the portfolio; and 2)
17 a monthly subscription based on a fixed cost per MWh determined at the time of
18 contracting. The Company also proposes to continue the \$5,000 NOI participation fee.
19 *Id.*, page 14-108 to page 14-109.

20 **Q. DOES THE COMPANY PROPOSE TREATMENT FOR ANY**
21 **UNSUBSCRIBED CARES CAPACITY?**

1 A. The Company proposes that unsubscribed portions of the Existing, New, and MUSH
2 subsets be procured to serve all GPC customers. *Id.*, page 14-109.

3 **Q. WHAT IS THE COMPANY'S PROPOSED PROCUREMENT TIMETABLE?**

4 A. My understanding is the Company proposes to issue three RFPs as part of the proposed
5 renewable procurement in this docket. The first proposed RFP would be issued in 2023
6 for 1,050 MW of utility scale resources in North Georgia to come online in 2026 and
7 2027 and 100 MW of distributed generation resources to come online in 2024. The
8 second proposed RFP would be in 2024 for distributed generation resources to come
9 online in 2025. The final proposed RFP would be in 2025 for 1,050 MW of utility
10 scale resources to come online in 2028 and 2029. The Company also proposes
11 petitioning the Commission between IRP cycles for approval of additional
12 procurements for the CARES Economic Development subset. *See* Direct Testimony
13 of Jeffrey R. Grubb, A. Wilson Mallard, Michael B. Robinson, and Jeffrey B. Weathers,
14 page 40, line 15 to line 19.

15 **Q. HOW DOES THE COMPANY PROPOSE TO DEFINE UTILITY SCALE AND**
16 **DISTRIBUTED GENERATION RESOURCES?**

17 A. The Company proposes to define utility scale as resources greater than 6 MW AC, and
18 distribution generation as resources between 250 kW AC and up to 6 MW AC. *Id.*,
19 page 41, line 3 to line 5.

20 **Q. WHAT ADDITIONAL SUM DOES THE COMPANY PROPOSE FOR ITS**
21 **RFPS?**

1 A. The Company proposes an additional sum of \$7.50/kW AC of the procured amount
2 annually for each PPA entered into. *Id.*, line 8 to line 9. This translates to
3 approximately \$0.00342/kWh, or \$3.42/MWh, produced for a solar system with a
4 capacity factor of 25 percent.⁷

5
6 *Commercial Group Response*

7 **Q. HAVE YOU PREVIOUSLY TESTIFIED CONCERNING LARGE**
8 **COMMERCIAL AND INDUSTRIAL RENEWABLE ENERGY PROGRAMS**
9 **IN GEORGIA?**

10 A Yes. In the 2016 Georgia Power IRP case in Docket 40161, I proposed on behalf of
11 the Commercial Group that a tranche of renewable power be set aside for the
12 development of a large C&I renewable energy program. Ultimately, this proposal was
13 included in the stipulation reached by Georgia Power and other parties, which the
14 Commission approved in its final order in that docket. Following that order, the
15 Commercial Group worked closely with Georgia Power and Commission Staff in the
16 successful development of this initial large C&I program.

17 Next, in the 2019 Georgia Power IRP case in Docket 42310, I supported on behalf
18 of the Commercial Group Georgia Power's proposal to develop another 950 MW
19 tranche of renewable power for large C&I customers. Once again, this proposal was
20 included in the stipulation reached by Georgia Power and other parties, and approved
21 (and even expanded) by the Commission in its final order. Further, as with the 2016

⁷ 1 kW x 8760 hours x 25% = 2,190 kWh. \$7.50/kW AC / 2,190 kWh x 1,000 = \$3.42/MWh.

1 IRP case, members of the Commercial Group once again worked closely with Georgia
2 Power and Commission Staff in the successful development of that large C&I program.

3 **Q. DOES THE COMMERCIAL GROUP BELIEVE THESE LARGE**
4 **COMMERCIAL AND INDUSTRIAL RENEWABLE PROGRAMS**
5 **BENEFITED GEORGIA BUSINESSES?**

6 **A.** Yes. The following testimony I gave in the 2016 IRP case (Chriss Direct Testimony,
7 p.10) remains true today:

8 A large C&I program would unleash the power of private enterprise in
9 Georgia to expand the footprint of renewable energy in Georgia in a
10 cost-effective manner to the benefit of all ratepayers and citizens of
11 Georgia. . . . Building more renewable energy in Georgia will not only
12 ensure cleaner air for Georgians, but it will also attract sustainably
13 focused C&I industrial companies to the state. These companies will
14 promote economic development, create jobs, and provide additional tax
15 revenue for the state.

16 **Q. WHAT IS THE COMMERCIAL GROUP'S FEEDBACK ON THE**
17 **COMPANY'S PROPOSED CARES PROGRAM?**

18 **A.** The Commercial Group appreciates GPC's continued interest in supporting the
19 renewable and clean energy goals of its customers and the proposed resource
20 procurements and CARES program structure. The Commercial Group supports
21 Commission approval of the program, subject to the proposed change discussed below.

22 **Q. WHAT IS THE COMMERCIAL GROUP'S PROPOSED CHANGE TO THE**
23 **PROGRAM?**

24 **A.** The Commercial Group proposes that the portions of Existing, New, or MUSH
25 renewable procurements not subscribed by participating customers within each subset
26 be first offered to other CARES program subsets before being shifted to all customers.

1 This will maximize the opportunities for qualifying customers to participate in the
2 CARES program.

3 **Q. DOES THE COMMERCIAL GROUP HAVE ANY ADDITIONAL**
4 **RECOMMENDATIONS TO THE COMMISSION?**

5 A. Yes. The Commercial Group recommends that the Commission require GPC to work
6 with interested commercial and industrial customer stakeholders throughout the
7 CARES program design process.

8
9 **Resilience Asset Service Tariff and Demand Response Credit Tariff**

10 *Program Description*

11 **Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED**
12 **RESILIENCE ASSET SERVICE TARIFF ("RAST-1")?**

13 A. My understanding is that the Company proposes RAST-1 as an optional program
14 available to commercial and industrial customers in which the Company will provide
15 resilience service to the participating customer through a Company-owned DER,
16 including, but not limited to, natural gas, diesel, and solar generators, and battery
17 storage resources. The Company proposes to install, operate, and maintain the DER,
18 including operation during service outages. GPC proposes to include the DER costs in
19 rate base, with the cost of service of the asset, including fuel expenses, covered by
20 participating customers through an agreement with the Company. See IRP 9.2, page 9-
21 61.

1 **Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY’S PROPOSED**
2 **DEMAND RESPONSE CREDIT PROGRAM (“DRC-1”)?**

3 A. My understanding is the Company proposes DRC-1 as an optional tariff available to
4 commercial and industrial customers in which those customers will receive a credit on
5 their bill in exchange for Company use of a DER located behind the participant’s meter
6 for demand response purposes during system reliability events. *Id.*

7 **Q. DOES THE COMPANY PROPOSE CUSTOMER ELIGIBILITY**
8 **PROVISIONS?**

9 A. Yes. The Company states that the present design requires a resilience need of 1 MW
10 or greater, which may be aggregated from multiple load and assets subject to minimum
11 load and asset sizes of 250 kW each. GPC proposes to exclude Fixed Pricing
12 Alternative, Electric Arc Furnace, and Time of Use-Supplier Choice customers from
13 participation, and to limit Real Time Pricing customer participation to the Customer
14 Baseline Load portion of usage. Finally, GPC proposes to limit participation to
15 customers who also take service on RAST-1, limiting the pool of DER to those owned
16 by the Company. *See* Direct Testimony of Francisco Valle, Andy Phillips, Jeff Smith,
17 and Lee Evans, page 26, line 7 to line 16.

18 **Q. DOES THE COMPANY PROPOSE TO LIMIT DRC-1 PARTICIPATION TO**
19 **ASSETS THAT ARE CERTIFIED AND PERMITTED FOR NON-**
20 **EMERGENCY USE?**

21 A. Yes. *Id.*, page 27, line 4 to line 8.

1 **Q. HOW DOES THE COMPANY PROPOSE TO DETERMINE THE DRC-1**
2 **CREDIT VALUE?**

3 A. The Company proposes to determine the DRC-1 credit value based on the capacity
4 value of the demand response that will be recognized in the IRP. Additionally, the
5 Company proposes three tranches of demand response value based on the duration of
6 expected response from different technologies. The tranches are proposed to be 8-hour
7 continuous response, 4-hour continuous response, and 2-hour continuous response. *Id.*,
8 line 10 to line 22.

9 **Q. DOES THE COMPANY PROPOSE DISPATCH LIMITATIONS FOR THE**
10 **PROGRAM?**

11 A. Yes. Other than as-needed dispatch for participant electric service outages, GPC
12 proposes to limit each system reliability dispatch event to 8 hours, with an annual total
13 dispatch of 200 hours. *Id.*, page 27, line 25 to page 28, line 2.

14 **Q. HAS THE COMPANY FILED PROPOSED RAST-1 OR DRC-1 TARIFFS OR**
15 **AGREEMENTS IN THIS DOCKET?**

16 A. No. The Company states in testimony that the tariffs would be developed and
17 submitted for Commission review and approval following the approval of the programs
18 in this docket. *Id.*, page 28, line 5 to line 8.

Commercial Group Response

Q. ARE THERE WAYS IN WHICH LARGE COMMERCIAL CUSTOMERS CAN HELP A UTILITY STRENGTHEN ITS DISTRIBUTION SYSTEM DURING A SEVERE WEATHER EVENT?

A. Absolutely. Developing technologies and operational sophistication have positioned large commercial customers, like Walmart and other Commercial Group members, to be a valuable resource for utilities, first responders, and the community at large during critical weather events. Specifically, deployment of DER allows a utility to restore power, reduce outage times, and improve service reliability more efficiently and cost effectively.

Q. WHAT IS A DER?

A. DER, as defined by the National Association of Regulatory Utility Commissioners (“NARUC”), is

a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load.

See Kiera Zitelman, Advancing Electric System Resilience with Distributed Energy Resources: A Review of State Policies, NARUC, April 2020, at 6 (the “NARUC DER Article”).

Q. WHAT TYPE OF SUPPORT CAN DERs PROVIDE DURING EXTREME WEATHER EVENTS?

1 As discussed at some length in the NARUC DER Article, one of the many benefits of
2 DERs is helping to improve system reliability and resilience by providing a
3 dispatchable generation resource that supplies power when electricity from the utility
4 is no longer available. This generation resource can operate independently, for
5 example, by providing back-up generation for a large commercial customer, work in
6 conjunction with other generation resources or storage located within a defined
7 electrical boundary, also known as a microgrid,⁸ and/or inject power back onto the grid.

8 **Q. HOW DOES A CUSTOMER-SITED DISPATCHABLE GENERATION**
9 **RESOURCE HELP REDUCE RESTORATION COSTS AND ENHANCE**
10 **REILABILITY DURING EXTREME WEATHER EVENTS?**

11 **A.** A customer-sited dispatchable generation resource, whether operating alone or within
12 a microgrid, may help reduce restoration costs by essentially allowing one or more
13 customers to be self-sufficient during the restoration process. Restoring power after a
14 severe weather event like a hurricane is likely an extensive process that requires the
15 utility to prioritize areas that are impacted by an outage and dispatch their field
16 personnel accordingly. If a portion of the utility's large customers are being supplied
17 by power independently, it allows the utility to focus its efforts on other areas.
18 Providing a utility with this type of "breathing room" gives the utility flexibility to
19 mobilize more cost-efficient restoration plans that may not otherwise be available.

20 **Q. HOW DOES IT ENHANCE RELIABILITY?**

⁸ The Department of Energy defines a microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. These multiple DERs may include small fossil generation, solar PV, and storage. See NARUC DER Article, page 17.

1 A. Speaking from the perspective of a large commercial customer who has extensive
2 operational experience during and after hurricanes, it is Walmart's experience that
3 utility personnel who are responsible for visiting sites and restoring the utility systems
4 require various supplies ranging from water to cell phones. It is important to Walmart
5 that it has the operational ability to serve these needs in order to ensure that field
6 personnel have what is required to restore the system and turn the lights back on for
7 everyone.

8 Moreover, it is not just utility employees who turn to Walmart and other large
9 commercial customers for necessary supplies. Walmart strives to be a leader in caring
10 for the needs of communities during times of tremendous hardship, like a hurricane or
11 other severe weather event. This includes providing supplies to first responders,
12 shelters, and citizens who live in the area and need everyday basics to live. Ensuring
13 that utility customers who provide essential services and critical supplies can remain
14 open and operational during and after a severe weather event enables that area to restore
15 faster, which in turn, makes the utility system more reliable and resilient.

16 **Q. DOES THE COMMERCIAL GROUP SUPPORT MONOPOLY UTILITY**
17 **PROVISION OF RESILIENCE TECHNOLOGIES TO CUSTOMERS?**

18 A. Generally, yes. The Commercial Group recognizes that DERs occupy a competitive
19 market space; however, the need for resilience products combined with a range of
20 operational and financial parameters and preferences across commercial customers can
21 justify options provided by the monopoly utility, so long as those options are not unduly
22 preferential and do not undercut competitive market options.

1 **Q. DOES THE COMMERCIAL GROUP OPPOSE COMMISSION APPROVAL**
2 **OF RAST-1?**

3 A. No. However, because much of the program structure has yet to be defined, the
4 Commercial Group recommends that the Commission require GPC to work with
5 interested commercial and industrial customer stakeholders throughout the program
6 design process.

7 **Q. DOES THE COMMERCIAL GROUP HAVE CONCERNS WITH THE**
8 **COMPANY'S PROPOSED DRC-1?**

9 A. Yes. The Commercial Group has two concerns with GPC's proposal to limit DRC-1
10 participation to RAST-1 participants. First, this limitation potentially creates undue
11 discrimination amongst similarly situated customers and undue preference for RAST-
12 1 versus competitive market options. Second, this limitation undercuts the system
13 reliability purpose behind DRC-1 by excluding DER that could be leveraged to benefit
14 the Company's system and all GPC customers.

15 **Q. PLEASE EXPLAIN HOW THE LIMITATION POTENTIALLY CREATES**
16 **UNDUE DISCRIMINATION AMONGST SIMILARLY SITUATED**
17 **CUSTOMERS.**

18 A. Simply, two commercial customers (or even two stores owned by the same corporate
19 parent) could be, from the utility system perspective, electrical twins, with similar load
20 size and usage patterns, service voltage and utility infrastructure, and the same size and
21 type of DER installed with same the response capabilities. GPC's proposal rests on
22 two differences: 1) one customer financed the DER through RAST-1 and one customer

1 deployed their own capital to finance the system, to which the utility system operation
2 is ultimately agnostic, and 2) the RAST-1 customer's DER is directly dispatched by
3 GPC and the other customer's DER requires notice to dispatch, which is a standard
4 industry practice. As an example, GPC's Demand Plus Energy Credit Rider has a
5 minimum 30-minute notice for customer response, and it could be reasonably
6 anticipated that both DRC-1 and the Demand Plus Energy Credit Rider would be called
7 to serve the same system reliability events.

8 Particularly if the compensation levels and structures differ significantly between
9 DRC-1 and other demand response opportunities for DER, the proposed participation
10 limitation, if approved, could unduly discriminate between RAST-1 and other similarly
11 situated customers. Additionally, if the compensation levels and structures are more
12 favorable for DRC-1, the proposed participation limitation, if approved, could create
13 undue preference for the RAST-1 program versus competitive market options.

14 **Q. WHAT IS THE COMMERCIAL GROUP'S RECOMMENDATION TO THE**
15 **COMMISSION ON THIS ISSUE?**

16 **A.** The Commercial Group does not oppose Commission approval of GPC's proposed
17 DRC-1 program, subject to the program being available to all DER, regardless of
18 ownership, that qualify per the operational parameters of the program. Similar to
19 RAST-1, the Commercial Group recommends that the Commission require GPC to
20 work with interested commercial and industrial customer stakeholders throughout the
21 program design process.
22

Demand Side Management Additional Sum

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED ADDITIONAL SUM FOR THEIR DSM PROGRAMS?

A. My understanding is the Company proposes the collection of an additional sum of 4 cents for every kWh saved using gross energy savings values for all residential and commercial DSM programs. Additionally, the Company proposes that if reported energy savings exceed 120 percent of a class's certified energy savings goal or as a portfolio during any year within the IRP cycle, the additional sum on the incremental savings of 120 percent would be 5 cents for every kWh saved. *See* Direct Testimony of Francisco Valle, Andy Phillips, Jeff Smith, and Lee Evans, page 21, line 3 to line 13.

Q. WHAT IS YOUR UNDERSTANDING OF THE REVENUE REQUIREMENT IMPACT OF THE COMPANY'S PROPOSED ADDITIONAL SUM?

A. My understanding is that the revenue requirement impact would be approximately \$17.2 million per year for 2023, 2024, and 2025, as shown in Table 1 below.

Table 1. Estimated Revenue Requirements from the DSM Additional Sum, 2023 to 2025.

Year	MWh Savings			Additional Sum Revenue Requirement, Total
	Residential	Commercial	Total	
2023	95,152	335,139	430,291	\$17,211,639
2024	95,830	335,139	430,969	\$17,238,755
2025	96,332	335,139	431,471	\$17,258,836

Source: 2022 IRP DSM Case Summary Data MG0.

1 **Q. ARE THESE AMOUNTS SIGNIFICANTLY HIGHER THAN RECENT**
2 **ADDITIONAL SUMS EARNED BY THE COMPANY?**

3 A. Yes. For years within the current IRP cycle (2020 to 2022), the Company has reported
4 earned additional sums for DSM of \$6.2 million in 2020 and \$7.8 million in 2021. See
5 STF-GDS-1-23 Attachment A.

6 **Q. IS THE ADDITIONAL SUM WELL IN EXCESS OF THE PROPOSED COST**
7 **PER KWH OF COMMERCIAL DSM?**

8 A. Yes. The Company's proposed cost per kWh saved of commercial DSM for 2023 is
9 1.36 cents/kWh, for 2024 is 1.38 cents/kWh, and for 2025 is 1.35 cents/kWh. See 2022
10 IRP DSM Case Summary Data MG0. As such, the Company proposed additional sum
11 is more than twice the proposed cost per kWh saved of commercial DSM programs.

12 **Q. DOES THE COMMERCIAL GROUP HAVE CONCERNS REGARDING THE**
13 **COMPANY'S PROPOSED ADDITIONAL SUM?**

14 A. Yes. The proposed additional sum of 4 cents/kWh is a significant cost adder to the
15 Company's proposed DSM programs and, in total, will result in more than double the
16 annual revenue requirement attributable to additional sum versus the Company's
17 reported additional sum earnings in 2020 and 2021. While the Commercial Group does
18 not dispute the importance of Georgia Power's DSM engagement, the Commission
19 should ensure that this work is done within the just and reasonable rate framework, and

1 not afford a profitability to those activities well above the Company's overall return or
2 return on other IRP initiatives.

3 **Q. IS THE PROPOSED ADDITIONAL SUM FOR DSM SIGNIFICANTLY**
4 **HIGHER THAN THE PROPOSED ADDITIONAL SUM FOR THE CARES**
5 **PROGRAM?**

6 A. Yes. Earlier in my testimony I estimated that the \$/kWh additional sum for the CARES
7 program is approximately \$0.00342/kWh. This is approximately 91 percent lower than
8 the Company's proposed additional sum for DSM of \$0.04/kWh.

9 **Q. WHAT IS THE COMMERCIAL GROUP'S RECOMMENDATION TO THE**
10 **COMMISSION ON THIS ISSUE?**

11 A. For the purposes of this docket and to limit bill increases to residential and commercial
12 customers, the Commercial Group recommends the Commission approve an additional
13 sum for DSM that, at 100 percent achievement of estimated results, does not increase
14 the resulting revenue requirement from the average of 2020 and 2021 additional sum
15 earned by the Company, or approximately \$7 million per year. See STF-GDS-1-23
16 Attachment A.

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

18 A. Yes.

1 BY MR. JENKINS:

2 Q Have you prepared a summary of your
3 testimony?

4 A I have.

5 Q Would you give it, please.

6 A Good afternoon. The Commercial Group members
7 are national and international businesses committed to the
8 use of cost-effective renewable energy is a key operational
9 and policy goal for Walmart itself. We are a member of the
10 Commercial Group. We are one of Georgia Power's largest
11 customers operating 214 retail units in seven distribution
12 centers in Georgia while employing over 70,000 associates in
13 the state.

14 For Walmart we have aggressive sustainability
15 goals to be supplied 100 percent by renewable energy by 2035
16 and have zero carbon emissions in our operations without
17 offsets by 2040, which includes the transition to low-impact
18 refrigerants for cooling and electric equipment for heating
19 by 2040 as well as transition of our transportation fleet.

20 So we talked about a number of different areas
21 within the case, and I'll just go through the
22 recommendations really quickly. The Commercial Group
23 supports approval of the Clean and Renewable Energy
24 Subscription program, or CARES. Subject to the approval of
25 the Commercial Group's proposal to first offer the portions

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1 of existing new or municipalities, universities, schools,
2 and hospitals renewable procurements not subscribed by
3 participating customers within those subsets to other CARES
4 program subsets before being shifted to all customers.

5 The Commercial Group recommends that the
6 Commission require Georgia Power to work with interested
7 commercial and industrial customer stakeholders throughout
8 the CARES design process.

9 Additionally, the Commercial Group does not
10 oppose Commission approval of Georgia Power's proposed
11 Resilience Asset Service Tariff, or RAST. However, because
12 much of the program structure has yet to be defined, the
13 Commercial Group also recommends that the Commission require
14 Georgia Power to work with interested commercial and
15 industrial customer stakeholders throughout the design
16 process.

17 Additionally, the Commercial Group does not
18 oppose the Commission approval of Georgia Power's proposed
19 demand response credit program subject to the program being
20 available to all distributed energy resources regardless of
21 ownership that qualify for the operational parameters of the
22 program.

23 Similar to the programs above, the Commercial
24 Group recommends that the Commission require Georgia Power
25 to work with interested commercial and industrial customer

1 stakeholders throughout the program design process.

2 And our final recommendation for the purposes
3 of this docket and to limit bill increases to residential
4 and commercial customers, the Commercial Group recommends
5 the Commission approve an additional sum for successful DSM
6 measures that at 100 percent achievement of estimated
7 results does not increase the resulting revenue requirement
8 from the average of 2020 and 2021 additional sum earned by
9 the company or approximately \$7 million per year.

10 And that concludes the summary.

11 MR. JENKINS: Very good. Mr. Chriss is
12 available for questioning.

13 COMMISSIONER McDONALD: Thank you. Georgia
14 Public Service Commission?

15 MR. THOMAS: Thank you, Mr. Chairman.

16 CROSS-EXAMINATION

17 BY MR. THOMAS:

18 Q So looking at your testimony, while you speak
19 about what you call "widely held concerns" about allowing
20 monopolies to enter competitive industries, you state that
21 a range of operational and financial parameters are -- and
22 preferences across commercial customers can justify
23 options provided by the monopoly.

24 Can you explain what financial parameters and
25 preferences you are referring to?

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1 A Sure. Can you give me the specific page
2 reference, just so we've got that on the record?

3 Q I'm sorry. I don't have that.

4 A Okay. I will find it. All right.

5 So we are looking at the bottom of page 19 of
6 my testimony. So when we look at operational and financial
7 parameters, there's a couple pieces in there. So, you know,
8 customers across the commercial customer space, which is the
9 space that we exist in and that I'm familiar with, customers
10 will have different access to capital to be able to deploy
11 projects on their own or different financing mechanisms.
12 They will have different risk preferences, whether or not
13 they want to take on the risk of asset ownership versus
14 having somebody else own it.

15 You know, operation of maintenance plays into
16 that as well. And so across customers or even within
17 customers you'll have a desire to have different options for
18 procurement of back-up generation. We see this for
19 ourselves because, you know, when we go for capital for
20 back-up generator, we're also competing with the same
21 capital that would go to build a new store or go to a store
22 expansion.

23 You know, customers have a lot of different
24 uses for capital, and so you can't always get that -- those
25 dollars for back-up generation. So when you have programs

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1 that can come through on the bill and be alternatively
2 financed, that can be attractive for customers. Will all
3 customers participate? Probably not.

4 And customers may do a mix. Some may have, you
5 know, a site where they look to do their own capital. They
6 may have a site where they look to participate in the
7 program. But it's important to have those options. I think
8 one of the -- one of the overarching themes that I hope the
9 Commission gets from the testimony is that resilience is a
10 big deal.

11 I know there was a comment earlier during one
12 of the testimonies that, you know, there hadn't been a
13 market study. But if you're -- if you're actually with
14 customers talking to them and don't -- you know, talking
15 through the issues that keep them up at night, resilience is
16 a huge one. Reliability as well. So whether from the grid
17 or from localized resources, if you're not thinking and
18 worried about reliability and resilience, you're not paying
19 attention to what's going on in the market right now.

20 So, you know, utilities don't tend to want to
21 spend time on the programs that customers don't want. So if
22 utilities are looking to offer these sorts of programs,
23 there's certainly customer demand for them.

24 Q Is the Commercial Group at all concerned
25 about undue preference or undercutting competitive market

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1 options if these tariffs are approved?

2 A Sure. I mean, there -- you definitely don't
3 want to have a program where, because of the advantages the
4 utility does have, where they're able to, you know, provide
5 preferential terms or pricing -- we talked about some of
6 that, too, in terms of the DRC tariff that they want to, you
7 know, attach only to RAST resources.

8 So it is important that the opportunity is
9 competitively neutral as possible to ensure that the market
10 can still function, and you're not locking out other
11 players.

12 Q Thank you.

13 A You're welcome.

14 COMMISSIONER McDONALD: You know the drill.

15 I'm not going through all these names. Who would
16 like to cross? Stand up if you want to cross.

17 Okay. Come forward.

18 CROSS-EXAMINATION

19 BY MS. BROWN:

20 Q Alicia Brown, Coalition of Local Governments.
21 So, Mr. Chriss, if I could direct you to page 6 of your
22 testimony. Specifically where you're talking about
23 utility partnerships.

24 A I'm there.

25 Q Okay. Can you speak to Walmart's paradigm
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1 for partnering with the utility on renewable energy
2 programs as listed in lines 1 through 4 of your testimony?

3 A Sure. So, yeah. To give you the high level,
4 essentially, we work with the utility partners across the
5 country to develop usable programs because, you know, you
6 don't want to develop a program that no one is going to use
7 and economic structures targeted to function within the
8 confines of the regulatory compact within that state -- I'm
9 happy to talk more about that -- and with minimal impact to
10 nonparticipating customers.

11 Q And specifically on that issue of minimal
12 impact to nonparticipating customers, you give multiple
13 examples of programs that you have had a role in
14 developing, and you specifically mention the SolarTogether
15 program in Florida?

16 A Um-hum.

17 Q Would you say that program is a good example
18 of one that has minimal impact on nonparticipating
19 customers?

20 A I think if you look at the program over the
21 lifespan of the resources, it's structured to not have
22 impact to other customers. The trick that you get into with
23 the programs down in Florida is that from a resource
24 perspective they are treating it like your traditional
25 rate-based rate of return resource.

1 So you get some in the early years, and so
2 you're dealing with that, but then you've levelized the cost
3 to the participants. And so in the early years, you do get
4 some squishy accounting where, if you look at it on a
5 year-by-year basis, you're going to have some
6 cross-subsidization within there. But by the -- but then
7 you have a crossover point, and then for the remainder of
8 the asset's life, it goes the other way.

9 So it is important to look at it over the
10 entire term of the program. Not just, you know,
11 cherry-picking sing- -- singular years. Sorry.

12 Q Of course. But we expect that those solar
13 farms to last 25 to 30 years?

14 A Yeah. I mean, that would be the hope. And the
15 program -- so SolarTogether, as it was initially proposed,
16 was intended to go for 30. The latest tariff that they have
17 published goes over 30 years.

18 Q So that program offers positive financial
19 opportunities to those who participate in it over -- over
20 time?

21 A It does. But those participants also take on
22 the risk of the resource. So the solar -- if the solar
23 resource doesn't produce, there is no credits issued. So
24 customers do take on that risk.

25 Q Sure. But would that risk be the same in any
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1 community solar program?

2 A Well, it's going to depend on how it's
3 structured. So for the Georgia Power program, in
4 particular, because of, you know, where we're sitting right
5 now, if the resource doesn't produce, the customer doesn't
6 pay for megawatt hours they don't get, because it's --
7 essentially, you pay for the megawatt hour, and then you
8 receive a credit based on when it liquidates against Georgia
9 Power System Lambda.

10 In Florida you pay a fixed per kW capacity
11 charge per month and then receive a per kWh credit which
12 they have based on their, I believe, on their long-term
13 avoided costs, so it's --

14 Q Are you sure you're speaking to the community
15 solar program and not the CARES program? Because I
16 believe community solar program has an upfront per
17 kilowatt charge.

18 A Oh. Oh, I apologize. So for -- I don't -- I'm
19 not familiar with the Georgia Power Community Solar Program.
20 We haven't participated in it. We are a participant in the
21 REDI program and are looking at the CARES program, but not
22 the Community Solar Program.

23 Q Why would you say you're not -- assuming that
24 they're now offering a commercial version of the community
25 solar program, why are you not intending to participate?

1 A Because at the scale that we operate at under
2 Georgia Power, we are looking at the largest -- basically,
3 the largest scale per terms that we can.

4 Q And the community solar program in Florida,
5 that's a much larger program. Would you say that gives it
6 more favorable economics?

7 A Yeah. I mean, bigger economics and more
8 resources -- bigger resources definitely have economies of
9 scale for the resources that they're able to put in there.

10 Q To summarize, would you say that the Florida
11 model does show the investor-owned utility can provide
12 financial benefits without cross-subsidization just based
13 on ideal sizing and program design measures?

14 A Essentially, yes. And it's going to be those
15 aspects of it that are critical, you know, when you're
16 working through program design to get right.

17 Q All right. Thank you so much.

18 A You're welcome.

19 COMMISSIONER McDONALD: Anybody else?

20 (No response.)

21 COMMISSIONER McDONALD: Georgia Power?

22 MR. MARZO: Thank you, Commissioner.

23 CROSS-EXAMINATION

24 BY MR. MARZO:

25 Q I did want the opportunity to say "hello" to
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1 Mr. Chriss, so I only get to see him, I think, at these
2 hearings every three years. Good to see you again,
3 Mr. Chriss.

4 A Good to see you.

5 Q And also to get to antagonize Mr. Jenkins.

6 I have got a few questions for you. A lot of
7 my questions were answered, or asked and answered already,
8 so I'll avoid those.

9 But in this case, you recommended the
10 Commission require that Georgia Power work with the
11 Commercial Group members on the CARES program development
12 design process; is that correct?

13 A That's correct.

14 Q Okay. And isn't it fair to say that Georgia
15 Power and the Commercial Group members have previously
16 worked closely together on the development and design of
17 renewable energy programs?

18 A Absolutely. It's really a recommendation for
19 the continuation of that momentum.

20 Q And I was just going to point out -- I mean,
21 I think even in the past you've noted the success that
22 you've had working with us both in the REDI C&I program as
23 well as the CRSP program most recently; is that correct?

24 A That's correct.

25 Q Okay. And is it your expectation that, based
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1 on your experience with working with Georgia Power in the
2 past, that we'll be able to work together again as we look
3 forward to the CARES program?

4 A That's correct.

5 Q Okay. I just had a couple of questions
6 related to your additional sum recommendation. And I
7 believe your position is that the additional sum requested
8 in this case is significantly higher than the additional
9 sum in 2020 and 2021; is that correct?

10 A That's correct.

11 Q Okay. And I don't know if you heard the
12 testimony earlier this morning from Miss Barber, but is it
13 your understanding, obviously, that 2020 and 2021 were
14 COVID-impacted years?

15 A That's my understanding.

16 Q Okay. And do you take into account the
17 impact that the COVID effect would have had on additional
18 sum for those years?

19 A I mean, I understand that the impact is there.
20 I think, you know, the perspective that the Commercial Group
21 is bringing to the table on this particular issue is that
22 we're already experiencing a lot in terms of rate
23 increases we've -- and then Georgia Power has the rate case
24 coming up -- that we have a lot of concern about the costs
25 going through -- that are hitting our bills.

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1 And so, you know, to the extent that there's
2 cost driving, what's going to increase our bills, that's one
3 thing. But the concept of the additional sum, where you're
4 taking sort of the profit level on these programs and then
5 increasing that, it -- right now that's a much harder pill
6 to swallow, just because of what we're having to face, the
7 cost pressures that we're seeing.

8 And so, ultimately, you know, we understand the
9 concept of the additional sum, why it's out there, why the
10 state has proposed it, and why they believe it's good
11 policy. But we just would caution the Commission in its
12 consideration of how it sets additional sum in this case
13 to -- to think deeply about the customer impacts, especially
14 because it's going to be -- that would be a rate increase on
15 top of other rate increases this year.

16 Q And I appreciate that, Mr. Chriss, and as
17 we -- as we think through that and talk through how best
18 to set the additional sum, obviously based on the statute,
19 would you agree with me, though, at least, as you looked
20 at those two years, those two years may not be the best
21 thing to look at as an example of what additional sum
22 should be set at, taking into account all the things you
23 just said?

24 A I mean, certainly, the COVID years have had --
25 have created some mathematical noise or dissonance within

1 the calculation of a number of different, you know, rates
2 and regulatory structures. But, you know, again, for us, it
3 just comes down to the cost and what we're getting for what
4 we're paying on our bills.

5 MR. MARZO: Okay. I appreciate that,
6 Mr. Chriss. That's all the questions I have,
7 Commissioner McDonald.

8 COMMISSIONER McDONALD: Thank you.
9 Mr. Jenkins, any redirect?

10 REDIRECT EXAMINATION

11 BY MR. JENKINS:

12 Q Yeah, I think just one. Do you have any
13 opinion as to the cost of the additional sum versus the
14 cost of the program itself for commercial customers?

15 A So I address that on page 23,
16 lines 8 through 11.

17 So my understanding of the company's proposed
18 cost per kWh saved of commercial DSM for 2023 is 1.36 cents
19 per kilowatt hour. For '24 is 1.38 cents per kilowatt hour.
20 And for 2025 is 1.35 cents per kilowatt hour. So an
21 additional sum of 4 cents is well in excess of the actual
22 costs to save energy.

23 MR. JENKINS: Thank you. Nothing further.

24 We would move Commercial Group Exhibit 1 into
25 the record.

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1 COMMISSIONER McDONALD: So record.

2 MR. JENKINS: Thank you.

3 (The document referred to was marked for
4 identification as Commercial Group Exhibit 1.)

5 MR. JENKINS: Thank you. And we'd ask
6 Mr. Chriss be excused for other things.

7 COMMISSIONER McDONALD: You may be excused.

8 WITNESS CHRISS: Thank you.

9 COMMISSIONER McDONALD: Concerned Ratepayers of
10 Georgia?

11 (No response.)

12 COMMISSIONER McDONALD: I'll say it twice.
13 Concerned Ratepayers of Georgia? Mr. Baker?

14 MR. BAKER: I'm going to go find my lost
15 client.

16 COMMISSIONER McDONALD: You are about to really
17 lose him.

18 Okay. We will move forward.

19 Cypress Creek Renewables?

20 MR. STAIR: Thank you, Commissioner.

21 On behalf of Cypress Creek Renewables, we'd
22 like to call Matthew Kozey to the stand.

23 COMMISSIONER McDONALD: Will you swear your
24 witness.

25 Thereupon,

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MATTHEW KOZEY,
having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. STAIR:

Q And, Mr. Kozey, could you please state your
full name for the record.

A Sure. Matthew Kozey.

Q And by whom are you employed?

A Cypress Creek Renewables.

Q And what is your job title at Cypress Creek,
and what are your job responsibilities?

A I'm the director for community scale markets,
and my responsibilities include development of policy and
advocacy for policy that supports community scale markets
for solar across the U.S.

Q And on May 6 of this year, did you file or
cause to be prefiled 7 pages of direct testimony in
question and answer format?

A Yes, I did.

Q Do you have any corrections to be made to
that testimony today?

A No.

Q And if I were to ask you the same questions
contained in your prefiled testimony, would your answers
be the same?

1 A Yes, they would.

2 MR. STAIR: Sir, I'd ask that Mr. Kozey's
3 prefiled testimony be copied into the record as if
4 given orally from the stand today.

5 COMMISSIONER McDONALD: So record.

6 (Whereupon, the prefiled direct testimony
7 of Matthew Kozey was entered into the record.)
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Introduction

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

A. My name is Matthew Kozey. My business address is 5310 S. Alston Ave. Bldg. 300, Durham, NC 27713. I am currently the Director for Community-Scale Markets at Cypress Creek Renewables.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Cypress Creek Renewables ("Cypress Creek" or "CCR"). Cypress Creek develops, finances, owns and operates utility-scale and community-scale solar and energy storage projects across the United States. Cypress Creek has developed more than 11 gigawatts of solar projects since its inception, and today it owns 1.7 gigawatts and operates 3.9 gigawatts of solar projects.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I joined Cypress Creek as the Director for Community-Scale Markets in April of 2020, focusing on policy development and policy advocacy across the United States. Prior to my time with Cypress Creek, I held several positions with the electric utility Pepco Holdings. I joined Pepco Holdings in 2013 as a Regulatory Strategy Policy Lead, drafting testimony and compiling data for regulatory reporting on behalf of the Power Delivery group. From 2016 to 2018, I served as the Manager of Regulatory Affairs for the District of Columbia, overseeing Pepco's regulatory activity before the Public Service Commission of the District of Columbia. I served as Pepco Holdings Communications Manager from January 2018 to April 2020, developing and executing integrated communications strategies for Pepco in the District of Columbia and

1 Maryland. Prior to joining Pepco, I worked as an analyst and project manager for a
2 non-profit research firm and spent time as a legal fellow on a U.S. House of
3 Representatives Subcommittee staff. I earned a Bachelor of Arts in Political Science
4 and a Juris Doctor from the University of North Carolina at Chapel Hill.

5 **Q. DO YOU HOLD ANY MEMBERSHIPS RELEVANT TO THE ISSUES**
6 **BEFORE THE COMMISSION FOR CONSIDERATION IN THIS DOCKET?**

7 A. Yes. Cypress Creek is a member of the Solar Energy Industries Association.

8 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE**
9 **GEORGIA PUBLIC SERVICE COMMISSION ("COMMISSION")?**

10 A. No. I am pleased to offer this testimony as my first before the Commission.

11 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER**
12 **STATE REGULATORY COMMISSIONS?**

13 A. Yes. I have submitted testimony on behalf of Pepco at the Public Service Commission
14 of the District of Columbia. My testimony addressed Pepco's communications and
15 education plans related to the DC Power Line Undergrounding Initiative (DC PLUG).
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Purpose of Testimony and Recommendation

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address aspects of Georgia Power Company's Integrated Resource Plan ("IRP") filing, specifically on opportunities for Georgia Power and the Commission to build on prior successful programs to bring benefits of community solar to customers by sharing CCR's experiences in other similarly regulated markets across the country.

Q. WHAT IS COMMUNITY SOLAR?

A. Community solar is a renewable energy development and billing arrangement in which solar installations sited on the distribution system allow for electric customers to save money on their bill by purchasing shares, or "subscriptions", of the facility's output at a discount. Community solar enabling regulations often share key elements, notably the identification of value that community solar facilities provide to the grid and to ratepayers in a tariffed rate.

Q. WHAT BENEFITS DO COMMUNITY SOLAR FACILITIES PROVIDE TO THE GRID AND TO RATEPAYERS?

A. Community solar facilities create value for the grid and ratepayers in multiple ways. Specifically, community solar facilities:

- offset the need to generate energy elsewhere (avoided energy costs);
- reduce the generation capacity that the system needs to procure (avoided capacity costs);

- reduce strain on the transmission and distribution systems, and therefore reduce the expense customers would otherwise see in rates for capital improvements (avoided transmission and distribution costs); and,
- reduce the emissions of the generating fleet by displacing (generally) older and higher-emitting peaking plants through generating and delivering energy during peak load periods (environmental value).

While a community solar facility's avoided cost benefits differ depending on the market, there are tried and true methods for quantifying the avoided costs benefits a project can deliver to the grid and to customers, based on robust input from utilities, ratepayer advocates, third-party consultants, and industry stakeholders. There are multiple ways to quantify the benefits of community solar to the grid and to ratepayers (both subscribers and non-subscribers), but the cornerstone of successful community solar is to offer guaranteed savings to customers who choose to subscribe – and that is what Cypress Creek is excited to discuss further in this proceeding.

Q. ARE COMMUNITY SOLAR FACILITIES RELIABLE?

A. Yes. Solar facilities are an important part of a reliable grid.¹ Beyond reliable blue-sky performance, community solar facilities in particular present an opportunity to increase system resilience based on their location on the distribution system, especially when paired with battery storage. Specifically, “[o]n the resiliency front, community solar creates an opportunity for co-siting community-scale storage. This can help keep the

¹ <https://e360.yale.edu/features/three-myths-about-renewable-energy-and-the-grid-debunked>

1 power on during a grid outage — but now at a community-accessible site, rather than
2 an individual home.”²

3 **Q. DO COMMUNITY SOLAR POLICIES EXIST IN SIMILARLY REGULATED**
4 **MARKETS?**

5 A. Yes. Multiple states with vertically integrated electric utilities have enacted community
6 solar enabling policy, including Colorado,³ Virginia,⁴ and New Mexico.⁵ The
7 regulations currently under development in New Mexico offer opportunities for sharing
8 of best practices with the Commission, as the regulatory structure of the New Mexico
9 electricity market is similar in many ways to that in Georgia (vertically integrated
10 investor-owned utilities operating alongside other electricity providers like electric
11 membership corporations and municipally owned electric systems).

12 **Q. WHAT ARE THE KEY PROPOSED ELEMENTS OF THE NEW MEXICO**
13 **REGULATIONS?**

14 A. The New Mexico regulations, which are being promulgated pursuant to legislative
15 action, contain several foundational elements that would be of interest to this
16 Commission. Specifically, the regulations will create a bill credit rate equal to the “total
17 aggregate retail rate less distribution cost components and fixed charges”, support

² See “California’s omission of community solar from distributed energy policies is shortsighted,” Duncan Callaway, associate professor in the Energy and Resources Group at the University of California, Berkeley and Anna Brockway, PhD candidate, Utility Dive, 2022.

<https://www.utilitydive.com/news/californias-omission-of-community-solar-from-distributed-energy-policies-i/618451/>

³ <https://co.my.xcelenergy.com/s/renewable/developers/community-solar-gardens>

⁴ <https://www.scc.virginia.gov/pages/Shared-Solar>

⁵ <https://www.nm-prc.org/utilities/community-solar/>

1 access for low- to moderate-income (LMI) customers to community solar, and will
2 provide for both utility and third-party ownership of community solar facilities.⁶

3 **Q. WHAT IS CCR'S RECOMMEDATION?**

4 A. Discussion of community solar enabling policies can and should be pursued in tandem
5 with existing pathways for deploying low-cost energy sources for Georgia consumers.
6 With inflation hitting record highs across the country and in Georgia,⁷ Cypress Creek
7 recommends hearing from interested parties in this proceeding regarding the role
8 community solar can play in the state's energy mix.

9 While Georgia Power has proposed removing the avoided cost ceiling for bids, thereby
10 allowing flexibility in selecting projects that exceed the Avoided Cost, Georgia Power's
11 avoided cost remains "the critical evaluation metric in determining the value to
12 customers of renewable resource additions." In developing the RFP, Cypress Creek
13 recommends that Georgia Power and the Commission consider that Long-Term
14 Avoided Cost does not accurately reflect all the benefits DG-sited renewables provide
15 to the grid. The benefits provided by DG-sited renewables, for which they should be
16 compensated, include avoided energy and capacity costs, avoided transmission and
17 distribution infrastructure investment, and price suppression in the form of lower
18 energy and capacity prices.

19 Cypress Creek believes that any RFP should consider some of the benefits that DG-
20 sited renewables can provide, such as direct community benefits and project siting to

⁶ <https://www.nm-prc.org/wp-content/uploads/2022/04/Community-Solar-Order-Adopting-Rule.pdf>

⁷ <https://www.ajc.com/news/atlanta-news/atlantas-inflation-tops-10-higher-than-national-average/LTFA4SH6NFEOLJX57T43RKGBMQ/>

1 best address grid constraints or capacity availability. A community solar framework is
2 better positioned to account for such benefits as well as others that are not possible
3 through a utility PPA offtake framework. Additional benefits possible via a community
4 solar structure include capacity carve-outs for LMI subscribers, an electricity bill
5 discount for LMI subscribers that is required or rewarded via RFP points, workforce
6 training programs, and others.

7 Cypress Creek also recommends that the RFP include project maturity requirements
8 for participation. Without such requirements, there is a risk that projects selected into
9 the program encounter a "fatal flaw" through further development and engineering that
10 render them inviable and results in their not being built.

11 Cypress Creek is excited to collaborate with the Commission, ratepayer advocates, and
12 Georgia Power to find innovative ways to reduce customers' bills while spurring
13 economic growth.

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

15 **A.** Yes, it does.

1 BY MR. STAIR:

2 Q And, Mr. Kozey, you did not attach any
3 exhibits to your testimony; is that correct?

4 A No, I did not.

5 Q And do you have a summary of your testimony
6 that you are prepared to give at this time?

7 A Yes.

8 MR. STAIR: And with your permission,
9 Commissioner, I would ask Mr. Kozey to give a
10 summary.

11 WITNESS KOZEY: Thank you, Commissioners. I
12 appreciate the opportunity to be here today.

13 I am testifying today on behalf of Cypress
14 Creek Renewables. Cypress Creek Renewables develops,
15 finances, owns, and operates utilities and community
16 scale solar facilities and storage projects across
17 the U.S.

18 Cypress Creek has developed more than
19 11 gigawatts of solar projects since our inception,
20 and today we own 1.7 gigawatts and operate
21 3.9 gigawatts of solar projects across the
22 United States.

23 As I said before, I'm the director for
24 community scale markets. My focus is to introduce
25 Cypress Creek to the Georgia Commission and to you

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1 all and address -- excuse me -- a few aspects of
2 Georgia Power's IRP filing, specifically,
3 opportunities for Georgia Power and the Commission to
4 build on prior successful programs in deploying
5 solar, to bring cost savings to customers, and other
6 benefits of community solar by sharing some of our
7 experiences in other similarly regulated markets.

8 Additionally, I like to emphasize our support
9 for Georgia Power's proposed modification to the
10 DG-RFP cost assessments, notably going from a strict
11 avoided cost ceiling to a best-cost methodology.
12 While the details remain critical here, an open and
13 transparent discussion of benefits of renewables on
14 the system is a very promising proposal, and we
15 support it. This would provide additional commercial
16 certainty, and ultimately, I think we would see
17 additional megawatts being deployed through these
18 RFPs.

19 I would also like to note our support for
20 staff's proposal to include a renewable energy credit
21 in the renewable cost benefit framework. Capturing
22 in a transparent and, again, full view the entirety
23 of the benefits of distribution-sited solar like
24 community solar is critical to identifying the best
25 cost future resource mix. And with that, I would

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1 conclude my prepared testimony.

2 MR. STAIR: Thank you, Mr. Kozey. The witness
3 is available for questions from commissioners and
4 cross-examination.

5 COMMISSIONER McDONALD: Commissioners?

6 (No response.)

7 Public Service Commission?

8 MR. THOMAS: No questions.

9 COMMISSIONER McDONALD: Anyone have questions?

10 (No response.)

11 Anyone have questions?

12 (No response.)

13 COMMISSIONER McDONALD: No questions. Thank
14 you.

15 It will be made part of the record.

16 MR. STAIR: Just ask that Mr. Kozey be excused.

17 COMMISSIONER McDONALD: He may be excused.

18 Thank you.

19 WITNESS KOZEY: Thank you.

20 COMMISSIONER McDONALD: We'll have Georgia
21 Association of Manufacturers.

22 MR. BAKER: Chairman McDonald, I found
23 my client.

24 COMMISSIONER McDONALD: He goes to the back of
25 the bus, Mr. Baker.

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1 MR. BAKER: All right, sir.

2 COMMISSIONER McDONALD: That will be after

3 Mr. --

4 MR. BAKER: -- Mahan or Goggin.

5 COMMISSIONER McDONALD: Goggin, yes. Unless he
6 wants to appeal to the chairperson, and she can make
7 adjustments, if necessary.

8 Georgia Association of Manufacturers, where are
9 you?

10 (No response.)

11 COMMISSIONER McDONALD: Georgia Center for
12 Energy Solutions?

13 MR. BAKER: I'm helping out Mr. Hubbard, so...

14 COMMISSIONER McDONALD: Okay.

15 MR. BAKER: All right. Mr. Hubbard, would you
16 please come and take the stand. Would you stand and
17 raise your right hand.

18 Thereupon,

19 PETER HUBBARD,
20 having been duly sworn, testified as follows:

21 DIRECT EXAMINATION

22 BY MR. BAKER:

23 Q All right. Would you please be seated.

24 Would you please state your name, business
25 affiliation, and business address for the record, please.

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1 A My name is Peter Hubbard. I work for the
2 Georgia Center for Energy Solutions, 55 Leslie Street, SE,
3 Atlanta, Georgia 30317.

4 Q All right. And are you appearing on behalf
5 of the Georgia Center for Energy Solutions today?

6 A I am.

7 Q And did you cause to be filed 25 pages of
8 prefiled testimony in question and answer format on May 6
9 of this year in these dockets?

10 A I did, along with 17 exhibits.

11 Q All right. And do you have any corrections
12 to either your prefiled testimony -- oh, let me just ask
13 you.

14 If I asked you the questions contained in your
15 prefiled testimony today, would your answers be the same?

16 A Yes.

17 Q All right. Do you have any corrections to
18 either your prefiled testimony or to any of your exhibits?

19 A I do not.

20 Q Thank you.

21 MR. BAKER: Mr. Chairman, I'd ask that
22 Mr. Hubbard's prefiled testimony and exhibits be
23 copied into the record as if read from the stand,
24 subject to cross-examination.

25 And I would ask that his exhibits be identified
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**DIRECT TESTIMONY OF
PETER HUBBARD
ON THE 2022 INTEGRATED RESOURCE PLAN**

I. INTRODUCTION

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

2 A. My name is Peter Hubbard. I am a Clean Energy Advocate with the Georgia Center
3 for Energy Solutions, Inc. ("GCES"). My business address is 55 Leslie Street SE,
4 Atlanta, Georgia 30317.

6 **Q. PLEASE DESCRIBE YOUR ORGANIZATION.**

7 A. GCES seeks to develop an economic and regulatory framework to transition
8 Georgia's electric, transportation, buildings, and agriculture sectors to a 100%
9 clean energy (zero-carbon) future in an equitable, reliable, resilient, sustainable,
10 rapid, and economically efficient manner and in furtherance of the public benefit.

12 **Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL
13 EXPERIENCE.**

14 A. I hold two Bachelor of Science degrees in Physics and Mathematics and one
15 Bachelor of Arts degree in French from the University of Memphis. I also hold one
16 Master of Arts degree from the Johns Hopkins University School of Advanced
17 International Studies in International Affairs with two Concentrations in
18 International Economics and Energy, Resources, and Environment and one
19 Specialization in Quantitative Methods and Economic Theory.

21 My professional experience is in energy management consulting focused on electric
22 utility Integrated Resource Plan ("IRP") project management, organized power
23 market analysis in North America, global gas market analysis, commodity price
24 projections, stochastic risk analysis, future scenario development, strategic

1 management consulting, capacity expansion modeling, production cost modeling,
2 new technology assessment, and general economic feasibility of clean energy
3 systems. I have 13 years of professional experience in the energy sector.
4

5 **Q. MR. HUBBARD, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
6 **GEORGIA PUBLIC SERVICE COMMISSION?**

7 A. I have previously filed direct testimony and given an oral summary of my direct
8 testimony related to Georgia Power Company's 2019 Integrated Resource Plan
9 before the Georgia Public Service Commission ("Commission") in Docket No.
10 42310.
11

12 **Q. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR**
13 **TESTIMONY?**

14 A. Yes. I am sponsoring the following exhibits:

- 15 • Exhibit GCES-01, Peter Hubbard's Curriculum Vitae
- 16 • Exhibit GCES-02, Record High Percentage of Renewable Generation
- 17 • Exhibit GCES-03, Total System Costs by Scenario
- 18 • Exhibit GCES-04, Annual Fuel Costs Comparison
- 19 • Exhibit GCES-05, Map of Proposed Gas PPAs
- 20 • Exhibit GCES-06, Company Affiliations
- 21 • Exhibit GCES-07, Purchased Power Cost Comparison
- 22 • Exhibit GCES-08, Uneconomic unit commitment
- 23 • Exhibit GCES-09, Rate Impact by Scenario
- 24 • Exhibit GCES-10, Company Reliability Metrics
- 25 • Exhibit GCES-11, Reserve Margin Comparison
- 26 • Exhibit GCES-12, System Exports
- 27 • Exhibit GCES-13, Coal Unit Underinvestment
- 28 • Exhibit GCES-14, AEO Price Outlooks
- 29 • Exhibit GCES-15, Gas Pipeline OFOs

- Exhibit GCES-16, ELCC and LCOE Comparison
- Exhibit GCES-17, States Mentioned in Oral Hearings

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Georgia Center for Energy Solutions.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is to lay out my findings from a detailed review of the 2022 IRP and demonstrate that Georgia Power Company's (the "Company") 2022 IRP fails to adequately demonstrate the economic, environmental, and other benefits to the state and to customers of the utility, as required by the Official Code of Georgia Annotated (O.C.G.A.) § 46-3A-2. In addition, the 2022 IRP fails to meet the requirements of Commission Rule 515-3-4-.05, which states that a Base Case IRP be "based on the most economic and reliable combination of demand and supply-side resources" while "minimizing customer bills, minimizing overall rates and maximizing net societal benefit." I present my findings in the form of a listing of fatal flaws and red flags that I have identified along with comments on what is in the best interests of Georgia and Customers of the Company. Given these findings, it is my recommendation that the Commission require the Company to produce a new IRP (and related studies that are specifically identified in this direct testimony) that fully meets the requirements of Georgia law and the Commission's rules, and which adequately addresses the concerns raised in this direct testimony.

Q. ARE THE RENEWABLE INTEGRATION PLAN AND FLEET TRANSITION PLAN PROPOSED IN THE 2022 IRP ACTION PLAN IN THE BEST INTERESTS OF GEORGIA AND CUSTOMERS OF THE COMPANY?

A. No, they are not. The Company is proposing to add 2,100 MW of utility scale solar to be online by 2029 (IRP 1-14), with a similar tranche in the next IRP to be online

1 by 2032, and so on, with a total of 6,000 MW incremental renewable capacity by
2 2035. This very long deployment schedule results in a higher-cost Proposed
3 Portfolio through continued uneconomic coal plant operations. The lagged schedule
4 also subjects Customers to significant and avoidable fuel commodity cost and price
5 volatility risk from a fossil-heavy portfolio. It subjects the System to correlated fuel
6 shortage risks. It continues to grow the \$8.99 billion and rising liability for Coal
7 Combustion Residuals Asset Retirement Obligation ("CCR ARO") that the
8 Company is asking to recover from Customers. And it puts upward pressure on
9 Customer rates. Rather, it is in the interests of Georgia and Customers of the
10 Company to accelerate the transition to the lowest cost generation resource, which
11 is utility-scale and distributed solar photovoltaics, as well as batteries, solar+storage
12 (also called Battery Energy Storage System + Charging Solar or "BESS+CS"),
13 energy efficiency, demand side management, and other resource options that will
14 put downward pressure on Customer rates.

15
16 **Q. IS IT POSSIBLE TO ACCELERATE RENEWABLE ENERGY**
17 **INTEGRATION ON THE SYSTEM EVEN FASTER THAN PROPOSED BY**
18 **THE COMPANY?**

19 **A.** Yes, it is possible to accelerate the integration of renewable energy on the System
20 ("System") (the Integrated Transmission System or tight electricity pool to which
21 Georgia belongs) without sacrificing reliability and, in fact, likely improving
22 currently poor reliability. Georgia Power Company and its Operating Company
23 affiliates have a low renewable penetration rate compared to most other organized
24 power markets in the United States and they have a similar poor ranking in terms
25 of record renewable generation in an hour (GCES Exhibit 02). This same exhibit
26 also demonstrates that it is technically feasible for renewable penetration rates to
27 reach 100% on the System, as was very recently reported in California. The barriers
28 to faster renewable energy integration are not technical. The barriers are embedded
29 in the 2022 IRP that the Company has put forward seeking approval.

1 Q. IS THE COMPANY'S PROPOSED PORTFOLIO IN THE BEST
2 INTERESTS OF GEORGIA AND CUSTOMERS OF THE COMPANY?

3 A. No, it is not. The Company is proposing the Moderate Gas, \$0 Carbon ("MG0")
4 case as its Base Case, which serves as the basis for the Proposed Portfolio. The
5 Proposed Portfolio includes the Chapter 19 Action Plan and all the requested
6 approvals in the Conclusion of Chapter 1. However, the Company acknowledges
7 that "continuing to invest in these [coal and oil] units for the long-term increases
8 the risk of new environmental compliance costs" (IRP 1-5). Gas units are subject
9 to many of the same cost risks that coal and oil units are subject to, including fuel
10 price volatility and carbon pricing. Gas units are subject to additional risks like
11 upstream methane leakage accounting that could exceed the cost risk to coal and
12 oil units. This conclusion is reached by the Company's own modeling which shows
13 significant upside risk to Total System Cost from high gas prices and any carbon
14 price (GCES Exhibit 03). These are risks that renewable capacity does not face
15 (GCES Exhibit 04).

16
17 Q. WHAT ARE THE FATAL FLAWS AND RED FLAGS YOU'VE
18 IDENTIFIED IN THE 2022 IRP?

19 A. I have identified at least five (5) fatal flaws and six (6) red flags in the 2022 IRP
20 document and appurtenant documentation. The first fatal flaw is embedded in the
21 Renewable Integration Study, which artificially inflates the required level of
22 operating reserves to meet the full intermittency of renewable energy, rather than
23 selecting for less expensive options than increased operating reserves. This results
24 in large mitigation costs that create an economic hurdle for renewables to be
25 selected in any model. First, the only mitigation option the Company uses to address
26 swings in net demand from solar is an increase in operating reserves. Instead,
27 operational curtailment of excess renewable generation could avoid the direct cost
28 of increased operating reserves. Second, economic curtailment of solar generation
29 is counted as a direct cost rather than an opportunity cost. This is done by increasing
30 operating reserves until pre-curtailment levels are reached, converting an

1 opportunity cost into a direct cost. Third, the Renewable Integration Study fails to
2 account for geographic diversity of solar (and wind) that would smooth out swings
3 in net demand, which further increases operating reserves and thus mitigation costs.
4 These three increases in 'required' operating reserves creates a more costly
5 Proposed Portfolio.
6

7 The second fatal flaw is that the long-term capacity expansion plan modeled in
8 AURORA was constrained to only allow for generic capacity expansion beginning
9 in the year of capacity need, which in this IRP is 2029. Capacity for the period of
10 2022-2028 comes from the 2022-2028 Capacity RFP ("Capacity RFP" or "RFP"),
11 which very plainly excluded and disadvantaged many lower-cost and lower-risk
12 resources, while advantaging gas-fired units (see following Q&A on the Capacity
13 RFP). The RFP resulted in 85% of the winning gas Power Purchase Agreement
14 ("PPA") capacity contracts belonging to a direct affiliate of Georgia Power
15 Company (GCES Exhibit 05 and Exhibit 06). It is also true that Purchased Power
16 is up to 2.3 times as costly as power that the Company provides from its owned
17 units (GCES Exhibit 07). Accordingly, the Capacity RFP did not result in a market-
18 based outcome and is not in the best interests of Georgia and Customers of the
19 Company.
20

21 The third fatal flaw is the failure to address uneconomic unit commitment. The
22 Company states that the System operates according to economic dispatch, which
23 seeks to minimize the total System production cost (IRP G-164). Although security
24 constrained economic dispatch is subject to operational constraints and reliability
25 considerations, the lowest cost generation assets are not being dispatched by the
26 Company to ensure that the lowest cost energy is produced every hour. This issue
27 was examined by Synapse in their November 2021 report "Georgia Power's
28 Uneconomic Coal Practices Cost Customers Millions" using publicly available
29 Company-reported data (GCES Exhibit 08). Synapse determined that the
30 Company's uneconomic unit commitment practices resulted in \$232 million in

1 excess costs for Customers from 2017 to 2020. The Proposed Portfolio does not
2 address the issue of uneconomic unit commitment and will continue the practice.
3 Accordingly, the 2022 IRP fails to adequately demonstrate the economic benefits
4 to Georgia and to Customers of the Company as required by O.C.G.A. § 46-3A-2.
5

6 The fourth fatal flaw is the continued overreliance on a non-diverse, gas-heavy
7 portfolio. The Company's own scenario modeling shows that there is significant
8 upside risk that Total System Costs could be much higher than the Base Case. This
9 creates upward rate pressure risk from any level of carbon pricing and from high
10 gas prices. The Base Case is six (6) times riskier than a low gas future if each
11 scenario is equally likely as the Company claims, which it is not (GCES Exhibit
12 09). This is not an acceptable risk when existing, commercial technologies like
13 solar+storage can provide all the energy, capacity, and ancillary services that gas-
14 fired units can provide, except at lower cost and lower risk than gas.
15

16 The fifth fatal flaw is the plan for an additional 6,000 MW of new renewables
17 resources by 2035. This number is unjustifiably low and does not come out of any
18 of the analysis or modeling presented in the 2022 IRP. Rather, it is based on the
19 Company's judgment. This very slow transition to replace higher cost coal and gas
20 units with utility-scale and distributed solar photovoltaics, batteries, solar+storage,
21 energy efficiency, demand side management, and other resource options results in
22 upward pressure on Customer rates. The Company is already moving too slowly to
23 procure the required renewable capacity stipulated in the last IRP, having issued
24 the second Renewable RFP only 10 days before this 2022 IRP was filed. The
25 McGrau Ford battery will not come online until 2027. The Company claims it
26 cannot expand the monthly net metering cap of 5,000 Customers until all systems
27 are interconnected, one full year passes, and a study is performed on the resulting
28 performance data. Meanwhile, the RFP Framework shows five (5) benefits and one
29 (1) cost to distributed generation. These delays put upward pressure on Customer
30 rates.

1
2 The first red flag is that reliability is talked about extensively in the IRP and the
3 Company invests significant capital expenditure on reliability, but actual Company
4 performance is demonstrably poor. According to self-reported data from EIA Form
5 861, Georgia Power Company ranks near the bottom among investor-owned
6 utilities for two common reliability metrics (GCES Exhibit 10).

7
8 The second red flag is that the System reserve margin is too high because the
9 generation capacity of Georgia Power Company and the other Operating
10 Companies in the pool is overbuilt, beyond what is recommended in the company's
11 economic Target Reserve Margin (GCES Exhibit 11). Furthermore, there are
12 significant historical energy exports to neighboring Balancing Authorities, which
13 is a strong signal of excess capacity, uneconomic unit commitment, or both (GCES
14 Exhibit 12). Overbuilt capacity is a significant cost that is not in the interests of
15 Georgia and Customers of the Company.

16
17 The third red flag is the underinvestment in Bowen Units 1-4 and Scherer Unit 3.
18 This reduction in spending was ordered by the Commission in the 2019 IRP.
19 However, there is a non-negligible risk that this underinvestment will impact
20 System reliability, which is already poor (GCES Exhibit 13).

21
22 The fourth red flag is the inconsistent use of models and swapping of data between
23 models, which results in a sub-optimal and uneconomic Proposed Portfolio. For
24 example, production costing is modeled in the Strategic Energy and Risk Valuation
25 Model ("SERVM") (IRP C-148), a legacy Southern Company-developed model
26 that is also used for the Reserve Margin Study and Renewable Integration Study
27 and that includes support from a legacy Southern Company consultant, Astrapé.
28 Production costing is also modeled in AURORA to determine marginal energy cost
29 for use in the Profitability Reliability Incremental Cost Evaluation Model
30 ("PRICEM") and RCB Framework (IRP C-151). Finally, production costing is

1 modeled in the Strategist model for the 2022-2028 Capacity RFP (IRP K-182). This
2 inconsistent use of three different production cost models creates discontinuities in
3 the IRP analysis and results in a higher cost portfolio.
4

5 The fifth red flag is that transmission planning was conducted independently of the
6 generation planning in the AURORA model and is only planned out 10 years, half
7 the time horizon as generation planning. Generation and transmission planning
8 analysis can be performed together at a high level using the AURORA model,
9 which provides internal consistency to the modeling and increased confidence in
10 results, after which more detailed transmission analysis (voltage, frequency,
11 thermal violations, etc.) can be conducted. This is another discontinuity that likely
12 results in a suboptimal Proposed Portfolio.
13

14 The sixth red flag was the Company's admission (Witnesses Phillips and Valle,
15 Day 2 at approximately 1 hour and 5 minutes into the hearing) that they dismissed
16 the conclusion of the Georgia DSM Working Group to use the AURORA model to
17 allow demand-side resources to compete head-to-head with supply-side resources.
18 However, the Company concluded that because it is a complex process to model
19 demand-side resources in AURORA, their current methodology is the most
20 appropriate. The Company can simply reach out to Energy Exemplar, the licensor
21 of the AURORA model, and they will provide guidance on implementing demand-
22 side resources.
23

24 **Q. WHAT ARE THE CONCERNS YOU'VE IDENTIFIED IN THE**
25 **RENEWABLE INTEGRATION STUDY?**

26 **A.** The Company is asking for approval of the Company's use of the Renewable
27 Integration Study for planning purposes (IRP 1-14). However, the study
28 demonstrates many fatal flaws and red flags that artificially inflate the required
29 renewable integration costs. As a result, use of the Renewable Integration Study in

1 the 2022 IRP results in a Proposed Portfolio that is economically sub-optimal and
2 puts upward pressure on Customer rates.

3
4 The first fatal flaw is that the Renewable Integration Study does not consider less
5 costly solutions. The Company states, "the intermittent nature of solar resources
6 creates unexpected swings in the momentary net demand on the system, which must
7 be met using the inherent flexibility of the system, including the flexibility
8 associated with available operating reserves." The sole solution proposed in the
9 Renewable Integration Study to mitigate swings in net demand is to increase
10 operating reserves, which is among the most expensive mitigation costs. The
11 Company did not consider that the solar resources themselves can provide the
12 needed flexibility by curtailing excess solar energy with Automatic Generation
13 Control ("AGC") and using behind-the-meter batteries to shave peaks and fill
14 troughs to provide firm energy and reduce unexpected swings in net demand. AGC
15 is affordable, as affirmed by Witness Mallard who estimates AGC has a price of
16 \$50k that is borne by the developer. Moreover, the Company admits that a
17 flexibility violation, "does not likely represent an actual loss of load." In sum, the
18 Company is proposing an expensive option for a problem that may or may not
19 occur, when less expensive alternatives are available.

20
21 The second fatal flaw is that the Renewable Integration Study falsely considers
22 solar generation curtailment as a direct cost rather than an opportunity cost to
23 displace more expensive generation or to generate revenues via off-system sales.
24 The Company states, "The increase between the pre- and post-mitigation
25 curtailment should be considered an additional integration cost." This adds even
26 more expensive operating reserves beyond what is needed to meet swings in net
27 demand, as discussed above. The so-called 'overgeneration' can simply be curtailed
28 with AGC and does not require an increase in operating reserves. Furthermore, the
29 Renewable Integration Study does not consider the impact of off-system sales of
30 surplus solar energy.

1
2 The third fatal flaw is that the Renewable Integration Study fails to account for
3 geographic diversity of solar resources across the System. It is well-documented
4 that the broader the geographic distribution of solar resources, the less volatile the
5 aggregate generation swings of solar resources. The Renewable Integration Study
6 does not take this effect into account, which would reduce the required level of
7 operating reserves and reduce mitigation costs.

8
9 The first red flag is that the Renewable Integration Study uses one-hour blocks to
10 determine the level of additional spinning reserves required to manage the change
11 in load from hour to hour. Spinning reserves are ready to dispatch at a moment's
12 notice. While a sub-hourly analysis of intrahour load changes was conducted, the
13 use of one-hour block requirements for additional spinning reserves likely inflates
14 the true requirement.

15
16 The second red flag is that the Renewable Integration Study does not include a
17 scenario to account for the Southeastern Energy Exchange Market ("SEEM"), and
18 as a result does not reflect the now certain future.

19
20 A third red flag is the reliance on the traditional Loss of Load Expectation
21 ("LOLE") metric as the sole reliability target. The North American Electric
22 Reliability Corporation ("NERC") issued a report ("Methods to Model and
23 Calculate Capacity Contributions of Variable Generation for Resource Adequacy
24 Planning" or "2011 NERC Study"), which the Company references and uses in the
25 2022 IRP, acknowledges that planning based on LOLE alone may be inadequate to
26 accurately measure a resource's reliability. The NERC report was issued 11 years
27 ago and does not capture the learnings on resource adequacy metrics of the last
28 decade. Accordingly, the Renewable Integration Study needs more diverse and
29 inclusive reliability metrics.
30

1 Q. WHAT ARE THE CONCERNS YOU'VE IDENTIFIED IN THE
2 RESOURCE MIX STUDY?

3 A. The Resource Mix Study demonstrates numerous fatal flaws and red flags that
4 result in the exclusion or disadvantaging of resources that, if included or evaluated
5 properly, would result in a more economically optimal portfolio. Its use in the 2022
6 IRP is an additional factor as to why the Proposed Portfolio is not in the best
7 interests of Georgia and Customers of the Company.

8
9 The first fatal flaw is that BESS+CS is excluded as a generic candidate expansion
10 resource. Solar and storage are available separately, but the generic expansion plan
11 should have offered the same resources as the Capacity RFP. Ostensibly, BESS+CS
12 could have been a resource option prior to the first year of capacity need (2029),
13 but it was greatly disadvantaged in the Capacity RFP and thus excluded from 2022
14 to 2028. Batteries, firm wind, compressed air energy storage, capacity in
15 neighboring Balancing Authorities, and other resources were also excluded from
16 the Capacity RFP.

17
18 The second fatal flaw is that CT additions only include the cost of contracting for
19 firm summer only natural gas delivery (page 12), whereas the larger and growing
20 larger reliability risk to the Company is in the winter when gas pipelines are the
21 most constrained. Furthermore, it should be noted that Witness Grubb testified to
22 the following: Daniel Walsh (Day 1 at approximately 1 hour 2 minutes into the
23 hearing): "In obtaining a firm gas transportation contract, did the Company assume
24 that it would be necessary to have a firm gas contract every day of the year?"
25 Witness Grubb responded, "Yes, we did." This inconsistency and failure to account
26 for the full cost of year-round firm transportation in the Resource Mix Study biases
27 the model toward selection of CTs at the expense of other resources.

28
29 The third fatal flaw is that the Base Case is based upon the Annual Energy Outlook
30 ("AEO") 2021 Reference Case, which is historically a poor predictor of future gas

1 prices, as all AEO forecasts are (GCES Exhibit 14) (note: the AEO includes
2 multiple scenarios to address this issue). This topic is discussed in detail in another
3 Q&A of this testimony.
4

5 The fourth fatal flaw is that unabated gas-fired resources are available for expansion
6 through 2039 in the case of Combined Cycle units and 2034 in the case of CTs.
7 These gas units will have a book value of 20 years or more, which is inconsistent
8 with the 2050 Net Zero Carbon target from Georgia Power's parent company. This
9 creates a stranded asset risk for these late-addition gas resources, which is a risk
10 that will be borne by Georgia and Customers of the Company. It will be very
11 expensive to retrofit unabated gas units for Carbon Capture and Sequestration or to
12 repower/re-engineer for hydrogen firing, so these are not economic options. The
13 latest that unabated gas should be allowed to be added to the System is 2030, to
14 remain consistent with the 2050 Net Zero Carbon target. The Company is proposing
15 gas PPAs in another Operating Company's service territory. Accordingly, the
16 System-wide 2050 Net Zero Carbon target should also be integrated into the 2020
17 IRP Resource Mix Study.
18

19 The red flag is that all expansion units were sized to 300 MW blocks for the sake
20 of modeling expediency. However, there is no reason to have equal sizes of capacity
21 blocks for different technologies, and this assumption biases selection toward large,
22 centralized units rather than smaller, more distributed assets.
23

24 **Q. IS THE 2022-2028 CAPACITY RFP IN THE BEST INTERESTS OF**
25 **GEORGIA AND CUSTOMERS OF THE COMPANY?**

26 **A.** No, it is not. The Capacity RFP is a critical element of the 2022 IRP Action Plan
27 but demonstrated serious technical flaws that arbitrarily excluded or constrained
28 market-based solutions, as well as financial, risk, and procedural flaws. These flaws
29 include, but are not limited to, the following:
30

Technical:

(1) the RFP excluded most resources less than 100 MW from participating in any manner in the RFP, including a notable gap between 30-100 MW. This arbitrary cut-off excluded many medium-sized projects that could provide additional value that small- and large-sized projects cannot deliver;

(2) the RFP created barriers that disadvantaged or excluded certain technology offerings that can provide capacity, notably including compressed air energy storage and all demand-side resources. This is contrary to the Company's statement, "This [IRP] process provides for an orderly and reasoned framework through which both demand- and supply-side resources are compared on an equitable basis to develop a plan that provides for reliable and economical electric energy to serve customers' needs over the planning horizon" (IRP 4-22). Excluding resources is not an equitable basis for soliciting capacity in order to meet reliability and resource adequacy requirements;

(3) the RFP required that any resource offering capacity must provide one full cycle in a 24-hour period in order to qualify for participation, without providing justification for this requirement, which disadvantaged BESS+CS resources;

(4) the Company states that renewable resources are weather-limited, drawing a contrast to gas resources. However, gas resources are not only weather-limited but face correlated fuel scarcity risk, which the RFP minimizes or ignores as a risk for gas resources. The Company acknowledges such weather-related limitations for gas resources, "These units operate primarily on natural gas while maintaining limited coal backup per the requirement of the Mercury and Air Toxics Standards rule to ensure reliable operation during periods when natural gas pipelines are constrained, such as during cold winter days." Most of the gas resources in the PPAs do not have coal backup, and not all expensive have Firm Transportation. As a result, gas resources were advantaged in the RFP;

(5) the Company did not accurately or fairly address the value of real-time operational flexibility provided by renewable resources (with Automatic Generation Control), the reduction in congestion costs from small- and medium-

1 sized resources that are distributed rather than resources that are centralized in
2 blocks of capacity 100 MW or larger, or the transmission and distribution capital
3 expenditure deferrals from small- and medium-sized resources in the RFP, all of
4 which disadvantaged renewable resources;

5 (6) the gas resources were advantaged in the RFP by ignoring permit condition
6 limitations. For example, Plant Monroe (Doyle Energy Facility) Units 1 & 2 are
7 limited to 1,550 hours each per consecutive 12-month period in order to limit
8 carbon monoxide emissions;

9 (7) the RFP ignored the symbiotic relationship of BESS+CS, which can make a
10 significant contribution to reliability of the System. Using a loss of load probability
11 model to estimate the capacity credit of solar resources and battery resources under
12 increasing penetrations of both technologies, in isolation and in tandem, North
13 Carolina State University researchers have demonstrated that as much as 40% more
14 of the combined capacity can be counted on during peak demand hours compared
15 to scenarios where the two technologies are deployed separately.

16
17 Financial:

18 (8) while BESS+CS and gas Combined Cycle ("CC") resources were treated
19 exactly equally in terms of Buy Down Payment penalties for capacity reduction,
20 despite nominally different products (Designated Storage Capacity vs. Designated
21 Capacity, respectively) that are functionally equivalent, BESS+CS resources were
22 treated unequally in the RFP and were disadvantaged in at least two ways by not
23 being allowed to designate Nominal Supplemental Capability ("NSC") on top of a
24 designation of Nominal Base Capability ("NBC") (IRP 11-74) like CC resources
25 were allowed to do with duct-firing and with an option for multiple tiers of NSC;

26 (9) the calculation of Contracted Capacity Cap in the RFP requires 102.5% of the
27 NBC, where 100% of capacity and energy generated by the unit must be sold to the
28 Company, with restrictions on NBC, but any shortfall of capacity below 92%
29 triggers a rapid 10-day Cure Period after which significant liquidated damages are
30 triggered, which disadvantaged BESS+CS resources;

1 (10) the BESS+CS resources were disadvantaged by the calculation of replacement
2 costs using Seasonal Availability Percentage compared to gas resources that
3 calculate replacement costs based on a Monthly Availability Percentage, which can
4 lead to higher performance hurdles and higher replacement costs on Undelivered
5 Scheduled Energy vs. Undelivered Energy;

6 (11) the BESS+CS resources were disadvantaged by the application of the
7 reductive Seasonal Availability Adjustment to the Monthly Capacity Payment,
8 which did not apply to gas resources;

9 (12) Certification of the PPAs arbitrarily and unfairly shifts fuel costs to non-
10 participating customers of the Company, including customers who fully subscribe
11 to the Company's solar programs such that they offset all their energy consumption
12 and capacity needs via solar resources. This is a cross-subsidization of gas resources
13 via the PPAs by non-participating customers of the Company.

14
15 Risk:

16 (13) the gas resources were advantaged in the RFP by ignoring the risks, which are
17 currently present and growing into the future, from federal regulation in multiple
18 matters presently before the Supreme Court of the United States (e.g., West
19 Virginia v. EPA), which are risks not faced by BESS+CS resources;

20 (14) the gas resources were advantaged in the RFP by ignoring the substantial risks
21 born presently by gas resources from fuel price volatility and correlated fuel
22 scarcity due to heavy dependence on interruptible transportation during winter
23 months on the Southern Natural Gas pipeline system, which experienced 41 days
24 of Critical Notice Operational Flow Orders ("OFO") from November 11, 2021 to
25 March 15, 2022, including two days of the highest OFO Type 6 in which daily
26 shipper imbalances threaten system integrity (GCES Exhibit 15). This risk is
27 inherent to gas-fired generation and follows from a dependence on vulnerable
28 pipeline infrastructure, and which are risks that BESS+CS resources do not face at
29 all;

1 (15) the gas resources were advantaged in the RFP by ignoring the risks of financial
2 impairment for gas-fired generation. These financial impairment risks are
3 derivative of the regulatory risk, climate risk, fuel price volatility risk, and
4 correlated fuel scarcity risk that gas resources face presently, which are risks that
5 BESS+CS resources do not face at all or in equal measure.
6

7 Procedural:

8 (16) the process was concluded without obtaining Post Evaluation Standard of
9 Conduct Agreements for five members of the RFP Evaluation Team, including
10 notably the Financial Analysis and Planning Manager and the Bulk Power
11 Operations Compliance Assurance Manager;

12 (17) the relationship between Southern Company's unregulated subsidiary,
13 Southern Power Company, and Southern Company's regulated subsidiary, the
14 Company, is unmonitored and unregulated, which can lead to conflicts of interest
15 between the Affiliates with substantial business before each other via the PPAs;

16 (18) the justification for the capacity required for Reliability and Resource
17 Adequacy that is solicited in the RFP is called into question by the 2021 Long-Term
18 Reliability Assessment issued in December by the North American Electric
19 Reliability Corporation ("NERC"), which demonstrates that the region in which the
20 Company, its affiliates, and merchant capacity operate (SERC-SE) is anticipated to
21 have a summer Reserve Margin as high as 46.8% in 2028 vs. the Company's Target
22 Reserve Margin of between 14.78% and 16.25% for summer periods or Economic
23 Reserve Margin of 20.5%.
24

25 **Q. WHAT ARE THE CONCERNS YOU'VE IDENTIFIED IN THE STUDY**
26 **OF RENEWABLE CAPACITY VALUES USING THE ELCC**
27 **METHODOLOGY IN THE SOUTHERN COMPANY SYSTEM?**

28 **A.** The Effective Load Carrying Capability ("ELCC") is the capacity value assigned
29 to energy-limited or non-dispatchable resources and is examined in the Study of
30 Renewable Capacity Values using the ELCC Methodology ("ELCC Study"). The

1 ELCC methodology is compared to the Company's current use of an Incremental
2 Capacity Equivalence ("ICE") Factor and the ELCC Study concludes that they are
3 equivalent. However, both methodologies discussed in the ELCC Study
4 demonstrate red flags.

5
6 The first red flag is that the ICE Factor methodology assumes a gas-fired
7 combustion turbine ("CT") is a fully dispatchable resource. (GCES Exhibit 16).
8 CTs experience forced outages. CTs have emissions and operations limitations.
9 CTs that lack dual-fuel capability can experience restricted energy supply during
10 critical periods of grid operation, such as during winter weather when constraints
11 on natural gas pipeline transportation are frequently seen (GCES Exhibit 15). This
12 fuel risk is augmented by its correlation among gas resources, as there are just two
13 pipelines serving all the Georgia Power gas fleet.

14
15 The second red flag is that the ICE Factor shows utility scale solar at 10% winter
16 and 35% summer (rooftop solar is 5% and 25%, respectively), meaning solar has
17 year-round capacity value. However, solar received a 0% capacity credit in the
18 Capacity RFP, and BESS+CS was significantly disadvantaged vis-à-vis gas
19 resources.

20
21 The third red flag is that the ICE Factor does not account for increasing resource
22 penetration levels or geographic diversity, which limits its usefulness, whereas the
23 ELCC methodology is dynamic and adapts to an increasing penetration level of
24 renewables that are dispersed across varying locations.

25
26 The fourth red flag is that the ICE Factor yields a non-winter capacity credit of 20%
27 whereas the ELCC method gives 40%, a major difference that will significantly
28 impact the long-term capacity expansion planning process and level of wind
29 recommended in the Resource Mix Study. Notably, wind received a 0% capacity
30 credit in the Capacity RFP because it was excluded.

1
2 **Q. WHAT ARE THE CONCERNS YOU'VE IDENTIFIED IN THE**
3 **ECONOMIC AND RELIABILITY STUDY OF THE TARGET RESERVE**
4 **MARGIN FOR THE SOUTHERN COMPANY SYSTEM?**

5 A. The Target Reserve Margin Study ("TRM Study") uses a probabilistic approach to
6 randomly select unit availability and performance, weather year, and load to
7 determine what level of reserve capacity is needed to reliably and economically
8 meet Customer load. However, the TRM Study demonstrates red flags.

9
10 The first red flag is that the TRM Study recommends a Summer TRM of 16.25%
11 whereas Base Case summer reserve margin for the Company reaches 30.6% in
12 2027, with an even higher 35% in 2021 for the System. The surplus capacity is a
13 cost that is being borne by Customers, but the modeling shows it is not needed
14 (GCES Exhibit 11).

15
16 The second red flag is the assumption that unit performance and availability are
17 less correlated than is implied by the Unplanned Outage Probability shown in
18 Figure I.8. Georgia Power's gas fleet relies on two pipelines only that are subject
19 to fuel scarcity risk, operational restrictions, cyberattack, and so on. The Company
20 states, "there have been occasions in the last ten years when more than 10% of the
21 capacity of the system has been in a forced outage state concurrently." In addition,
22 the use of historical weather years minimizes the correlation. Using weather
23 patterns from 1962 through 2019 dilutes the recent acceleration of weather pattern
24 change and ignores the expected acceleration of weather pattern changes over the
25 2022 IRP planning horizon.

26
27 The third red flag is that the TRM Study ignores and does not include in its
28 reliability assessment a metric for forced unserved energy from Customer shutoffs.
29

1 Q. WHAT ARE THE CONCERNS YOU'VE IDENTIFIED IN THE UNIT
2 RETIREMENT STUDY?

3 A. The Unit Retirement Study demonstrates fatal flaws and red flags that result in a
4 flawed assessment of optimal unit retirement dates. The first fatal flaw is that the
5 results of Capacity RFP were used as actionable information in this Unit Retirement
6 Study. However, the Capacity RFP excluded and disadvantaged many lower-cost
7 and lower-risk resources, which resulted in 85% of the proposed gas PPA capacity
8 offered by a Georgia Power Company direct affiliate and this purchased power will
9 be more expensive than self-generation (GCES Exhibit 07). The Unit Retirement
10 Study only evaluated the winning Capacity RFP resources in its replacement
11 capacity cost analysis through November 2039, rather than looking at lower-cost
12 resources like solar+storage that were excluded from the Capacity RFP to be
13 evaluated for their replacement capacity cost or benefit prior to the end of
14 November 2039.

15
16 The second fatal flaw is the use of a Pre-Retirement Avoided Energy Cost
17 ("PAEC") that assumes all coal units remain online through 2041 to calculate
18 hourly marginal cost. This PAEC is then used to derive the energy benefit for each
19 unit in isolation. This is a sub-optimal use of the AURORA model. The model has
20 a Long-Term Capacity Expansion module that evaluates unit retirements in an
21 integrated manner on a level playing field, allowing for head-to-head competition
22 among all resources—both supply-side and demand-side.

23
24 The first red flag is that Asset Retirement Obligations ("ARO") are not included in
25 the Unit Retirement Study, on the grounds that existing AROs are a sunk cost.
26 However, continued operation of coal units through 2030 and beyond will create
27 incremental and expanded AROs that should be included in the assessment of unit
28 retirement.

29

1 The second red flag is that the CO₂ price from \$0 to \$50 per ton is not reflective of
2 the full social cost of carbon, which advantages fossil fueled generation units in this
3 Unit Retirement Study.
4

5 **Q. WHAT ARE THE CONCERNS YOU'VE IDENTIFIED IN THE**
6 **BATTERY STORAGE COST-BENEFIT ANALYSIS?**

7 A. The Battery Storage Cost-Benefit Analysis demonstrates that a battery is a cost-
8 effective proposal for Customers of the Company in all scenarios. All six of the key
9 observations show very positive benefits provided by batteries. The concern with
10 the results of this analysis is that the results are largely being ignored. Standalone
11 batteries were not allowed in the Capacity RFP and BESS+CS were disadvantaged
12 in the Capacity RFP, excluding them from AURORA model selection until 2029 at
13 the earliest. Instead, the Company selects a round number of 1,000 MW by 2030 of
14 Energy Storage System capacity, which is based on the Company's pre-selected
15 level of renewable capacity on the system in that year. The 1,000 MW of battery
16 capacity is not based on economic modeling and is not optimized to be in the best
17 interests of Georgia and Customers of the Company.
18

19 **Q. WHAT ARE THE CONCERNS YOU'VE IDENTIFIED IN THE RCB**
20 **FRAMEWORK?**

21 A. It is clear from Table 1 in the Public Disclosure Renewable Cost-Benefit
22 Framework ("RCB Framework") analysis, as updated for the 2022 IRP, that
23 distributed generation offers multiple benefits with only integration costs to net out
24 some of the benefit. The Company must realize that Customers can simply defect
25 from the System with their own distributed generation and monetize all those
26 benefits to achieve lower electricity costs for the now ex-Customer. The
27 Company's position on monthly net metering—that it cannot recommend an action
28 until it first interconnects the initial 5,000 customers, waits a full year, performs an
29 assessment, and then puts a proposal in front of the Commission—this is a major
30 impediment to deploying more distributed generation, whereas the net benefits are

1 clear in the RCB Framework. The chief concern for the Commission is that, due to
2 the upward rate pressure from defections, the Customers left behind on the System
3 will see their rates rise even faster than they otherwise would.
4

5 **Q. HOW DOES A FLEET THAT CONSISTS OF 45% GAS GENERATING**
6 **CAPACITY PUT UPWARD PRESSURE ON CUSTOMER RATES?**

7 A. Georgia Power Company currently has a non-diverse fleet that consists of 66%
8 fossil generation capacity, including 45% gas-fired. Gas-fired assets cost more to
9 own and operate—whether they are existing or new units—compared to utility-
10 scale solar+storage. Growth in load and replacement capacity should be met with
11 solar capacity, energy efficiency, demand side management, and other lower cost
12 options. The failure to move rapidly away from gas-fired generation capacity to
13 lower cost options like solar+storage puts upward pressure on Customer rates.
14

15 The 2022 IRP Base Case is based on a low (sub-\$4) natural gas price outlook to
16 2041 and beyond. Natural gas prices were historically low in the past decade but
17 are now moving higher based on long-term fundamentals. The Company does not
18 capture this market shift in its Base Case (GCES Exhibit 14). On the fundamentals,
19 the past decade of low-cost capital allowed companies to pursue ever more drilling
20 to grow production from hydraulically fractured wells that have very steep decline
21 rates. However, interest rates are now rising, which is itself a reaction to current
22 high inflation. Further, the U.S. natural gas market is now more closely linked to
23 global markets via Liquefied Natural Gas (“LNG”), including Elba Island LNG
24 near Savannah, putting upward pressure on natural gas prices in the United States.
25 In fact, Europe saw skyrocketing gas prices even before the Russia-Ukraine war,
26 due to short supply. As gas prices move higher and given Georgia Power
27 Company’s heavy dependence on gas-fired generation, there will be upward
28 pressure on Customer rates as a result.
29

1 In addition to fuel commodity costs moving higher, gas-fired generation carries
2 substantial risk from fuel price volatility. Gas prices are very volatile and while this
3 risk can be partially mitigated, the hedging program itself adds to overall cost. Gas-
4 fired units also face risk from correlated fuel scarcity. Georgia Power Company
5 relies on just two pipelines to supply natural gas, which frequently experience
6 Critical Notice Operational Flow Orders that, in some cases, threaten system
7 integrity (GCES Exhibit 15). Even firm gas transportation is subject to operational
8 restrictions and susceptible to cyberattacks.

9
10 These risks are all inherent to gas-fired generation and follow from a dependence
11 on a volatile, scarce commodity (natural gas) and vulnerable infrastructure
12 (pipelines), which are risks that BESS+CS resources do not face at all. As a result,
13 the failure to transition away from 45% gas generating capacity—including the
14 requested certifications for gas PPAs—toward low-cost alternatives puts upward
15 pressure on Customer rates.

16
17 **Q. DID GEORGIA POWER COMPANY AND THE COMMISSION FOLLOW**
18 **ANY RECOMMENDATIONS IN YOUR TESTIMONY IN THE 2019 IRP?**

19 A. In my 2019 testimony I made several recommendations, including: (1) increase
20 solar procurement to 3,000 MW from 1,000 MW; (2) publish a distributed solar
21 hosting capacity map; (3) commit to evaluate solar+storage as a dispatchable
22 resource; and (4) commit to develop a clearly articulated roadmap to achieve a 100
23 percent zero carbon system by 2050 at latest. The Company did not pose any
24 questions in cross examination but has proposed a hosting capacity analysis in the
25 2022 IRP. The Commission stipulated more than doubling solar capacity
26 procurement in the 2019 IRP. The Company minimally complied with this
27 stipulation by issuing its second utility-scale solar Request for Proposals (“RFP”)
28 10 days before the present 2022 IRP was filed. This demonstrates an inability to
29 execute on required obligations in a timely manner and a lack of respect for the
30 Commission’s stipulation. The Company failed to adequately evaluate

1 solar+storage in both its 2022-2028 Capacity RFP and the 2022 IRP. Finally, the
2 Company does not address in the 2022 IRP the 2050 Net Zero Carbon target set by
3 its parent company, despite the Company modelling out to the year 2056.
4

5 **Q. DO YOU HAVE ANY ADDITIONAL COMMENTS?**

6 A. Yes. Florida and California were brought up in oral hearings. On Florida, the
7 Commission noted that the state, through their legislature, rolled back net monthly
8 netting. On April 27, 2022, Governor DeSantis vetoed CS/CS/HB 741 Net
9 Metering bill, which authorized public utilities to impose an Additional Sum to
10 recover lost revenues resulting from residential solar generation that exceeds the
11 public utility's estimate. Gov. DeSantis states, "The amount that may be recovered
12 under this provision is speculative and would be borne by all customers." In
13 California, there are brief times when the 35 GW of solar capacity drives down
14 daytime marginal energy costs to \$0. Prices can go negative with transmission
15 constraints and to account for lost revenues from Renewable Energy Credit.
16 However, Georgia is years from this problem. Georgia has 1/8 the solar capacity
17 and 1/4 the population of California. Careful planning and market reform can
18 mitigate this risk (GCES Exhibit 17).
19

20 **Q. PLEASE PROVIDE A CONCLUDING SUMMARY OF YOUR DIRECT**
21 **TESTIMONY.**

22 A. In my direct testimony, I have provided numerous examples of the fatal flaws and
23 red flags I discovered during my detailed review of the 2022 IRP and accompanying
24 studies, documents, and witness testimony provided by the Company. It is clear
25 from the public disclosure information and my analysis that the Company's
26 Proposed Portfolio was developed using flawed methodologies, arbitrary
27 constraints, and limiting assumptions. This resulted in some resources being
28 advantaged at the expense of other resources, with the ultimate result being a sub-
29 optimal portfolio that fails to adequately demonstrate the economic, environmental,
30 and other benefits to the state and to customers of the utility, as required by

1 O.C.G.A. § 46-3A-2. Specifically, the Preferred Portfolio is costlier than it should
2 be, which puts upward pressure on Customer rates. It is my recommendation that
3 the Commission require the Company to produce a new IRP that fully meets the
4 requirements of Georgia law and the Commission's rules, and which adequately
5 addresses the concerns raised in this testimony.

6
7 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

8 **A.** Yes, at this time.

1 COMMISSIONER McDONALD: Mr. Hubbard?
2 MR. BAKER: Excuse me.
3 COMMISSIONER McDONALD: Go ahead, Mr. Baker.
4 MR. THOMAS: I didn't say anything.
5 MR. BAKER: Okay.

6 BY MR. BAKER:

7 Q Mr. Hubbard, do you have a summary of your
8 prefiled testimony you would like to present to the
9 Commission at this time?

10 A I do. I also have just two exhibits that I
11 would also like to make available to the commissioners, to
12 whoever might be interested, if I may. Thank you.

13 COMMISSIONER McDONALD: Proceed, Mr. Hubbard.

14 WITNESS HUBBARD: Thank you. Thank you,
15 Commissioners, for your attention. I appreciate it.

16 Allow me to summarize my findings from the
17 detailed review of the 2022 integrated resource plan
18 and its underlying studies. It is over 1100 pages in
19 total, not including any of the questions and answers
20 and data requests.

21 So by way of credentials, I have directly
22 managed and contributed to multiple IRP projects over
23 the past six years, for utilities in Florida and
24 Tennessee, Indiana, Michigan, New Mexico, California,
25 Puerto Rico, and in other markets.

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1 In these IRPs, I used the Aurora model
2 extensively, the same model used in this IRP for a
3 wide range of analysis. And for the six years prior
4 to that, I also provided expertise on natural gas
5 markets to a wide range of corporate clients. So I
6 speak from a position of having considerable industry
7 experience with IRPs and gas markets, and I'm very
8 familiar with many of the models and methodologies
9 used in this IRP.

10 My testimony identifies and describes the ways
11 in which Georgia Power Company's IRP does not meet
12 the requirements to adequately demonstrate the
13 economic and environmental benefits to Georgia and to
14 customers of the company. Five key reasons why the
15 company's IRP and, specifically, the proposed
16 portfolio will be costlier, put upward pressure on
17 customer rates, and be far riskier than an
18 alternative plan. That is focused on near-term
19 deployment of renewables and storage.

20 First, the IRP assumes very high requirements
21 for operating reserves as have been discussed by many
22 other witnesses. And this makes the cost to
23 integrate renewables much higher than it is in
24 reality. Specifically, the renewable integration
25 study inflated the requiring operating reserves in

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1 three ways: by requiring 100 percent of renewable
2 intermittency be met with expensive operating
3 reserves; by requiring 100 percent of renewable
4 curtailment be met with expensive operating reserves;
5 and third, by ignoring the geographic diversity among
6 renewable resources which require even more expensive
7 operating resource.

8 So as a result, the cost to integrate
9 renewables is much higher than it otherwise would be.

10 Second key reason is that the IRP is not --
11 that it is not adequate is that it excluded renewable
12 and storage resources in its 2022, 2028 capacity RFP,
13 and it excluded them in many ways in how it used its
14 17 different models in this IRP.

15 So three brief points to make here. Again,
16 renewables and storage were excluded or disadvantaged
17 in the last capacity RFP, and the only resources --
18 and only successful resources in that RFP were
19 allowed to provide capacity in the first seven years
20 of this IRP.

21 This resulted in a strong bias in the resource
22 mix study in the IRP in favor of gas-fired resources,
23 in particular.

24 Second, the demand-side management group
25 measures were excluded from head-to-head competition

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1 in the Aurora model. Georgia Power Company concluded
2 that because it would be difficult to implement DSM
3 in Aurora, its current methodology was good enough.
4 And finally, the production costs modeling was done
5 across at least three different models which
6 introduces discontinuity in the analysis.

7 The third reason is that this plan will result
8 in higher costs than an alternative plan based on
9 renewables and storage. So I just draw your
10 attention to the first exhibit that I handed out,
11 Exhibit 7. All this is is a simple comparison, and
12 this -- I just want to make clear -- this is part of
13 my prefiled testimony. This isn't a demonstrative
14 exhibit.

15 This simply is using Georgia Power's own data
16 as filed by its parent company to another regulator
17 showing the difference between purchase power and
18 power that's generated by Georgia Power. And what
19 you can see from that exhibit is that purchase power
20 is up to 2.3 times as expensive as power generated by
21 Georgia Power Company. This is a key reason why the
22 gas PPAs are not in the interest of Georgia or
23 customers of the company.

24 And then one other point very briefly on this
25 is just that the IRP ignores a loss of \$232

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1 million of consumer wealth in Georgia from 2017 to
2 2020 due to uneconomic coal unit commitment
3 practices. So this is unaddressed in the IRP, a key
4 component of the IRP.

5 So moving on, the fourth key reason the IRP is
6 inadequate is that it has far greater risk than it
7 needs to have. And this will be demonstrated I think
8 in the second exhibit that I handed out, Exhibit 9,
9 which has the company's own modeling data showing the
10 rate impact from a number of different scenarios,
11 most of which are biased towards higher pricing from
12 carbon pricing and high gas prices.

13 So if we accept the Georgia Power Company's
14 premise that all of the scenarios they modeled are
15 equally probable, then there's, in fact, six times
16 the risk of a higher portfolio from carbon and gas
17 pricing than there would be from a lower U.S. -- a
18 lower cost gas portfolio.

19 And just the last risk -- so there's quite a
20 bit more risk here to the company and to the
21 customers of the company, much of which is from fuel
22 costs and from the risks that come with that. And I
23 would just point out as well that these -- this
24 upward pressure on rates that we see in Exhibit 9,
25 GCS Exhibit 9, it grows rapidly with any level of

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1 carbon pricing above zero dollars with high gas
2 prices, like we see now, in fact.

3 And so with a portfolio of 41 percent gas
4 capacity, there is a significant risk that comes from
5 fuel price volatility, from correlated fuel outages,
6 from correlated unit outages, and from a number of
7 other asset retirement obligations that will continue
8 to grow with the current proposed portfolio.

9 This is just not an acceptable risk when
10 existing commercial technologies, like renewables and
11 storage, can provide all of the energy capacity and
12 ancillary services that gas-fired units can provide
13 except at lower cost and lower risk.

14 And the fifth and final key reason this IRP is
15 inadequate is that the transition to carbon-free
16 energy is going far too slowly, a very long
17 deployment schedule for renewables. The same amount
18 of renewable capacity that was deployed over the last
19 12 years is what is being asked to be deployed over
20 the next 12 years despite vastly lower costs.

21 This will result in a higher cost and less
22 reliable proposed portfolio through continued and
23 economic coal operations, in purchase powers, and
24 through significant and avoidable risks.

25 The 2022 IRP as proposed will put upward
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1 pressure on customer rates by delaying
2 decarbonization. I identified a number of other
3 flaws, shortcomings, red flags in my testimony that I
4 will set aside for the moment, but they are quite
5 serious, and they cause this proposed portfolio to
6 fall short.

7 So in conclusion, to reiterate, this plan is
8 not in the economic interests of Georgia and
9 customers to the company. I used theory and
10 methodology that is widely accepted among grid-edge
11 utilities in the scientific community and are
12 confirmed by many other experts in this docket,
13 including -- for example, we have yet to hear, but
14 Michael Goggin on behalf of the Southern Renewable
15 Energy Association.

16 This adherence to a measured approach to
17 renewables and storage deployment is not in the
18 economic interests of Georgia. So the traditional
19 70/30 split on purchase power is not in the economic
20 interests of Georgia. And the IRP fails to account
21 for the benefits of an accelerated transition to a
22 decarbonized power grid which will broadly
23 incentivize new economic development, lower
24 electricity costs, and allow Georgia and the people
25 who live here to prosper. And this concludes my

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1 summary.

2 COMMISSIONER McDONALD: Mr. Jenkins?

3 MR. JENKINS: Mr. Hubbard is available for
4 questions from the Commission and for
5 cross-examination.

6 COMMISSIONER McDONALD: Thank you.

7 Georgia Public Service Commission?

8 CROSS-EXAMINATION

9 BY MR. THOMAS:

10 Q Thank you, Mr. Chairman. Mr. Hubbard, if you
11 could turn to page 7 of your testimony. On page 7,
12 lines 7 and 8, you indicate that there is a significant
13 upside risk that costs could be much higher than the
14 company's base rate.

15 Can you explain that concern?

16 A In fact, this is illustrated by
17 GCES Exhibit No. 9 that I handed out. This is specifically
18 related to rate impacts by scenario. But I'm simply relying
19 on the company's own modeling that shows that the base case
20 could expand -- the rate impact could be as much as
21 49 percent higher than the proposed portfolio based on their
22 own modeling.

23 And that's based on, again, a \$50 carbon cost,
24 but the social cost of carbon could be quite higher than
25 that. So the sky is the limit on the rate impact.

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1 Q At lines 10 and 11, you say that the base
2 case is riskier than a low-gas future if each scenario is
3 equally likely as the company claims and that each
4 scenario is not equally likely.

5 Why are the scenarios not equally likely?

6 A Well, I would say that we know that, for
7 example, there may not be a market value for carbon right
8 now, but in much the same way that caregivers, family
9 caregivers, do not -- are not compensated or remunerated for
10 giving care to elders or their children, there is still a
11 value to that. So what I'm saying is that there is a lot
12 more upside risk to this portfolio from carbon from gas than
13 there is to downside risk. And that's the point that I'm
14 trying to make here.

15 Q On page 7, lines 12 to 14, you say that
16 existing technologies like solar and storage can provide
17 all energy capacity and ancillary services at a lower cost
18 and lower risk than gas-fired units.

19 Did you review the final report of the
20 independent evaluator related to the 2022 through
21 2028 capacity RFP?

22 A I did.

23 Q Okay. And do you know whether solar and
24 storage bid in to the capacity RFP or whether they were
25 evaluated at a lower cost or lower risk than the PPAs that

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1 were selected?

2 A Well, I knew that there was interest in the --
3 in the solar plus storage option. But I think as a prior
4 expert witness testified to, the Accion Group, they really
5 just executed on the RFP, the capacity RFP, as was designed
6 through the stakeholder process. But they -- they only
7 executed on the plan as was provided. Certain resources
8 were allowed to compete. Other resources were not allowed
9 to compete or were disadvantaged.

10 So I -- I hesitate to look to that final report
11 as the definitive conclusion as to whether or not existing
12 resources, as your question asked, are cost competitive to
13 gas-fired resources. I don't think it was a level playing
14 field in that specific instance.

15 Q Okay. Following up on that, on your comment
16 about disadvantaged resource, on page 12 of your
17 testimony, you describe how BESS+CS was greatly
18 disadvantaged in the RFP.

19 Can you comment further on that?

20 A Yes. Well, I think in many ways. So what I
21 would do is -- I don't want to belabor the point here, but I
22 listed 18 different points in an earlier filing, and then I
23 also provided them here as well, in terms of how BESS plus
24 charging storage is disadvantaged. And what I tried to do
25 is group them in four different groupings. One, technical;

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1 one, financial; one, just simply based on risk; and then one
2 based on the procedure of it that was outlined in that final
3 report by the Accion Group.

4 This -- I don't think I need to go into it in
5 detail, but there were 18, at least, different areas where I
6 identified that BESS plus charging solar was disadvantaged.

7 Q But it is true that standalone batteries
8 weren't excluded from the capacity RFP; right?

9 A I don't think that they were -- I may be
10 mistaken on this, but I think BESS plus charging solar was
11 offered but not standalone storage.

12 Q Okay. Can capacity and neighboring balancing
13 authorities be considered firm and dispatchable in your
14 opinion?

15 A Yes. Absolutely. With firm transmission, I
16 think that, if I'm not mistaken, currently there already is
17 wind energy capacity being -- being utilized from outside
18 the balancing area with firm transmission to make sure that
19 that's provided. So that's already being done.

20 Q On page 16 of your testimony, lines 9, you
21 talk -- or you state that certification of the PPA's
22 arbitrarily and unfairly shifts fuel cost to
23 nonparticipating customers of the company.

24 Will you define what you mean by
25 "nonparticipating customers"?

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1 A Yeah. What I would say here is that a -- for
2 example, if a customer would like to offset 100 percent of
3 their energy use through one of the options that's
4 available, the renewable energy options, that's their
5 energy. Not necessarily capacity. But they are still being
6 asked to -- there's a cost transfer there that's happening
7 with respect to these -- they're not consuming necessarily
8 any of the energy that's on the system, but they're still
9 cross-subsidizing and helping to pay for the fuel that's
10 being consumed on the grid.

11 So what I mean there is that they -- these
12 customers that are trying to offset 100 percent of their
13 energy use through these programs are still ending up paying
14 for grid services that they otherwise shouldn't have to pay
15 for.

16 Q Are you suggesting that they shouldn't be
17 required to pay for fuel costs associated with the PPAs?

18 A I'm saying that there is -- I don't -- I think
19 that there -- if the emphasis is on eliminating or reducing
20 cost shifts, I don't think that that goal has been
21 accomplished here with these gas PPAs that are being
22 proposed for certification.

23 I think that there is some cross-subsidization
24 going on by customers who are seeking renewable, 100 percent
25 renewable resources, are ending up paying for resources that

1 they shouldn't have to pay for.

2 Q And are you familiar with Georgia Power's
3 solar program such as community solar?

4 A I am.

5 Q Isn't it correct that Georgia Power will
6 offset a customers's purchase and delivered energy by the
7 amount of the energy produced by the associated solar
8 facility based on the subscription level?

9 A Yeah. There's different blocks that you can go
10 through. I think 25 percent up to 100 percent, yes.

11 Q Turning to page 21 of your testimony, line 1,
12 you say that the second red flag is that CO2 price from
13 zero to \$50 per ton is not reflective of the full social
14 cost of carbon, which advantages fossil-fueled generation
15 units in the unit retirement study.

16 What price on carbon do you recommend as
17 appropriate in order to not advantage one type of generation
18 over another in the unit retirement study?

19 A Well, I can tell you from previous experience
20 that trying to model \$170 social cost of carbon, it's very
21 difficult for models like Aurora to actually capture
22 something like that. It will give you very odd results that
23 are difficult to parse.

24 But there is a cost to carbon that's not being
25 captured fully, I think, in this IRP. What I've seen is

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1 that many other utilities will start with something that's a
2 bit more reasonable.

3 They'll look to current legislation. Many of
4 the proposals have been out there would start at something
5 like \$15 a ton and then move up incrementally, say, by 10 or
6 \$15 a ton each year. That's what I would suggest is
7 something that eases us into this transition that starts to
8 account for the true costs of generation on the grid.

9 MR. THOMAS: Thank you, Mr. Hubbard.

10 MADAM CHAIR PRIDEMORE: Georgia Power?

11 CROSS-EXAMINATION

12 BY MS. PRYOR:

13 Q Good afternoon, Mr. Hubbard. You raised
14 several concerns in your testimony regarding the company's
15 capacity RFP.

16 Did you submit a bid into the capacity RFP?

17 A I did not.

18 Q And are you aware that even nonbidders and
19 interested parties are invited to submit comments and
20 provide feedback through the IE website on the RFP
21 documents while they're under development?

22 A I am.

23 Q Did you register for the IE website?

24 A I did.

25 Q And did you submit any questions or comments?

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1 A I did not.

2 Q Okay. But you're aware that you could have?

3 A Yes.

4 Q And did you raise any of your concerns noted
5 on pages 13 through 16 of your testimony with the company,
6 Commission staff, or the independent evaluator before
7 your -- you filed your testimony in this case?

8 A I would say that some of these concerns I
9 raised three years ago in the last integrated resource
10 planning process, but not specifically in the capacity RFP,
11 no.

12 Q Okay. And do you have any basis for the
13 statement on page 17, lines 12 through 15, that Georgia
14 Power's relationship with Southern Power is unmonitored
15 and unregulated?

16 A The basis for that result is simply -- or that
17 statement is simply the result of the capacity RFP where
18 85 percent of the capacity went to an unregulated subsidiary
19 of Southern -- Southern Company.

20 Q And are you aware that the Commission staff
21 and the independent evaluator actively monitored and
22 independently confirmed the results of the company's
23 capacity RFP?

24 A Yes. Yes, I'm aware.

25 Q And yet it's still your testimony that it was
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1 unmonitored?

2 A Insufficiently monitored.

3 Q And are you aware that all moni- -- all
4 members of Georgia Power's evaluation team signed and
5 affirm adherence to a strict standard of conduct for the
6 RFP?

7 A No, I am not aware of that.

8 Q Are you aware that all members of Southern
9 Power's bid team also sign and affirm adherence to a
10 similar standard of conduct?

11 A All members?

12 Q All members of both teams.

13 A That wasn't my understanding from the reading
14 of the Accion final report, that there were some members who
15 did not submit that statement you're asking about.

16 Q That did not submit at the very end of it or
17 the beginning?

18 A At the end of it.

19 Q At the end of it.

20 Are you aware that a couple of the team
21 members, I think to which you are referring, retired during
22 that time frame?

23 A No, I was not aware.

24 Q Are you aware that all communications between
25 the company and bidders are conducted through the

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1 IE website?

2 A Yes.

3 Q And by filtering all communications through
4 one portal, staff and the independent evaluator can
5 confirm that the RFP is being conducted fairly and
6 transparently?

7 A Yeah. I have no concern with the conduct of
8 the RFP. It was the structuring of the RFP, what resources
9 were included or excluded are disadvantaged.

10 Q And you did not submit any kind of
11 communication to any of the stakeholders involved in the
12 capacity RFP to reflect that?

13 A No.

14 MS. PRYOR: Okay. Thank you.

15 MADAM CHAIR PRIDEMORE: I may have gotten a
16 little ahead of myself. Any other cross for Georgia
17 Center for Energy Solutions?

18 (No response.)

19 Mr. Baker?

20 MR. BAKER: Just like to move Mr. Hubbard's
21 17 exhibits into the record and ask that he be
22 excused.

23 MADAM CHAIR PRIDEMORE: Okay. Very good. So
24 moved. You are excused.

25 (The documents referred to were admitted in
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1 evidence as GCES Exhibits 1-17.)

2 MR. PRENOVITZ: Madam Chairman, I was out of
3 the room very briefly. Very briefly. And, you know,
4 Mr. -- Commissioner McDonald went on to the next
5 couple witnesses, so I'd like to get back and do my
6 testimony, if I may?

7 MADAM CHAIR PRIDEMORE: You are welcome to do
8 your testimony, Mr. Prenovitz. Who's going to swear
9 you in?

10 MR. PRENOVITZ: Commissioner Baker.

11 MADAM CHAIR PRIDEMORE: Commissioner Baker.

12 COMMISSIONER McDONALD: She's a lot nicer than
13 I am.

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

15 MADAM CHAIR PRIDEMORE: He's got better hair.

16 Before you move forward, Mr. Baker,
17 Mr. Prenovitz, it's good to see you. I'm glad you're
18 back. Glad you're healthy. Please remember our
19 rules about witness and about time. And if we extend
20 to areas of discussion beyond this IRP in this
21 docket, we will put you on the clock. Okay?

22 MR. PRENOVITZ: I understand. Thank you,
23 ma'am. You've been very gracious, and I appreciate
24 it.

25 MR. BAKER: All right, Mr. Prenovitz. Would
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1 you please raise your right hand.

2 Thereupon,

3 STEVEN PRENOVITZ,

4 having been duly sworn, testified as follows:

5 DIRECT EXAMINATION

6 BY MR. BAKER:

7 Q All right. Would you please state your name
8 and address for the record, please.

9 A Steven C. Prenovitz, 4295 Amberglade Court,
10 Norcross, Georgia.

11 Q All right. And who are you appearing --
12 testifying on behalf of today?

13 A Concerned Ratepayers of Georgia.

14 Q All right. Thank you.

15 Did you cause to be filed with the Commission
16 on May 3rd 29 pages of testimony and two exhibits?

17 A I did.

18 Q You did. Do you have any corrections to the
19 prefiled testimony that you filed?

20 A I do not.

21 Q All right. If I were to ask you the same
22 questions contained in your prefiled testimony, would your
23 answers be the same today?

24 A They would.

25 MR. BAKER: Madam Chairman, I'd ask that
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Mr. Prenovitz's 29 pages including the two exhibits
be copied into the record as if read from the stand,
subject to cross-examination.

MADAM CHAIR PRIDEMORE: So moved. So marked.

MR. BAKER: Thank you.

(The documents referred to were marked for
identification as Concerned Ratepayers of Georgia
Exhibits 1 and 2.)

(Whereupon, the prefiled direct testimonies
of Mr. Prenovitz follows:)

DIRECT TESTIMONY AND EXHIBITS OF
STEVEN C PRENOVITZ
GPC's 2022 IRP
CONCERNED RATEPAYERS OF GEORGIA

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Pdf file-- Business Forum [Griswold & Prenovitz] (#2)

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Q. Please state your name, profession, and business location.

My name Steven C Prenovitz, I am an MBA and management consultant to CRG focusing on many of the major areas GA Power presents to the GA Public Service Commission, including but not limited to-- the Vogtle project, IRP proceedings, rate cases and prudency reviews. My business address is 4295 Amberglade Ct Norcross, GA 30092.

Q. On whose behalf are you testifying?

CONCERNED RATEPAYERS OF GEORGIA, (CRG). We represent real estate investors, grass-roots consumers, and businesses that are customers of Georgia Power. CRG is a non-profit advocacy group focused on promoting sound public policy that protects utility customers and seeks to lower the cost of regulated services.

Q. Please summarize the purpose/essence of CRG's testimony.

CRG is deeply concerned about the rates that the GA Public Service Comm allows GA Power to charge its customers. Hence our name-- Concerned Ratepayers of GA.

1 Our focus in this IRP proceeding is to aid the Commission in fulfilling its role and
2 responsibility to assure that GA Power's IRP is both committed to producing electricity
3 in adequate supplies and in the most cost effective manner.

4
5 **Q. Is the Company's 2022 IRP committed to providing adequate supplies of**
6 **electricity in the most cost effective manner?**

7 Adequate supplies- Yes. Most cost effective manner- No. Rates keep increasing
8 incrementally, in several different ways--- rate cases, IRPs, Vogtle hearings, Fuel
9 charges, Vogtle semi-annual reviews, NCCR tariffs, ECC tariffs, et al. According to
10 Jeffrey Polloch's testimony in Oct 2021 [Doc # 43838], witness for GA Assoc of
11 Manufactures, there will be four base rate increases from Jan 2022 to Jan 2023. This
12 IRP not only ignores this situation, but will generate additional rate increases over the
13 next few years. In fact, there is a scheduled rate case in July 2022.

14
15 **Q. Why is this important?**

16 It is a hard time economically for many citizens of Georgia. The Commission has an
17 obligation to try to protect the public from escalating electricity prices.

18
19 The purpose of regulation is to act as a surrogate for competition. Since GPC is a
20 monopoly, it is essential that there is proper regulatory oversight to assure the public is
21 protected from monopolist pricing. There must be a strong incentive for GA Power to
22 control costs, especially its Capital Costs.

23
24 High costs yield high rates. Lower costs yield lower rates. The emphasis must be on
25 Company controlling its costs which in turn enables the utility to offer its product at the
26 lowest prices. This mission is reinforced by the Hope Supreme Court Decision (1944)
27 which requires regulators to balance the needs of both the customer and the public. It
28 also emphasizes that regulation does not guarantee the company's net revenues.

29
30 **Q. Mr. Prenovitz, what qualifications do you offer to both critique GA Power's**
31 **plan and offer counsel to this Commission?**

1 I am a graduate of Northeastern University, Boston, MA with a BS/BA in finance and
2 economics, and an MBA from Suffolk University, Boston, MA.; with a concentration in
3 management. Extensive experience and expertise is in the areas of-- finance,
4 economics, marketing, strategic assessment and implementation, quality management,
5 organizational development, and inter-disciplinary problem solving. Also
6 comprehensive knowledge both of the current Vogtle project and Vogtle's history,
7 encompassing Vogtle 1 & 2 construction in the 1980s. In addition, wide-ranging
8 expertise in many phases of the Georgia regulatory process involving planning,
9 finance, prudence and rates. Have been involved in current Vogtle project and other
10 GPC related proceedings since 2009 (13 years). In addition, have published articles in
11 the AJC and other publications.
12

13 **Q. How do you explain the fact that your testimony differs from the majority of**
14 **witnesses, who are very well compensated?**
15

16 John Maynard Keynes, considered by many as the world's greatest economist, said it
17 best-- Worldly wisdom has taught it is often better for reputation to fail conventionally
18 than to succeed unconventionally. Many are paid much to be wrong. CRG is paid little
19 to be right.
20

21 **Q. Have you included a bio?**

22 Same bio used in 2019 IRP testimony, which is part of the summary/attachment.
23

24 **Q. Mr. Prenovitz, have you previously testified as an expert witness before this**
25 **Commission?**
26

27 Yes, on four occasions-- the 8th, 16th, 20/21st VCM, and the 19th IRP. Have also
28 appeared as a public witness, conducted cross-examination of both GPC and PSC staff
29 witnesses several times and have prepared comprehensive briefs. In addition, testified
30 as an expert witness in the Vogtle 1 & 2 hearings in the 1980s, and also conducted

1 cross-examination.

2

3 **Q. How did GA Power respond to your previous testimony?**

4 They tried to ignore it. To date, GA Power has failed to ask one question. In IRP 19,
5 CRG publically requested/ challenged Kevin Green to cross examine our testimony.
6 He declined. However, GPC did try to disqualify/limit our testimony on two previous
7 occasions.

8

9 **Q. Why do you think GPC had no questions of your testimony?**

10 Because it was based almost exclusively on GA Power's own data extracted from their
11 annual reports, budgets and testimony over many years. The data and the numbers that
12 supported CRG's analysis were indisputable. Hence, they had no questions.

13

14 **Q. What financial incentives does the Company have to control its Capital**
15 **Investment Costs?**

16

17 Not many. Since costs are the driving force of rates-- The higher the cost that can be
18 passed on to the Customer, the higher the rates that can be charged to their customers.
19 Conversely the lower the capital costs, the lower the customer's rates. Also the Hayet
20 panel highlighted this issue in VCM 17 (page 27-29), that the higher Plant Vogtle's
21 cost, the higher GPC's profitability. This is a negative incentive.

22

23 **Q. Is GA Power committed to their customers to offer services at lowest possible**
24 **cost?**

25 No. Costs are a secondary concern. As GPC's current and previous IRPs highlight--
26 The primary focus is to invest in Capital projects that may be needed in the future.
27 These projects cost billions of dollars over several years. Not much attention is directed
28 toward pursuing the lowest cost alternatives. High capital expenditures generate higher
29 rates.

30 **Q. Why are costs a secondary concern for GA Power?**

1 As things now stand-- GA Power is able to recover all, or at least most, of its capital
2 investment costs. Hence, there is little incentive in pursuing investment options at the
3 lowest possible cost.

4
5 **Q. How has the Commission handled GPC's large capital expenditure projects?**

6 Usually they have allowed all or at least most of these costs into the rate base. This in
7 turn has driven up customers' total power bills. Cost and rates continue to escalate on
8 an incremental basis. Case after case continues to produce higher rates for GA Power
9 customers. Little to no attention has been paid to the cumulative impact of these
10 incremental rate increases.

11
12 **Q. Why?**

13 GA Power and their witnesses can be persuasive, supported by strong political and
14 financial resources. The historical precedent is to rely of GA Power's explanations,
15 regardless of the deficiencies of their arguments. They sound good. One example, the
16 four members of the Grub panel were on the witness stand for over 10 hours. That even
17 impressed me.

18
19 This situation has historical precedent. Socrates provided an interesting frame of
20 reference, during this trial (399 BC)--- How you felt, gentlemen of Athens, when you
21 heard my accusers, I do not know. But I, well I, nearly forgot who I was, they were so
22 convincing. But as for truth, practically not a word was spoken.

23
24 **Q. Are you implying that GA Power's plans are not truthful?**

25 NO. I am stating that over many years, GPC's plans and forecasts have consistently
26 been proven to be unreliable. It would be naive to believe things will be different today.

27
28 **Q. Have GA power's three panels presented convincing evidence?**

29 NO. They had a solid operational plan, but neglected the strategic planning component.
30 GA Power's 2022 IRP is very similar to GPC's 2019 IRP. The focus is on trying to

1 forecast what will happen 20 years into the future and conclude that massive capital
2 expenditure projects will be needed and that the Company expects the customer to pay
3 for all of it. This strategy is not in the best financial interest of the public.

4
5 **Q. Explain.**

6 Limited innovated/creative thinking to deal with current challenges. No commitment to
7 controlling and reducing costs-- both operational and involving Capital Expenditures.
8 No assessment of the Company's Strengths & Weaknesses, both current and historical.
9 No acknowledgement of any past mistakes and proposed corrective actions.

10
11 Extension of what GPC has done in past (IRP 2019). Propose expensive capital
12 expenditure projects, some of untested technology. Pay little attention to cost. Rely on
13 long term demand forecasts that have consistently been proven to be inaccurate.
14 Acknowledge environmental issues but have no handle of what the cost will be, such as
15 cleaning up the 20+ ash ponds. Limited concern/attention to cost because GPC is
16 committed to passing on all, or at least most, of these costs to their customers and the
17 current ECC (14% of current service bill) allows this to happen.

18
19 **Q. Summarize the key points of GA Power's three panels of witnesses.**

20
21 **Grubb, Mallard, Robinson, Weathers panel's Testimony.**

22
23 CRG commends the Panel for testifying for over 10 hours. The key components of
24 their extensive testimony are:

- 25
- 26 • Coal plants are no longer economical to operate and the plan is to close down
27 most of these plants over the next few years
 - 28 • Replace coal plants with cost effective alternatives. Analysis driven by
29 economics
 - 30 • Assume a 26% reserve margin
 - 31 • Modernize hydro units 5 to 8 plants. Estimated cost \$100 Million+ . No
32 feasibility studies completed
 - 33 • Forecast 1000 MW battery storage plants. Assume cost effective by 2030.
34 Rely on models. No hard data.

Despite the panel's lengthy testimony, little attention was given to the cost impact of replacing coal units. The assumption was-- this needs to be done and GPC is committed to doing it. Argue this is in the best interest of the customers. Yet no indication as to how to control costs. Assumption is the customer should pay for it, since the Company argues it is in their best interests. CRG respectfully disagrees.

Valle, Philips, Smith , Evens Panel-- Load Forecasting

Capital projects often driven by load forecasts. Rely on models.

Some of the historical data presented by the panel was incorrect.

On page 8 the panel stated:

At the end of 2020, retail sales were down 2.2% as compared to the prior year. Residential sales ended the year up 3.4%, while the commercial and industrial classes were down 5.3% and 4.5%, respectively. Although 2021 commercial sales remained below 2019 levels, total retail sales for 2021 finished higher than pre-pandemic levels due to growth in the residential and industrial classes.

[Valle panel, page 8]

Below is the actual data for years 2019 → 2021

GPC-- Total KWHs Sales (Millions)				% change 2019-2020
	<u>2021</u>	<u>2020</u>	<u>2019</u>	
Residential	27,800	27,800	28,201	-1.4%
Commercial	31,300	30,500	32,818	
Industrial	23,300	22,000	23,163	
Other	<u>500</u>	<u>500</u>	<u>518</u>	
Total- Retail	82,900	80,800	84,700	-4.6%
Wholesale	<u>3,200</u>	<u>2,700</u>	<u>2,980</u>	
Total Sales	86,100	83,500	87,680	-4.8%

Source: SC 10-K 2019,2020,2021

1 GPC's historical data shows Retail sales declined 4.6% from 2019 to 2020, not 2.2%.
2 Residential sales did not increase 3.4%, but actually decreased 1.4% from 2019 to
3 2020. It is correct the total retail sales were higher in 2021 over 2020, but they were
4 lower than total retail sales for 2019.

5
6 CRG makes no attempt at reconciliation. However, these discrepancies highlight the
7 necessity of viewing GPC's forecasts with a healthy skepticism.

8
9
10 **Berry, Mitchell Panel- Environmental Issues**

- 11
12
 - Close 29 Ash Ponds
 - Cost unknown-- final stages of bids
 - Does not track ECCR cost
 - Each ash pond requires specific designs. Costs yet to be determined.
 - Focus on requesting RFPs from various vendors.

13
14
15
16
17
18 A major deficiency of this strategy is the company is depending on others to determine
19 the costs of environmental projects. They should at least attempt to determine these
20 costs internally. They do not.

21
22 It should be noted that Environmental Compliance Costs are currently automatically
23 passed on to the customer each month, with an additional cost of about 14% over the
24 base service charge. Hence, as things now stand, the Company has little incentive to
25 control the cleanup cost of ash ponds.

26
27 It should also be noted that in the 19th IRP, the panel admitted they did not know what
28 such a cleanup would cost. Three years later they still do not know. The best they
29 could do is to announce the Company requested cost proposals from various vendors.
30 They also testified that each ash pond is different and will require site specific plans.

31
32 **Q. You mention that GPC's plans overlook the impact of costs on rates-- what**
33 **proof do you offer to document this serious problem?**

34 Jeff Pollack, witness for Georgia Association of Manufacturers (GAM), documented in

1 his October 2021 testimony [Doc # 43838] that GA Power will have four major rate
2 changes in a 13 month period (total rate impact appx \$970 million) from Jan 2022 to
3 Jan 2023. [page 2-3 Pollack testimony]

4
5 1. Third phase of 2019 rate increase effective Jan 2022 for \$386 million. Two
6 prior increases of \$342 million Jan 2020 and \$111 million in Jan 2021.

7 2. Vogtle unit 3 schedule delay will eliminate the expected \$134 million
8 NCCR reduction.

9 3. GPC is requesting a \$369 million increase effective one month after Unit 3
10 completion.

11 4. Fourth base rate increase will likely result from GPC's July 2022 upcoming
12 rate case. Rate impact unknown at this time.

13
14 **Q. Did any of GA Power's three panels reference Vogtle 3 & 4's "challenges" and**
15 **its almost \$30 billion total project cost?**

16 No

17
18 **Q. What is the current status of Vogtle 3 & 4?**

19 The project is years behind schedule and billions of dollars over budget. Every other
20 utility in the US cancelled their nuclear construction projects, all but GA Power. For
21 the GA Power 46% share of the project, the initial budget (construction & finance) was
22 \$6.1 billion. According to GPC's 2021 annual report (SC 10-K, page II-153) Vogtle's
23 budget through Dec 2021, more than doubled to \$13.8 B. In addition, GA Power
24 recorded a \$3.1 billion loss/write-off for Vogtle in years 2018 → 2021.

25
26 **Q. Have GPC witnesses indicated the Company intends to learn from the Vogtle**
27 **experience to better control costs on future large capital expenditure projects?**

28 NO. The issue has been totally ignored.

29
30 **Q. What grade would you assign to GA Power's 2022 IRP?**

31 Incomplete. It is a solid operational plan, but lacking in strategic thinking & planning.

1 Again the current plan pays little attention to the cost impact of the company's capital
2 expenditures decisions.

3
4 **Q. What is missing in GPC's current IRP plan?**

5
6 There is little to no strategic thinking and planning. It completely overlooks a key
7 concern to Customers-- the importance of controlling costs and rates. It is a
8 continuation of past policies, very similar to GPC's 2019 IRP.

9
10 CRG focused on these issues in depth in our 2019 IRP testimony. CRG provides a
11 comprehensive summary of the key points of that testimony in Appendix 1.

12
13 **Q. As a Consultant, could you offer some guidance to both the Company and the**
14 **Commission as to how to combine strategic thinking/planning with effective**
15 **operational implementation?**

16
17 Yes. Under the guidance of my mentor, Harold Griswold, we developed a
18 methodology for improving quality and productivity, by combining innovative strategic
19 thinking with effective operational execution. This work product became the lead
20 article in Business Forum and was published under the title-- How to Translate
21 Strategy into Operational Results.

22
23 The article provides a step by step approach, with a flow chart, on how to achieve the
24 desired results. This is a generic approach that applies to a wide range of industries and
25 organizations. In fact, the article was included into the curriculum of the Wharton
26 Business School and the Copenhagen Business School. Enclosed- Appendix 2

27
28 **Q. How should the Commission respond to GPC's current plan?**

29 Do the right thing and finally require the Company to adequately address Costs. As
30 Churchill noted during WWII, You can always depend on the Americans to do the right

1 thing-- after trying everything else. For 13 years both the Company and the
2 Commission have overlooked the impact and importance of controlling costs--
3 specifically capital investment. Time to correct this oversight. Do the right thing.
4

5 **Q. Are you optimistic that the Commission will do it?**

6
7 Not really, but one must keep trying. Change is hard. The Commission has yet to even
8 implement a simple improvement procedure of having panels of witnesses place a
9 name tag /plate card in front of them, similar to what is done in Congressional hearings.
10 Also, each Commissioner has his/her name plate in front of them. It is not a good sign,
11 if the Commission cannot even implement the easy stuff.
12

13 **Q. Any suggestions to help the Commission with the hard stuff?**

14
15 Retain the expertise of someone who understands the complexity of the entire
16 regulatory process and who is committed to balancing the needs of the utility with that
17 of the public. A man also with the courage and expertise unafraid to challenge
18 conventional thinking and is committed to speaking truth to power, specifically to the
19 regulators of GA Power. Current consultants too closely aligned with GPC's interests.
20

21 **Q. Who do you recommend the Commission consider?**

22 Peter Bradford -- a former NRC commissioner, former state utility regulator, former
23 president of NARUC, international utility consultant, professor, author, and expert
24 witness-- who testified on behalf of Southern Alliance for Clean Energy in VCM 17.
25 His testimony has proven to be quite prophetic.

26
27 Four years ago, Mr. Bradford offered to assist the Commission with these difficult
28 challenges. In fact, Commissioner McDonald demonstrated tremendous respect for
29 Mr. Bradford. For a reference, the four other Commissioners are encouraged to discuss
30 Bradford's character & expertise with Commissioner McDonald. [Note: Detailed
31 reference to Bardford entire 2017 testimony is included in CRG's VCM 25 brief].

1

2 **Q. Anything else?**

3 Yes. The Commission's attention must finally turn to controlling costs, as should GA
4 Power's. The current 2022 IRP is deficient and should be revised and updated. As the
5 medieval scholar and philosopher Maimonides said-- teach thy tongue to say I do not
6 know, and thou shall progress Again, hard to do, but worth the effort. Influenced by
7 the commentary of Dr Ron Bigalke, the following recitation may prove inspirational.

8

9 **Now is the time for turning.**

10 Seasons turn, leaves turn colors, birds turn south for the winter, and animals
11 turn to store food for the winter.

12 For leaves, birds, and animals-- turning comes easily.

13 For us-- turning does not come easily.

14 It takes an act of will. It means breaking with old habits. It means admitting
15 that we may have been wrong. It means starting all over again. It means saying

16 I am sorry. It means admitting we have the ability to change.

17 All of this is both painful and very hard to do.

18 But unless we turn, we will be trapped forever in yesterday's ways.

19 Lord, help us turn-- From callousness to sensitivity, from pettiness to purpose,
20 from carelessness to discipline, from fear to faith.

21

22 **Q. Any final comments?**

23 Do it.

24

25 **Q. Does this conclude your testimony?**

26 Yes

27

28

29

30

31

32

CRG Attachment # 1

1 BY MR. BAKER:

2 Q Mr. Prenovitz, did you also cause to be filed
3 one addendum on May 9th, to your testimony?

4 A I did.

5 Q All right. Do you have any corrections to
6 your addendum?

7 A No. That was a two-page statistical analysis.
8 No corrections.

9 Q All right.

10 MR. BAKER: Madam Chairman, I ask that it be
11 identified as Concerned Ratepayers of Georgia,
12 Exhibit 3 for the record, please.

13 MADAM CHAIR PRIDEMORE: So marked.

14 (The document referred to was marked as
15 Concerned Ratepayers of Georgia Exhibit 3.)

16 BY MR. BAKER:

17 Q All right. Mr. Prenovitz, did you cause to
18 be prepared a summary of your prefiled testimony for the
19 Commission?

20 A I did.

21 Q Would you please present your summary at this
22 time.

23 A Thank you.

24 COMMISSIONER McDONALD: Mr. Prenovitz, before
25 you do that, let me ask you a question now that you
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1 are under oath.

2 WITNESS PRENOVITZ: Yes, sir.

3 COMMISSIONER McDONALD: When you appealed to
4 the chair about your absence when I called for you,
5 you said you were briefly out. There was a posse
6 that went out looking for you, and we waited and I
7 called twice. Do you want to retract that word
8 "briefly"?

9 WITNESS PRENOVITZ: Well, I was in the men's
10 room, sir. And that's why you had me sit by the door
11 there. They give me a special seat. So I was -- I
12 did it very quickly, but I guess I was out of ear
13 sight from you. So, you know, I apologize. I
14 apologize for any inconvenience there. It was not
15 intentional. I didn't have a choice. Okay?

16 MADAM CHAIR PRIDEMORE: What a Wednesday.

17 WITNESS PRENOVITZ: Thank you.

18 MADAM CHAIR PRIDEMORE: Would you like to read
19 your summary?

20 WITNESS PRENOVITZ: Thank you, ma'am. I would.
21 Okay.

22 Good afternoon, Commissioners. I'm Steve
23 Prenovitz with Concerned Ratepayers of Georgia. The
24 Grub panel defined Georgia Power's IRP process as
25 follows: A benchmark plan that contains Georgia
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1 Power's demand and energy forecast over a 20-year
2 period. Its purpose is to meet the requirements of
3 the forecast which will benefit customers through the
4 development of a diverse resource mix in an
5 economical and reliable manner.

6 CRG's testimony will evaluate this IRP plan to
7 determine if this is the most economical and reliable
8 way to benefit customers. The Commission's role is
9 similar, within the context of effective utility
10 regulation.

11 Over many years, I've appeared before the
12 Georgia PSC many times in many different capacities.
13 Since 1983 I have been an expert witness, public
14 witness, consultant, author, cross-examiner, and once
15 even did an invocation.

16 Areas of expertise include finance, economics,
17 strategic planning, quality management, marketing,
18 and an MBA. Reception has been mixed. Ranging from
19 Bobbie Pafford, Commissioner Shaw's uncle, bestowing
20 upon me the honorary title of Dr. Prenovitz, to
21 Commissioner Wise referring to me as an abomination.

22 Moving on to the obvious, which is often
23 overlooked, Georgia Power is a monopoly supplying a
24 critical product to the people of Georgia.

25 The principles of classical economics, driven
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1 by Adam Smith's principle of the invisible hand of
2 competition, do not apply to Georgia Power. Reason
3 being, the company has no competition. Hence the
4 need for regulation.

5 The purpose of regulation is to protect the
6 public from monopolistic pricing by acting as a
7 surrogate for competition, also to assure there is an
8 adequate supply to meet customer needs. Georgia
9 Power's IRP should be evaluated within this context.

10 The key question is, does Georgia Power's
11 current IRP and its previous IRP provide the reliable
12 energy -- safe, reliable energy in the most
13 cost-effective manner? The answer is no.

14 High capital costs are consistently ignored.
15 The focus is getting projects approved and completed.
16 Not controlling cost. Vogtle is an example. Georgia
17 Power's share of Vogtle costs more than doubled since
18 project inception, from 6.1 to 13.4 billion.

19 Georgia Power takes no responsibility for
20 escalating costs. Last month Mr. McKinney argued all
21 of Vogtle's costs to date have been prudently
22 incurred. This despite the fact that Georgia Power
23 wrote off \$3.1 billion in Vogtle losses over the past
24 three years which excluded financing.

25 Since the Vogtle construction projects have
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1 been consistently underperformed, is it prudent to
2 expect that future CAPAX projects will perform any
3 better? Also, there has been little to no financial
4 consequences for missing budgets.

5 Churchill observed, "You can always depend on
6 the Americans to do the right thing after trying
7 everything else."

8 The Commission has basically tried everything
9 else, such as accepting cost overruns as normal;
10 accepting Georgia Power's forecasts as gospel; secret
11 stipulated agreements with Georgia Power; and
12 granting most of Georgia Power's requests. Staff is
13 mostly complicit.

14 There are many flaws in Georgia Power's current
15 IRP as there were in Georgia Power's 2019 IRP. Most
16 notably, cost control is not a primary objective.

17 Since the 2019 IRP, there have been several
18 incremental cost increases, adjustments, riders, rate
19 increases passed on to the customer. Jeff Pollock,
20 witness for the Georgia Association of Manufacturers,
21 documented in his October '21 -- 2021 testimony that
22 Georgia Power will have four major rate changes
23 totaling approximately \$970 million in a 13-month
24 period from January '22 to January '23.

25 There are also add-on riders, such as fuel
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1 costs, environmental costs, NCCR riders, municipal
2 franchise fee, and a Georgia tax on these charges.

3 Pollock's testimony was sobering. I did not
4 realize the frequency of rate adjustments and its
5 cumulative impact. Metaphorically speaking,
6 consistent and incremental rate increases are similar
7 to placing a frog in water and gradually increasing
8 the temperature until the frog boils to death.

9 Time to stop treating customers as frogs. The
10 right thing for this Commission to do is focus on
11 cost control and put an end to these constant
12 incremental base rate increases. Reason being, high
13 capital costs produce high power bills.

14 The 2022 IRP ignores the pain that these
15 incremental and constant rate charges impose upon its
16 customers. Rather than trying to bring down costs,
17 this IRP will increase costs and hence power bills.

18 Another problem is the IRP plan is driven by
19 load forecast which in turn become the basis of
20 Georgia Power's multi-billion dollar capital budget
21 plans. Yet accurate long-term forecasting is not
22 possible, a fact Georgia Power continues to prove
23 with its dismal forecasting track record. Steve
24 Baron also referenced this issue.

25 Despite Georgia Power's optimistic load
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1 forecasts over the years, load growth has actually
2 declined. Georgia Power's chart, which has been
3 Attachment 3, I believe, highlights these realities.
4 Over an 18-year time frame, Georgia Power's total
5 kilowatt hour sales decreased from 87.4 billion
6 kilowatt hours to 83.5 in 2020. 2021 it went up to
7 86 billion. Still below 2020, total.

8 Peter Drucker, the father of management, modern
9 management, defined long-range forecasting as not a
10 respectable human activity and not worthwhile beyond
11 the shortest time periods.

12 The company's capacity forecasts are no better.
13 In 2009 when Vogtle began, Georgia Power's forecast
14 was for an additional 8,000 megawatts of capacity
15 would be needed within 10 years. The reality is
16 Georgia Power's capacity actually declined from
17 16,000 megawatts in 2009 to 14,400 in 2020. Again,
18 see the chart.

19 As the data clearly documents, these forecasts
20 are unreliable and should not be used to justify
21 multi-billion dollar CAPAX projects, but they are.
22 From an incentive vantage point, the higher Georgia
23 Power's capital cost, the higher the consumer rates
24 will be, thus producing higher revenues. This is a
25 negative incentive that drives many of the company's

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1 decisions.

2 From a customer and regulatory vantage point,
3 controlling customer power bills is their primary
4 concern -- not building new and expensive power
5 plants. Again, this is the role of regulation, to
6 protect the public from monopolistic pricing, such as
7 paying for the company's mistakes.

8 Since an IR plan has its roots in the strategic
9 plan, I will provide a brief overview of the planning
10 process and identify some of the generic deficiencies
11 of IRP '22 and 2019.

12 Strategy is defining what are the right things
13 to do from both the company and the consumer
14 perspective -- the customer perspective. Operational
15 implementation focuses on "how do we do things
16 right?"

17 Strategy sets the proper direction: mission
18 and high-level requirements. Effective operations
19 makes it happen. There are conflicting interests
20 between the company and the customer's needs and
21 objectives.

22 From Georgia Power's perspective, it's to
23 assure system reliability regardless of cost. From a
24 customer's perspective, it's to keep costs/rates as
25 low as possible, end constant rate increases, need

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1 price stability.

2 An effective IR plan should attempt to
3 reconcile these differences, not ignore them.
4 Georgia Power ignores these differences.

5 Our testimony addresses some of the strategic
6 weaknesses. Basically, a SWOT analysis is referred
7 to on page 19 of our testimony, which deals with
8 strengths, weaknesses, opportunities, and threats,
9 has basically been ignored. Also, there are general
10 steps to the strategic planning process on page 17.

11 Then in going to the Kennedy analysis -- and as
12 a historical footnote, Mr. Baron and I first met in
13 1987 when he had -- when we had questions, two hours'
14 worth, concerning Kennedy's Vogtle's 1 and 2
15 feasibility study.

16 The current testimony states, higher reserve
17 margins provide greater reliability but also greater
18 cost, implied to be absorbed by the customer.
19 Indeed, an appropriate balance. We agree. An
20 appropriate balance is needed, yet there is no
21 balance.

22 Kennedy concludes the average winter reserve
23 margin of the utilities in their survey was
24 18 percent. Georgia Power recommended 26 percent.
25 Staff recommended 24.5 percent. Then Kennedy

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1 concluded that their recommendation is, quote, very
2 conservative. We disagree. A 1.5 lower rate than
3 Georgia Power and a 6.5 percent higher rate than
4 survey results is not conservative. It is basically
5 appeasement.

6 Also, Kennedy ignored the cost impact on
7 customers. Especially in combination with other cost
8 increases over the past couple of years. Nor did
9 they explore other alternatives that may be available
10 to assure winter reliability without the need for
11 major capital expenditures. This is a constant
12 deficiency with Georgia Power's IRPs which Kennedy
13 did not address.

14 Our alternative: Reviewing this IRP reminded
15 me of my finance professor who praised me for
16 identifying problems and then challenged me to offer
17 solutions. Will try. Several years ago we published
18 an article titled "How to Translate Strategy Into
19 Operation Results." The methodology may prove
20 helpful to both the company and the Commission in
21 formulating and reviewing their plans.

22 The article was well-received. In fact, former
23 Georgia Power Southern Company and a chairman, Bill
24 Dahlberg, helped us review the article before
25 publication. We were also literally on the cover

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1 story of Business Forum, and here's a copy of the
2 article. Nice pretty graphics and that type of
3 thing.

4 And basic- -- and also, the Warden Business
5 School and the Copenhagen Business School included
6 our work in their curriculum. Others have also
7 referenced it, including Nissan, in implementing the
8 company's improvement process.

9 We focus on three components, and we had a
10 flowchart that did that; and, again, it's in the
11 testimony there, which it breaks it down into the
12 strategic thinking process, operational
13 implementation process, and management of the
14 implementation process.

15 And also, the editor of Business Forum
16 introduced our article as follows: You devised what
17 appears to be an excellent strategic plan for your
18 firm. Now the big hurdle, getting results. Our lead
19 article "How to Translate Strategy Into Operational
20 Results" is an excellent blueprint of the process.

21 All parties are encouraged to review the
22 article with a focus on the flowchart and our
23 step-by-step explanation.

24 The 2022 and 2019 IRP omitted several of these
25 steps. Specifically the strategic thinking process

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1 and a candidate's strengths and weaknesses. For
2 those that may be interested, I kept copies available
3 I'm glad to give you. Fellow consultants are
4 encouraged to get one, so see me if you are so
5 inclined.

6 Conclusions: To review, Georgia Power's stated
7 purpose of this IRP is to benefit customers through
8 the development of a diverse resource mix in an
9 economical and reliable manner. Focus on economical
10 manner. This IRP focuses on reliability but ignores
11 the economics and cost control.

12 As both CRG's testimony and the historical data
13 document, the plan is deficient on providing these
14 resources in a cost-effective manner. If Georgia
15 Power was in a competitive environment, such a plan
16 would never be presented, much less approved. The
17 IRP should be reworked to focus on the mission of
18 controlling costs while providing reliable power in a
19 cost-effective manner.

20 In essence, major change is required. For many
21 years, change has been proven very difficult. For
22 some inspiration, motivated by Dr. Bigalke, you may
23 want to reference page 13 of our testimony, which
24 titled "Now is the Time for Turning."

25 Finally, consultants are needed who advocate
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1 for the public interest. As our testimony on page
2 12 states, Peter Bradford is most capable. He
3 appeared in the '17 VCM and impressed both
4 Commissioner McDonald and myself. He also offered
5 his assistance in effectively confronting these
6 challenges. Perhaps the Commission may take
7 advantage of that.

8 I welcome questions from the Commission,
9 Georgia Power, and all intervenors; and also breaking
10 with tradition, if any consultants have any
11 questions, I'd be glad to take those. Thank you all
12 for your attention.

13 MADAM CHAIR PRIDEMORE: Questions from the
14 Commission?

15 COMMISSIONER McDONALD: Thank you very much.
16 Mr. Prenovitz, you said early on -- and I guess that
17 was the summary you just gave us. But you said early
18 on that Georgia Power had no competition.

19 WITNESS PRENOVITZ: Yes.

20 COMMISSIONER McDONALD: Are you familiar with
21 the load competition between Georgia Power, Electric
22 Membership Cooperatives, and Municipal Electric
23 Authorities?

24 WITNESS PRENOVITZ: It's very limit -- you are
25 very right. It's very limited competition. My

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1 apologies.

2 COMMISSIONER McDONALD: Well, you said --

3 WITNESS PRENOVITZ: You are right. I did that.

4 COMMISSIONER McDONALD: -- they didn't have

5 competition.

6 WITNESS PRENOVITZ: Okay.

7 COMMISSIONER McDONALD: That's what you said.

8 WITNESS PRENOVITZ: They have no residential

9 competition. There might be some competition in some

10 of these other areas when, you know, regulations

11 changed.

12 COMMISSIONER McDONALD: That wasn't what you

13 said, though.

14 WITNESS PRENOVITZ: Okay. I stand corrected,

15 sir.

16 COMMISSIONER McDONALD: Thank you.

17 WITNESS PRENOVITZ: Thank you.

18 MADAM CHAIR PRIDEMORE: Any other questions

19 from Commissioners?

20 (No response.)

21 MADAM CHAIR PRIDEMORE: For the sake of

22 brevity, does anyone wants to cross Mr. Prenovitz?

23 COMMISSIONER McDONALD: Mr. Prenovitz, one

24 thing. I'm sorry, Madam Chair.

25 No residential competition. What about solar

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1 energy? Is that competition that residential have?

2 WITNESS PRENOVITZ: Not really.

3 COMMISSIONER McDONALD: Really? Not really?

4 WITNESS PRENOVITZ: Not really.

5 COMMISSIONER McDONALD: No?

6 WITNESS PRENOVITZ: It's a very minor part.

7 So, I mean, it's an option, but it's very minor. And
8 I've had that, too. I mean, I've had solar people
9 come up to us and make their proposals and so on like
10 that, and it's definitely --

11 COMMISSIONER McDONALD: But if one desires to
12 put solar on their house or in their yard or
13 whatever, they can disconnect from the power company.
14 Is that not correct?

15 WITNESS PRENOVITZ: No. They are still
16 connected.

17 COMMISSIONER McDONALD: No, no. They can
18 disconnect.

19 WITNESS PRENOVITZ: Okay. My understanding is
20 they're still connected, but basically, the main part
21 of their power would come from solar.

22 COMMISSIONER McDONALD: They don't have to use
23 the main part of the power. They can disconnect
24 totally if they elect to do so.

25 WITNESS PRENOVITZ: Okay. I'm unfamiliar with
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1 that part of it.

2 MADAM CHAIR PRIDEMORE: Any other questions
3 from commissioners?

4 (No response.)

5 MADAM CHAIR PRIDEMORE: Okay. Do any of the
6 intervenors wish to cross-examine Concerned
7 Ratepayers for Georgia?

8 (No response.)

9 MADAM CHAIR PRIDEMORE: Okay. Georgia Public
10 Service Commission?

11 MR. THOMAS: No, thank you.

12 MADAM CHAIR PRIDEMORE: Okay. Georgia Power?

13 MR. HEWITSON: No, thank you.

14 MADAM CHAIR PRIDEMORE: All right. There is
15 nothing to do redirect on. And so all of your
16 handouts have been -- have been submitted.

17 MR. BAKER: I ask that Mr. Prenovitz's prefiled
18 testimony and exhibits be entered into the record.

19 MADAM CHAIR PRIDEMORE: So marked.

20 (Concerned Ratepayers of Georgia Exhibits 1-3
21 were admitted into evidence.)

22 MR. BAKER: Thank you, Madam Chair. And could
23 he please be excused?

24 MADAM CHAIR PRIDEMORE: You may be excused,
25 Mr. Prenovitz.

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1 WITNESS PRENOVITZ: Thank you, Madam Chairman.
2 I appreciate health, and it's good to see you again.

3 MADAM CHAIR PRIDEMORE: Good to see you, too.
4 You have a good day.

5 WITNESS PRENOVITZ: In person.

6 MADAM CHAIR PRIDEMORE: Okay. Let's see. We
7 have Georgia Association of Manufacturers. Let me
8 ask you before you get going, Mr. Jones, how much
9 time are you going to -- are you going to be a little
10 bit?

11 MR. STEVEN JONES: I think his direct and his
12 summary is probably 10 minutes.

13 MADAM CHAIR PRIDEMORE: Going to be a little
14 bit.

15 MR. STEVEN JONES: So we can take a break if
16 you would prefer to.

17 MADAM CHAIR PRIDEMORE: Yeah. Let's go ahead
18 and take a break now. Let's --

19 MR. STEVEN JONES: Before we -- before we do,
20 can I just say I apologize for us coming out of
21 order. I want to apologize to Commissioner McDonald.
22 Apparently, Jeff Stair set a record for getting a
23 witness up and down off the stand in the time that we
24 were trying to go to the restroom. So apologize and
25 thank you for resuming us anyway.

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1 MADAM CHAIR PRIDEMORE: Your issues are not to
2 be blamed on Jeff Stair or anybody else.

3 MR. STEVEN JONES: No. I like to give Jeff a
4 little grief.

5 COMMISSIONER McDONALD: You and Mr. Prenovitz
6 got to applaud the chair.

7 MR. STEVEN JONES: Yes, ma'am -- yes, sir.

8 COMMISSIONER McDONALD: Because you'd have gone
9 to the back of the bus.

10 MR. STEVEN JONES: I appreciate it, and I would
11 not want to do that, so thank you very much.

12 MADAM CHAIR PRIDEMORE: Keep Mr. Stair out of
13 this next time.

14 MR. STEVEN JONES: I will. I apologize. I
15 apologize, Jeff.

16 MADAM CHAIR PRIDEMORE: All right. Let's take
17 a break, and let's come back at 3:20.

18 (A recess was taken.)

19 JEFFRY POLLOCK,
20 having been duly sworn, testified as follows:

21 DIRECT EXAMINATION

22 BY MR. C. JONES:

23 Q Would you state your name for the record.

24 A I'm Jeffry Pollock.

25 Q Okay. And Mr. Pollock, how are you employed?

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1 A I am employed with J. Pollock, Incorporated.

2 Q All right. On May 6th did you file or cause
3 to be filed in this docket 37 pages of Q. and A. direct
4 testimony, along with two appendices, A and B?

5 A Yes.

6 Q And did you also cause to be filed on
7 May 23rd an errata with changes to pages 19 and 27 of your
8 testimony?

9 A Yes.

10 Q And if I were to ask you the same questions
11 in your prefiled direct testimony as amended by your
12 errata, would your answers be the same?

13 A They would.

14 MR. C. JONES: Okay. Madam Chair, I would ask
15 that the witness's prefiled testimony with amended
16 pages 19 and 27 be copied into the record as if given
17 orally from the stand.

18 MADAM CHAIR PRIDEMORE: So marked.

19 MR. C. JONES: Thank you.

20 (Whereupon, the prefiled direct testimony
21 of Mr. Pollock follows:)

22

23

24

25

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Jeffry Pollock; 12647 Olive Blvd., Suite 585; St. Louis, Mo., 63141.

3 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

4 A I am an energy advisor and President of J. Pollock, Incorporated.

5 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

6 A I have a Bachelor of Science in electrical engineering and a Master's in Business
7 Administration from Washington University. Since graduation, I have been engaged in
8 a variety of consulting assignments, including energy procurement and regulatory
9 matters in the United States and in several Canadian provinces. I have participated in
10 numerous regulatory proceedings before the Georgia Public Service Commission,
11 including rate cases and rulemaking cases. My qualifications are documented in
12 **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

13 **Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

14 A I am testifying on behalf of the Georgia Association of Manufacturers (GAM). The
15 members of GAM are customers of Georgia Power Company (GPC). They consume
16 large quantities of electricity under a variety of tariffs and represent a significant amount
17 of the electricity sold to the Large Business and Marginally Priced customer classes.
18 The decisions made in this Integrated Resource Plan (IRP) will ultimately affect GAM
19 members' electricity costs.

**1. Introduction, Qualifications
and Summary**

J. POLLOCK
INCORPORATED

1 Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?

2 A I shall discuss:

- 3 • The Clean and Renewable Energy Subscription (CARES) program;
- 4 • GPC's proposed capacity expansion plan;
- 5 • Cost recovery of the decertified plants; and
- 6 • Additional sum.

7 Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

8 A Yes. I'm sponsoring Exhibits GAM-1 through GAM-8.¹

9 Q ARE YOU ENDORSING GPC'S PROPOSALS ON THE ISSUES NOT ADDRESSED
10 IN YOUR TESTIMONY?

11 A No. The fact that I am not addressing every issue should not be interpreted as an
12 endorsement of GPC's proposals in this proceeding.

13 **Summary**

14 Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

15 A My findings and recommendations are as follows:

16 **CARES Program**

- 17 • GAM supports GPC's proposed CARES program. It is consistent with similar
18 programs that allow customers to voluntarily subscribe to renewable energy
19 resources. These voluntary programs are now offered by regulated utilities in
20 18 states and are widely available in states with active competitive retail
21 markets.
- 22 • Approval of the CARES program alone is insufficient to ensure that eligible
23 customers subscribe. Crucial to the success of the program will be
24 implementing balanced terms and conditions that protect the interests of both
25 subscribers and non-subscribers. The terms and conditions for the CARES
26 program will be vetted in the upcoming rate case.

¹ Exhibits GAM-1, GAM-2 and GAM-3 were entered into evidence in the April 4th hearing.

- Examples of balanced terms and conditions are (1) flexible initial contract lengths, (2) contract renewals, (3) assignment to another qualified customer without penalty, (4) a requirement to mitigate damages in the event of early termination, and (5) an early termination payment that reflects actual damages.
- GAM does not object to GPC using updated commodity price assumptions to project avoided costs prior to issuing future requests for proposals.
- GPC should clarify how the "best-cost" standard would be implemented. Specifically, the proposal should identify the "system needs" that would be potential exceptions to the avoided cost standard and define how cost-effectiveness would be determined.

Capacity Expansion Plan

- While GAM does not oppose the retirement of power plants that are both uneconomical and not needed to maintain reliability, GPC's proposed capacity expansion plan goes too far. Its primary focus is implementing a generation fleet makeover (*i.e.*, the early retirement of the vast majority of GPC's coal units) and permanently increasing the long-term winter target reserve margin (TRM) to 26% rather than meeting the growth in peak demand.
- With the exception of the winter of 2023 (due to the early retirement of Wansley and delays in placing Vogtle Units 3 and 4 in service), GPC's proposed capacity expansion plan would result in winter reserve margins that exceed the proposed winter TRM.
- Absent the early retirements of Wansley, Scherer Units 1, 2 and 3, and Bowen Units 1 and 2, GPC would have ample capacity to meet its higher winter TRM without the six capacity Power Purchase Agreements (PPAs). Even with Wansley retired in 2022, GPC would have surplus capacity through the late 2020s with the exception of the winter of 2023.
- However, the 2023 need would disappear completely if GPC's winter TRM were based on the same loss-of-load expectation (LOLE) reliability standard widely used throughout the industry, which would result in a 20% winter long-term TRM. NERC uses this standard to establish reference reserve margins (ranging from 10.7% to 23.1%) in its long-term reliability assessments.
- GPC has not demonstrated that setting a TRM higher than 20% would guarantee that customers would avoid *potentially* higher production costs that it would incur during, for example, severe weather events and difficult operating conditions that may require load shedding, additional market purchases, and the dispatch of high cost resources. Such occurrences, however, are non-recurring, low-probability events.

- 1 • With the addition of the six capacity PPAs, more than 10,000 MW (nearly 60%)
2 of GPC's total winter capacity would be comprised by generating resources that
3 rely primarily on natural gas. Natural gas prices can be highly volatile during
4 extreme cold weather when heating demand is also high and pipeline capacity
5 is constrained. With natural gas generation as its primary reserve capacity,
6 GPC cannot guarantee that it will not incur and pass through higher production
7 costs incurred during severe weather and difficult operating conditions.
- 8 • Increased production costs due to higher natural gas prices will be passed
9 through to customers under GPC's Fuel Cost Recovery (FCR) rate. There is
10 little GPC could do to mitigate high natural gas prices or prevent higher FCR
11 rates.
- 12 • Ironically, the early retirement of Scherer Units 1, 2, and 3 and Bowen Units 1
13 and 2, coupled with adding the six capacity PPAs, would make rates more
14 susceptible to higher natural gas prices. This conclusion is supported by GPC's
15 Unit Retirement Study (URS), which demonstrates that keeping these coal units
16 operational is less costly than retirement under the Moderate Gas (MG) and
17 High Gas (HG) planning scenarios.
- 18 • The recent spike in natural gas prices, coupled with more restrictive permitting
19 limiting expanded production and pipeline capacity, cast serious doubt that the
20 low gas prices of the past will return anytime soon.
- 21 • The early retirement of Scherer Units 1, 2 and 3 and Bowen Units 1 and 2 is not
22 supported by GPC's URS because:
 - 23 ○ Four of the seven planning scenarios assume that Congress will enact
24 a national carbon fee on fossil fuel emissions effective in 2025 while
25 continuing to extend renewable tax credits.
 - 26 ○ GPC did not consider the possibility of rising costs for solar PPAs and
27 battery energy storage systems (BESS) that would replace the capacity
28 provided by these units.
- 29 • Despite decades of debate and discussion, Congress has not enacted a
30 national carbon tax or fee. Further, there is no pending legislation that is likely
31 to result in a national carbon tax anytime in the near future. In lieu of a carbon
32 tax, Congress has enacted and extended on many occasions various tax credits
33 to encourage renewable energy deployment.

- Solar PPA offer prices increased 6% in the first quarter of 2022 and 15.8% year over year. The reason for rising prices include supply chain difficulties (exacerbated by a recent Department of Commerce investigation on the import of solar panels from Southeast Asia), and higher costs for labor, materials, and shipping (due to high gasoline/diesel prices). Wind and BESS projects are not immune to these pricing pressures. The latter are being challenged by rising costs for lithium, steel, aluminum, and critical rare earth minerals.
- The URS also assumes no accelerated recovery of GPC's remaining investment (\$3.1 billion as of last December) in Scherer Units 1, 2, and 3 and Bowen Units 1 and 2, and it excluded any additional sum associated with the replacement capacity (*i.e.*, six capacity PPAs and solar PPAs). Recognizing these variables would increase the costs of early retirement.

Cost Recovery of Retired Plant

- GPC has far too much invested in Scherer Units 1, 2 and 3 and Bowen Units 1 and 2 to simply abandon them in this IRP.
- Unlike in past IRPs, GPC will be seeking recovery of a substantial amount of investment along with a return on that investment while simultaneously recovering the annual fixed charges and additional sum on the replacement capacity. Customers should not have to pay twice for the same capacity.
- Determining the amount of cost recovery and the length of the recovery period should be deferred to a future rate case.
- The Commission should not decide whether Scherer Units 1, 2, and 3 and Bowen Units 1 and 2 should be decertified in this IRP. Accordingly, it should reject GPC's proposal to reclassify the investments in these units as regulatory assets.

Additional Sum

- The purpose of an additional sum is to encourage GPC to pursue resource alternatives that do not directly contribute to shareholder earnings.
- GPC collects the additional sum in base rates. The revenues collected flow through to GPC's net income. Thus, the additional sum provides additional earnings for GPC's shareholder.
- GPC would recover \$17.7 million per year — more than triple the pre-tax return for its shareholder than GPC is currently allowed to recover on the existing PPAs — from the proposed additional sum associated with the six capacity PPAs. The additional sum was derived on the assumption that GPC would have built a new generating project in lieu of executing the capacity PPAs.

- 1 • GPC's self-build generating project was not cost competitive. Other capacity
2 PPAs that were not selected were far less expensive than GPC's self-build
3 project. Because a new self-build generator would place more upward pressure
4 on rates than a PPA sourced from an older depreciated asset, the cost will be
5 inflated. Consequently, the savings are inflated.
- 6 • GPC does not meet the requirements of Rule 515-3-4-.11 in this IRP because
7 there are no lost revenues or lost earnings associated with five of the six
8 capacity PPAs with the GPC affiliate, Southern Power. Southern Power's
9 earnings on the PPAs will flow to the benefit of GPC's parent, Southern
10 Company. Further, GPC has not demonstrated that there are any changed
11 regulatory or financial risks. In particular, this Commission's ratemaking
12 practices are viewed by the investment community as being highly constructive
13 and supportive of GPC. Any credit risks associated with any new PPAs are as
14 yet unknown and will not be known until the upcoming rate case.
- 15 • The circumstances surrounding this IRP are unique (*i.e.*, GPC's generation fleet
16 makeover is the critical driver — not load growth) and more complicated (*i.e.*,
17 customers would have to pay twice for the same capacity) than when the IRP
18 rule was originally adopted.
- 19 • Accordingly, the proposed additional sum on the six capacity PPAs should not
20 be approved at this time.
- 21 • However, if the Commission approves the six capacity PPAs and also
22 determines that it must approve an additional sum in this IRP, the current \$2.30
23 per kW-year should be retained thereby rejecting GPC's proposal to triple the
24 additional sum.

2. CARES PROGRAM

1 **Q WHAT IS THE CARES PROGRAM?**

2 **A** As described in GPC's direct testimony, the CARES program incorporated feedback
3 from customers, including GAM members, who want to procure electricity generated
4 from various renewable energy resources for both existing and planned new load
5 through a voluntary subscription program.² The introduction of a Carbon Free Energy
6 - Around-the-Clock (CFE-ATC) option is both an innovative and creative way for
7 customers to procure carbon-free energy on a daily basis — not just when the sun is
8 shining and/or the wind is blowing.

9 **Q ARE VOLUNTARY RENEWABLE ENERGY SUBSCRIPTION PROGRAMS**
10 **BECOMING INCREASINGLY MORE PREVALENT THROUGHOUT THE ELECTRIC**
11 **UTILITY INDUSTRY?**

12 **A** Yes. According to S&P, utilities in at least 18 states that fully regulate electric utilities
13 have implemented voluntary green tariffs (see **Exhibit GAM-4**). Further, retail
14 customers located in states with competitive electricity markets can voluntarily procure
15 renewable energy either directly from the wholesale market or through arrangements
16 with retail electric providers to directly assign and pass-through all of the costs and
17 attributes from the renewable energy resource.

18 These voluntary renewable energy programs help to meet the needs of those
19 customers who consider the direct procurement of renewable energy and renewable
20 energy certificates (RECs) as essential to meeting their corporate sustainability goals.

² Direct Testimony of Jeffrey R. Grubb, A. Wilson Mallard, Michael B. Robinson and Jeffrey B. Weathers at 43.

1 Q DOES GAM GENERALLY SUPPORT THE PROPOSED CARES PROGRAM?

2 A Yes.

3 Q WILL APPROVAL OF THE CARES PROGRAM NECESSARILY ENSURE THAT
4 CUSTOMERS WILL FULLY SUBSCRIBE TO THE 2,100 MEGAWATTS (MW) THAT
5 GPC IS PROPOSING TO PROCURE?

6 A No. Critical to the success of the CARES program will be for GPC to enter into various
7 PPAs that are the result of fully competitive processes. Procurements that result in
8 prices at or below avoided cost are essential to mitigate upward pressure on rates.

9 However, the willingness of customers to fully subscribe to the CARES program
10 will ultimately require that the contract terms and conditions provide an appropriate
11 balance that protects both the participants and non-participating customers.

12 Q DO YOU HAVE SOME EXAMPLES OF TERMS AND CONDITIONS THAT ARE
13 ESSENTIAL TO ACHIEVE AN APPROPRIATE BALANCE?

14 A Yes. For example, subscriptions must allow customers to choose from a variety of
15 contract terms – 5, 10, 15 or 20-year contracts. This recognizes that customers may
16 not be in a position to commit to longer term contracts. Not all solar PPAs are 15 and
17 20-year deals. According to LevelTen Energy (LevelTen), the average term of solar
18 PPAs is 14.3 years.³

³ Exhibit GAM-8 at 10 which is an excerpt from LevelTen. LevelTen Energy, *Q1 2022 PPA Price Index North America*. LevelTen provides software that enables faster, safer, and more efficient transactions for the renewable energy industry, delivering the transaction infrastructure required to accelerate the clean energy economy. LevelTen's platform provides renewable energy advisors, developers, large-scale buyers, and financiers with instant access to the full market of renewable energy projects, on two continents, combined with the automated analytics and technology to get better deals done, faster.

2. CARES Program

1 Second, customers who enter into shorter term agreements should have the
2 option to extend those contracts on a favored nation basis. Favored nation status
3 means that customers extending the initial contract term would be made whole for the
4 higher costs incurred as a result of initially opting for a shorter contract term.

5 Third, the terms should also allow customers to assign their contract obligations
6 to another customer, provided that the assignee meets reasonable credit requirements
7 that are acceptable to GPC.

8 Further, the termination provisions should include an obligation that both parties
9 take steps to mitigate potential damages if a customer terminates a subscription early,
10 and the termination payment should reflect only those costs that, if shifted to other
11 customers, would otherwise put upward pressure on rates.

12 **Q HAS THE COMPANY PROPOSED SPECIFIC TERMS AND CONDITIONS**
13 **APPLICABLE TO THE CARES PROGRAM?**

14 **A** No. These issues will be addressed in more detail in GPC's upcoming rate case. Their
15 successful resolution will be critical to the success of the CARES program.

16 **Q GPC IS PROPOSING TO IMPLEMENT A "BEST COST" STANDARD FOR**
17 **PROCURING RENEWABLE ENERGY. DOES THIS REPRESENT A SIGNIFICANT**
18 **POLICY CHANGE?**

19 **A** Yes. GPC states it would be a significant change from current practice.⁴ My
20 understanding is that the best-cost standard would allow GPC to update the projected
21 avoided costs rather than disqualify proposals that exceed the avoided costs

⁴ 2022 IRP Main Document at 14-99 and 14-100.

1 determined in this IRP using the moderate gas zero carbon (MG0) planning scenario.
2 Assuming this specific change would essentially involve updating, rather than changing
3 either the methodology or other key assumptions, GAM does not oppose this aspect of
4 the best-cost standard.

5 **Q DO YOU HAVE ANY OTHER CONCERNS WITH THE PROPOSED BEST-COST**
6 **STANDARD?**

7 **A** Yes. GPC states that the best-cost standard could result in procurements that exceed
8 the then-determined avoided cost threshold if they are deemed appropriate to help
9 GPC meet certain system needs in a cost-effective manner.⁵ However, GPC does not
10 specifically state what system needs a future acquisition would be required to meet,
11 and it did not propose a specific process for determining whether the need can be met
12 in a cost-effective manner. This second aspect of the best-cost standard is, in my
13 opinion, too broad and should not be adopted at this time.

14 **Q WHAT DO YOU RECOMMEND?**

15 **A** Future procurements that would exceed avoided cost should be subject to Commission
16 review and approval. In its rebuttal testimony in this IRP, GPC should clearly define
17 the system needs that would qualify as possible exceptions to the avoided cost
18 standard and specify how cost-effectiveness would be determined.

⁵ *Id.*

3. CAPACITY EXPANSION PLAN

1 **Q WHAT IS GPC'S PROPOSED CAPACITY EXPANSION PLAN?**

2 **A** GPC's proposed capacity expansion plan would replace approximately 3,500 MW of
3 existing capacity (mostly coal) with 2,356 MW of capacity from new PPAs (capacity
4 PPAs), 2,100 MW of solar, and 1,000 MW of BESS, and various distributed energy
5 resource programs. Table 1 summarizes the capacity that GPC is proposing to
6 decertify in this IRP.

Table 1 Proposed Capacity Decertifications			
Plant	In-Service Date	Assumed Unavailability Date	Winter Retail Capacity (MW)
Wansley Units 1-2/CT	1976/78	8/31/22	965
Boulevard (Oil)	1970	8/31/22	19
Bowen Units 1-2	1971/72	12/31/27	1,432
Gaston Units 1-4/CT (Gas)	1960/70	12/31/28	470
Scherer Units 1, 2, and 3	1982/84/87	12/31/28	648
Source: IRP Main Document at A-137.			

7 The proposed decertifications would result in retiring Wansley Units 1 and 2, Bowen
8 Units 1 and 2, and Scherer Units 1, 2, and 3 by eight years, three years, and up to 19
9 years prior to their current lifespans, respectively.

10 These changes would allow the Southern Company system to achieve a 26%
11 winter TRM over the long term. To accomplish the latter objective, GPC would have to
12 maintain a 25.18% (long-term) and 24.69% (short-term) winter TRM and a 15.28%
13 (long-term) and 14.78% (short-term) summer TRM.⁶

⁶ *Id.* at 5-27.

As discussed later, while GAM does not oppose retiring fossil fuel plants that are neither economical nor necessary to maintain reliability, GPC's capacity expansion plan goes too far.

Q WOULD GPC'S PROPOSED CAPACITY EXPANSION PLAN RESULT IN ACHIEVING THE TARGET WINTER TRM?

A Yes and more. With the exception of 2023, GPC's proposed capacity expansion plan would result in winter reserve margins that exceed 25.18% until 2029. The 2023 winter reserve margin would be below GPC's stand-alone (23.9%)⁷ short-term TRM due to the delays in placing Vogtle Units 3 and 4 in service and the proposed early retirement of the Wansley plant in 2022. If the Wansley retirement is delayed to 2023, GPC would achieve its winter TRM in 2023.

Q IS THE PROPOSED CAPACITY EXPANSION PLAN BEING DRIVEN BY THE PROJECTED GROWTH IN PEAK DEMAND?

A No. Exhibit GAM-5, page 1, summarizes GPC's projected peak demand growth (columns 1 and 5) and the proposed capacity changes (columns 2 through 4 and 6 through 8). Through 2031, GPC is projecting cumulative peak load growth of 470 MW during the winter months and 299 MW during the summer months (line 10). Over the same period, GPC is proposing to retire more capacity (between 7,200 MW and 7,300 MW) than it is proposing to add (between 3,300 MW and 3,700 MW). As a result, net capacity would be reduced by between 3,600 MW (summer) and 3,900 MW (winter). Thus, the proposed changes in net capacity from 2022 through 2031 would substantially outweigh the projected cumulative load growth.

⁷ GPC's stand-alone short-term TRM is assumed to be 95% of the corresponding long-term TRM (*i.e.*, 95% of 25.18% = 23.9%).

Therefore, it is clear that GPC's proposed capacity expansion plan is solely about achieving a complete makeover of its generation fleet rather than expanding capacity to meet peak demand.

Q WHAT RESERVE MARGINS WOULD BE ACHIEVED UNDER GPC'S PROPOSED CAPACITY EXPANSION PLAN?

A Exhibit GAM-5, page 2, summarizes the projected reserve margins for the period 2022 through 2031, adjusted for the recent delays in the in-service dates of Vogtle Units 3 and 4. The projected winter reserve margins are shown in columns 1 through 3 and the projected summer reserve margins are shown in columns 4 through 6. The reserve margins under GPC's proposed capacity expansion plan are shown in columns 1 (winter) and 4 (summer).

With the exception of 2023, GPC would more than achieve its winter TRM during the period 2022 through 2028 (column 1). Accordingly, over the same 2022 through 2028 period the projected summer reserve margins (column 4) would also exceed the 15.28% long-term summer TRM, including 2023.

Q BUT FOR GPC'S PROPOSAL TO DECERTIFY APPROXIMATELY 3,500 MW OF CAPACITY, WOULD GPC NEED TO INCREASE GENERATION CAPACITY TO MEET ITS TARGET RESERVE MARGINS?

A No. For example, in **Exhibit GAM-5**, page 2, I have also calculated the projected reserve margins assuming that none of the coal plants that GPC is proposing to decertify in this IRP (*i.e.*, Wansley; Scherer Units 1, 2, and 3; and Bowen Unit 1 and 2) are retired early and that GPC does not purchase additional capacity from the six PPAs procured in its recent capacity RFPs. The results show that GPC could more than achieve its winter TRM (column 2) through 2029 and its summer TRM (column 5)

3. Capacity Expansion Plan

1 through 2028. However, assuming that the Wansley coal plant is retired in 2022 as
2 proposed, GPC would have a small capacity deficit during the winter months in the
3 years 2023 and 2025 (column 3) through 2029, but it would otherwise have more than
4 adequate capacity during the summer months, at least through the year 2028 (column 6).

5 **Q WOULD GPC HAVE SUBSTANTIAL CAPACITY SURPLUSES UNDER ITS**
6 **PROPOSED EXPANSION PLAN?**

7 **A** Yes. This is shown in **Exhibit GAM-5**, page 3. Under its proposal, GPC would have
8 significant capacity surpluses in both the winter (column 1) and the summer (column 5).

9 **Q WOULD GPC NEED THE CAPACITY FROM THE SIX PPAS IF THE WANSLEY,**
10 **SCHERER UNITS 1, 2 AND 3, AND BOWEN UNITS 1 AND 2 ARE NOT RETIRED**
11 **EARLY?**

12 **A** No. Even without the six capacity PPAs, GPC would have surplus capacity in both the
13 winter and summer months if Wansley, Scherer Units 1, 2 and 3, and Bowen Units 1
14 and 2 are not retired early (columns 2 and 6).

15 **Q WOULD GPC NEED ADDITIONAL CAPACITY IF THE STAND-ALONE WINTER**
16 **TRM WERE 20%?**

17 **A** No. If the winter TRM were only 20%, GPC would not need additional capacity prior to
18 the year 2030. Thus, it is clear that the planned early retirements and higher TRM are
19 the primary drivers of GPC's proposed capacity expansion plan. Absent the early
20 retirements or higher TRM, GPC would not need to add new generation capacity until
21 2030.

1 **Target Reserve Margin**

2 **Q WHAT IS GAM'S POSITION ON GPC'S PROPOSED LONG-TERM TARGET**
3 **RESERVE MARGINS?**

4 A GAM members support GPC's primary mission to provide reliable electricity service at
5 affordable prices. However, as discussed in GPC's testimony, the proposed long-term
6 TRM is also driven by economics and risk tolerance. Thus, the proposed long-term
7 TRM goes above and beyond the need to provide reliable service.

8 **Q WHAT LONG-TERM TARGET RESERVE MARGIN WOULD BE REQUIRED IF GPC**
9 **WERE TO CONSIDER ONLY RELIABILITY?**

10 A The Company's TRM Study indicates that if reliability were the sole consideration, the
11 long-term winter TRM would be approximately 20%. A 20% long-term winter TRM
12 would be sufficient to ensure only one hour of outage every ten years. This is
13 equivalent to a 1:10 loss of load expectation (LOLE). As discussed later, this planning
14 methodology (*i.e.*, a 1:10 LOLE) is widely used throughout the electric industry.

15 **Q HOW DO ECONOMICS AND RISK TOLERANCE EFFECT THE LONG-TERM**
16 **TARGET RESERVE MARGIN?**

17 A As shown in **Exhibit GAM-1**, introducing economic considerations increases the long-
18 term winter TRM from 20% to 24.25%. GPC's assessment of risk tolerance would
19 further increase the long-term winter TRM to 26% (25.18% for GPC alone).

20 **Q WHY IS GPC PROPOSING TO INCLUDE ECONOMICS AND RISK TOLERANCE IN**
21 **ESTABLISHING ITS TRM?**

22 A GPC asserts that by introducing economic considerations and risk tolerance, a higher
23 target reserve margin would protect customers because GPC could avoid incurring

1 potentially high production costs during severe weather and adverse operating
2 conditions. Production costs are the generation (*i.e.*, fuel, variable operating and
3 maintenance expense) and purchase costs associated with serving load requirements
4 throughout the year.⁸ The latter would include emergency energy purchases from
5 neighboring systems.

6 **Q WOULD SETTING A TRM ABOVE 20% GUARANTEE THAT CUSTOMERS WILL**
7 **AVOID HIGH PRODUCTION COSTS DURING SEVERE WEATHER OR ADVERSE**
8 **OPERATING CONDITIONS?**

9 A No. GPC cannot guarantee that customers will avoid higher production costs even if it
10 adds capacity to achieve a TRM above 20%.

11 **Q PLEASE EXPLAIN.**

12 A A higher TRM will allow GPC to use more of its own capacity to serve customers during
13 severe operating conditions rather than rely on emergency off-system purchases,
14 which, at times, could be very expensive. However, a higher TRM will not necessarily
15 avoid higher production costs. In fact, a higher TRM means that GPC will incur higher
16 production costs because, for example, the six capacity PPAs will obligate GPC to incur
17 \$[REDACTED] million in annual fixed payments, excluding the proposed additional sum.⁹
18 Every dollar of these charges will be included in base rates and paid for by GPC
19 customers.

⁸ 2022 IRP Main Document, Attachment C at C-148.

⁹ GPC Response to STF-JKA-2-20 (Trade Secret).

1 Q WOULD A HIGHER TARGET RESERVE MARGIN NECESSARILY AVOID HIGHER
2 PRODUCTION COSTS?

3 A No. With the addition of the six capacity PPAs, more than 10,000 MW (nearly 60%) of
4 GPC's total winter capacity would be supplied by natural gas-fired generating
5 resources. Gas-fired generation is more prone to price volatility, especially during
6 extreme cold weather when heating demand is high and pipeline capacity is
7 constrained. Under these circumstances, GPC may experience high prices for natural
8 gas supply when demand exceeds available supply, deliverability constraints that may
9 result from operational flow orders issued by the pipelines, and higher transportation
10 charges for gas delivery in excess of the current firm transportation contract. All of
11 these circumstances would result in higher production costs. These higher production
12 costs would be passed through to GPC's customers under the FCR rate.

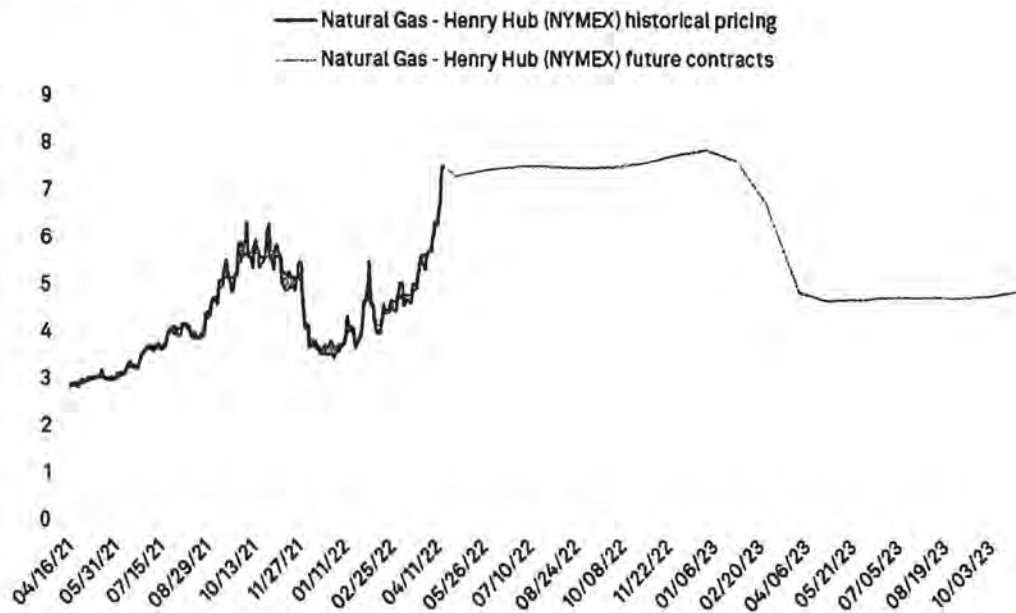
13 Therefore, regardless of how high the TRM is set above 20%, if the additional
14 reserves are being supplied by natural gas generation, particularly during the summer
15 and winter peak months, there is very little GPC could do to mitigate high production
16 costs. In fact, the only way for GPC to avoid these higher production costs would be
17 to fully hedge both the gas price and the supply. Gas price hedges require certainty
18 about the monthly gas volumes for each of the various gas-fired power plants.
19 However, severe weather is a low-probability non-recurring event. It would neither be
20 practical nor cost effective to hedge the price of an unknown quantity of gas for
21 resources that are not in continuous operation. Hedging gas supply would be
22 potentially more feasible because GPC could purchase storage or install dual-fuel
23 capability. Either option, however, would entail additional costs.

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1 Q HAVE RECENT CHANGES IN NATURAL GAS PRICES HEIGHTENED THESE
2 CONCERNS?

3 A Yes. As reported by S&P Capital IQ^{PRO}, natural gas prices are trending much higher.

With gas in storage low, NYMEX gas futures are high
(\$/MMBtu)



As of April 17, 2022
Source: S&P Global Market Intelligence

4 Q WHAT ARE NYMEX FUTURES CONTRACTS?

5 A The New York Mercantile Exchange (NYMEX) operates a natural gas futures market
6 and publishes natural gas futures contracts prices. They represent actual transactions
7 between buyers and sellers who put real money at risk in their day-to-day operations.
8 Futures contracts are highly liquid in the near term, and futures prices are highly visible
9 because they are widely disseminated by the various financial and commodity
10 exchanges. Thus, futures contract prices are an important source of price discovery
11 for sellers and producers.

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- 1 **Q WHAT IS CONCERNING ABOUT THE RECENT SPIKE IN NATURAL GAS PRICES?**
- 2 **A** First, gas prices are already higher than the prices assumed in GPC's resource mix
- 3 model. GPC's MG scenarios were based on the Energy Information Administration's
- 4 (EIA's) Reference forecast as published in its 2021 Annual Energy Outlook (AEO).
- 5 GPC's LG and HG scenarios were based on the EIA's High and Low Oil and Gas
- 6 Supply cases, respectively. However, the EIA is projecting higher gas prices in its 2022
- 7 AEO than the 2021 AEO published just one-year earlier. This is shown in Table 2.

Table 2 Natural Gas Price Projections (Nominal \$/MMBtu)				
Publication	Planning Scenario	2023	2024	2025
2021 AEO	LG0/20	\$2.70	\$2.41	\$2.42
2022 AEO		\$3.19	\$2.82	\$2.68
2021 AEO	MG0/20	\$3.10	\$2.95	\$3.10
2022 AEO		\$3.64	\$3.38	\$3.27
2021 AEO	HG0/20	\$3.82	\$3.90	\$3.96
2022 AEO		\$3.90	\$3.96	\$4.41
NYMEX Futures	Last 30 Days	\$4.45	\$3.76	\$3.69

- 8 Second, even before the EIA's 2022 AEO was published, near-term natural gas
- 9 prices were trending higher. Even if NYMEX gas futures contracts were to decline
- 10 below \$4 per MMBtu early next year, they would be well above the GPC's MG planning
- 11 scenarios and somewhat closer to GPC's HG planning scenarios.

- 12 Therefore, at least in the near term, more emphasis should be given to GPC's
- 13 MG and HG scenarios in its URS.

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1 Q HOW DOES GPC'S TARGET RESERVE MARGIN ANALYSIS COMPARE WITH THE
2 PRACTICES USED IN OTHER REGIONS?

3 A The practices used in other regions are summarized in **Exhibit GAM-6**. The
4 information in **Exhibit GAM-6** was sourced from NERC's 2021 Long-Term Reliability
5 Assessment.

6 As can be seen, most of the assessment areas use a 0.1 day/year LOLE
7 expectation to determine their minimum reserve margins. This is the same LOLE
8 metric that GPC uses to determine its reliability-based TRM. The assessment areas
9 that use the 0.1 day/year LOLE includes SERC Corporation and SERC-Southeast.
10 Both areas have established a 15% reference reserve margin level. Southern
11 Company is a SERC member and it is located in the SERC Southeast assessment
12 area.

13 Q PLEASE SUMMARIZE YOUR CONCERNS ABOUT GPC'S PROPOSED LONG-
14 TERM TARGET RESERVE MARGINS.

15 A While GPC's desire to protect customers from adverse extreme events is admirable,
16 setting a higher TRM alone will not prevent customers from paying higher production
17 costs as a result of price spikes and gas supply shortages. The much higher natural
18 gas prices that we are currently experiencing will be reflected in higher FCR rates as
19 early as next year. Further, the higher TRM will require customers to incur higher base
20 rate costs.

21 Q WHAT DO YOU RECOMMEND?

22 A GPC has not demonstrated whether and how customers would benefit (in the form of
23 lower rates) from setting a long-term TRM that reflects economics and risk tolerance in

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1 addition to maintaining system reliability. Without any price protection, customers
2 would be at risk for paying higher production costs through the FCR rate during periods
3 of extreme weather and difficult operating conditions. Further, the proposed 25.18%
4 long-term winter TRM is much higher than the 15% reference reserve margins used by
5 most of the regional assessment areas. Therefore, the TRM should be set no higher
6 than is required to maintain system reliability.

7 **Unit Retirement Study**

8 **Q YOU PREVIOUSLY STATED THAT GPC WOULD HAVE ADEQUATE RESERVE**
9 **MARGINS BUT FOR THE PROPOSED EARLY RETIREMENTS OF WANSLEY,**
10 **SCHERER UNITS 1, 2 AND 3 AND BOWEN UNITS 1 AND 2. HAS GPC**
11 **CONCLUSIVELY DEMONSTRATED THAT THESE UNITS SHOULD BE RETIRED**
12 **EARLY?**

13 **A** No. A summary of the URS results for each of the seven planning scenarios is provided
14 in Table 3 below, which includes the information presented in **Exhibit GAM-2** for all
15 seven planning scenarios used by GPC.

16 Table 3 demonstrates that the results are, at best, mixed for Scherer Units 1, 2,
17 and 3 and Bowen Units 1 and 2. As discussed later, based on the results from the
18 more likely planning scenarios, these units should not be retired early. The only firm
19 conclusions are that the early retirement of Wansley and Gaston are supported.

Table 3 Summary of Unit Retirement Study Net Cost of Early Retirement Exceeds Net Benefits of Continued Operation					
Planning Scenario	Wansley 1-2	Bowen 1-2	Gaston 1-4	Scherer 3	Scherer 1-2
LG0	Yes	Yes	Yes	No	No
MG0	Yes	No	Yes	No	No
HG0	No	No	Yes	No	No
LG20	Yes	Yes	Yes	Yes	Yes
MG20	Yes	Yes	Yes	Yes	Yes
HG20	Yes	Yes	Yes	Yes	Yes
\$50*	Yes	Yes	Yes	Yes	Yes
Gas Price	Carbon Adder				
LG: Low Gas	\$20/Metric Ton				
MG: Mod. Gas	\$50/Metric Ton				
HG: High Gas					
Source: Technical Appendix Volume II, Unit Retirement Study. *\$50: Moderate Gas \$50/Metric Ton Carbon Adder.					

1 However, I would note that there remains some risk that Vogtle Units 3 and 4 may not
 2 be placed in service in 2023 as GPC currently projects. As previously stated, retiring
 3 Wansley early without Vogtle Units 3 and 4 in service would not allow GPC to achieve
 4 its short-term winter TRM.

5 **Q DO THE RESULTS OF GPC'S UNIT RETIREMENT STUDY CONCLUSIVELY**
 6 **SUPPORT THE EARLY RETIREMENT OF SCHERER UNITS 1, 2 AND 3' AND**
 7 **BOWEN UNITS 1 AND 2?**

8 **A** No. The benefits of retiring these units early would only be realized if Congress were
 9 to enact legislation that imposed a carbon price on fossil fuel generation. As can be
 10 seen in Table 2, four of the seven planning scenarios examined in the URS assume

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1 that a significant fee – either \$20 per metric ton or \$50 per metric ton – would be
2 charged for all CO₂ emissions.

3 **Q WHAT IS THE SOURCE OF THE ASSUMED \$50 CARBON FEE SCENARIO?**

4 A The \$50 per metric ton carbon fee scenario was one of three alternative policy
5 scenarios modeled by the EIA in its 2020 AEO. As discussed in the 2020 AEO:

6 **Carbon Fees**

7 *The AEO2020 Reference case generally assumes that existing laws*
8 *and regulations remain as enacted throughout the projection period,*
9 *including when the laws or policies are scheduled to sunset.* However,
10 in the area of policies that target emissions reduction, history has
11 demonstrated that there is significant uncertainty in this assumption. To
12 examine the effects of this uncertainty across the energy sector, EIA
13 modeled three levels of economy-wide carbon fees. These fees apply only
14 to CO₂ from energy combustion and do not include other gases such as
15 methane.

16 **Methodology**

17 *The three carbon fee cases start with fees of \$15, \$25, and \$35 per*
18 *metric ton (mt) of CO₂ beginning in 2021. The fees rise by 5% per year*
19 *in real 2019 dollars* during the projection period, as shown in Table 1.
20 Incorporating CO₂ fees increases the costs of certain forms of energy and
21 reduces total consumer disposable income in the economy; returning
22 revenues to consumers helps offset some of the loss in disposable income
23 but does not completely mitigate it. EIA did not consider distributional effects
24 within consumer segments in this analysis.¹⁰ (emphasis added)

25 The \$50 per metric ton carbon fee is based on the assumptions that (1) a \$35 per
26 metric ton fee is first implemented in 2021 and (2) the fee will escalate by 5% per
27 year above the prevailing inflation rate to \$50 per metric ton by 2025.

¹⁰ U.S. Energy Information Administration, *Alternative Policies* at 16 (March 2020).

1 **Q IS IT REALISTIC TO ASSUME THAT CONGRESS WILL ENACT LEGISLATION**
2 **IMPOSING A CARBON FEE ON FOSSIL FUEL GENERATION?**

3 **A No.** Carbon emissions have been a topic of discussion for the last several decades.
4 For example, in 2009 the Obama administration proposed a federal budget that
5 included nearly \$650 billion dollars in new climate related revenues through 2019.
6 These revenues would have been collected as taxes, primarily from energy producers,
7 manufacturers and other industries that emit carbon dioxide. Several bills were
8 proposed in Congress to enact carbon taxes, including: S.2191 - Lieberman-Warner
9 Climate Security Act of 2007; H.R. 2454 - American Clean Energy and Security Act of
10 2009 (Waxman-Markey bill); and S.1733 - Clean Energy Jobs and American Power Act
11 (Kerry-Boxer). Only the latter was passed by the Senate, but it was never enacted.
12 Thus, no carbon adder or carbon cap has been implemented on a national scale.
13 Further, there is no pending legislation that would lead to the enactment of a carbon
14 adder or carbon cap on a national scale.

15 Therefore, giving weight to planning scenarios that assume that Congress
16 would pass legislation imposing a carbon tax such as the carbon adders modeled by
17 GPC in this proceeding is clearly unjustified. Accordingly, little or no weight should be
18 given to these planning scenarios.

19 **Q HAS CONGRESS CHOSEN ANOTHER MEANS OF ENCOURAGING THE BUILD**
20 **OUT OF RENEWABLE ENERGY OTHER THAN THROUGH THE ENACTMENT OF**
21 **CARBON TAXES?**

22 **A Yes.** Renewable energy resources are eligible for various tax credits. The "temporary"
23 Production Tax Credit (PTC) for wind power, enacted in 1992, has been extended 13
24 times. The Investment Tax Credit (ITC) for solar has been extended thrice. These tax

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1 credits have been extended on several occasions to encourage further build out of
2 renewable resources, including BESS. In fact, Congress is now considering further
3 extensions of the existing tax credits for renewable energy and BESS (see Exhibit
4 GAM-7).

5 **Q DO YOU HAVE ANY OTHER CONCERNS ABOUT THE MIXED RESULTS OF GPC'S**
6 **UNIT RETIREMENT STUDY FOR SCHERER UNITS 1, 2 AND 3 AND BOWEN UNITS**
7 **1 AND 2?**

8 **A** Yes. The benefits of early retirement derived in the URS were based on replacing the
9 decertified units with a portfolio of resources, including the six capacity PPAs as well
10 as additional solar and BESS capacity. In modeling solar, GPC assumed that future
11 procurements would result in a first-year price of \$25 per MWh with a 3% per year
12 escalation. This would result in a \$34 per MWh levelized cost of energy (LCOE). GPC
13 further assumed that subsequent solar PPAs would also have a \$34 per MWh LCOE.
14 In other words, the cost to replace the decertified plants would decline in real terms.

15 **Q IS IT REASONABLE TO ASSUME THAT SOLAR COSTS WILL DECLINE IN REAL**
16 **TERMS?**

17 **A** No. First, it is evident that GPC's \$34 per MWh LCOE for solar could only be achieved
18 if the current 30% investment tax credit is extended. This is demonstrated in Table 4,
19 which compares GPC's assumed \$34 per MWh LCOE of solar to similar estimates
20 prepared by the EIA in its 2022 AEO, adjusted for inflation through 2025.

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Table 4 Levelized Cost of Solar Energy (2025\$ per MWh)	
Description	Amount
Georgia Power Company PPA	\$34.00
EIA: Solar, Standalone (2027, Capacity-Weighted)	\$36.65
EIA Solar, Standalone (2027, Unweighted)	\$37.05
Sources: 2022 IRP Main Document, Att. F at F-159. Energy Information Administration, <i>Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022</i> , Tables 1a and 1b; 2.3% per year inflation rate.	

1 As Table 4 demonstrates, the EIA's estimate of solar LCOE is higher than GPCs. As
2 Congress has preferred tax credits over carbon fees, planning scenarios that reflect
3 both extended tax credits and carbon fees are clearly unrealistic.

4 **Q IS THERE EVIDENCE THAT SOLAR COSTS HAVE BEEN AND ARE FORECAST**
5 **TO TREND HIGHER?**

6 **A** Yes. **Exhibit GAM-8** is an excerpt from a report published by LevelTen. LevelTen
7 surveys all renewable PPAs consummated in various regions throughout North
8 America.

9 As can be seen, PPA offer prices are for projects under development to be
10 constructed two to three years in the future that were posted by developers on the
11 LevelTen Energy Marketplace. For the first time since publishing the PPA Price Index
12 Report, prices increased across all ISOs for both wind and solar quarter over quarter,
13 with the Technology-Blended Price Index rising by 9.7% in the first quarter of 2022.

14 Specifically, LevelTen's reported prices for solar projects with commercial
15 operation dates from 2022 through 2026 are shown in Table 5.

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Table 5 Solar PPA Prices By Commercial Operation Date (\$/MWh)					
2021 Q2	2022	2023	2024	2025	2026
\$31.45	\$40.81	\$33.38	\$35.00	\$36.98	\$50.70

LevelTen notes that 2022 was an exception due to the reverberations of the 2020-2021 pandemic-induced shockwaves and supply chain challenges. The Market-Averaged Index for solar prices rose by 6% in the first quarter and 15.8% year over year.

Q WHAT IS DRIVING THE HIGHER PROJECTED SOLAR PPA PRICES?

LevelTen cited the "pervasive and unabating headwinds renewable developers are encountering on nearly every front of project development."¹¹ Among the headwinds are "[s]upply chain turmoil and spiking prices for commodities, labor, and project components" which have "added substantial costs and uncertainty for developers as they look to set PPA prices years in advance of project construction" and uncertainties surrounding the continuation of tax credits.¹²

Further, "[w]ith high gas prices, the cost of transporting and assembling components for renewable projects is also increasing as suppliers along every step of the supply chain account for these fuel costs by raising prices, creating a cascading effect of price increases for developers."¹³ The supply of photovoltaic (PV) panels,

¹¹ Exhibit GAM-8 at 3.

¹² *Id.*

¹³ *Id.*

1 which are essential to solar projects, is "still adapting to immense disturbances driven
2 by a human rights crisis and a larger polysilicon shortage."¹⁴

3 In particular the Commerce Department's investigation into whether
4 manufacturers have used factories in Southeast Asia to circumvent tariffs on PV
5 imports from China is leading to a wave of delays and cancellation of solar module
6 shipments.¹⁵ These headwinds will make it harder for developers to commit with
7 certainty to a long-term PPA price.

8 **Q HAS GPC MODELED RISING SOLAR AND BESS COSTS?**

9 A No. All of GPC's eleven planning scenarios assume declining solar and BESS costs.
10 The Tech planning scenario, however, assumed even lower costs than the other ten
11 scenarios.¹⁶

12 **Q WHAT DO YOU RECOMMEND?**

13 A Based on the above report and information published by the EIA, it is highly unlikely
14 that solar PPA prices will continue to decline in real terms as GPC is assuming in its
15 resource mix and URS. Further, recent dramatic increases in lithium prices and other
16 rare earth minerals that are essential to wind projects and BESS further cast doubt on
17 the reasonableness of the technology costing assumptions used in developing the
18 planning scenarios. For this reason, GPC should have included a planning scenario
19 that assumes increasing PPA prices for solar projects and the impact of rising mineral
20 costs on BESS.

¹⁴ *Id.*

¹⁵ *Id.* at 6.

¹⁶ 2022 IRP Resource Mix Study at 14.

1 Q DO YOU HAVE ANY OTHER CONCERNS WITH THE UNIT RETIREMENT STUDY?

2 A Yes. First, the URS implicitly assumes that GPC would not propose to accelerate
3 recovery of the remaining investment in each of the decertified plants. For example,
4 the retirement dates for Scherer Units 1, 2 and 3 range from 2040 through 2044. If
5 GPC were to accelerate recovery to coincide with the retirement date, that would
6 reduce the net benefits of early retirement.

7 Similarly, GPC did not consider the additional sum associated with the capacity
8 PPAs that would replace the capacity provided by the decertified plants. The proposed
9 additional sum would increase the cost of early retirement by approximately \$17.7
10 million per year, as shown in Table 6.

Table 6 Proposed Additional Sum on the Capacity PPAs				
PPA	Capacity (MW)	Effective Date	Proposed (\$/kW-Year)	Amount (\$Millions)
Wansley 7	598	12/1/24	\$8.63	\$5.2
Dahlberg 2 & 6	152	6/1/25	\$9.03	\$1.4
Harris 2	660	12/1/24	\$8.67	\$5.7
Dahlberg 1,3 & 5	228	1/1/28	\$8.12	\$1.9
Monroe 1 & 2	309	12/1/24	\$6.70	\$2.1
Dahlberg 8-10	228	6/1/25	\$6.77	\$1.5
Total	2,175			\$17.7
Source: STF-LA-3-3.				

11 As previously stated, the capacity PPAs would not be needed if Scherer Units 1, 2 and
12 3 and Bowen Units 1 and 2 were not being retired prior to the end of their useful lives.
13 Recognizing the potential for accelerated cost recovery and/or the additional sum
14 associated with the capacity PPAs would further reduce the benefits of decertification.

3. Capacity Expansion Plan

1 Q WHAT CONCLUSIONS SHOULD BE DRAWN FROM THE UNIT RETIREMENT
2 STUDY?

3 A The URS does not support the early retirement of Scherer Units 1, 2 and 3 and Bowen
4 Units 1 and 2. This is because four of the seven planning scenarios assumed that a
5 national carbon fee on fossil fuel emissions and renewable tax credit extensions would
6 co-exist, and the replacement generation portfolio ignored recent trends indicating
7 higher (not lower) solar costs and higher costs for BESS. Further, the LG scenarios
8 assumed continued low natural gas prices. These scenarios are undermined by the
9 recent short-term natural gas price spikes. GPC has far too much invested in Scherer
10 Units 1, 2 and 3 and Bowen Units 1 and 2 to simply abandon them at this time.

11 Q ARE THERE ANY ADVANTAGES TO DELAYING THE DECERTIFICATION OF
12 THESE UNITS AT THIS TIME?

13 A Yes. The advantages of delay include (1) avoiding upward pressure on rates due to
14 accelerated cost recovery of \$3.1 billion of remaining investment, (2) retaining
15 additional fuel diversity and (3) increasing resiliency during periods of high gas prices
16 and pipeline constraints that would mitigate high production costs.

17 In addition, electric utilities are poised to spend record amounts on transmission
18 system improvements. The competition for labor and materials will be significant.
19 Thus, delaying the decertification would provide a hedge against cost pressures and
20 prolonged delays in installing the transmission facilities required by retiring these
21 resources.

4. COST RECOVERY OF RETIRED PLANT

1 Q HOW MUCH HAS GPC INVESTED IN THE PLANT THAT IT IS NOW PROPOSING
2 TO DECERTIFY IN THIS IRP?

3 A As shown in **Exhibit GAM-3**, GPC has yet to recover \$3.1 billion of investment in the
4 Wansley, Scherer and Bowen units that it is proposing to decertify in this IRP. The
5 \$3.1 billion represents approximately 25% of GPC's retail net production plant as of
6 December 31, 2021.¹⁷

7 Q IS GPC CURRENTLY RECOVERING THE INVESTMENT AND EARNING A
8 RETURN ON THE PLANTS THAT IT IS NOW PROPOSING TO DECERTIFY?

9 A Yes.

10 Q FOR HOW LONG WOULD GPC BE ALLOWED TO RECOVER THE REMAINING
11 INVESTMENT AND EARN A RETURN ON THE PLANTS THAT IT IS PROPOSING
12 TO DECERTIFY?

13 A The period of time over which cost recovery would continue is unknown and will not be
14 determined until a future rate case. Currently, the investment in Wansley and Bowen
15 Units 1 and 2 would be fully recovered by 2030, while the investments in Scherer Units
16 1, 2 and 3 would extend to the years 2042 through 2047.

17 Q WILL GPC BE SEEKING COST RECOVERY FOR THE SIX CAPACITY POWER
18 PURCHASE AGREEMENTS DURING THIS SAME TIMEFRAME?

19 A Yes. GPC will request (1) recovery of and (2) an additional sum on the six capacity

¹⁷ GPC's 2021 Annual Surveillance Report, Section 2.

PPAs that will replace Wansley, Bowen Units 1 and 2 and Scherer Units 1, 2 and 3 commencing December 2024. This will result in higher base rates because in addition to seeking a recovery of and a return on the decertified plants, GPC will also be seeking (1) recovery of and (2) an additional sum on 2,100 MW of solar PPAs to be placed in service by 2029, as well as (1) a recovery of and (2) a return on 1,000 MW of BESS beginning in 2030. In other words, under GPC's capacity expansion plan, customers would pay twice for the same capacity even though the capacity of the decertified plants will no longer be used and useful.

Q WHY SHOULD THE COMMISSION BE CONCERNED ABOUT THE POSSIBILITY THAT CUSTOMERS WOULD HAVE TO PAY TWICE FOR THE SAME CAPACITY?

A Although the IRP is not a rate case, the decisions made in an IRP will have implications in setting future base rates. This concern is especially relevant because GPC will be filing its next rate case before this IRP is decided. Further, it will be seeking higher base rates when (1) Vogtle Unit No. 3 goes online (currently scheduled for the 1st quarter of 2023) and (2) when fuel is loaded in Vogtle Unit No. 4 sometime later in 2023. With the prospect of substantial base rate increases occurring as early as next January, the Commission should be especially mindful of the impact that the decisions in this IRP will have on GPC customers.

Q WHAT DO YOU RECOMMEND?

A The Commission should defer any decision on the regulatory treatment of the remaining investment in the decertified plants. Both the amount subject to recovery and the amortization period, which will impact rates, are best decided in future rate cases.

4. Cost Recovery of Retired Plant

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5. ADDITIONAL SUM

1 **Q WHAT IS THE PURPOSE OF AN ADDITIONAL SUM?**

2 A The purpose of an additional sum is to encourage GPC to pursue resource alternatives
3 that do not directly contribute to shareholder earnings. When GPC installs generation
4 capacity, the investment is included in rate base, and GPC is allowed to recover the
5 investment (*i.e.*, depreciation) and earn a shareholder return (*i.e.*, return on equity) on
6 the investment. In contrast, when GPC enters into PPAs, the expense is included in
7 base rates without a shareholder return.

8 **Q HOW IS THE ADDITIONAL SUM RECOGNIZED ON GPC'S REGULATORY**
9 **BOOKS?**

10 A GPC collects the additional sum in base rates. Since there are no actual offsetting
11 expenses, the revenues collected from the additional sum flow through to GPC's net
12 income. Thus, the additional sum provides additional earnings for GPC's shareholder.

13 **Q IS GPC PROPOSING TO INCREASE THE AMOUNT OF REVENUES COLLECTED**
14 **IN BASE RATES FOR THE ADDITIONAL SUM?**

15 A Yes. As previously explained, GPC is proposing to recover \$17.7 million per year of
16 additional sum associated with the six capacity PPAs. Currently, GPC is allowed to
17 earn \$2.30 per kilowatt (kW) year on the current PPAs. If applied to the six capacity
18 PPAs, the \$2.30 per kW-year additional sum would generate \$5 million per year of
19 annual revenues. Thus, GPC's proposed additional sum would more than triple the
20 pre-tax return for its shareholder.

5. Additional Sum

1 Q IS GPC ALSO PROPOSING TO EARN AN ADDITIONAL SUM ON THE NEW SOLAR
2 PPAS?

3 A Yes. GPC is proposing to earn \$7.50 per kW_{ac}-year of nameplate capacity associated
4 with the solar PPAs.¹⁸ This would generate an additional \$22.5 million per year
5 assuming that 2,100 MW of new solar projects are procured as anticipated.

6 Q WHAT IS THE REQUIREMENT FOR APPROVING AN ADDITIONAL SUM?

7 A Rule 515-3-4-.11 (Cost Recovery and Financial Incentives) states that:

8 The certified or actual cost, whichever is less, of purchase of any
9 certificated long-term power purchase shall be recovered in rates by the
10 utility along with the additional sum as determined by the Commission
11 to encourage such purchases. *The Commission shall consider lost*
12 *revenues, if any, changed risks, and an equitable sharing of*
13 *benefits* between the utility and its retail customers...(emphasis added)

14 Q DO YOU HAVE ANY SPECIFIC CONCERNS WITH THE PROPOSED ADDITIONAL
15 SUM ON THE SIX CAPACITY PPAS?

16 A Yes. The proposed additional sum was based on an estimate of the savings between
17 the fixed charges under the six PPAs and the Company-owned (self-build) project over
18 the terms of the former. However, the Company-owned project was not cost
19 competitive. Numerous other offers were much less costly than the Company-owned
20 project, and any of these would have been selected in lieu of one of the six PPAs.
21 Accordingly, GPC's proposed shared-savings analysis is inflated.

22 Q HAS GPC MET THE REQUIREMENTS OF RULE 515-3-4-.11 IN THIS IRP?

23 A No. First, there are no lost revenues or lost earnings associated with five of the six
24 capacity PPAs. This is because the owner of the assets, Southern Power, is a GPC

¹⁸ 2022 IRP Main Document at 14-102.

1 affiliate and is owned by the same holder, Southern Company. It is logical to assume
2 that Southern Power's pricing proposal, which was ultimately selected by GPC in the
3 most recent capacity RFP, included a return for Southern Power. Even though the
4 PPAs will not provide a direct return to GPC, Southern Power will earn a return and
5 that return will flow to the benefit of the parent company, Southern Company.

6 Second, GPC has not demonstrated that there has been any changed risks
7 either with respect to regulatory policy or to its creditworthiness that would justify an
8 additional sum. Regulatory risks are minimal under the Commission's ratemaking
9 practices, which allow the use of a future test year and multi-year accounting orders to
10 set base rates. GPC has had no difficulty earning its authorized return on equity. The
11 Commission's ratemaking practices also allow the deferral of eligible fuel expense.
12 Accordingly, there is zero risk that GPC will not fully and timely recover all of the costs
13 associated with the capacity PPAs, solar PPAs and the future BESS.

14 Whether these new PPAs would create any additional credit or financial risks
15 would require a full assessment of GPC's capital structure, credit metrics, and how
16 these obligations are viewed by credit rating agencies. These determinations, however,
17 are more appropriately determined in a rate case.

18 Finally, the third consideration (an equitable sharing of benefits) is not relevant
19 under the circumstances of this IRP. Specifically, the choice in this IRP is not simply
20 between self-build and purchased capacity to meet rising demand. Instead, the choice
21 is to determine the best options for replacing existing capacity representing over \$3
22 billion of unrecovered investment that has between seven and over 20 years of
23 remaining useful life. The Commission will also have to decide in future cases how,
24 and over what period, GPC will be allowed to recover its remaining investment. In other

5. Additional Sum

1 words, because customers would have to pay twice for the same capacity, there are
2 no benefits to share, only costs.

3 Thus, the circumstances in this IRP are clearly unique and far more complicated
4 than when the IRP rule was originally adopted.

5 **Q WHAT DO YOU RECOMMEND?**

6 **A** GPC's proposal to more than triple the additional sum on the capacity PPAs is both
7 extreme and unnecessary given the circumstances of this IRP. Further, GPC has not
8 satisfied the considerations required under Rule 515-3-4-.11 for five of the six PPAs.
9 In particular, there are no lost revenues and GPC's shareholder will be compensated
10 for the \$3.1 billion of remaining investment in the plants to be retired, as well as the
11 additional sum on the capacity and solar PPAs that will replace them. All of these costs
12 will be at customers' expense. Finally, the proper venue for vetting any financial risks
13 that may be attributed to the PPAs by credit rating agencies is in the upcoming rate
14 case.

15 Therefore, the proposed additional sum should not be approved at this time.
16 However, if the Commission approves the capacity PPAs, and also decides to award
17 an additional sum in this IRP, the current \$2.30 per kW-year should be retained.

5. Additional Sum

6. CONCLUSION

1 Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES
2 ADDRESSED IN YOUR TESTIMONY?

3 A The Commission should make the following findings:

- 4 • Adopt the CARES program.
- 5 • Allow GPC to update the projected avoided costs prior to issuing subsequent
6 requests for proposals to recognize updated commodity price projections.
- 7 • Reject GPC's proposed best-cost standard as currently outlined.
- 8 • In the alternative, adopt a revised best-cost standard that (1) identifies the
9 system needs that could be met by procuring a new capacity resource at a cost
10 that exceeds the then-projected avoided cost, and (2) defines how cost-
11 effectiveness would be determined.
- 12 • Reject GPC's long-term winter target reserve margin.
- 13 • Approve a 20% long-term winter target reserve margin as necessary to maintain
14 a reliable generation system.
- 15 • Reject GPC's proposed early retirement of Scherer Units 1, 2, and 3 and Bowen
16 Units 1 and 2.
- 17 • Reject GPC's proposal to treat the remaining investments in Scherer Units 1, 2,
18 and 3 and Bowen Units 1 and 2 as regulatory assets.
- 19 • Reject the six capacity power purchase agreements that would otherwise
20 replace Scherer Units 1, 2, and 3 and Bowen Units 1 and 2.
- 21 • In the alternative:
 - 22 ○ If the six capacity power purchase agreements are approved, find that
23 GPC has not met the requirements of Rule 515-3-4-.11 for an additional
24 sum.
 - 25 ○ If an additional sum is approved in this IRP, retain the current \$2.30 per
26 kW-year additional sum that applies to existing capacity power purchase
27 agreements.

28 Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

29 A Yes, at this time.

6. Conclusion

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APPENDIX A
Qualifications of Jeffry Pollock

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 **A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis,**
3 **Missouri 63141.**

4 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

5 **A I am an energy advisor and President of J. Pollock, Incorporated.**

6 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

7 **A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree**
8 **in Business Administration from Washington University. I have also completed a Utility**
9 **Finance and Accounting course.**

10 Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc.
11 (DBA). DBA was incorporated in 1972 assuming the utility rate and economic
12 consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to
13 November 2004, I was a managing principal at Brubaker & Associates (BAI).

14 During my career, I have been engaged in a wide range of consulting
15 assignments including energy and regulatory matters in both the United States and
16 several Canadian provinces. This includes preparing financial and economic studies
17 of investor-owned, cooperative and municipal utilities on revenue requirements, cost of
18 service and rate design, tariff review and analysis, conducting site evaluations, advising
19 clients on electric restructuring issues, assisting clients to procure and manage
20 electricity in both competitive and regulated markets, developing and issuing requests

Appendix A

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1 for proposals (RFPs), evaluating RFP responses and contract negotiation and
2 developing and presenting seminars on electricity issues.

3 I have worked on various projects in 28 states and several Canadian provinces,
4 and have testified before the Federal Energy Regulatory Commission, the Ontario
5 Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas,
6 Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky,
7 Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New
8 Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington,
9 and Wyoming. I have also appeared before the City of Austin Electric Utility
10 Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of
11 Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the
12 Bonneville Power Administration, Travis County (Texas) District Court, and the U.S.
13 Federal District Court.

14 **Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.**

15 **A** J. Pollock assists clients to procure and manage energy in both regulated and
16 competitive markets. The J. Pollock team also advises clients on energy and regulatory
17 issues. Our clients include commercial, industrial and institutional energy consumers.
18 J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
EL PASO ELECTRIC COMPANY	Freeport-McMoran, Inc	52195	Cross-Rebuttal	TX	Rate 38, Class Cost-of-Service Study, Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoran, Inc	52195	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation, Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation, Production Tax Credits, Radial Lines, Load Dispatching Expenses, Uncollectible Expense, Class Revenue Allocation, LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation, LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses, Jurisdictional Cost Allocation, Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study, Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study, Revenue Allocation, Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study, Rate Design, Revenue Requirement	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study, Revenue Allocation	6/28/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan, Reserve Surplus, Solar Base Rate Adjustments, Class Cost-of-Service Study, Class Revenue Allocation, CIL/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021

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OGE GAS COMPANY	Association of Businesses Advocating Tariff Equity	LI-20540	Direct	MI	Class Cost-of-Service Study, Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation, Class Cost of Service Study, Class Revenue Allocation, LGS-T Rate Design, Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study, Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-057-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula, Time Differentiated Costs, Time-of-Use Fuel Factor	4/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation, Class Cost-of-Service Study, Class Revenue Allocation, Large Lighting and Power Rate Design, Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenor	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification, revised Electric Embedded Cost-of-Service Study, revised Distribution Main Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs, Amortization of Mine Closure Costs, Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenor	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service, Class Revenue Allocation, Rate Design, Revenue Decoupling Mechanism	12/23/2020
NIAGARA MOHAWK POWER CORP	Multiple Intervenor	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51361	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP	Multiple Intervenor	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service, Class Revenue Allocation, Rate Design, Earnings Adjustment Mechanism, Advanced Metering Infrastructure Cost Allocation	11/25/2020

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year, Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Petroleum Ltd	20-00143	Direct	NM	RPS Incentives, Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions, ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study, Time-of-Use period definitions, Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Substantive	PA	Interruptible transportation tariff, Allocation of Distribution Mains, Universal Service and Energy Conservation, Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load, Allocation of Distribution Capacity Costs, Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation, Design Day Demand, Class Revenue Allocation, Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study, Financial Compensation Method, General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020

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CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study, Transportation Rate Design, Gas Demand Response Pilot Program, Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study, Class Revenue Allocation, Infrastructure Recovery Mechanism, Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines, Allocation of Transmission Costs, SPP Administrative Fees, Load Dispatching Expenses, Uncollectible Expense	3/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses Depreciation Expense (Rev Req Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study, Class Revenue Allocation, Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study, Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	19-00170-UT	Direct	NM	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49615	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42515	Direct	GA	Return on Equity, Capital Structure, Coal Combustion Residuals Recovery, Class Revenue Allocation, Rate Design	10/17/2019

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NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenor	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service, Class Revenue Allocation, Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenor	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service, Class Revenue Allocation, Rate Design, Amortization of Regulatory Liabilities, AMI Cost Allocation	9/20/2019
AEP TEXAS INC	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs, Class Revenue Allocation, Customer Support Costs	8/13/2019
AEP TEXAS INC	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design, Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study, Rate Design, Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains, Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study, Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmission Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	49057	Direct	TX	Transmission Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019

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CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20185	Direct	MI	Integrated Resources Plan, Projected Rate Impact, Risk Assessment, Early Retirement of Coal Units, Financial Compensation Mechanism	10/15/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Rebuttal	MI	Class Cost-of-Service Study, Average Historical Profile, Distribution Cost Classification and Allocation, Rate Design	10/1/2018
ENERGY+ INC	Toyota Motor Manufacturing Canada	EB-2018-0028	Initial Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	9/27/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Direct	MI	Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	9/10/2018
KANSAS GAS AND ELECTRIC COMPANY	Occidental Chemical Corporation	18-KG&E-303-CON	Rebuttal	KS	Benefits of the Interruptible Load Provided in the Special Contract	8/29/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Cross-Rebuttal	TX	4CP Moderation Adjustment	8/28/2018
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	48371	Cross-Rebuttal	TX	Class Cost-of-Service Study, Schedule FERC	8/16/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Direct	TX	Tax Cuts and Jobs Act, Rider TCRF, 4CP Moderation Adjustment	8/13/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Surebuttal	PA	Post Test-Year Adjustment, Tax Cuts and Jobs Act, Class Cost-of-Service Study, Distribution System Improvement Charge	8/8/2018
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	48371	Direct	TX	Revenue Requirements, Tax Cuts and Jobs Act, Riders	8/1/2018
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	48371	Direct	TX	Class Cost-of-Service Study, Firm, Interruptible and Standby Rate Design	8/1/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Rebuttal	PA	Class Cost-of-Service Study, Class Revenue Allocation	7/24/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Cross-Rebuttal	TX	Allocation of TCJA reduction	7/19/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Direct	TX	Allocation of TCJA reduction	7/15/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Direct	PA	Post Test-Year Adjustment, Tax Cuts and Jobs Act, Class Cost-of-Service Study, Class Revenue Allocation	6/28/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Cross-Rebuttal	TX	Class Cost-of-Service Study, Revenue Allocation	5/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permar Ltd	17-00255-UT	Rebuttal	NM	Class Cost-of-Service Study, Revenue Allocation	5/2/2018

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ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Stipulation	AR	Support of Stipulation	4/27/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Present Base Revenues Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Tax Cuts and Jobs Act, SPP Transmission and Wheeling Costs, Depreciation Rate, LLPPAs, Imputed Capacity, Off-System Sales Margins	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Direct	NM	Class Cost-of-Service Study, Revenue Requirements, Revenue Allocation	4/13/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Supplemental	AR	Certificate of Convenience and Necessity	4/6/2018
METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY	MEIUG, PICA and WPPH	2017-2637855 2017-2637857 2017-2637858 2017-2637866	Rebuttal	PA	Recovery of NITS Charges	3/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	2nd Supplemental Direct	TX	Support of Stipulation	3/2/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18424	Direct	MI	Class Cost of Service	2/28/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Direct	AR	Certificate of Convenience and Necessity	2/23/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47553	Direct	TX	Off-System Sales Margins, Renewable Energy Credits	2/20/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	2nd Supplemental Direct	TX	Certificate of Convenience and Necessity	2/7/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Supplemental Direct	TX	Certificate of Convenience and Necessity	1/4/2018
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenor	17-E-0459/G-0460	Rebuttal	NY	Electric and Gas Embedded Class Cost of Service, Class Revenue Allocation, Gas Rate Design, Revenue Decoupling Mechanism	12/18/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Supplemental Direct	NM	Support of Unanimous Comprehensive Stipulation	12/11/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Direct	TX	Certificate of Convenience and Necessity	12/4/2017
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenor	17-E-0459/G-0460	Direct	NY	Electric and Gas Embedded Class Cost of Service, Class Revenue Allocation, Customer Charges, Revenue Decoupling Mechanism, Carbon Program and EAM	11/21/2017

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	17-00044-UT	Direct	NM	Certificate of Convenience and Necessity	10/24/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Cross-Rebuttal	TX	Certificate of Convenience and Necessity	10/23/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Supplemental Direct	TX	Certificate of Convenience and Necessity	10/6/2017
KENTUCKY POWER COMPANY	Kentucky League of Cities	2017-00179	Direct	KY	Class Cost-of-Service Study, Class Revenue Allocation	10/3/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Direct	TX	Certificate of Convenience and Necessity	10/2/2017
NIAGARA MOHAWK POWER CORP	Multiple Intervenor	17-E-0238 / 17-G-0239	Rebuttal	NY	Electric/Gas Embedded Class Cost of Service, Class Revenue Allocation, Electric/Gas Rate Design	9/15/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Rebuttal	MI	Class Cost-of-Service Study, Rate Design	9/7/2017
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Water Large Users Group	R-2017-2595853	Rebuttal	PA	Rate Design	8/31/2017
NIAGARA MOHAWK POWER CORP	Multiple Intervenor	17-E-0238 / 17-G-0239	Direct	NY	Electric/Gas Embedded Class Cost of Service, Class Revenue Allocation, Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation	8/25/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Direct	MI	Revenue Requirement, Class Cost-of-Service Study, Rate Design	8/10/2017
FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	170057	Direct	FL	Fuel Hedging Practices	8/10/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Cross-Rebuttal	TX	Class Revenue Allocation and Rate Design	5/19/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Direct	TX	Revenue Requirement, Class Cost-of-Service Study, Class Revenue Allocation and Rate Design	4/25/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Supplemental Direct	KY	Class Cost-of-Service Study, Class Revenue Allocation	4/14/2017
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	46416	Direct	TX	Certificate of Convenience and Necessity - Montgomery County Power Station	3/31/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Cross-Rebuttal	TX	Cost Allocation Issues, Class Revenue Allocation	3/16/2017
ENTERGY LOUISIANA, LLC	Occidental Chemical Corporation	U-34283	Direct*	LA	Approval to Construct Lake Charles Power Station	3/13/2017
LOUISVILLE GAS AND ELECTRIC COMPANY	Louisville/Jefferson Metro Government	2016-00371	Direct	KY	Revenue Requirement issues, Class Cost-of-Service Study Electric/Gas, Class Revenue Allocation Electric/Gas	3/3/2017

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KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Direct	KY	Revenue Requirement Issues, Class Cost-of-Service Study, Class Revenue Allocation	3/3/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design, TCRF Allocation Factors, McAllen Division Deferrals	2/29/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46025	Direct	TX	Long-Term Purchased Power Agreements	12/12/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Sur rebuttal	MN	Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source	10/18/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-926	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	9/23/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Sur rebuttal	KS	Formula-Based Rate Plan	9/22/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service, Class Revenue Allocation, Rate Design	8/16/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study	9/7/2016
METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPH	2016-2537349 2016-2537352 2016-2537359	Sur rebuttal	PA	Post-Test Year Sales Adjustment, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	8/31/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-WSTE-496-TAR	Direct	KS	Formula-Based Rate Plan and Debt Service Payments	8/30/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Direct	NY	Embedded Class Cost of Service, Class Revenue Allocation, Rate Design	8/25/2016
METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPH	2016-2537349 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation	8/17/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement, Class Cost-of-Service, Revenue Allocation, Rate Design	8/16/2016
METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPH	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	7/22/2016
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	Direct	FL	Multi-Year Rate Plan, Construction Work in Progress, Cost of Capital, Class Revenue Allocation, Class Cost-of-Service Study, Rate Design	7/7/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016

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MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	15-00295-UT	Direct	NM	Support of Stipulation	5/13/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HolyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HolyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016
NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44668	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/18/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	1/15/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	12/11/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design, Riders, Formula Rate Plan	11/24/2015
MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase	11/17/2015

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GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenor	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015
ENTERGY ARKANSAS, INC	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design, Riders, Formula Rate Plan	9/29/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenor	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors	9/8/2015
ENTERGY ARKANSAS, INC	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2466981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
WESTAR ENERGY INC and KANSAS GAS & ELECTRIC CO	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2466981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Decoupling	7/21/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015
ENTERGY ARKANSAS, INC	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015
WESTAR ENERGY INC and KANSAS GAS & ELECTRIC CO	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distribution Grid Resiliency Program	7/9/2015
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	43958	Supplemental Direct	TX	Certificate of Need for Union Power Station Power Block 1	7/7/2015
ENTERGY ARKANSAS, INC	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015

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PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study, Class Revenue Allocation	6/8/2015
FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments, Weather Normalization	5/15/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study, Class Revenue Allocation	5/15/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificate of Need for Union Power Station Power Block 1	4/29/2015
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff	1/27/2015
WEST PENN. POWER COMPANY	West Penn Power Industrial intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study, Class Revenue Allocation, Large Commercial and Industrial Rate Design, Storm Damage Charge Rider	1/6/2015
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study, Class Revenue Allocation, Large Commercial and Industrial Rate Design, Storm Damage Charge Rider	1/6/2015
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study, Class Revenue Allocation, Large Commercial and Industrial Rate Design, Storm Damage Charge Rider	1/6/2015
WEST PENN. POWER COMPANY	West Penn Power Industrial intervenors	2014-2428742	Rebuttal	PA	Class Cost-of-Service Study, Class Revenue Allocation, Large Commercial and Industrial Rate Design, Storm Damage Charge Rider	12/16/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Rebuttal	PA	Class Cost-of-Service Study, Class Revenue Allocation, Large Commercial and Industrial Rate Design, Storm Damage Charge Rider	12/16/2014

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METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Rebuttal	PA	Class Cost-of-Service Study, Class Revenue Allocation, Large Commercial and Industrial Rate Design, Storm Damage Charge Rider	12/18/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Cross	CO	Clean Air Clean Jobs Act Rider, Transmission Cost Adjustment	12/17/2014
WEST PENN. POWER COMPANY	West Penn Power Industrial Intervenor	2014-2428742	Direct	PA	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design, Partial Services Rider, Storm Damage Rider	11/24/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Direct	PA	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design, Partial Services Rider, Storm Damage Rider	11/24/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Direct	PA	Class Cost-of-Service Study, Class Revenue Allocation, Rate Design, Partial Services Rider, Storm Damage Rider	11/24/2014
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenor	14-E-0318 / 14-G-0319	Direct	NY	Class Cost-of-Service Study, Class Revenue Allocation (Electric)	11/21/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Direct	CO	Clean Air Clean Jobs Act Rider, Electric Commodity Adjustment Incentive Mechanism	11/7/2014
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	140001-E	Direct	FL	Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities	9/22/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014
INDIANA MICHIGAN POWER COMPANY	ISM Industrial Group	44511	Direct	IN	Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider	9/17/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Cross	WY	Class Cost-of-Service Study, Rule 12 Line Extension	9/5/2014
VARIOUS UTILITIES	Florida Industrial Power Users Group	140002-EI	Direct	FL	Energy Efficiency Cost Recovery Opt-Out Provision	9/5/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Surrebuttal	MN	Nuclear Deprecation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design	8/4/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Direct	WY	Class Cost-of-Service Study, Rule 12 Line Extension	7/25/2014

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DUKE ENERGY FLORIDA	NRG Florida, LP	140111 and 140110	Direct	FL	Cost-Effectiveness of Proposed Self Build Generating Projects	7/14/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation, Cost Allocation Issues, Rate Design Issues	1/10/2014
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenor	R-2013-2372129	Supplemental	PA	Class Cost-of-Service Study	12/13/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenor	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study, Cash Working Capital, Miscellaneous General Expense, Uncollectable Expense, Class Revenue Allocation	12/9/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenor	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service, Class Revenue Allocation	11/26/2013
ENTERGY TEXAS, INC ITC HOLDINGS CORP	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan, Conditions re Transfer of Control of Ownership	11/6/2013
SHARYLAND UTILITIES	Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions, Class Revenue Allocation, Allocation of TTC costs	11/4/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation Surplus	11/4/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenor	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Deprecation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
SHARPLAND UTILITIES	Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebuttal	IA	Class Cost-of-Service Study	10/1/2013
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Deprecation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
WESTAR ENERGY INC and KANSAS GAS & ELECTRIC CO	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
WESTAR ENERGY INC and KANSAS GAS & ELECTRIC CO	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation	8/21/2013
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost, Standby Rate Design	8/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/26/2013
JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers, AREP Rider	6/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement, Process for Exemption From Regulation, Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013

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MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
ENTERGY TEXAS, INC ITC HOLDINGS CORP	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings Subsidiary	4/30/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Supplemental	MN	Deprecation, Used and Useful, Cost Allocation, Revenue Allocation	4/12/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation	3/25/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Deprecation, Used and Useful, Property Tax, Cost Allocation, Revenue Allocation, Competitive Rate & Property Tax Riders	2/29/2013
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	38951	Second Supplemental	TX	Competitive Generation Service Tariff	2/1/2013
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	38951	Second Supplemental	TX	Competitive Generation Service Tariff	1/11/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap, Revenue Requirements, Class Cost-of- Service Study, Class Revenue Allocation, Industrial Rate Design	12/10/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
NIAGARA MOHAWK POWER CORP	Multiple intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies	9/25/2012
NIAGARA MOHAWK POWER CORP	Multiple intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service, Study, Revenue Allocation, Rate Design, Historic Demand	8/31/2012
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
WESTAR ENERGY INC and KANSAS GAS & ELECTRIC CO	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	38951	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	38951	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
ENTERGY TEXAS, INC	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Surrebuttal	MN	Deprecation, Non-Asset Margin Sharing, Step-In Increase, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	5/26/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Rebuttal	MN	Classification of Wind Investment	5/4/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Deprecation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011

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1 BY MR. C. JONES:

2 Q Mr. Pollock, did you also cause to be filed
3 with your testimony eight exhibits marked GAM-1 through
4 GAM-8?

5 A Yes.

6 Q Are there any changes you need to make to
7 those exhibits?

8 A No.

9 Q And is it your understanding that Exhibits
10 GAM-1 through GAM-3 are already admitted into evidence?

11 A Yes.

12 Q Okay. Thank you.

13 MR. C. JONES: Madam Chair, I ask that exhibits
14 GAM-4 through GAM-8 to Mr. Pollock's testimony be
15 marked as such.

16 MADAM CHAIR PRIDEMORE: So marked.

17 The documents referred to were marked for
18 identification as GAM Exhibits 4-8.)

19 BY MR. C. JONES:

20 Q Okay. Mr. Pollock, did you also cause to be
21 filed a trade secret version of your testimony?

22 A Yes.

23 Q And as amended by the errata, if I were to
24 ask you the same questions in the trade secret version of
25 your testimony, would your answers be the same?

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1 A Yes.

2 MR. C. JONES: Madam Chair, I ask that the
3 witness's trade secret version of his testimony be
4 marked as GAM-10.

5 MADAM CHAIR PRIDEMORE: So marked.

6 MR. C. JONES: Thank you.

7 (The document referred to was marked for
8 identification as GAM Trade Secret Exhibit 10.)

9 BY MR. C. JONES:

10 Q Mr. Pollock, have you prepared a summary of
11 your testimony this afternoon?

12 A I have.

13 MR. C. JONES: Madam Chair, with your
14 permission, I would like the witness to present his
15 testimony in summary.

16 MADAM CHAIR PRIDEMORE: You may go ahead.

17 WITNESS POLLOCK: Thank you.

18 Good afternoon, Commissioners. The Georgia
19 Association of Manufacturers supports a thoughtful
20 transformation to carbon-free generation. In this
21 respect, we commend Georgia Power's approach to
22 emphasizing utility-scale subscription-based solar
23 programs in general and the proposed CARES program in
24 particular.

25 This dramatic expansion of solar programs would
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1 not have been possible absent the vision and support
2 of this Commission. Allowing customers to
3 voluntarily subscribe to utility-scale solar is
4 consistent with similar voluntary programs offered by
5 regulated utilities in 18 states, and are widely
6 available in states with active competitive retail
7 markets.

8 We also agree with giving Georgia Power more
9 flexibility to alter its solar procurement strategy
10 to reflect changing circumstances, provided that it
11 can also identify the system needs that would be met
12 with potential exceptions to the avoided cost
13 standard and to define how cost-effectiveness would
14 be determined.

15 While we do not oppose the retirement of power
16 plants that are both uneconomical and are not needed
17 to maintain reliability, Georgia Power's proposed
18 capacity expansion plan goes too far. It would
19 require customers to continue paying billions of
20 dollars to prematurely retire needed and capable
21 generating units at the same time that they are also
22 having to pay for the replacement capacity and to be
23 increasingly exposed to high and extremely volatile
24 natural gas prices.

25 Higher gas prices are an unfortunate reality.

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1 They are certain to drive rates upward in 2023. In
2 fact, they already did this year.

3 Despite a 15 percent interim increase in the
4 fuel cost rate in January, the fuel balance is rising
5 and is now north of 490 million. This recent spike
6 in gas prices, coupled with more restrictive
7 permitting, limiting expanded production, and
8 pipeline capacity casts serious doubt that the low
9 gas prices of the recent past will return anytime
10 soon, which is a concern because with the addition of
11 the six capacity PPAs proposed by the company, more
12 than 10,000 megawatts, nearly 60 percent of its total
13 winter capacity, would be comprised by generating
14 resources that rely primarily on natural gas.

15 With natural gas generation as its primary
16 reserve capacity, the use of economic planning
17 criteria cannot guarantee that higher production
18 costs incurred during severe weather and difficult
19 operating conditions will not be passed through to
20 customers. However, we believe that the six PPAs
21 would not be needed absent the early retirements of
22 Wansley, Scherer Units 1, 2, and 3, and Bowen Units 1
23 and 2.

24 Even with Wansley retired in 2022, Georgia
25 Power would have surplus capacity through the late
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1 2020s, with the exception of the winter of 2023.

2 However, the 2023 need would disappear
3 completely if Georgia Power's winter target reserve
4 margin were based on the same loss of load
5 expectation and reliability standard used reli- --
6 used widely through the industry, which would result
7 in a reserve margin no higher than 20 percent on the
8 winter basis.

9 I say no higher than 20 percent because both
10 staff and STLC have identified a flaw in how Georgia
11 Power's model load forecast error, which, if
12 corrected, would reduce that target reserve margin by
13 about 2 percentage points.

14 NERC also uses loss of load expectation to
15 establish reference reserve margins in its long-term
16 reliability assessments that range from 10.7 percent
17 to 23 percent.

18 Much higher gas prices also support the
19 continued operation of Plant Scherer Units 1, 2, and
20 3, and Bowen Units 1 and 2. This is demonstrated in
21 Georgia Power's unit retirement studies under the
22 moderate gas and high gas planning scenarios.

23 The staff study also shows Bowen 1 and 2 and
24 Scherer 3 would -- should not be retired under these
25 scenarios. However, this result is anomalous given

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1 that all three Scherer units are younger in age, have
2 lower average heat rates, and source coal from Powder
3 River Basin at about 40 percent less than the
4 delivered cost of coal at Plant Bowen.

5 In fact, Plant Scherer is quite similar to
6 Plant Miller in Alabama, which is notable because
7 Alabama Power has no plans to retire Plant Miller
8 prior to 2040.

9 We believe that little weight should be given
10 to planning scenarios that include a carbon tax or
11 fee. Four of the seven planning scenarios in the
12 company's and staff's retirement studies assume that
13 Congress will enact a national carbon fee on fossil
14 fuel emissions as early as 2025 while also continuing
15 to extend renewable tax credits.

16 Despite decades of debate and discussion,
17 Congress has not enacted a national carbon tax or
18 fee. Further, there is no pending national
19 legislation that would result in a national carbon
20 tax in the near future. In lieu of a carbon tax,
21 policymakers have consistently preferred, and acting
22 and extending on many occasions, various tax credits
23 to include -- to encourage the development and
24 deployment of renewable resources.

25 Further, Georgia Power and staff did not
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1 consider the possibility of rising costs for solar
2 PPAs, purchase power agreements, and battery energy
3 storage systems. As reported in level 10 in its
4 second quarter report, solar PPA offer prices
5 increased 6 percent in the first quarter of 2022 and
6 a 15.8 percent year-over-year increase.

7 The reason for rising prices include supply
8 chain difficulties, higher costs for labor,
9 materials, and shipping due to high gasoline and
10 diesel prices, and the recent Department of Commerce
11 investigation on the import of solar panels from
12 Southeast Asia.

13 Wind and battery energy storage projects are
14 not immune from these pricing pressures. They're
15 being challenged by rising costs for lithium, steel,
16 aluminum and critical rare elements.

17 The bottom line is that Georgia Power has far
18 too much invested in Scherer Units 1, 2, and 3, and
19 Bowen Units 1 and 2 to simply abandon them at this
20 time. Also placing upward pressure on rates is the
21 proposed additional sum on the six capacity PPAs,
22 which would increase base rates by up to 17.7 million
23 per year. This is more than triple the pretax return
24 that Georgia Power currently is allowed to recover on
25 its existing PPAs for the same amount of capacity.

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1 Georgia Power doesn't meet the requirements of
2 Rule 515-3-4-.11 in this IRP because there are no
3 lost revenues or lost earnings associated with five
4 of the six capacity PPAs, which are with Georgia
5 Power affiliate Southern Power. Southern Power's
6 earnings on the PPAs will flow to the benefit of
7 Georgia Power's parent, Southern Company.

8 Further, Georgia Power hasn't demonstrated that
9 there are any changed circumstances, regulatory or
10 financial risks. In particular, this Commission's
11 ratemaking practices are viewed as -- by the
12 investment community as being highly constructive in
13 support of Georgia Power, and any credit risk
14 associated with any of the new PPAs are as yet
15 unknown and will not be vetted until the upcoming
16 rate case.

17 I would also add that -- that -- that compared
18 to the time when the IRP was originally adopted by
19 this Commission, the circumstances surrounding this
20 IRP are -- are really different and more complex. In
21 the past, if the company saw increasing load, they
22 would add capacity to meet that need.

23 Today, the principal driver for Georgia Power's
24 capacity expansion program is not to meet increased
25 load, but it's to transform its generation fleet.

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1 Accordingly, the proposed additional sum on the
2 six capacity PPAs should not be approved at this
3 time; however, if y'all approve the six PPAs and also
4 determine that you want to approve additional sum in
5 this IRP, we recommend that the current \$2.30 per
6 kW-year be retained.

7 That concludes my summary. Again, I
8 appreciate, as always, your time and attention, and I
9 invite your questions.

10 MR. C. JONES: Madam Chair, the witness is
11 available for questions from the Commission and
12 cross-examination.

13 MADAM CHAIR PRIDEMORE: Questions from
14 Commissioners?

15 (No response.)

16 MADAM CHAIR PRIDEMORE: Yes, Mr. Pollock, I
17 wanted to know if you had an opinion on the DER
18 proposal.

19 WITNESS POLLOCK: On the DER proposal?

20 MADAM CHAIR PRIDEMORE: Uh-huh.

21 WITNESS POLLOCK: This is the proposal to allow
22 the company to put investment behind the company -- a
23 customer's meter?

24 MADAM CHAIR PRIDEMORE: To help large
25 commercial industrial-type customers maintain --

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1 We have a real bad ring, IT.

2 To maintain continuity of electricity service
3 in times of outages or issues.

4 WITNESS POLLOCK: Yeah. I -- I think there --
5 there can be pros and cons in such programs. I think
6 if you're going to have a program like that, you need
7 to make sure that it's fully funded and supported by
8 the customers that -- sorry for that ring -- for the
9 customers that are receiving the service.

10 But I think in -- and I think staff raised an
11 interesting point in their testimony about creating a
12 competitive disadvantage for other entities that can
13 do the same thing without having, you know, a
14 regulated rate base to support the cost.

15 I think that -- I think that should be a factor
16 that y'all should consider before approving that
17 program. You know, you're going to end up doing more
18 harm to the market because Georgia Power doesn't have
19 a national monopoly on installing this equipment, and
20 it would be better to have the market evolve and
21 develop competitively and allow it to evolve as it
22 naturally would without competition by customers that
23 would be having -- potentially subsidizing the cost.

24 MADAM CHAIR PRIDEMORE: Interesting. Okay.
25 Any other questions?

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1 (No response.)

2 MADAM CHAIR PRIDEMORE: All right. Let's go
3 through the list. How about this? You guys just
4 tell me, does anybody want to question -- I've got
5 some takers. All right. So we'll go through the
6 list.

7 Americans for Affordable Clean Energy.

8 MR. GALLOWAY: No questions.

9 MADAM CHAIR PRIDEMORE: Commercial Group.

10 MR. JENKINS: No questions.

11 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
12 for Georgia.

13 (No response.)

14 MADAM CHAIR PRIDEMORE: Cypress Creek
15 Renewables.

16 MR. STAIR: No questions.

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

19 MR. HUBBARD: No questions.

20 MADAM CHAIR PRIDEMORE: Coalition of Local
21 Governments.

22 MS. BROWN: No questions.

23 MADAM CHAIR PRIDEMORE: GIPL.

24 MS. KYSOR: No questions.

25 MADAM CHAIR PRIDEMORE: GLSSA.

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1 MR. CARVER: No questions.

2 MADAM CHAIR PRIDEMORE: Vote Solar.

3 MR. THOMASSON: No questions.

4 MADAM CHAIR PRIDEMORE: Georgia Watch.

5 (No response.)

6 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

7 MR. CARVER: No questions.

8 MADAM CHAIR PRIDEMORE: Chattooga Gorge.

9 MR. S. JONES: No questions.

10 MADAM CHAIR PRIDEMORE: Sierra Club.

11 MR. FABISH: Yes.

12 MADAM CHAIR PRIDEMORE: Okay. Ms. Coyle beat

13 you in here.

14 MR. WALSH: Commissioner Pridemore, I just --

15 I'm fine with whatever order the Chair wants. I just

16 wanted to let you know that staff does have some

17 questions.

18 MADAM CHAIR PRIDEMORE: Okay.

19 MR. WALSH: I wasn't -- I was waiting. I

20 wasn't sure if you would call --

21 MADAM CHAIR PRIDEMORE: Sorry. I'm rattled by

22 the audio right now. I obviously am. Go ahead,

23 staff.

24 Hold just a minute, Sierra Club.

25 Mr. Mahan, would you please alert Ms. Coyle.

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1 Thank you.

2 CROSS-EXAMINATION

3 BY MR. WALSH:

4 Q Good afternoon, Mr. Pollock. It's nice to
5 see you again. For the record, Dan Walsh on behalf of the
6 Commission Advocacy Staff.

7 A Hey, Mr. Walsh.

8 Q Could you please turn to page 26 of your
9 testimony.

10 A Yes.

11 Q In the Q and A that begins on line 4, you
12 testified that there's evidence that solar costs have been
13 and are going to trend higher, and you reference Exhibit 8
14 to your testimony, which is the level 10 report; is that
15 correct?

16 A Yes.

17 Q Okay. Is it also correct that there are no
18 projects in the Southeast in the level 10 platform?

19 A That's true. They record projects mostly
20 behind the RTO hubs at this stage.

21 Q Thank you.

22 Could I get you now to turn to page 31 of your
23 testimony.

24 A Yes.

25 Q Here you talk about Georgia Power recovering
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1 the remaining investment on the plans it is asking the
2 Commission to decertify; is that correct?

3 A Yes.

4 Q And then you talk about the company seeking
5 cost recovery for six purchase power agreements during the
6 same time; right?

7 A Right.

8 Q Okay. And then moving on to page 32 of your
9 testimony, specifically the question that begins on
10 line 9, am I correct that you refer to the fact that the
11 company would be recovering the remaining net book value
12 on its existing coal units, and also seeks to recover PPA
13 costs as customers having to pay twice for the same
14 capacity? Have I correctly understood your testimony?

15 A That's right.

16 Q Okay. But that's not actually the same
17 capacity, is it?

18 A Well, it's not the same physical capacity, but
19 it's the same functional capacity because the coal plants
20 are not going to be -- after a certain point, they're going
21 to be gone, you're going to be paying for those, assuming
22 that the cost recovery occurs as planned, plus you're going
23 to be paying for all of the replacement capacity that
24 replaces those coal units. So, effectively, functionally,
25 you're paying for capacity twice.

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1 Q But would you agree that if a resource is no
2 longer economical to run and there are less expensive
3 alternatives, that early retirement can be appropriate?

4 A It can be. The question is not whether the
5 retirement is appropriate. The question is what happens to
6 the cost remaining for the plant that's being retired and
7 how soon will that cost be recovered, if it's going to be
8 recovered sooner than it otherwise would and it will be
9 recovered over the same period as the cost of the capacity
10 that they're going to replace it with.

11 Q So would you dispute, then, whether the
12 company is entitled to recover its remaining net book
13 value on the resource that is being retired?

14 A I'm not raising that as an issue. That's a
15 rate case issue. It's a determination the Commission has to
16 make as to whether or not the company should be entitled to
17 recover costs associated with a plant that it finds are no
18 longer used and useful but that's not the issue that we're
19 raising in this proceeding.

20 Q Could you turn to page 24 of your testimony.

21 A Twenty-four, yes.

22 Q At the top of page 24 you asked whether it is
23 reasonable to assume that Congress will enact
24 legislation -- I'm sorry. I think you said realistic, not
25 reasonable. Whether it's realistic to assume that

1 Congress will enact legislation imposing a carbon fee on
2 fossil fuel generation. And your conclusion is that it is
3 not realistic, and then the rest of your answer is support
4 for that conclusion.

5 Have I read your testimony correctly on
6 page 24?

7 A Yes.

8 Q Okay. And am I also correct that the only
9 reason you give in this answer to support your conclusion
10 is that such legislation has not been enacted?

11 A It's that such legislation has been discussed
12 for decades and no legislation has actually been enacted --

13 Q Okay.

14 A -- nationally.

15 Q And that's --

16 A Despite all the discussions.

17 Q Despite --

18 A Nothing has happened, and policymakers have
19 preferred to use tax credits as a means of encouraging
20 deployment of renewable sources as opposed to a carbon
21 adder.

22 Q Could you turn to page 27 of your testimony
23 on that issue?

24 A Okay.

25 Q On line 9 of your prefiled direct, do you

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1 testify that there are uncertainties surrounding the
2 continuation of tax credits?

3 A I'm sorry. What page are you on?

4 Q It's on 27 on my copy. It's -- the question
5 is -- it's in response to the question on line 4, "What is
6 driving the higher projected solar PPA prices?"

7 A Okay. Repeat your question, please.

8 Q Okay. On page -- on line 9 of this page, do
9 I understand your testimony that there are uncertainties
10 surrounding the continuation of the tax credits?

11 A There are some uncertainties, yes. I mean,
12 they're currently scheduled to phase out. There are
13 discussions, however, being had currently, I think I've
14 included as one of the exhibits, that many of the players
15 that want to continue to encourage the renewable development
16 will continue to urge Congress to extend the current tax
17 credits.

18 Q If it's uncertain that the tax credits are
19 going to be continued, would you agree that the tax
20 credits would not be a reason for concluding that it's
21 unrealistic that Congress would enact legislation imposing
22 a carbon fee?

23 A Well, the two are different things, but they
24 tend to do the same thing; right? A carbon fee and tax
25 credits both tend to make renewable resources more expensive

1 and more favorable in comparison to nonrenewable or fossil
2 fuel resources. So you have to look at it, either you have
3 a carbon fee or you have tax credits, but you don't look at
4 both. If you look at both things at the same time, then
5 you're putting your thumb on the scale too much to try to
6 favor the renewable resources over the other fossil fuel
7 resources.

8 Q Okay. And I guess where I was going was it
9 seemed like part of your rationale for why it would be
10 unrealistic to expect Congress to enact the carbon fee
11 legislation is that they'd rather to do the tax credits.
12 And I guess my question is, if there's a possibility or
13 there's uncertainty as to whether the tax credits are
14 going to continue, does that affect your view as to how
15 realistic the possibility is of a carbon fee?

16 A That's a great question. I have no crystal
17 ball about that, but if the past is any -- any indicator of
18 the future, then you'll see the tax credits without the
19 carbon fee because there's a lot of opposition to a carbon
20 fee.

21 Q Are you familiar with the definition of
22 externalities in the Commission's integrated resource
23 planning rule?

24 A Yes.

25 Q And so you're aware that the Commission rule

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1 defining externalities states, in part, that externalities
2 should be quantified and expressed in monetary terms where
3 possible?

4 A Where possible, yes.

5 Q And then the rule says those externalities
6 that cannot be quantified or expressed in monetary terms
7 shall be, nonetheless, qualitatively considered in the
8 societal cost test to develop resource plans?

9 A As far as demand-side management programs are
10 concerned, yes.

11 Q Are you aware under the IRP rules that
12 externalities are among the factors that the Commission
13 considers in determining which combinations of resources
14 options -- options best serve the public interest?

15 A In evaluating -- the societal cost test is a
16 test that has sometimes been used in evaluating various
17 demand-side management programs. It's my understanding the
18 Commission hasn't really done or accepted externalities
19 because they're very hard to quantify and very subjective.
20 But the rules do suggest that the -- you know, if you can
21 quantify them, you can do that in the context of demand-side
22 management programs.

23 Q Does your testimony address externalities?

24 A Only addresses whether carbon fee should be
25 concluded in evaluating a capacity expansion plan.

1 Q Is it your testimony that Georgia Power
2 should not quantify externalities in its unit retirement
3 study?

4 A I don't believe it should, no. Not unless that
5 externality is something that's likely to become a policy.

6 Q Could you turn to page --

7 A And then let me clarify. And then it shouldn't
8 give equal weight to something that can't happen, or hasn't
9 happened. So they are really two answers to the question.
10 One is if it's the likelihood that there's going to be a
11 policy, yeah, you take that probability into account. If
12 there's not, then you give it the weight that it should get,
13 which is very little, if there's no actual indication that
14 such a policy will be enacted.

15 Q Could you turn to page 22 of your testimony.

16 A Twenty-two.

17 Q And I'm looking at the Q. and A. that begins
18 on lines 5 through 9.

19 A Okay.

20 Q Here you asked: Do the results of Georgia
21 Power's unit retirement study conclusively support the
22 early retirement of Scherer Units 1, 2, and 3, and Bowen
23 Units 1 and 2?

24 And your answer is: No. The benefits of
25 retiring these units would only be realized if Congress were

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1 to enact legislation that imposed a carbon price on fossil
2 fuel generation.

3 A Yes.

4 Q I guess my -- my question is, is it -- is
5 your testimony that there are no environmental benefits to
6 retiring these units?

7 A Well, these units have the necessary
8 environmental equipment to continue operating.

9 Q So your answer is there would be no
10 environmental benefits?

11 A Well, okay, if you could be more specific.
12 Environmental in what -- what benefits are we talking about?

13 Q I'm speaking broadly, just -- when you --
14 when you said the benefits of retiring these units early
15 would only be realized if Congress were to enact
16 legislation imposing carbon price on fossil fuel
17 generation, did you consider environmental benefits as
18 part of that statement?

19 A Ignoring the externality of a carbon fee, which
20 is an externality, there would not be any benefits of an
21 early retirement.

22 Q So did you consider environmental impact when
23 you were saying that there would be no benefit if
24 legislation was not enacted?

25 A Well, okay, so you're asking me did I consider
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1 the financial cost of maintaining the environmental
2 equipment necessary to keep those plants in operation? I'm
3 assuming that those costs were reflected in the retirement
4 study. Or are you asking me did I consider potential
5 externalities associated with environmental effects?

6 Q Externalities, the latter.

7 A Okay. The answer is no.

8 Q Okay. Is it your testimony -- well, let me
9 withdraw that.

10 Do you think the Commission can consider
11 evidence of externalities in this proceeding and make its
12 own policy decision on what it believes is the best -- is in
13 the best interest of Georgia?

14 A The Commission can certainly make a policy
15 decision, and I would urge that the Commission make a -- in
16 the foundation of that policy decision, to keep in mind the
17 effect on customers, because these are costs that customers
18 are going to pay. These are going to put upward pressure on
19 rates if you retire plants prematurely and accelerate
20 recovery, and then replace them on top of it with other
21 types of capacity.

22 We have high fuel costs. We have an
23 under-recovered FCR balance, at least two Vogtle rate
24 increases and a rate case coming up. I just think that's
25 a -- I think I said last year at this time, or last October,

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1 this is the perfect storm, and I would hope that even though
2 this is not a rate case, that the decisions that you make in
3 this IRP case certainly have significant rate implications
4 and that you'll consider those.

5 Q And I understand your testimony and I'm
6 trying to ask you about how you view the process for the
7 Commission to reach the IRP.

8 And would you agree that it is within the
9 Commission's discretion to consider externalities such as
10 the impact on health and climate of increasing the
11 concentration of carbon dioxide in the atmosphere regardless
12 of whether Congress passes legislation and imposes the
13 carbon tax?

14 A They could. And then they should also consider
15 the externalities of the effects on people that are working
16 at these plants and communities that tax -- the tax proceeds
17 that these plants produce for the communities that benefit
18 from the plants. So if we're going to go to some
19 environmental benefits, let's also talk about, you know,
20 community benefits and other benefits.

21 MR. WALSH: That's all the questions I have.

22 Thank you very much, Mr. Pollock.

23 WITNESS POLLOCK: Thank you.

24 MR. WALSH: Thank you, Madam Chair.

25 MADAM CHAIR PRIDEMORE: Thank you, staff.

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1 Sierra Club.

2 CROSS-EXAMINATION

3 BY MR. FABISH:

4 Q Good afternoon. Zach Fabish for the Sierra
5 Club.

6 So you're familiar with the company's unit
7 retirement study; correct?

8 A Yes.

9 Q Okay. To your knowledge, did the company's
10 unit retirement study include scenarios with costs due to
11 potential future environmental regulations aside from the
12 carbon prices?

13 A I don't know.

14 Q You don't know?

15 A I don't recall if they did. I think they
16 looked at the current loss, current existing requirements.

17 Q Okay. Just as a general question, could
18 modeling the carbon price and the unit retirement analysis
19 function as a stand-in for unknown potential future
20 environmental compliance costs?

21 A Well, I think that's the reason why the company
22 is using the carbon adder is as a stand-in. But the
23 question -- the problem with the stand-in is, is that -- how
24 is it -- is it a realistic stand-in, and where do you draw
25 the line as to what number to pick? Because you have no

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1 basis on which to actually determine whether it's \$15, \$20,
2 \$30, \$60, 80, whatever, whatever it is. There's no rational
3 basis for coming up with a number that tries to predict what
4 future legislation might look like.

5 Q But isn't the point of long-term resource
6 planning to not figure out what will happen but to figure
7 out a strategy that performs well ideally, the best,
8 across a range of potential scenarios?

9 A Yes, clearly.

10 Q Okay. So scenarios such as including
11 currently unknown but future environmental compliance
12 costs?

13 A If you can model what those environmental
14 compliance costs might be, as opposed to just a simple
15 assumption about a carbon adder, sure.

16 Q Uh-huh.

17 A You definitely would take that into account.

18 Q Okay. Do you think it's possible --

19 A As long as it's -- as long as it's --

20 Q Oh, sorry.

21 A -- objectively based. I'm sorry, I should have
22 said that.

23 Q No, I --

24 A As long as it's objectively based.

25 Q Are you finished?

1 A Yes.

2 Q Okay. Good. Sorry.

3 A Sorry.

4 Q I didn't mean to talk back and forth over
5 you. And I apologize to you, Court Reporter.

6 I mean, would you -- would you think that it's
7 possible that in the years to come, there might be new rules
8 with new environmental compliance costs that are applicable
9 to Georgia Power's coal fleet?

10 A There could be certainly new rules and
11 certainly new technologies that could address those rules
12 that we currently don't know about.

13 Q Sure. Okay. And then I guess my last
14 question would be: Did you do expansion or optimization
15 modeling like staff did to evaluate the unit retirement
16 study?

17 A No.

18 MR. FABISH: Okay. Thank you. That's all my
19 questions.

20 MADAM CHAIR PRIDEMORE: Southern Alliance for
21 Clean Energy and Southface Energy Institute.

22 CROSS-EXAMINATION

23 BY MR. BAKER:

24 Q Afternoon, Mr. Pollock. A few follow-up
25 questions to Mr. Fabish's line of questioning.

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1 You're aware of the Clean Air Act passed by
2 Congress in 1990?

3 A I'm aware of it, yes.

4 Q And have you considered the possibility or
5 likelihood the EPA will regulate greenhouse gas emissions
6 from utilities under the Clean Air Act, say, within the
7 next decade or so?

8 A Well, they -- they've already tried that and
9 then they were reversed by the Supreme Court decision. So
10 that's not to say that they couldn't try it again, but it's
11 been tried and it failed.

12 Q Wasn't that because of the --

13 A Clean Power Plan?

14 Q Excuse me?

15 A The Clean Power Plan was rejected by the
16 Supreme Court.

17 Q It wasn't because of notice and opportunity
18 for comment?

19 A It was rejected so it never was (inaudible).

20 Q Okay. Are you also aware of local Georgia
21 government laws that set economy-wide carbon reduction
22 targets in Georgia?

23 A I'm not familiar with those.

24 Q Okay. So you didn't consider -- you're not
25 aware. All right. Thank you very much, sir.

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1 A Sure.

2 MADAM CHAIR PRIDEMORE: Southern Renewable
3 Energy Association.

4 MR. MAHAN: No questions.

5 MADAM CHAIR PRIDEMORE: Georgia Power.

6 MR. MARZO: Yes, Chair Pridemore, yes, I have
7 some questions.

8 CROSS-EXAMINATION

9 BY MR. MARZO:

10 Q Good afternoon, Mr. Pollock.

11 A Mr. Marzo.

12 Q It's good to see you in person. It's been a
13 while.

14 A It has.

15 Q I have some questions for you regarding your
16 testimony. Let me start off with where I think we have
17 some agreements. This may be a short line of cross, but
18 we -- you talked earlier at the beginning of your
19 testimony about the CARES program. And would you agree
20 with me that the program like CARES are growing across the
21 country due to the demands of customers for greater access
22 to renewable energy?

23 A Yes, clearly.

24 Q And, in fact, you provided in your testimony,
25 I think it's GAM-4, which was the RRA report published by
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1 S&P Global to make that point; correct?

2 A That's right.

3 Q Okay. And isn't it true that some of your
4 own members or GAM members are entities requesting greater
5 quantities of renewables?

6 A Yes.

7 Q Okay. And you've asked -- or you had some
8 concerns, I believe, from your testimony related to best
9 cost procurements, as the company had talked about in its
10 testimony; is that right?

11 A Yes.

12 Q Okay. And you indicated in your testimony, I
13 believe that you're concerned specifically with procuring
14 resources above avoided costs, and you recommended the
15 future procurements that are made by the company, that
16 they would -- if they exceeded avoided costs, the
17 Commission would need to review and approve those; is
18 that --

19 A I'm assuming that would be the case, but --

20 Q Okay.

21 A -- yes, there should definitely be a process.
22 And I think it also mentioned that it needs to be -- that
23 the term "system benefits" needs to be better understood and
24 defined.

25 Q Okay. And I -- just for clarity, and I
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1 believe you know this, but just for the record, you're
2 aware that, obviously, the Commission here has a very
3 defined RFP process that's governed by Commission rules?

4 A Yes.

5 Q Okay. And you're aware that once resources
6 are selected, they're brought before this Commission for
7 certification; correct?

8 A Yes.

9 Q Okay. And so during that process of
10 certification, which requires a hearing, would you agree
11 with me there was an opportunity to review those deals and
12 whether or not those are in the best public interest?

13 A Yes.

14 Q Okay.

15 A As long as the rules are understood and the
16 terms are -- and the conditions are well-defined, I think
17 that's a good process.

18 Q Okay. Now, as it pertains to your testimony
19 on unit retirements, I just want to talk a little bit -- I
20 believe Mr. Walsh asked a number of questions and they've
21 already taken some of my cross, so I'll try to cut this
22 down.

23 But in your testimony, as it pertains to at
24 least what we agree on, I understood your testimony to be
25 okay with, and lack of a better word, or agree on the

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1 retirement of Wansley and Gaston.

2 A Yes.

3 Q Is that correct?

4 A Yes.

5 Q Okay. And it's also your position, is it
6 not, that -- and I think you said this to Mr. Walsh, you
7 don't oppose retirements of power plants that are both
8 uneconomical and no longer needed for reliability; is
9 that --

10 A That's right. Or are capable of continuing to
11 operate under some mechanism if the capability is needed.

12 Q Okay. But that would have to prove out to be
13 economic; correct? I mean, there would have to be a
14 benefit to customers to do that?

15 A Well, okay, so we say economic, that can have
16 different contexts. Economic could mean it could be the
17 lower-cost option, but if a unit is needed, like the
18 reliability must-run unit is needed, even though it's not
19 economical, then it's legitimate to consider it in that
20 role.

21 So I think we need to look at it in the context
22 of, well, it's not just needs to be cost-efficient, but if
23 it also has a need because it's serving a reliability
24 purpose, even though it's a higher cost than would otherwise
25 be acceptable, then that would also be a legitimate reason

1 to keep a plant operating.

2 Q And I was looking at it from the perspective
3 that, you know, GAM members, for example, if they're going
4 to pay you for a unit to stay on the system, they're going
5 to want to know that it's in the public interest and that
6 there's value to that. Would you agree with that?

7 A Yes.

8 Q Okay. And you relied largely on the
9 company's analysis in your testimony; is that correct?

10 A Yes.

11 Q And in order to make unit retirement
12 decisions in this case, you understand that the company
13 reviewed multiple planning scenarios that include a
14 variety of assumptions regarding gas prices, carbon
15 prices, future costs, and perform- -- future costs of
16 performance generation, as well as load; correct?

17 A Yes.

18 Q And you understand the company reviewed all
19 this information and made its resource recommendations to
20 the Commission as it has in all of its prior IRPs;
21 correct?

22 A Right. Yes.

23 Q Okay. Now, you discussed the seven planning
24 scenarios that were used by the company, or you have seven
25 planning scenarios listed on page -- page 22 of your

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1 testimony; is that correct?

2 A Yes.

3 Q And it's essentially your position that the
4 Commission should make no -- it should make its resource
5 decisions primarily on two scenarios, which would be the
6 zero carbon moderate gas or zero carbon high gas; right?

7 A Yes.

8 Q Okay. And I think earlier in discussions
9 with Mr. Walsh you said you don't have a crystal ball. So
10 isn't part of what we do here as part of these proceedings
11 with our multiple planning scenarios is to allow the
12 Commission to have the best information it can have in
13 multiple outcomes, because none of us have a crystal ball;
14 correct?

15 A None of us has a crystal ball, though, you
16 know, when it comes to things like gas prices, there's a lot
17 more visibility into the future than, say, for future
18 unknown legislation or -- or regulations.

19 Q Okay. And if we look at your best-case
20 scenario presented -- I believe this is your best-case
21 scenario, or one of your better-case scenarios, in GAM-2,
22 which represents the net benefits from the zero carbon
23 moderate gas scenario, is it fair to say that even in that
24 scenario, which would be favorable to your position, the
25 savings there are marginal?

1 A You have to define marginal. I mean --

2 Q They're under --

3 A If there are savings -- if there are savings,
4 it means that there still are some benefits of continuing to
5 operate.

6 Q Okay. So anything -- so a dollar above zero
7 would justify not retiring the facility in the scenario in
8 your --

9 A Well, these are not dollars, these are millions
10 of dollars, so it's --

11 Q Well, that's -- yeah.

12 A In terms of order of magnitude, it's -- you
13 know, let's not -- this is not chump change. This is real
14 money.

15 Q Yeah, it's south of ten, but I want to
16 understand, you said anything above, you said any amount.
17 So just to make sure, we're talking millions to you?

18 A Yes.

19 Q Okay. So the numbers here, even though south
20 of 10 million for the ones we're looking at, are
21 reflective of what you believe is justification to
22 overcome the other cases where there's substantial lack of
23 net benefit?

24 A Yes. I think you have to recognize, and I
25 think the Commission does recognize, that all models have a

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1 margin of error. And if a model can show that under
2 different scenarios that there is some benefit, regardless
3 of what it is, considering how much investment is still
4 there and how much is in rate base and how much is yet to
5 recover, and as well as the age of the asset itself, I think
6 you can make an -- an informed decision based on that
7 information.

8 Q Yeah. And part of making an informed
9 decision in a world where none of us have a crystal ball
10 is to look at multiple scenarios though; correct?

11 A Yes.

12 Q So if some scenarios have significantly less
13 benefits and some scenarios that are more favorable have
14 very marginal benefits, wouldn't you agree with me that
15 would factor in to how you would look at those scenarios?

16 A You know, just the number of scenarios doesn't
17 really cut it. It's really what do you think is more likely
18 to happen based on the information that you have. So it's
19 not, well, we threw up seven scenarios; we think they're all
20 equally possible. They're not all equally possible. They
21 can't be equally possible because they're different.

22 So I think with -- if you look at these
23 scenarios and decide which ones you should give greater
24 weight to, then I think you can have a more informed
25 decision.

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1 Q And it's GAM's position that even in a world
2 where their members are demanding greater and greater
3 amounts of renewables, that we're going to live in a world
4 where there will be zero carbon moderate gas for a very
5 long time?

6 A So what GAM members and all clients that I
7 represent say, we like renewables but we're not going to pay
8 any price for it. So, yes, we do want -- and members do
9 want cost-effective renewable resources, but not at any
10 price.

11 Q Now, you primarily relied on the company's
12 analysis, but you understand that staff did its -- an
13 independent analysis and they came to very similar
14 conclusions as a company; correct?

15 A That's my understanding, yes.

16 Q All right. Now, on page 18 of your
17 testimony, you discuss some concerns that you have
18 regarding natural gas prices; is that right?

19 A Yes, prior to -- yeah, page 18?

20 Q Yeah.

21 A Yes.

22 Q And for clarity, the NYMEX gas futures chart
23 you refer to on page 18 runs through October of 2023;
24 correct?

25 A That's right.

1 Q And can we agree that the majority of coal
2 retirements in this case, the ones, at least, that I think
3 are in dispute here between us, are retired in 2027 and
4 2028; correct?

5 A That's right. So you'd have look at the table
6 on page 19 and then extend it out, but you can kind of get
7 the pattern just --

8 Q Yeah.

9 A -- just by looking at the numbers that are in
10 the table.

11 Q And I just wanted to confirm that you also
12 are aware that the PPAs that issued here are at a date
13 after October 2023, in the 2024 --

14 A Yes.

15 Q -- time frame?

16 A Yes.

17 Q Okay. Now, you discuss natural gas
18 volatility throughout your testimony, but what I didn't
19 see was any discussion regarding some of the issues and
20 volatility around coal. Would you agree with me that
21 there is volatility with coal as well; correct?

22 A Well, yes. Given COVID and various supply
23 chain issues, yeah, every commodity has had some volatility.
24 I think the expectation is that in the case of coal, that
25 with the higher gas prices particularly, and eventually

1 working out of those supply chain issues, that that
2 volatility will be lessened going forward.

3 For example, we saw a big run-up in the Powder
4 River Basin costs, but that run-up has since run down. So
5 there has been volatility, but the price is essentially
6 correct.

7 Q And would you agree with me that in addition
8 to sort of the price volatility that we're seeing, we're
9 also seeing transportation volatility and the ability to
10 get coal from one location to the actual plants where it
11 can get burned; correct?

12 A That's right. That's right.

13 Q Yeah.

14 A And you have that issue -- could have that
15 issue with natural gas if we don't get more pipeline
16 permitting in a timely basis.

17 Q Okay. So really with any of these resources,
18 as I think we agree, there is potential volatility,
19 there's potential transportation risk, but the coal itself
20 is not panacea as it pertains to --

21 A And --

22 Q -- those issues; correct?

23 A That correct. And neither are wind and solar.
24 They all have transportation and other supply chain issues
25 that affect everything.

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1 Q Now, you reference GAM-6, which is a summary
2 example of how GPC's proposed target reserve margin
3 compares to other regions of the country. And I think
4 that's page -- GAM-6. I'm sorry. It's not a page.

5 A It's an exhibit.

6 Q It's actually your attachment. Yes.

7 A Yes.

8 Q Do you have it?

9 A I do, yes.

10 Q Okay. Now, first, the target reserve margin
11 of GAM-6 appears to be stated in summer target reserve
12 margin; is that correct?

13 A That's correct.

14 Q And obviously, we're doing a comparative here
15 to the 26 percent. This would not be the comparative to
16 that; correct?

17 A Correct.

18 Q Okay. Now, the exhibit also shows that
19 there's several utilities and RTOs that plan at 15 percent
20 reserve margin; is that correct?

21 A Now, these are reference margin levels, so
22 these are not -- these are not necessarily the planning
23 reserve margins of different RTOs. They could be higher.
24 For example, MISO, I think about -- MISO is higher. It's
25 18 -- 18.3.

1 Q Well, but you --

2 A They could be a little bit different based on
3 the specific RTO criteria.

4 Q And you may have just cut through a few of my
5 questions there, because I was -- so these are -- you
6 agree, these are a reference?

7 A That's what --

8 Q Yeah.

9 A I'm not suggesting that these are the numbers.
10 I'm saying these are the reference numbers that NERC uses to
11 determine whether or not there are going to be potential
12 problems in the future.

13 Q Okay. And as I think I asked the panel
14 yesterday, if you look at the SERC Southeast, obviously,
15 the reference to 15 percent, we know that a number of
16 Southern Company operating companies are planning at
17 26 percent. And Florida is planning at 20 percent. On
18 the record, we think it's much higher than that, as well.

19 A Yeah, the FRCC still uses a 15 percent
20 criteria, but there was a settlement back in the early '80s
21 that -- that allowed the utilities to plan for a 20 percent
22 reserve margin.

23 Q Now, as it relates to the target reserve
24 margin in the Southeast, Mr. Pollock, you have also filed
25 testimony of behalf of Alabama Industrial Energy Consumers

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1 Group in the 2019 Alabama Power Company public certificate
2 of public convenience proceeding --

3 A Yes.

4 Q -- before the APC; is that correct?

5 A Yes.

6 Q Okay. Am I correct that in that case, the
7 company, being Alabama Power Company, proposed a
8 16.25 percent summer and a 26 percent winter target
9 reserve margin?

10 A They did, yes.

11 Q Okay. And you opposed that in that case; is
12 that correct?

13 A Yes.

14 Q Okay. Let me provide you with a -- you and
15 Mr. Jones with a copy of that.

16 MR. MARZO: Madam Chair, may approach the
17 witness?

18 MADAM CHAIR PRIDEMORE: You may.

19 MR. MARZO: Madam Chair, if I could mark this
20 as GPC Exhibit, I believe it's 9 --

21 MS. PRYOR: 13.

22 MR. MARZO: Sorry, I missed a few. 13.

23 MADAM CHAIR PRIDEMORE: Stay with us,
24 Mr. Marzo.

25 So marked.

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1 (The document referred to was marked for
2 identification as GPC Exhibit 13.)

3 MR. MARZO: Thank you, Madam Chair.

4 And, here, give this to -- please give this to
5 Mr. Pollock as well so he will have a copy. Thank
6 you.

7 WITNESS POLLOCK: Thank you.

8 BY MR. MARZO:

9 Q And I'll give you an opportunity to review
10 that, Mr. Pollock.

11 MR. MARZO: And for the record, Commissioners,
12 this is Docket 32953 in the Alabama Public Service
13 Commission's docket.

14 BY MR. MARZO:

15 Q And what I handed you in addition to the
16 order and what the Commissioners received was an excerpt
17 from that order which approved the company's, or Alabama
18 Power Company's 26 percent winter target reserve margin in
19 that case. And I handed you pages 20 and 21 from that
20 order.

21 A Yes.

22 Q Would you read for me the highlighted
23 language.

24 A Sure. It's on page 20. "However, Alabama
25 Power's target winter reserve margin cannot legitimately be
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1 established through an averaging exercise involving the
2 margins adopted by others as these intervenor witnesses
3 seemed to suggest. Rather, the development of such planning
4 margins requires comprehensive modeling and utility-specific
5 analysis. Putting that aside, however, we further note that
6 Mr. Pollock acknowledged at the hearing that the Tennessee
7 Valley Authority and PowerSouth Energy Cooperative, two
8 electricity suppliers with obligations in Alabama, both
9 utilize winter target reserve margins comparable to the
10 level Alabama Power proposed in this petition."

11 "In addition, Mr. Wilson agreed at the hearing
12 that several regional reliability entities projected
13 virtually no chance of a reliability event in January 2018,
14 carrying actual reserve levels ranging from 32 percent to
15 well over 60 percent, and yet nearly suffered outages, a
16 near miss, when a polar vortex-type event occurred that
17 month."

18 Q So in that order, the APC -- the Alabama
19 Public Service Commission both acknowledged that there
20 were higher reserve margin targets around the region of
21 Alabama, as well as rejected the concept, generally, of
22 averaging; is that fair?

23 A Yes.

24 Q Okay. Now, would you agree with me,
25 ultimately, though, Mr. Pollock, is whether we average it,

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1 which is not appropriate -- I think we can agree -- or
2 whether it's done specifically for each utility, what --
3 what we really want to know is how these utility --
4 utilities ultimately performed; right? Isn't that the
5 most important thing for the Commission to know?

6 A Well, that's really separate and aside. So
7 from a planning perspective, a utility should develop a
8 reserve margin that reflects its characteristics. I'm not
9 arguing anything differently than that. In fact, my
10 recommendation is, based on LOLE, that the reserve margin a
11 little south of 20 percent is appropriate for Georgia Power.

12 That said, you know, the separate issue, the
13 second issue is how well the utilities performed during
14 adverse conditions. That's not a planning issue, that's an
15 operational issue. And clearly, in Texas and other places
16 that had rolling blackouts in Winter Storm Uri, now the
17 performance -- despite the high reserve margins, the
18 performance was not up to snuff, and that's reflected in the
19 analysis, after-action analysis.

20 Q And I guess that's my point. For purposes of
21 the Commission's understanding, that they're looking at
22 averages on a sheet of paper, really, the most important
23 thing is how those utilities performed, and what we --
24 what this Commission knows, obviously, is what Georgia
25 Power's performance has been. But if they're going to be

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1 compared to other utilities, wouldn't it be more
2 informative that they know kind of how those utilities did
3 in the situations that stressed the system and the target
4 reserve margin.

5 A What I think the Commission should understand
6 is that setting a planning reserve margin is -- should
7 reflect the characteristics of the utility involved, and
8 it's based on the best information that you can have in
9 terms of what you think your unit's performance is.

10 But if the utility, you know, suffers extreme
11 circumstances and the units fail to perform, that's an
12 operational issue, that's a -- that becomes an issue of
13 prudence that the Commission should then examine. Whether
14 the utility was prudent in the way that it was operating its
15 generation, really has little to nothing to do with what
16 kind of reserve margin the utility should have.

17 Q Now, Mr. Pollock, my understanding in looking
18 at your recommended reserve margin is that you're only
19 looking at reliability, correct, and not economics; is
20 that correct?

21 A I'm looking at what NERC looks at and what a
22 lot of other systems look at, which is a reliability-based
23 reserve margin.

24 Q And were you here yesterday when Mr. Hayet
25 testified before the Commission?

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1 A I was not.

2 Q Okay. Are you aware -- because I know you've
3 been here a lot, too, Mr. Pollock. Are you aware this
4 Commission has, over the numerous IRPs, adopted a
5 methodology that considers both economic and reliability
6 to set reserve margin?

7 A Yeah, I have some ambiguity in terms of what
8 the Commission adopted. I think in the last case, the
9 Commission said go ahead and plan for the higher reserve
10 margin, but the issue is still in play.

11 Q And the issue there was the level of
12 reserves, but do you understand the methodology that's
13 historically been used by this Commission has been one
14 that's considered both reliability and economics?

15 A I will confess that I don't recall the
16 Commission, you know, giving its blessing about the economic
17 reserve margin --

18 Q Okay.

19 A -- or economic criteria. But I think that
20 that's something that the Commission should consider or
21 reconsider, even if it did give its approval in the past.

22 Q Now, I know you just said a moment ago you
23 weren't here yesterday. Mr. Jones had used an exhibit on
24 Plant Miller, which I'm sure you're probably familiar
25 with, and Plant Scherer. Would you agree with me that the

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1 delivered cost to those plants is very different than
2 deliver for each plant than it is -- which could justify
3 the different treatment. Would you agree with that?

4 A Yeah. And I'm not disputing that. In fact,
5 because Plant Miller is closer to the Powder River Basin,
6 you would expect it would have lower delivered coal cost
7 than Plant Scherer. What I was really doing was comparing
8 the fact that Scherer has delivered coal costs that are
9 40 percent less than Bowen, and that somehow Bowen is
10 economic and Scherer is not. That didn't make a lot of
11 sense.

12 Q Okay. But we can agree to this, that sheet
13 in and of itself doesn't give enough information to know
14 what those differences are; correct?

15 A What differences are we talking about?

16 Q The exhibit in the GAM-9, I believe. It's
17 GAM-5 or 9.

18 MR. C. JONES: I think it was 9.

19 MR. MARZO: Yeah. If he doesn't have it, we
20 can -- I can withdraw that question.

21 MR. C. JONES: Please try to clarify your
22 question.

23 MR. MARZO: Okay.

24 BY MR. MARZO:

25 Q Oh, my que- -- oh.

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1 A Yeah, what information are you talking about?

2 Q Yeah. I was referring to GAM-9. And I guess
3 my point is that, ultimately, that worksheet that
4 Mr. Jones shared, that's not -- that's not sufficient
5 information to understand whether or not there are
6 transmission issues, what the delivery -- what the impacts
7 of the delivery costs are on having those units, whether
8 they're economic or not. Those are -- there's several
9 criteria and things that aren't shown in that exhibit;
10 correct?

11 A And it's -- Yeah, GAM-9 is not a unit
12 retirement study.

13 Q Okay.

14 A It's simply a historical five-year comparison
15 of costs between two plants -- three plants, actually,
16 because Bowen was on there, as well as --

17 Q Yeah.

18 A -- Scherer and Miller.

19 Q And that's fair. I just wanted to make sure
20 that we were clear on what it was.

21 A Yeah.

22 Q Now, you were asked a couple of questions by
23 the Chair related to the DER program. And I want to
24 clarify, you don't have testimony on the DER program;
25 correct?

1 A I have not addressed that issue.

2 Q All right.

3 A Yes.

4 Q Okay. You haven't performed any independent
5 analysis on that; right?

6 A Not of this specific program. We've reviewed
7 the description of the program and that, but we have not
8 addressed that in our testimony.

9 Q Okay. Thank you.

10 Finally, Mr. Walsh asked you some questions
11 about net book value and I just want to make it clear for
12 the record. Your testimony is not proposing any
13 disallowance or imprudency as it relates to the operation of
14 the coal plants proposed for retirement in this case;
15 correct?

16 A No. This is not a rate case.

17 Q Okay. And can you agree with me that those
18 units have been in service to customers for decades and,
19 you know, if we took your position in this case, they
20 would continue to serve customers for longer, so I'm
21 assuming you don't believe they're being operated
22 imprudently; correct?

23 A I'm sorry. Your voice trailed off.

24 Q I'm sorry. I assume you're not suggesting
25 they're being operated imprudently because you're

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1 suggesting we continue to operate them; correct?

2 A Oh, I'm not making any suggestion about how the
3 plants have been operating.

4 MR. MARZO: Okay. I believe that's all I have,
5 Madam Chair.

6 MADAM CHAIR PRIDEMORE: Redirect.

7 REDIRECT EXAMINATION

8 BY MR. C. JONES:

9 Q Mr. Pollock, just a couple of points. You
10 were asked questions by Staff about the likelihood of the
11 enactment of a carbon tax versus uncertainty about
12 renewable -- of renewal of tax credits. Do you remember
13 that line of the questioning?

14 A Yes.

15 Q Have there been carbon taxes enacted in the
16 United States?

17 A Not a national tax.

18 Q Not a national tax?

19 A Right.

20 Q But there have been -- have there been
21 renewable tax credits such as those discussed in your
22 testimony? Have those been enacted?

23 A Since -- yeah, since the mid 1990s, I think.

24 Q Do you see any difference in the likelihood
25 of those two things?

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1 A Clearly the policy preference has been to tax
2 credits and not the carbon (inaudible).

3 Q And the second question is, Mr. Marzo
4 referred to the several scenarios that the company looked
5 at, the seven scenarios, and did you hear the testimony of
6 Georgia Power witnesses in the first round of hearings
7 about how they provided equal weight to those scenarios?

8 A I heard that, yeah. I was very surprised by
9 that.

10 Q Do you agree that's an appropriate way to
11 weight those scenarios?

12 A No, no. I really think that to give the
13 Commission informed information, I think you need to attach
14 probabilities to each of the scenarios. And if you want to
15 consider seven scenarios, that's totally fine, but to give
16 them equal weight I think is really not a fair analysis.

17 MR. C. JONES: Thank you, Mr. Pollock.

18 Madam Chair, I'd like to move our exhibits into
19 the record. And I would ask that if there are no
20 further questions from the Commission that the
21 witness be excused.

22 MADAM CHAIR PRIDEMORE: So marked. You may be
23 excused.

24 WITNESS POLLOCK: Thank y'all.

25 (GAM Exhibits 4-8, 10 was admitted into
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1 evidence.)

2 MADAM CHAIR PRIDEMORE: Georgia Coalition for
3 Local Governments.

4 MS. BROWN: Thank you, Madam Chair. At this
5 time, I would like to call the panel of Dr. Howard
6 Axelrod and John R. Seydel.

7 MADAM CHAIR PRIDEMORE: Give the court reporter
8 a few minutes to get reset, please, ma'am.

9 You may go ahead and swear in your witnesses.

10 MS. BROWN: Okay. Gentlemen, if you will stand
11 and raise your right hand.

12 Thereupon,

13 HOWARD AXELROD, Ph.D.,
14 JOHN SEYDEL,
15 having been duly sworn, testified as follows:

16 DIRECT EXAMINATION

17 BY MS. BROWN:

18 Q Dr. Axelrod, please state your full name,
19 employer, and your role for the record.

20 A (Witness Axelrod) My name is Howard J. Axelrod.
21 Sorry about that. And I'm employed -- I'm actually
22 president and owner of Energy Strategies Incorporated, and
23 I'm prepared to give a summary of my presentation.

24 Q Mr. Seydel, can you also give your name,
25 role -- employer and role?

A (Witness Seydel) Absolutely. John R. Seydel,
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1 director of sustainability for the City of Atlanta. I
2 represent the City of Atlanta as our director of
3 sustainability for three administrations, going on six
4 years, and have led a multitude of internal and external
5 energy efficiency as well as energy programs as well as
6 policy development and implementation. That's as far as
7 clean energy, energy efficiency, clean transportation
8 adoption.

9 In 2019, our office developed a Clean Energy
10 Atlanta plan, which is a roadmap for the city's commitment
11 to 100 percent clean energy by 2025.

12 Q Thank you.

13 Gentlemen, on May 6, did you prefile or cause
14 to be prefiled 30 pages of testimony, including two
15 exhibits?

16 A (Witness Seydel) Yes.

17 Q Do you have any changes to that testimony at
18 this time?

19 A (Witness Axelrod) No.

20 Q If I were to ask you the same questions today
21 under oath, would your answers be the same?

22 A (Witness Seydel) Yes.

23 A (Witness Axelrod) Yes.

24 MS. BROWN: Madam Chair, at this time, I ask
25 that their testimony be entered into the record as if
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given orally on the stand.

MADAM CHAIR PRIDEMORE: So moved.

MS. BROWN: May I also ask that the exhibits marked as HJA-1 and JRS-1 be identified as Georgia Coalition of Local Governments Exhibits 1 and 2?

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were marked for identification as Georgia Coalition of Local Governments Exhibit 1 and 2.)

(Whereupon, the prefled direct testimonies and errata of Mr. Seydel and Mr. Axelrod follows:)

I. INTRODUCTION

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

A. My name is Howard J. Axelrod, and I am President and owner of Energy Strategies, Inc, a management consulting firm I started in 1995. My business address is 2402 Thompson Rd. NE, Brookhaven, Georgia 30319.

Q. DR. AXELROD, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of Rensselaer Polytechnic Institute where I earned my Doctor of Philosophy degree in Managerial Economics. I also received an MBA in Marketing from the State University of New York (Albany) and MSEE and BSEE degrees in Power Systems engineering from Northeastern University. While working for General Electric, I completed its 3-year training program as an Application Engineer. I am a Senior Life Member of the Institute of Electrical and Electronic Engineers and a Professional Engineer (retired). I am also a member of the Atlanta Economics Club, the National Association of Business Economists, and the Professional Risk Management International Association.

I have been a management consultant for the last 37 years and the owner and chief executive officer of Energy Strategies, Inc. since 1995. Energy Strategies, Inc. specializes in resource planning, strategic analysis, and risk management. Our clients have included electric utilities, regulatory agencies, and large industrial customers throughout the United States. As indicated on my firm's web site (www.energystrategiesin.com) I have been retained by:

- 13 investor-owned utilities
- 19 public power systems
- 14 state and federal regulators

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- 9 Independent Power Producers
- 8 large industrial firms and
- 7 advanced energy technology firms

Prior to my consulting career, I served for nearly fourteen years in a number of senior level positions with the New York State Public Service Commission (PSC), the Consumer Protection Board (CPB) and the New York State Energy Research and Development Authority (NYSERDA). I was also appointed by then Governor Mario Cuomo as the Chief Economist on the Shoreham Commission. At the PSC I served as a special assistant to Chairman Alfred Kahn where I oversaw the development of utility productivity measures and the advancement of research and development programs funded by electric and gas utilities in New York. I was Director of Utility Intervention at the CPB, which at the time was the Nation's largest residential and small business advocacy organization. Finally, as a Program Manager at NYSERDA, I directed a number of innovative research and development projects including the development of one of the first comprehensive DSM screening models.

Over the last 25 years I have personally performed a number of studies and analyses relating to power systems requirements, alternative generation and renewable resources and emerging technologies including vehicle to grid (V2G) applications, smart meters and superconducting applications for transmission and distribution systems. For the latter, I served as Executive Director of CCAS, the Coalition for Commercial Advancement of Superconductors.¹

¹ Dr. Axelrod's resume appears in Exhibit HJA-1

1 **Q. FOR THIS PROCEEDING, WHO DO YOU REPRESENT?**

2
3 **A.** I have been retained by the Georgia Coalition of Local Governments which is a
4 collaboration of the following local and county governments to intervene in the 2022 IRP
5 proceedings before this Commission. Members of this coalition include:

- 6
7
 - The City of Atlanta
 - 8 • The City of Decatur
 - 9 • The City of Savannah
 - 10 • Athens-Clarke County Unified Government
 - 11 • Dekalb County

12
13 Collectively, this coalition represents the interests of some 2.1 million residents of Georgia.
14 Their purpose is to provide constructive input in support of greater renewable energy access
15 by both governmental bodies and the communities they serve, particularly disadvantaged
16 populations.

17
18 **Q. DR. AXELROD, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS**
19 **COMMISSION?**

20 **A.** Yes. I testified in Georgia Public Service Commission ("Commission") Docket No. 3549-
21 U, in 1987. This docket related to the Plant Vogtle (1 & 2) rate phase-in proposals that I
22 developed for Georgia Power. Those proposals were prepared independent of GPC's
23 direction and were based upon both representative industrial and residential input as well
24 as the oversight of the GPSC staff. Chase Econometrics, at that time a leading economic
25 forecaster, was also retained and under my direction performed the economic studies
26 required to assess the impact of electric price increases on Georgia's industrial output,
27 employment and wages for each county served by GPC. As I recall, the GPSC staff had
28 been planning to similarly investigate a rate phase-in plan that could mitigate rate shock
29 associated with the cost recovery of Vogtle 1 & 2. As I had been a principal author of the

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1 first rate phase-in legislation in the United States passed in New York, I was asked by
2 Georgia Power to manage a similar project with the oversight and input of the Commission
3 staff. Based on this collaborative study, the Commission did approve such a unique
4 approach to mitigate the price elastic response of Georgia's vibrant industrial expansion
5 and provide Georgia Power long term rate recovery of prudently incurred expenditures.

6 **Q. DO YOU HAVE ANY EXPERIENCE WITH DISTRIBUTED ENERGY**
7 **RESOURCES (DER)?**

8 A. Yes. My experience with DER related initiatives dates back to 2009 when I was retained
9 by Unitil Energy Services, an investor-owned utility providing electricity and gas to
10 communities in Massachusetts, New Hampshire, and Maine. The New Hampshire
11 legislature passed bill RSA 374-G:5 which incentivized electric utilities to invest in small
12 scale renewable resources:

13 The Purpose of RSA 374-G states that DER *"can increase overall energy efficiency*
14 *and provide energy diversity by eliminating, displacing or better managing energy*
15 *deliveries from the centralized bulk power grid..."*. The section goes on to say *"It*
16 *is therefore in the public interest to stimulate investment in distributed energy*
17 *resources in New Hampshire by encouraging New Hampshire electric public*
18 *utilities to invest in distributed energy resources..."*

19
20 In short, an electric utility would be able to invest in behind the meter DER and receive its
21 return on investment even should that investment be transferred to the property owner. The
22 criteria for this non-traditional form of capital investment were that:

- 23
- The DER be strategically located on the grid

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- 1 • The DER be designed to avoid, or forestall, the need for conventional transmission
- 2 and distribution remedial action
- 3 • The benefit cost ratio was greater than one.

4 My role included three responsibilities: 1) work with the PUC staff to develop a set of
5 regulatory procedures to evaluate and approve such requests, 2) help Unital identify and
6 evaluate the B/C ratio for identified pilot projects and 3) perform, as required by RSA 374-
7 G, an economic impact statement addressing the incremental benefits to the local
8 communities in terms of income and employment. I would note that this regulatory
9 provision continues to flourish in New Hampshire as a more recent application by Liberty
10 Utilities (in 2017) sought approval from the Commission to subsidize the cost of buying
11 and installing 1,000 residential battery storage systems and controls “with the goal of
12 reducing transmission costs and studying other potential system benefits.” I would further
13 note that the PUC’s approval criteria also require no cross-subsidization plus a showing
14 that the programs will have a positive impact on the local economy served by that utility.

15
16 Currently, I am assisting one of the US territorial island electric utilities to develop plans
17 to double the penetration of its rooftop solar systems while improving the reliability and
18 security of its generation, transmission, and distribution systems. Like Liberty Utilities in
19 New Hampshire, there is a focus on small scale DER including battery storage to provide
20 load management control, mitigation of feeder voltage swings, and reductions in harmonic
21 distortion and frequency swings, the latter causing unintended generation tripping.

22
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1 As a final example, I have recently completed an engagement for New York State Cayuga
2 County Legislature to evaluate and design a Community Choice Aggregation (CCA)
3 program and strategic plan that would offer the County's 33 towns and villages an
4 opportunity to procure 100% carbon free "home grown" electricity while concurrently
5 providing its farming community greater opportunity and resources to invest in solar and
6 wind generation and anaerobic digestion.

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

8 A. The objective for my testimony is twofold:

- 9 1. To evaluate whether Georgia Power's Community Solar program's proposed
10 monthly residential rate of \$27.99 is just and reasonable.
- 11 2. To explore the opportunities for GPC to offer, without incurring cross
12 subsidization, a rebate or subsidy for small scale distributed solar.

13 **Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMUNITY SOLAR**
14 **PROGRAM.**

15 A. To understand whether the proposed subscription fee is just and reasonable, I developed an
16 Excel spreadsheet model to understand the financial impact of the program on both
17 participating customers and the Company. The customer-focused analysis considered a range
18 of usage conditions, from low (650 kWh a month) to high (1500 kWh a month). It also
19 considered a range of subscription conditions, from a single block to four blocks. The
20 company-focused analysis considered typical solar installation costs, as informed by NREL
21 research reports, as well as industry standard O&M estimates and the company's stated
22 program costs. These calculations justified a subscription rate of roughly \$17.

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<i>Cost Category</i>	<i>Cost/Month</i>	<i>Explanation</i>
Capital Cost for Solar System	\$11.93	\$1,175/kW adj with ITC & 20% CF = \$.083/kWh
Program Administration	\$2.78	Based on \$33/unit
O&M Expenses ²	\$1.75	NREL \$21/yr/kW
Franchise Tax	\$.35	Assumed at 2.1%
Total Monthly Subscription	\$16.80	

In an attempt to understand the proposed rate of \$27.99, I incorporated the suite of riders and adjustments that customers pay on their bill, assuming that the Company included them in the monthly rate to “make them whole.” These include environmental cost recovery, nuclear cost recovery, the DSM rider, and the fuel adjustment clause which for 144 kWh totaled \$6.16/month. However, even with those charges included, I could only account for \$22 to \$23 of the proposed subscription fee. ($\$16.80 + \$6.16 = \$22.96$)

Q. PLEASE SUMMARIZE YOUR FINDINGS.

The analysis produced the following findings:

1. *The monthly charge of \$27.99 per 1 kW block appears to be too high.* As noted, my analysis of likely charges that make up GPC’s proposed monthly subscription rate found that when adding the estimated capital cost for the solar facility, typical operation and maintenance costs, program administrative costs and franchise fees, the monthly rate was closer to \$17/month per 1 kW block excluding the added riders. However, even with those charges included, I calculated the monthly rate to be in the range of \$22 - \$23.

² “Model of Operation-and-Maintenance Costs for Photovoltaic Systems”, Technical Report NREL/TP-5C00-74840, page 3, June 2020

- 1 2. *The inclusion of the monthly riders, is not consistent with the rate treatment of residential*
2 *owners of solar DER.* Behind the meter solar customers do not pay fees for fuel, nuclear
3 cost recovery, or DSM on the energy produced by their own rooftop solar systems. If I am
4 correct that the Company included these fees in the Community Solar subscription rate as
5 discussed above, it would be only consistent that this purchase agreement for community
6 solar receive the same rate treatment as consumers who owned rooftop solar. I would think
7 it would be unreasonable to charge the Community Solar participant who, in effect, is
8 contracting a dedicated renewable supply resource with all its inherent risks, also be
9 charged for environmental compliance, nuclear cost recovery, DSM and fuel, resources
10 which it is intended to replace.
- 11 3. *The inclusion of these adders also can lead to program participants paying double for*
12 *those specific charges and as a result subsidizing non-participants.* Assuming the
13 Company's monthly subscription fee does recover these expenses, and that those expenses
14 are based on an expected level of monthly production, should that actual production fall
15 below the average, then a consumer would first be paying these expenses through the
16 monthly \$27.99 rate and then again on sales from GPC to "make up for" any deficiencies
17 in solar production.
- 18 4. *It does not appear as if the Company provides adequate information as to the degree of*
19 *risk the participating customer assumes.* My analysis found that at \$27.99/month, should
20 the solar plant produce zero output throughout that month either due to poor weather or
21 unplanned outages, a small user with one 1 kW block would experience a 34% increase in
22 their bill for that month and 135% increase if they so happen to procure 4 blocks. Larger
23 users would similarly experience 18% and 71% increases, respectively.

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5. *Furthermore, should the output of the community solar farm be significantly greater than expected, to the point that it exceeds the customers own demand, the consumer would only receive a credit of about \$.03/kWh while paying a monthly flat fee that equates to about \$.19/kWh.*³ To illustrate the extreme, like a customer goes on a month-long vacation, the consumer would be paying \$27.99 per month and might only receive \$4.32⁴ for all the solar power delivered from the community solar farm.

6. *Even in the subsidized low-income program, customers assume a large amount of risk. My analysis found that at \$6.99/month a small user achieved 9 percent savings with one block and over 34 percent with four. However, as noted above, these consumers would experience similar risk exposure should the solar plant not achieve its expected output. In the extreme, where the solar farm failed to operate for one 1 kW block, rates for that period could rise by up to 9% and with four blocks by up to 34%. Because income qualified customers may be enticed to procure more blocks due to the prospect of significant savings, the Company should clearly inform prospective participants of the possibility that their monthly electric bills could significantly rise the more blocks of solar they commit to.*

Q. BASED UPON YOUR FINDINGS ASSOCIATED WITH THE COMMUNITY SOLAR PROGRAMS, WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. *Recommendations: Community Solar and Income Qualified Community Solar*

³ The \$.19/kWh is derived by assuming a 1kW block will produce 144kW per month or 1kW X 30 days X 24 hrs X .2 (Capacity Factor)

⁴ That is 144 kWh times \$.03/kWh.

1 Generally, I found that the monthly subscription rate of \$27.99 was excessive. I was also
2 unable to find a comprehensive explanation of the cost components and how they were
3 derived, except for the generality that this cost would provide full recovery of the
4 Company's expenses. By my calculations, a price of \$17.00 per month, which would
5 include the cost recovery of the community solar farm, O&M expenses, program
6 administration costs and franchise tax would be a more reasonable subscription price unless
7 the company can justify other valid expenses. This equates to \$.12/kWh assuming the 144
8 kWh/month solar output which is slightly less than the average residential cost for a 650
9 kWh/month consumer ($\$82.73/650 = \$.127/\text{kWh}$) without the community solar program.
10 When I did include the other riders like nuclear, DSM, FAC and environmental, the total
11 monthly subscription rate added another \$6.16 thereby increasing the total subscription rate
12 to \$24.00/month. Based on this review I offer the following set of recommendations:

- 13 1. Direct GPC to submit a comprehensive explanation of how the monthly subscription
14 rate was calculated, including an explanation of why that rate is 17% higher than the
15 "all in" rate of \$24/month, and 65% higher than the \$17.00 rate representing the cost
16 to own, operate and administer the community solar farm.
- 17 2. Direct GPC to explore program designs that do not penalize low users. As currently
18 proposed, community solar customers with low usage could pay up to 60% more than
19 they would if they were not enrolled in the community solar program.
- 20 3. Direct GPC to explain their justification to add all of the other riders to the cost of a
21 dedicated resource assuming they had. If they had not, then explain what other factors
22 accounted for the increase from \$17.00, the base cost to own, operate, maintain, and
23 administer the Community Solar to \$27.99/month.

Direct Testimony of Dr. Howard J. Axelrod, John R Seydel
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- 1 4. Direct GPC to discuss what safeguards they have implemented or plan to implement to
2 ensure that prospective participants in both the Community Solar and the Income
3 Qualified Community Solar Pilot are explicitly aware of the risks associated with
4 subscribing to one or more 1kW blocks.
- 5 5. Finally, and as an aside, I would recommend to the Company to advertise the monthly
6 subscription rate as simply \$28 per month, not \$27.99. In my experience, the concept
7 of reducing the price by a penny is an old marketing trick that plays on a consumer's
8 propensity to later recall the price as rounded down to the lowest whole number, so
9 \$27.99 becomes \$27, not \$28.

10 *Small Scale Behind the Meter Distributed Energy Resource Rebate*

11 **Q. GPC HAS PROPOSED TO PROCURE 200 MW OF DISTRIBUTED ENERGY**
12 **RESOURCES THROUGH TWO 100 MW PROCUREMENTS. DO YOU BELIEVE**
13 **THAT THIS PROCUREMENT IS IN THE BEST INTEREST OF CUSTOMERS?**

14 **A.** While I support GPC's investment in distributed generation, I have a concern with one
15 element of their proposal. GPC is proposing to procure distributed resources in the capacity
16 range of 250 kW to 6 MW. This is somewhat surprising, given GPC's own
17 acknowledgement that previous DER procurements have been challenged by unexpectedly
18 high interconnection costs. With this in mind, I would encourage GPC to also consider
19 smaller systems. These smaller systems generally have low to no interconnection cost and
20 can be installed at a much faster pace. Moreover, if some or all of the systems are located at
21 low-income homes, they can also reduce energy burdens.

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1 Q. ASSUMING SMALLER SYSTEMS ARE GENERALLY MORE EXPENSIVE
2 THAN UTILITY SCALE SYSTEMS, HOW COULD GEORGIA POWER
3 PROCURE SOLAR ENERGY FROM SMALL SYSTEMS AT A RATE AT OR
4 BELOW ITS LONG-TERM AVOIDED COST?

5 A. One promising form of cost-share would be to offer a solar rebate to help residential
6 customers to install rooftop solar. Currently, the Company purchases excess solar energy
7 as it is produced at its solar avoided cost. Depending on the customer's load profile and the
8 size of the system, this excess solar energy can range from 20-40%⁵ of production. Rather
9 than credit customers for this energy in real time, I propose that the Company offer
10 customers the net present value of the expected supply of "surplus" solar production as an
11 upfront payment or rebate. As opposed to real time crediting i.e., in lieu of receiving
12 payment for the surplus energy, an upfront payment would improve customer financials by
13 reducing financing costs. From a Company perspective, the financial impact would be
14 virtually the same, as they will be recouping this expense over time.

15 Q. PLEASE DESCRIBE YOUR ASSESSMENT OF SUCH A POTENTIAL SOLAR
16 REBATE PROGRAM.

17 A. I have performed a very simple calculation to illustrate how a rebate could be structured to
18 minimize cross subsidization between participating and non-participating customers.
19 Assuming a 6 kW residential rooftop solar system, I calculated what the benefit to the
20 utility would be if the participating customer consumed 60 percent of the solar output and

⁵ Source: Solar Energy Industry Association

1 exported the other 40 percent to the grid. Based on GPC's recently calculated 30-year solar
2 avoided cost, the value to the Company would be approximately \$500/kW, or \$3,000 in
3 the case of the hypothetical 6 kW system.

4 **Q. WOULD THIS REBATE PROPOSAL RESULT IN CROSS- SUBSIDIZATION**
5 **BETWEEN PARTICIPATING AND NON-PARTICIPATING CUSTOMERS?**

6 **A.** Generally, no. If the residential consumption rate remains constant, the Company will
7 recover all of the rebate costs over time.

8 **Q. BESIDES A REBATE, ARE THERE ANY OTHER APPROACHES THAT THE**
9 **COMPANY COULD USE?**

10 **A.** Yes. As I noted earlier, collaboration between the electric utility and its consumers can
11 address a number of system issues that ordinarily can only be addressed by the utility. With
12 proper incentives, distributed generation as well as battery storage can be effectively used
13 to address a number of operational issues including voltage management, line loss
14 mitigation, and frequency and harmonic correction.

15 With this in mind, the Company could expand its proposed local reliability and constraints
16 pilot to include residential and small commercial customers who have or would like to
17 acquire rooftop solar and battery storage. By either installing or providing a rebate for the
18 solar and/or storage systems, the Company could alleviate transmission and distribution
19 challenges to the benefit of all customers while simultaneously benefitting host customers.
20 The primary difference between this proposal and the one I just discussed would be that

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1 the rebate would be based on the avoided investment and operational costs either resolved
2 or deferred by the solar system.

3 I have already referenced the New Hampshire DER program I helped design and
4 implement. There the state provided electric utilities regulatory incentives to procure for
5 the customer, behind-the-meter solar DER and storage systems, and still receive its return
6 on investment based on the strategic location of the DER system in order to remediate local
7 distribution and transmission issues. I would refer the Company to New Hampshire
8 legislation RSA 374-G which has been in effect since 2009. More recently, Liberty
9 Utilities received commission approval to install up to 1,000 battery storage systems under
10 this same program. While GPC has initiated a similar program for larger scale systems, a
11 key benefit of the smaller scale residential and small commercial market is the speed at
12 which these systems can be installed. This could be especially beneficial in North Georgia,
13 where concerns about a lack of generation and transmission capacity is delaying the closure
14 of increasingly uneconomic coal resources.

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

16 **A.** Yes, it does.
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Howard J. Axelrod
 2402 Thompson Rd NE
 Brookhaven, GA 30319
 (518) 369-9969
 Email: HJA@energystrategiesinc.com



Dr. Howard J. Axelrod fosters a collaborative style of management yet has successfully managed to address complex and periodically controversial issues for his clients providing objective and independent opinions that balance the pressures of inherent enthusiasm with risk and uncertainty awareness. The challenges facing this industry are daunting. A planning horizon as short as ten years may witness technological, environmental, and political trends that will necessitate a rethinking of business-as-usual. Utility management must be prepared to embrace the fact that distributed resources of renewable generation combined with storage capacity will force the refocus of a traditionally fully integrated utility structure into a facilitative role of interconnection and distribution of a diverse set of residential, commercial, and independent power resources.

Fields of Expertise

Enterprise risk management, governance, risk and uncertainty analysis, strategic planning, executive management consulting, regulatory economics, energy planning and forecasting, prudence review, wholesale market practices and procedures, energy trading and power contract management, counterparty credit risk assessment, merger and acquisition analysis, emerging energy technology market valuation and outage preparation and storm restoration best practice assessment. (Please visit www.energystrategiesinc.com for greater detail)

Best Practices

- Enterprise Risk Management
- Energy Procurement, trading, hedging and Front/Mid/Back Office Operations
- Board Governance: Board interface with Chief Risk Officer
- Generation Analysis and risk management (from nuclear to rooftop solar)
- Regulatory strategy
- Merger and Acquisition support including condemnation analysis (municipalization defense)

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1
2 *Howard J. Axelrod* has more than 40 years of experience in management consulting, strategic
3 planning, and marketing for the electric and gas industry. In 1995 he found Energy Strategies, Inc.
4 (ESI) and has continuously served as the firm's President and Chief Executive Officer. He has
5 also been retained to serve as Chief Risk Officer and Board risk advisor for a New England based
6 wholesale electric company. Prior to forming ESI, Howard was an officer and executive consultant
7 for two national firms, Planmetrics and Resource Management International.

8
9 Earlier in his career, Howard served under four Governors in New York including senior positions
10 at the New York Public Service Commission, the Energy Research & Development Authority and
11 as Director of the Consumer Protection Board. At the NYPSC, he served as a special assistant to
12 Dr. Alfred Kahn, Chairman and at the State Consumer Protection Board he represented residential
13 and small business before the NYPSC.

14
15 Howard was awarded his Doctorate in Managerial Economics from Rensselaer Polytechnic
16 Institute (RPI), an MBA in Marketing from the State University of New York, and MSEE and
17 BSEE degrees in Power Systems from Northeastern University. He was an Adjunct Professor at
18 RPI and Russel Sage College and a guest lecturer at Colgate University and Georgia Tech.
19 Howard has over 25 publication and presentation citations and has testified in over 40 regulatory
20 proceedings.

21 His professional associations include membership in the Atlanta Economics Club, Life
22 Membership in the Institute of Electrical and Electronic Engineering, Senior Membership of the
23 Power and Energy Society, Member of the Professional Risk Managers International Association
24 and has been a registered Professional Engineer (retired license in New York)

25 Howard has for the last four years served on the Board of Trustees for Cliff Valley School, a
26 private learning institution in Atlanta. He previously had served as Chairman of Corporate Giving
27 at Wildwood Schools of Albany, NY which serves consumers with neurological disorders and
28 learning disabilities and as a PTA President in Colonie, New York.

Example Strategic Assessments

- For such municipal electric systems as Glendale California, Sacramento Utility District, Denton Tx Municipal power system, Guam Power Authority, and Cayuga County (NY) Energy Commission, have performed studies supporting the expansion of distributed generation, development of Community Choice Aggregation (CCA) programs and the assessment of advanced applications of Smart and Micro Grid applications.
- Santee Cooper: Provided executive management and its BOD independent assessment of the V.C. Summer 2 & 3 nuclear project economic and financial risk exposure.
- For Georgia Power, retained by senior management to design the first utility sponsored rate phase-in plan mitigating the “rate shock” associated with the commercial operation of Vogtle 1 & 2.
- For Oglethorpe Power, lead in the development of its first Integrated Resource Planning analysis. Also retained by OPC to perform an independent assessment of its acquisition of the Rocky Mountain Storage project.
- For MEAG, as a founding member of The Energy Authority (TEA), performed an independent assessment of its energy procurement and risk management practices and procedures.
- For the Alabama Municipal Electric Authority, performed an independent analysis of the economic impact of PowerSouth’s 20 year purchased power agreement with MEAG for 125 MW of Vogtle 3 & 4.
- Unitil: For its Chairman/CEO he was asked to collaborate with the New Hampshire PUC staff to develop an innovative regulatory process by which Unitil received a premium ROI for behind the meter solar investments.
- For Ameritech, he managed a market assessment of a failing investment that led to the sale of its “smart meter” start-up subsidiary to Commonwealth Energy of Massachusetts.
- American Transmission Company: For ATC’s Chairman he facilitated and supported the strategic assessment of ATC’s potential transformation from a joint transmission utility ownership model to an investor-owned, for-profit corporation.
- Southern Company: Dr. Axelrod was retained by senior management to support the company’s enterprise risk management (ERM) initiative and provide its Board with an independent assessment of its risk management compliance with Sarbanes Oxley.

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- 1 • MMWEC: Retained to lead the implementation of an ERM program and subsequently
2 served as the Board's Chief Risk Officer. During the "great" recession was asked to
3 manage MMWEC's mid-office function as credit default risk manager.
4
- 5 • New York ISO: Retained by NYISO Board to perform a comprehensive enterprise-wide
6 risk management review leading to major operational improvements and the further
7 retention to support the development of an internal ERM program.
8
- 9 • Edison Electric Institute: Retained by EEI's chief operating officer to assist in
10 preparing EEI's response to FERC Standard Market Design (SMD) NOPR and craft a
11 transmission planning white paper that both its transmission and generation members
12 could support.
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1 **Q. Please state your name, position, and business address.**

2 **A.** My name is John R. Seydel. I am the Director of Sustainability for the City of Atlanta. My
3 business address is 55 Trinity Ave SW, Atlanta, GA 30303

4 **Q. On whose behalf are you testifying in this proceeding?**

5 **A.** I am testifying on behalf of the Georgia Coalition of Local Governments.

6 **Q. Please summarize your qualifications and work experience.**

7 **A.** I have extensive experience in the clean energy and energy efficiency space. For more than
8 five years and across three administrations I have been the Director of Sustainability for
9 the City of Atlanta. Our office has led a multitude of internal and external clean energy and
10 energy efficiency programs as well as legislation and financing pathways that supports
11 clean energy, energy efficiency, and clean transportation expansion. In 2019, our office
12 was tasked with developing Clean Energy Atlanta, a plan and roadmap to for City's
13 commitment to a 100% clean energy by 2035 City-wide. During my time working as
14 Director, our office has led on multiple energy efficiency programs including but not
15 limited to the City's Energy Savings Performance Contracts (ESPC), which has given an
16 innovative pathway for energy audits and the corresponding retrofits to be paid back
17 through the savings of the energy conservation measures (ECO). These ESPC's will help
18 the City of Atlanta save millions of taxpayer dollars over the lifetime of these energy
19 conservation measures. In addition, our office passed the Commercial Building Energy
20 Efficiency Ordinance, the Electric Vehicle Readiness Ordinance, and the City's
21 Sustainable Building Ordinance. Through the Solar Atlanta program our team has led the
22 effort for the City to enter into the largest municipal Solar Energy Procurement Agreement
23 (SEPA) in the state of Georgia, with 17 solar installations on City-owned buildings
24 including recreation centers, fire stations, with more installations in the pipeline. Through
25 Solar Atlanta, we are predicting to save over \$5 million in taxpayer dollars through the 20-
26 year term of the SEPA. In partnership with Invest Atlanta, our team has also made \$500
27 million dollars available in financing for commercial properties to implement energy
28 efficiency and clean energy improvements through property assessed clean energy
29 financing (C-PACE). We have co-led not one, but two of the most successful solarize
30 campaigns in the state of Georgia adding solar as well as battery storage in many cases to

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1 hundreds of Atlantans rooftops through the innovative solar, battery crowdsource, bulk
2 purchase Solarize Atlanta and Solarize Atlanta 2.0 programs. (John R's resume appears in
3 Exhibit JRS-1)

4 **Q. Have you previously testified before the Georgia Public Service Commission**
5 **("GPSC" or "the Commission")?**

6 **A.** No

7 **Q. What is the purpose of your testimony?**

8 **A.** My testimony has four key purposes. The first is to propose changes to the Clean and
9 Renewable Energy Subscription (CARES) program, and more specifically the
10 Municipalities, Universities, Schools, and Hospitals (MUSH) carveout, to make it more
11 feasible for local governments. The second is to advocate for the continuation of the
12 Automated Benchmarking Tool (ABT) as a core Demand Side Management (DSM)
13 offering, rather than a subscription-based product. The third is to advocate for the
14 continuation and expansion of the DSM working group. The final reason is to advocate for
15 improvements to income-qualified energy efficiency programs to increase program
16 participation by low- and moderate-income families.

17 **Q. What qualifies you as an expert on these issues?**

18 **A.** In my 5 plus years working for the City of Atlanta as Director of Sustainability, I have led
19 a comprehensive portfolio of energy efficiency and clean energy programmatic and policy
20 work for both internal and external applications pursuant to the City's 100% clean energy
21 goal by 2035. I have experience in internal energy efficiency and clean energy programs
22 that range from installation of solar on City-owned and operated buildings to leading our
23 benchmarking ordinance compliance work in accordance with the City of Atlanta
24 Commercial Building Energy Efficiency Ordinance.

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1 Q. Are you submitting exhibits along with your testimony?

2 A. Yes. Please see JRS-1 regarding my experience and background.

3 Q. Please summarize your recommendations for the Commission in approving the
4 Company's 2022 IRP.

5 A. My recommendations are as follows:

- 6 1. The \$5,000 NOI fee for the CARES program should be deferred or waived for
7 Municipalities, Universities, Schools, and Hospitals, regardless of whether they are
8 participating in the program within the MUSH carveout or within another segment, such
9 as the Existing Load segment. Public sector entities like the local governments within the
10 Georgia Coalition of Local Governments often lack the resources for an upfront payment
11 of that amount. Moreover, as stewards of taxpayer dollars, it is hard to justify spending
12 thousands of dollars on a program that may not result in procurement of energy at all. As
13 currently proposed, we would be putting taxpayer dollars at risk with no guarantee of being
14 selected to participate. Waiving the fee entirely, or even allowing it to be paid over time if
15 selected as part of our normal energy bill would be far more feasible for organizations like
16 ours.
- 17 2. The Automated Benchmarking Tool should be continued as a core DSM program, rather
18 than a subscription-based offering, at least on a probationary basis. Several of the local
19 governments within our Coalition have or are developing Building Performance Standards
20 that will use the tool to drive real reductions in building energy use.
- 21 3. The Demand Side Management Working Group should be continued and better promoted
22 to allow for ongoing improvements and additions to Georgia Power's DSM portfolio.
- 23 4. To increase participation in the income-qualified Home Energy Efficiency Assistance
24 Program (HEEAP) and Residential Investment for Saving Energy (RISE) pilot, the
25 Commission should:
 - 26 a. Allocate a portion of program marketing funds to local governments and trusted
27 community organizations that have a deep and institutional knowledge of local
28 energy burdens. Referencing an example, I'd like to specifically take this moment
29 to thank Georgia Power for its \$50,000 commitment to support the City of Atlanta's

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1 Low-income energy efficiency program, WeatherRISE ATL, to directly support
2 outreach and auditing efforts for applicable residents. Through partnerships like
3 this we can support Georgia Power's efforts to meet its energy efficiency goals and
4 create deeper connections within our communities.

5 b. Provide or obtain funding for pre-requisite health and safety repairs. These can be
6 considered a program administration cost or included in a broader portfolio of
7 measures for cost-effectiveness testing purposes.

8 c. Simplify income verification processes. One possible solution is to qualify families
9 based on the income or energy burden of their census tract, rather than their
10 individual situation.

11 d. Expand the RISE pilot geography to the participating governments in this coalition.

12 **Q. What is the City of Atlanta's interest in the CARES program?**

13
14 **A.** The City of Atlanta has a goal to meet 100% of its energy needs with clean and renewable
15 energy by 2035. To achieve that goal, we will need to procure large amounts of renewable
16 energy at a cost-competitive rate.

17
18 **Q. Has the City of Atlanta considered participating in a renewable energy subscription
19 program through Georgia Power before?**

20 **A.** Yes. The City of Atlanta is currently in the process of participating in the CRSP program,
21 which is the precursor to CARES.

22
23 **Q. Where is the City in that process?**

24 **A.** We have passed legislation to accept a donation to cover the NOI fee, signed the required
25 NDA, and are preparing an application for submission prior to the June 30th cutoff.

26
27 **Q. What is your impression of the program so far?**

28 **A.** The Programs continues to be an expensive, high barriers to entry for local governments,
29 not set up for specific procurement needs for City.

30
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1 **Q. Based on your experience applying for the CRSP program, what changes would**
2 **help the program better meet Atlanta's needs?**

3 **A.** The \$5,000 NOI fee for the CARES program should be deferred or waived for
4 Municipalities, Universities, Schools, and Hospitals, regardless of whether they are participating
5 in the program within the MUSH carveout or within another segment, such as the Existing Load
6 segment. Public sector entities like the local governments within the Georgia Coalition of Local
7 Governments often lack the resources for an upfront payment of that amount. Moreover, as
8 stewards of taxpayer dollars, it is hard to justify spending thousands of dollars on a program that
9 may not result in procurement of energy at all. If the NOI fee for CRSP hadn't been donated to the
10 City, we would be putting taxpayer dollars at risk with no guarantee of being selected to participate.
11 Waiving the fee entirely, or even allowing it to be paid over time, if selected, as part of our normal
12 energy bill, would be far more feasible for organizations like ours.
13

14 **Q. Does the City of Atlanta use the Automated Benchmarking Tool?**

15 **A.** Yes. We reference the tool as a resource for our commercial building owners that have multiple
16 tenants to support compliance of the City of Atlanta's Commercial Building Energy Efficiency Ordinance
17 (CBEEO). Georgia Power developed the ABT to enable building owners and property managers to retrieve
18 energy consumption data for upload to Energy Star Portfolio Manager, which the City of Atlanta utilizes
19 for CBEEO Compliance.
20

21 **Q. How might the City use the tool differently in the future?**

22 **A.** Benchmarking is the first step towards reducing energy use. It's hard to measure the financial
23 or environmental impacts of energy efficiency retrofits or energy efficiency behavioral programs
24 unless you first measure what energy you are using in the first place. If GPC continues to offer the
25 ABT for free use, the City will become more intentional in advertising ABT. We will feature it
26 prominently on our benchmarking website (atlantabuildingbenchmarking.com) and City energy
27 program overview site (100ATL.com) to further enhance benchmarking compliance and ABT use.
28

29 **Q. Do any other local governments in the Coalition have plans for Benchmarking**
30 **ordinances or building performance standards like Atlanta?**

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1 A. Yes. Most immediately, the City of Savannah has committed to developing and passing a
2 building performance standard by Earth Day 2024 as part of the National Building Performance
3 Standards Coalition, a coalition in which the City of Atlanta also participates.
4

5 **Q. Has the City of Atlanta participated in the Demand Side Management Working**
6 **Group before?**

7 A. Yes.
8

9 **Q. What did that entail?**

10 A. The City of Atlanta was a stakeholder and participant in recommending, advising, and
11 collaborating with GPC on existing and potential DSM programs.
12

13 **Q. Do you feel like your participation in that working group was beneficial?**

14 A. Yes.
15

16 **Q. If the working group were continued, what would you hope to accomplish?**

17 A. Atlanta hopes to continue in formal partnership with Georgia Power, as well as including
18 more local governments and community partners across the service territory in this DSM working
19 group to give feedback on existing programs and propose additional innovative energy efficiency
20 programs and resource paths. Additionally, I recommend that the DSM working group work with
21 Georgia Power to create a centralized resource of organizations, funding and financial support,
22 and use cases. This centralized resource would act as a publicly accessible, one stop shop to help
23 demonstrate and connect the ecosystem of organizations and programs that support and fund
24 energy auditing, energy efficiency retrofits, health and safety resources, and more for the
25 residential and commercial space. This resource would be an incredibly useful tool for Atlanta's
26 residents and businesses and would also be something that all governments in this coalition can
27 add to, support, and share in our public facing communications and resources.
28

29 **Q. Would you recommend participation to other local governments with similar clean**
30 **energy goals?**

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1 A. Yes, I would. I have already encouraged the other cities in the coalition to participate, if
2 given the opportunity.

3
4 **Q. In your experience working with communities in Atlanta, what are some barriers low-**
5 **income families face in accessing energy efficiency programs?**

6 A. Low-income families face several barriers to accessing energy efficiency programs.
7 These include lack of awareness, application challenges stemming from connectivity issues or
8 income verification barriers, scheduling issues for those who work long hours, health and safety
9 issues in the home, and challenges relating to a lack of ownership in the case of renters, or lack
10 of clear ownership, in the case of heirs' properties.

11
12 **Q. In your experience, are the citizens of Atlanta familiar with the efficiency programs**
13 **available through Georgia Power?**

14 A. Not as much as they should be. As part of the development of our clean energy plan, we
15 issued a survey that asked around 1,800 residents (79% which lived in the Atlanta and Metro
16 Atlanta area) if they were familiar with energy savings and clean energy programs offered by their
17 utility, more than half of the residents answered no. This is a huge collaborative opportunity.

18
19 **Q. What kinds of health and safety issues would prevent residents from accessing energy**
20 **efficiency services?**

21 A. Common health and safety issues include roof leaks, structural weakness, mold issues,
22 disturbed lead paint, vermiculite insulation (which is often contaminated with asbestos),
23 knob and tube wiring, and gas leaks.

24
25 **Q. Are there any other funding sources available to correct these issues?**

26 A. There is some, but it is limited. For example, the U.S. Department of Housing and Urban
27 Development provides some funding for lead abatement, and the federal Weatherization
28 Assistance Program will cover combustion appliance safety testing to check for gas leaks and other
29 issues. Some non-profits and local governments may also cover minor home repairs, but these vary
30 widely from jurisdiction to jurisdiction.

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1
2 **Q. Besides increased participation in energy efficiency programs, do you believe offering**
3 **funding for health and safety repairs would provide other benefits?**

4 A. Yes, I do. From a customer perspective, health and safety repairs will improve the health
5 of the resident and comfort of the home and increase the value of the home. From a social
6 perspective, health and safety repairs will reduce blight and support local economic
7 development. From a utility system perspective, health and safety repairs will enhance the
8 benefits we are already seeing from energy efficiency programs—avoided energy, avoided
9 demand, avoided emissions, and reduced arrearages. Further, these repairs would also allow for
10 residents to be able to qualify for additional energy efficiency resources outside of utility
11 programs.
12

13 **Q. Can you give an example of situations where current income verification standards**
14 **might present a barrier for interested households?**

15 A. Income verification can be difficult for workers with irregular or inconsistent work
16 schedules, like gig economy workers. Income verification can also be difficult for multi-
17 generational households or households that share bills but otherwise do not support each other
18 financially (e.g. roommate situations). Finally, income verification can be challenging for families
19 that do not have reliable access to the internet or transportation, since some documents are only
20 available online or in person.
21

22 **Q. Besides increased participation in energy efficiency programs, would a simplified**
23 **income verification process provide any other benefits?**

24 A. Yes, a simplified income verification process would likely reduce administrative costs.
25

26 **Q. What is your specific recommendation regarding income verification?**

27 A. I am recommending that Georgia Power qualify would-be participants based on the energy
28 burden or median income of their census tract, rather than the participant's individual situation. Of
29 course, interested participants should retain the ability to use other options, but automatic
30 verification based on address will be far easier for both participants and the utility.

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1 Q. Does this conclude your testimony?

2 A. Yes it does.

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1 BY MS. BROWN:

2 Q Gentlemen, do you have summaries prepared at
3 this time?

4 A (Witness Seydel) That's correct.

5 A (Witness Axelrod) Yes. Thank you very much.
6 Thank you.

7 Q Please give it.

8 A (Witness Axelrod) For this proceeding, I'm
9 representing the Georgia Coalition of Local Governments, and
10 I have two areas relating to Georgia Power's proposed solar
11 programs, the Community Solar and the proposed distribution
12 generation procurement. Let me address my findings and
13 recommendations.

14 The proposed monthly subscription rate for the
15 residential Community Solar program of \$27.99 I found was
16 too high. I recognize that it is a rate-base issue, but on
17 the other hand, our analysis shows, as I said, too high.

18 Upon further analysis, I found that the fee
19 includes far more than the incremental cost of the solar,
20 expected O&M, and program administration costs. It also
21 includes riders for nuclear cost recovery, fuel cost, and
22 environmental compliance.

23 It is my opinion that the recovery of these
24 costs through Community Solar tariff is unjust and
25 unreasonable.

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1 When customers enroll in a Community Solar
2 program they are signaling their intention to get that
3 prescribed portion of their energy exclusively from solar.
4 As such, they should not be asked to pay for the cost other
5 than fuel sources through the subscription.

6 If rooftop solar customers aren't charged for
7 fuel, nuclear, recovery on the kilowatt hours they use
8 behind the meter, Community Solar customers should not be
9 charged for these costs either. When the riders are
10 removed, the subscription rate is reduced to closer to \$17 a
11 month. Moreover, by including riders in the subscription
12 fee, there is a potential to create a cross-subsidization
13 flowing from the program participants to nonparticipants
14 which is contrary to the company and this Commission's
15 objective to achieve rate neutrality.

16 Let me explain. For example, when solar output
17 is lower than planned, the consumer will have already paid
18 all of Georgia Power Company's added charges but will
19 again -- will pay again as the company provides its normal
20 service.

21 Though Georgia Power has been transparent about
22 the premium nature of -- excuse me a second. Transparent
23 about the -- sorry -- about the prices that -- I lost track
24 of my line. Sorry about that.

25 About the premium nature of the Community Solar
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1 program, they have been -- they have not been as transparent
2 as how much these prices may change in the future.

3 Under questioning, Georgia Power admitted that
4 the subscription costs will continue to rise as rates
5 increase. This eliminates any incentive for price
6 predictability and hedging against rising fuel costs. As
7 such, I would imagine that it would be difficult to fully
8 subscribe to the program even with the addition of the
9 commercial subscription.

10 Finally, while I applaud the creation of an
11 income equality program, I would note that the overpriced
12 subscription blocks will be a disincentive to potential
13 philanthropic and corporate sponsors. The selling point for
14 sponsorship is helping low-income families access solar, not
15 helping low-income families pay for Plant Vogtle, fuel, and
16 other environmental compliance costs.

17 With regard to distribution solar, Georgia
18 Power has requested to procure 200-megawatts of distributed
19 resources in the size range of 250 kilowatts up to
20 6 megawatts. At the time it has conceded in this filing
21 that that high interconnection costs have delayed or
22 derailed previous procurements in 2016 and 2019 IRPs.

23 With this in mind, we would like to offer that
24 the company could avoid these challenges and still procure
25 energy below its long-term avoided costs through a rebate

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1 program for small solar energy systems. Currently, Georgia
2 Power compensates exports to the grid from behind-the-meter
3 solar system at its solar avoided cost.

4 The rebate we are proposing would follow the
5 same logic and be set to the present value of expected
6 surplus energy credits at the avoided solar rate. By my
7 calculation, this methodology would result in a rebate of
8 about \$500 per kW.

9 Finally, it is worth noting that Georgia Power
10 could use rebates or other subsidies to strategically locate
11 solar and other DER. In my testimony, I highlight an
12 innovative approach developed in New Hampshire that provides
13 an incentive to its electric utilities to subsidize the
14 development of rooftop -- residential and small commercial
15 applications where the subsidy or rebate was based upon the
16 economic value that the resource offered to the electric
17 system. Georgia Power has proposed such a model on a pilot
18 basis in this IRP, but it is worth considering full
19 development of this model, especially in light of the
20 reliability concerns in North Georgia.

21 Given the ongoing costs of uneconomic coal
22 resources and the avoided costs of strategic DER, the
23 avoided costs of strategic DER deployment could be
24 substantial.

25 Thank you very much.

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1 A (Witness Seydel) Well, first, I just wanted to
2 say thank you. It's 4:30 and it feels like we have that
3 type of 4:30 energy in here today.

4 And first, I just wanted to thank the
5 Commission for inviting us, the City of Atlanta, to
6 participate in the IRP back in 2019. I'm excited to be here
7 along with the rest of our local governments and the
8 coalition that share our clean energy goals.

9 And there's no way that we're going to be able
10 to meet these 100 percent clean energy goals and our climate
11 goals without deep collaboration and cooperation with both
12 Georgia Power and with the Commission.

13 So thanks so much for having me, and I'll go
14 ahead and just dive right into my recommendations unless
15 y'all want to hear my -- my experience and my background,
16 but I'll just go straight to the recommendations.

17 So my testimony focuses on four key
18 recommendations. The first is proposing changes to the
19 clean and renewable energy subscription known as CARES
20 program, and more specifically, the Municipalities,
21 Universities, Schools, and Hospitals carve-out, also called
22 MUSH, MUSH, to make it more feasible for local governments
23 to truly reflect a demand for this program.

24 The second is to advocate for the continuation
25 of the ABT, the Automated Benchmarking Tool, as a core

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1 demand-side management offering.

2 The third is to advocate for the continuation
3 and expansion of the DSM, demand-side management working
4 group.

5 The last is to advocate for improvements to
6 income-qualified energy efficiency programs to increase
7 participation by low and moderate income families.

8 Diving into my recommendations, the 5,000 NOI,
9 notice of intent fee, for the CARES program should be
10 deferred or waived for municipalities, universities,
11 schools, and hospitals regardless of whether they are
12 participating in the program within the MUSH carve-out or
13 within another segment such as the existing load.

14 I'm also advocating specifically as well for
15 the municipalities and for local governments specifically
16 because public sector entities like local governments within
17 the Georgia Coalition of Local Governments often lack the
18 resources for an upfront payment of that amount.

19 Moreover, as stewards of our taxpayer dollars,
20 it's very hard to justify spending thousands of dollars on a
21 program that might not result in any type of renewable
22 energy procurement at all. And as currently proposed, we
23 would putting taxpayer dollars at risk with no guarantee of
24 being able to -- of being selected, much less able to
25 participate.

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1 So waiving the fee entirely or even allowing
2 it to be paid over time if selected as part of this
3 normal -- part of our normal energy bill, would be far more
4 feasible for organizations like ours.

5 My testimony notes the City of Atlanta's
6 efforts to participate in the predecessor CRSP program, the
7 Customer Renewable Supply Program. And these comments are
8 representative of our experiences thus far.

9 There's demand for this program. Alisha from
10 the City of Savannah asked Georgia Power where the
11 50 megawatts came from for the MUSH carve-out, and if that
12 was based on demand. And from the panel, what we heard was
13 that there wasn't any demand shown by local governments.

14 So I'm here to say that the City of Atlanta is
15 and is going for that, knowing that the NOI closes out
16 June 30th.

17 And the City of Atlanta alone could subscribe
18 to more than the last 300 megawatts now being offered as
19 part of the CRSP program. In an effort to show demand for
20 the future CARES MUSH program, and to further identify
21 participation for barriers to Georgia Power and to the
22 Public Service Commission, like the upfront fee for the NOI,
23 the City of Atlanta is working to submit an NOI specifically
24 focusing on our airport despite these barriers, and to also
25 identify these barriers for the future.

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1 My second piece, the Automated Benchmarking
2 Tool, should be continued as a core DSM program. Several of
3 our local governments within our coalition have benchmarking
4 policies in place or are developing building bench --
5 building performance standards that will continue to use --
6 to utilize the tool to benchmark their energy use and then
7 drive real reductions in building energy use. As we heard
8 earlier today, this also in line with -- the ABT
9 recommendation is in line with the PSC staff, based on their
10 testimony.

11 My third piece, the demand-side management
12 working group, should be continued, expanded, and better
13 promoted to allow for ongoing improvements, in addition to
14 Georgia Power's DSM portfolio. The City of Atlanta in 2019,
15 as a part of the rate case, was invited to be a part of
16 that. I know we had heard a discussion earlier today
17 from -- from staff and that was one of the really exciting
18 things coming out of that, because it really does show that
19 we are here to be partners. We're here to collaborate with
20 the Public Service Commission and Georgia Power, and we
21 won't meet our climate and clean energy goals without it.

22 And the outcomes have been pretty darn
23 exciting. Six out of 11 recommendations, over 50 percent of
24 those recommendations have been adopted into the Georgia
25 Power's DSM portfolio as part of this IRP. Given our

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1 coalition testimony and participation, having representation
2 from each of our local governments would help Georgia Power
3 and the Public Service Commission, especially during the
4 next three years before the next IRP on program ideation and
5 recommendations.

6 This will allow us to be able to give critical
7 insights on barriers to Georgia Power and the Public Service
8 Commission before the IRP submission in January 2025 where
9 proposed programs at that point are so far along in the
10 development and vetting process that, I mean, we're just
11 asking for tweaks instead of actually formulating --
12 formulating projects and programs.

13 This request is also in line with the
14 recommendations from the PSC Staff and their testimony in
15 terms of continuing the DSM working group and clarifying,
16 not adding, the other co- -- governments in our coalition.
17 But I do want to make that point, though, that is what I'm
18 here advocating for.

19 My last recommendation, to increase
20 participation in the income-qualified Home Energy Efficiency
21 Assistance Program, also known as HEEAP, double E and an A,
22 and residential investment for saving -- Residential
23 Investment for Saving Energy pilot, otherwise known as the
24 RISE pilot.

25 The Commission should simplify, number one,
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1 simplify the income verification process to identify this
2 issue. One possible solution is to qualify families based
3 on median income from their census track, energy burdens,
4 rather than their individual situation. This would reduce
5 administrative time, resources, and effort used on
6 processing individual applications and would open many
7 individuals to qualify, as well as reduce barriers for
8 low-income community members, especially those who are
9 elderly or who have limited capacity or access to the
10 internet, WiFi, or transportation to be able to participate
11 online or in person.

12 Of course, interested participants should
13 retain the ability to use other options, but automatic
14 verification based on this -- based on their address will be
15 far easier for both participants and the utility. And
16 really leaving any type of resources on the table is -- is
17 something that's the -- I think the biggest shame at all
18 when talking about energy efficiency for people who need it
19 the most and those that are energy-burdened the most.

20 So I have a couple of other recommendations.
21 Allocating a portion of program marketing funds to local
22 governments and trusted community organizations that have a
23 deep and institutional knowledge of local energy burdens in
24 the communities that we serve. Referencing a specific
25 example, I'd like to thank and shout out, on behalf of the

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1 City of Atlanta, Georgia Power for it's \$50,000 commitment
2 to support the City of Atlanta's low-income energy
3 efficiency program, WeatherRISE ATL, to directly support
4 outreach and auditing efforts for applicable residents.
5 Through partnerships like this, we can support Georgia
6 Power's efforts to meet its energy efficiency goals and
7 create deeper connections within our communities and not
8 leave any energy efficiency money on the table.

9 My third recommendation: Provide or obtain
10 funding for prerequisite health and safety repairs. These
11 can be considered a program administration cost or included
12 in a broader portfolio of measures for cost-effectiveness
13 testing purposes. These health and safety repairs could be
14 on issues including mold, lead abatement, vermiculite
15 insulation, roof leaks. These are the things that actually
16 can prevent all those from taking advantage of not just
17 Georgia Power energy efficiency resources, but a lot of
18 energy efficiency resources that are available to the
19 community, federal grants, et cetera.

20 The reason why I first started off with the
21 simplified income verification process, and I know I touched
22 it already, it could reduce, potentially, administrative
23 costs and resources. I think that those potential costs and
24 reductions could go towards programs like health and safety
25 repairs that can help those in the community be able to take

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1 advantage of those energy efficiency resources that are out
2 there, and to even be able to qualify.

3 My last recommendation is around the RISE --
4 the RISE pilot. And I'm here to advocate the expansion of
5 the RISE pilot geography to participating governments in
6 this coalition. We want to make sure that all 500 spots are
7 filled. And PSC Staff in their testimony said that they are
8 "concerned that the pilot may not be able to find enough
9 eligible participants to reach the goal of 500 customers
10 despite the changes that have already been made to increase
11 participation." And overall expanding this geography to
12 those that are in our coalition would help expand the
13 potential participation pool.

14 And that includes my testimony summary.

15 MADAM CHAIR PRIDEMORE: Ms. Brown, strictly on
16 my oversight. You did such a wonderful job calling
17 your witnesses that I looked for the esquire and I
18 didn't see it. So real quick, before you guys field
19 questions, Preston, let me go ahead and let you swear
20 in these witnesses. But other than that, run your
21 show.

22 Hey, she's watched a lot of "Law and Order"
23 like I have.

24 MR. THOMAS: It's okay.

25 MADAM CHAIR PRIDEMORE: I'm not an attorney
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1 either, Ms. Brown.

2 MR. THOMAS: At this time, I'd like to swear in
3 the panel of Howard Axelrod and John Seydel.

4 Would you both please raise your right hand.

5 Thereupon,

6 HOWARD AXELROD, Ph.D.,
7 JOHN SEYDEL,
8 having been duly sworn, testified as follows:

9 DIRECT EXAMINATION

10 BY MR. THOMAS:

11 Q And can I ask you both to please -- you can
12 have a seat. You can please for the record just state
13 your name, title, business address, and responsibilities.

14 A (Witness Seydel) Absolutely.

15 Do you want to start?

16 A (Witness Axelrod) My name is Howard Axelrod.

17 COMMISSIONER MCDONALD: Microphone, please.

18 WITNESS AXELROD: Sorry. My name is Howard
19 Axelrod. I live at -- or I work there as well, 2402
20 Thompson Road in Brookhaven. And I'm president and
21 owner of Energy Strategies, Incorporated.

22 MADAM CHAIR PRIDEMORE: Thank you.

23 Mr. Seydel.

24 WITNESS SEYDEL: John R. Seydel. Director of
25 Sustainability for the City of Atlanta. I'm located
 right across the street at 55 Trinity Avenue SW,
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1 Atlanta, Georgia 30303.

2 BY MR. THOMAS:

3 Q And if I were to ask you the same questions
4 today that were asked in your prefiled testimony, would
5 your answers be the same?

6 A (Witness Seydel) Yes.

7 A (Witness Axelrod) Yes.

8 Q Okay. Thank you.

9 MADAM CHAIR PRIDEMORE: Thank you, Mr. Thomas.
10 Thank you, Ms. Brown. Go back to your
11 witnesses now.

12 MS. BROWN: So, Madam Chair, these witnesses
13 are available for questions from you and the other
14 Commissioners, as well as cross-examination.

15 MADAM CHAIR PRIDEMORE: Very good.

16 Questions from Commissioners.

17 (No response.)

18 MADAM CHAIR PRIDEMORE: Well, you two are
19 getting off easy.

20 All right. Intervenors, does anybody wish to
21 question these witnesses?

22 MR. THOMASSON: I have a couple.

23 MADAM CHAIR PRIDEMORE: All right. This would
24 be Georgia Solar Energy Industries Association, Solar
25 Energy Association, and Vote Solar.

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1 COMMISSIONER SHAW: I've got one quick
2 question. Sorry. And I apologize if this was in
3 your testimony, but is there -- is -- are the
4 goals -- would you just repeat what your clean energy
5 goals, are and are those -- is that a common goal
6 between all these municipalities or do they vary?
7 And do you anticipate more municipalities joining in
8 with this effort?

9 WITNESS SEYDEL: So I can -- so for the City of
10 Atlanta, it's one hundred percent clean energy by
11 2035. Thank you for the question. I know the City
12 of Savannah -- and correct me if I'm wrong, Alicia --
13 a hundred percent clean energy as well, 2035. For --

14 MS. BROWN: Communitywide.

15 WITNESS SEYDEL: Communitywide.

16 UNIDENTIFIED MALE: For Athens, I believe
17 it's -- it is 2035 for Athens Municipal.

18 WITNESS SEYDEL: And then 2050 for (inaudible).

19 And then I know Decatur is working on a one
20 hundred percent clean energy on a commitment. DeKalb
21 is also -- also has a one hundred percent clean
22 energy commitment, I believe also by 2035. And there
23 are -- there are jurisdictions that are- -- that
24 aren't a part of this coalition that do share that.
25 The City of Clarkston -- yes, Clarkston also has a
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1 hundred percent clean energy goal

2 MS. BROWN: And Augusta.

3 WITNESS SEYDEL: And Augusta. I'm not sure
4 about --

5 MS. BROWN: It counts as the sixth.

6 WITNESS SEYDEL: Got it. So I think Augusta
7 does too, but I'm not an expert for Augusta, so,
8 quote, subject to check.

9 COMMISSIONER SHAW: Thank you very much.

10 WITNESS SEYDEL: Thank you.

11 BY MR. THOMASSON: (CROSS-EXAMINATION)

12 Q All right. Gentlemen, I just have a couple
13 quick questions. Let's see if y'all can help me
14 understand your recommendations about distributed solar
15 generation that I believe is in Mr. Axelrod's testimony --

16 A (Witness Axelrod) Yes.

17 Q -- starting on page 12.

18 You make the comment that you would hope that
19 Georgia Power would consider distributed generation in
20 system sizes smaller than 250 kW; is that correct?

21 A (Witness Axelrod) That's correct.

22 Q What I wasn't clear about from your
23 testimony, are -- are you proposing that systems smaller
24 than 250 kW be included in the DG procurement process that
25 they're proposing that starts at the larger size, or are

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1 you proposing this other sort of rebate program as an
2 alternative approach for those smaller systems?

3 A (Witness Axelrod) I would say the latter. I
4 think the numbers of possible participants would be large
5 even though each contribution will be small. So
6 administratively, I think it would be a separate program.

7 Q Okay. And could you help explain how you
8 envision structuring this rebate that you're proposing
9 that would be based on expected, I guess, export for the
10 system; correct?

11 A (Witness Axelrod) That's correct. Well,
12 there's two aspects how it's structured. Let me give you a
13 little bit of the genesis. This was a law passed 10, 12
14 years ago in New Hampshire that directed -- it's a public
15 service law in New Hampshire created to provide incentives
16 for electric utilities to use distributed energy resources
17 for residential and small businesses.

18 Some of the focus was -- the objective was to
19 stimulate distributed energy resource distribution within
20 the smaller community -- or smaller users as well as enhance
21 local economical development. Concerns were even large
22 solar farms and large wind farms, a lot of the money flowed
23 out of the community, whereas at the local level on rooftop
24 types of systems, the percentage of local labor and
25 materials were substantially higher, so that was one of the

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1 goals.

2 The -- in New Hampshire, it's obviously a lot
3 smaller. I think New Hampshire is probably smaller than the
4 City of Atlanta. But they -- they asked a host utility, one
5 of the utilities to sponsor, help put this program together.
6 Legislation passed. And I was retained by the company to
7 work with the Commission staff to develop the regulations
8 around the law and then to develop a program by which
9 Unitil, which is the utility up there, would be used as, in
10 a sense, the guinea pig.

11 And the concept was to identify places where
12 the utility had expected local issues on the distribution
13 network that could be resolved or deferred through the
14 application of targeted or strategic location of rooftop
15 solars.

16 And we didn't know if that was going to work or
17 not, but lo and behold, it was -- it did work. We
18 identified numbers of projects in which you could defer, for
19 example, a new transformer on a particular feeder. You
20 could -- and, well, I won't go through other things, but we
21 identified a number of projects.

22 In that program, the incentive was that the
23 utility, even if it contributed through a full rebate, in
24 other words, they paid for the solar and consumer owned it,
25 the utility was able to still rebate -- or rate base that

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1 and receive a regulatory treatment to compensate the
2 utility.

3 We're not asking for that now. We think we
4 have a simpler approach. Given its size and volume of
5 dollars, it's probably not significant. But it's really to
6 use -- we know that on a given solar system typically the
7 consumer only consumes about 60 percent, in that ballpark,
8 of that energy because they can only use so much solar
9 during the times of day that it's being produced, and
10 without batteries, it -- it has gone to waste or it's sold
11 back to the utility. And in Georgia, if you were one of the
12 5,000 that were lucky enough to participate, you received
13 the avoided solar cost.

14 And our proposal is that to get, especially low
15 income folks, the ability to put these systems online, is
16 that the surplus that flows back is used over time to pay
17 back the utilities, so you don't get a credit, but the
18 utility in effect pays for -- not full credit. They will
19 pay for a substantial part of the cost of the solar system
20 through a rebate upfront. They receive the money over time.

21 And that's an idea that was brought to me
22 actually by the coalition, and I thought it was very
23 interesting, because it played on the same concept of what I
24 saw in New Hampshire. And now, I mention New Hampshire,
25 there are a number of states that are starting to apply this

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1 approach. But in any case, that's the genesis of what we're
2 talking about.

3 COMMISSIONER MCDONALD: Mr. Axelrod, when you
4 say the utility will pay, you mean the ratepayer?
5 Which one do you mean?

6 WITNESS AXELROD: I -- what we're talking about
7 is a rebate, and it comes to around \$500 a kW. And
8 if you put in a typical, say, 6-kW system, that would
9 be about a \$3,000 rebate that the utility would
10 provide that consumer to install it.

11 Now, that system will probably cost more like
12 \$10,000, but in order to help to recover those costs
13 and not be cross-subsidizing the nonparticipants,
14 those fees will be made up -- that rebate will be
15 paid for by that consumer over time through the flow
16 of the surplus energy back into the system.

17 So they wouldn't be getting the 3 point
18 whatever -- whatever the long run -- the solar
19 avoided cost for a period of time until that rebate
20 is paid back.

21 BY MR. THOMASSON:

22 Q But am I understanding correctly you're
23 basically proposing that that -- what would normally be
24 that longer payback that avoided cost would be sort of a
25 front loaded lump sum payment instead of --

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1 A (Witness Axelrod) Absolutely.

2 Q That -- so that would form the rebate;
3 correct?

4 A (Witness Axelrod) Yes. You said it better
5 than I did.

6 Q Have you done any Georgia-specific analysis
7 on what those numbers might look like in Georgia?

8 A (Witness Axelrod) Not Georgia specifically. I
9 used, for example, my analysis was based on a lot of
10 NREL-related -- National Energy -- yeah, Energy Lab,
11 right -- which does a lot of analysis on the cost of solar
12 usage patterns in terms of their load factors and so forth.

13 So on that basis, you know, I didn't use -- I
14 didn't go out to solar distributors in the area to come up
15 with the prices.

16 Q Okay. So the numbers you're using are just
17 sort of rough guidelines of conceptual kind of illustrated
18 numbers?

19 A (Witness Axelrod) Well, I would say they're
20 more than rough, because, you know, a lot of the studies
21 that utilities use are developed through these national
22 studies.

23 Q And I guess the other thing I wasn't clear
24 about, what -- how broad are you considering this rebate
25 program to be? I mean, given the background from New

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1 Hampshire, you also mentioned Georgia Power could expand
2 the local reliability pilot then sort of site projects
3 specifically where congestion is.

4 Is that what you're proposing here in Georgia
5 or are you proposing it more generally or for income
6 qualified customers?

7 A (Witness Axelrod) Well, right now we're
8 proposing it as an idea that broadens the company's program
9 and for the larger scale distributed solar. If you're
10 looking at North Georgia where they're expecting or
11 antic- -- or experiencing shortages of capacity, some of
12 those programs will take years to develop in terms of the
13 bidding, acceptance, construction.

14 This can be done rather quickly in much smaller
15 increments. I mean, we're talking about a typical home of 6
16 to 10,000 kW, but it can be done quickly.

17 Now, I'll give you another example. And more
18 recently this program has continued in New Hampshire. I
19 haven't studied the entire case, but another utility called
20 Liberty Utilities are doing the same thing for batteries and
21 they're talking about on -- adding onto residential solar,
22 and we're taking about thousands that they're anticipating
23 over the next couple of years. So the concept, while it's
24 small increments, could happen a lot quicker and solve the
25 problem more immediately.

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1 MR. THOMASSON: Okay. Madam Chair, that's all
2 I have.

3 MADAM CHAIR PRIDEMORE: Okay. Georgia Watch
4 has left for day.

5 Interstate Gas Supply? Anybody else? Try to
6 keep this efficient.

7 (No response.)

8 All right. Georgia Power.

9 BY MS. PRYOR:

10 Q Good afternoon. Allison Pryor for Georgia
11 Power Company.

12 Mr. Axelrod, on page 8 of your testimony, to
13 determine the reasonableness of Georgia Power's proposed
14 Community Solar charge, you attempted to recreate the
15 assumed cost components of the charge.

16 Does your capital cost assumption assume
17 realization of the ITC on day 1?

18 A (Witness Axelrod) It assumes, as I under- --
19 well, I'm not sure how Georgia Power would do it. But I
20 believe under the ITC regulations, an entity could write it
21 off immediately and others have chosen to do like a
22 50 percent write-off immediately, and then depreciate --
23 well, use it as like a depreciation over time, or tie it
24 against the depreciation rate. And that's the approach I
25 took. I took half immediately and half spread over the

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1 remaining life of the property.

2 Q So you're not aware that the company can't
3 realize those benefits in that way due to tax
4 normalization issues?

5 A (Witness Axelrod) I didn't realize that.

6 Q Okay. Would you be surprised to learn that
7 Georgia Power priced its Community Solar based on lost
8 revenues to prevent shifting costs to nonparticipants
9 rather than pricing it to recover the capital cost of the
10 facilities?

11 A (Witness Axelrod) Well, that's what the -- I
12 understand it. I read it. And quite honestly, I didn't
13 spend my life trying to find it, but I spent a fair amount
14 of time, and I couldn't find anywhere that it broke down
15 what you meant by it. I understand the language you're
16 saying. I understand you're recovering your costs, but I
17 couldn't find anywhere that broke down clearly what those
18 components were that differ-- -- that brings the 16 -- I have
19 \$16.80. And I recognize it's a ballpark number.

20 But the point is, I got up to \$17, roughly, and
21 that's the cost, what appears to be a fair price if it was a
22 subscription rate without the additional costs. Now, it
23 doesn't include franchise tax and so forth that might be
24 added.

25 And just to add on, so I complete my thought
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1 here is, I added on those fees that are on, you know, the
2 residential tariff at the same rate, and I got up to 22 or
3 \$23. So I just stopped there because I couldn't find a
4 clear explanation from the company other than a generality
5 that it avoids cross-subsidization.

6 Q Did you review the work papers Georgia Power
7 provided in response to Data Request STF-DEA-2-12?

8 A (Witness Axelrod) I don't know if that
9 particular one I saw.

10 Q Okay.

11 A (Witness Axelrod) I mean, I just don't
12 recognize the number.

13 Q Sure.

14 A If you have it available, I can -- I'd be glad
15 to look at it.

16 Q I don't have it with me, but I can get that
17 to you if you'd like to see it.

18 Did you happen to review the information about
19 Georgia Power's Community Solar program available on its
20 website?

21 A (Witness Axelrod) Yes.

22 Q And so you didn't review the frequently asked
23 questions where Georgia Power explained how customers
24 bills looked like after the Community Solar charge is
25 applied?

1 A (Witness Axelrod) I mean, I read it all, so I
2 don't know what you mean by that, but...

3 Q Did you or anyone who's associated with the
4 coalition reach out to anybody at Georgia Power to get
5 additional clarification on how that charge was
6 calculated?

7 A (Witness Axelrod) I did not, no.

8 Q Okay. Regarding your proposal to create a
9 solar rebate, are you aware that Georgia Power
10 continuously studies and evaluates many different solar
11 program designs and puts forth the portfolio of programs
12 in this IRP that Georgia Power believes offers the most
13 value for customers?

14 A (Witness Axelrod) I do, and that's why we
15 offered another one.

16 Q Regarding the CARES program, does the
17 Coalition of Local Governments support the CARES program
18 generally?

19 A (Witness Seydel) Yes. I mean, we're -- the
20 City of Atlanta is trying to go after CRSP, the precursor
21 for CARES.

22 Q And you agree that municipalities can
23 participate in both the MUSH carve-out and the existing
24 customer segment?

25 A (Witness Seydel) If they have a big enough
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1 load, yeah.

2 Q But there's no restriction preventing a
3 certain class of customer from participating, other than
4 the size restriction?

5 A (Witness Seydel) Other than that, and, you
6 know -- and the 5,000 fee which I think applies to all
7 classifications, whether it's MUSH or, you know, outside of
8 that. But, I mean, that -- I mean, the City of Atlanta, we
9 had to get outside funding to be able to pay for that. So,
10 you know, it -- that, by itself, is a massive barrier,
11 especially with no guarantee of, you know, trying to pitch
12 leadership, much less community members that we're going to
13 spend \$5,000 for potentially having renewable energy.

14 Q If the NOI fee were waived for MUSH
15 participants, do you think it's fair that other customers
16 pay that fee instead?

17 A (Witness Seydel) Come again. What was that?

18 Q So if the NOI fee were waived for MUSH
19 participants, do you think it's fair that other customers
20 pay that fee instead?

21 A (Witness Seydel) I think -- and what I
22 suggested in my testimony is that either waived to show that
23 there's demand, because when Georgia Power comes out and
24 says there's no demand for it, and that's what created the
25 50 megawatts for MUSH, but you had these barriers that

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1 pretty much go against our commitment to taxpayer
2 stewardship, which is different from a lot of businesses and
3 corporations that, you know, can, as a part of their ESG
4 goals, or whatever else, can apply for it. It's a
5 fundamentally different class, and that's why I think MUSH
6 was -- I would think that that's why MUSH would be carved
7 out.

8 Q Would you agree participation in the MUSH
9 segment of the program is allocated on a pro rata basis?

10 A (Witness Seydel) I would have to check.

11 Q So if that were true, if you -- if you agreed
12 with that, doesn't that mean that all interested MUSH
13 customers who participate will get allocated some portion
14 of the output of the supplying portfolio?

15 A (Witness Seydel) I'd have to check. And also
16 as part of my testimony, too, it's, you know, whether that's
17 waived or whether -- because I understand that you want skin
18 in the game. I understand that it costs money for people
19 to -- and time and resources to look over applications.

20 And so even, like, reinstructing it in a way
21 where, you know, if we are selected to be a part of the
22 program, you know, have that as something that's paid, you
23 know, over time, you know, to show that we have skin in the
24 game, I think that makes sense, but...

25 Q In your testimony on page 22, lines 17

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1 through 18, you recommend that the Automated Benchmarking
2 Tool be continued as a core DSM program. What do you mean
3 by core DSM program?

4 A (Witness Seydel) On page?

5 Q Twenty-two.

6 A (Witness Seydel) Twenty-two. Thanks.

7 So what I'm referring to here, for a
8 demand-side management program, it's funded by Georgia
9 Power. It's utilized as a mechanism for building owners to
10 be able to first be able to get on that scale as a precursor
11 for, you know, losing weight for the energy efficiency
12 investment.

13 And, I mean, anybody who works in energy
14 efficiency knows, especially when you're trying to, you
15 know, measure how much you want to -- how much you want to
16 lose, by having that -- by having the Automated Benchmarking
17 Tool, that helps especially a lot of building owners with a
18 bunch of tenants be able to see exactly how much -- how much
19 energy that building is consuming. And, therefore, you
20 know, taking those next steps of whether that's an audit or
21 just going ahead and doing, you know, basic energy
22 efficiency upgrades to help reduce those costs.

23 Q So just to clarify, are you asking that the
24 ABT, the Automated Benchmarking Tool, be certified, tied
25 to energy savings, and eligible for the company to earn an

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1 additional sum?

2 A (Witness Seydel) I am advocating for it to be
3 aligned with what staff has recommended to continue to have
4 it funded at the -- I think it's at -- what was it, around
5 \$500,000 a year?

6 Q So you're not advocating for a change from
7 how it's currently treated in the existing program cycle?

8 A (Witness Seydel) That's correct.

9 Q Okay. So -- and your testimony is, just to
10 clarify, that Georgia Power should continue offering this,
11 meaning it's paying for this tool; is that correct?

12 A (Witness Seydel) That's correct. That to --
13 to continue funding it or, you know, as in the last hearing,
14 to not stop funding -- yeah, yeah.

15 Q Are you aware that through the end of 2021,
16 the cities of Savannah and Atlanta were the largest users
17 of this tool?

18 A (Witness Seydel) I'm not surprised.

19 Q And are you aware that to date, that use
20 hasn't directly translated into energy efficiency savings?

21 A (Witness Seydel) I'd be interested to see --
22 you know, is this versus 2019?

23 Q Just through the end of 2021?

24 A (Witness Seydel) With what as a base year?

25 Q That, I don't know.

1 A (Witness Seydel) Because I can -- I have a
2 feeling that, you know, in just -- you know, being the
3 teleworking person myself for the most part -- I mean, I'm
4 here to today in front of y'all -- but, you know, especially
5 in 2020 where you had COVID impacts and you had a lot of our
6 commercial buildings not being utilized, some of the -- you
7 know, I'd be interested to see what base year you're looking
8 at because I think that alone would probably show that there
9 is some incre- -- at least incremental energy efficiency
10 measured across that. I think it's around 900 buildings or
11 at least requests that had been given back to be able to
12 provide -- that the ABT provided.

13 Q Are you aware that nonutility companies offer
14 the same type of service to the market?

15 A (Witness Seydel) Not surprised.

16 Q On page 25 of your testimony, lines 20
17 through 25, you recommend that the DSM working group work
18 with Georgia Power to create a centralized resource of
19 organizations, funding and financial support, and use
20 cases. And my question is, who would pay the cost to
21 develop and maintain such a resource?

22 A (Witness Seydel) Well, I -- so I'm going to
23 answer your question, but when we had our one-on-one
24 stakeholder meetings, it was actually something that was
25 already mentioned as a part of that meeting where -- and I'm

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1 not -- I can't remember the specific name, but there was a
2 centralized resource that Georgia Power was talking about
3 where residents, commercial building owners would be able to
4 get that information, and that we were invited to help
5 participate in, you know, bringing different nonprofits.

6 You know, all the things that are out there for
7 energy efficiency, including I talked a little bit about
8 health and safety, to bring it into that same ecosystem. I
9 can't remember what the name is. But to answer your
10 question, I mean, in this case, it just depends on who wants
11 to host it. I don't think I specified who should actually
12 host the centralized resource, but if Georgia Power wants to
13 take that on, that's great. But -- and I think would help
14 deepen our relationship between us and our participating
15 coalition of governments.

16 Q Is that something the City of Atlanta would
17 be willing to provide?

18 A (Witness Seydel) I can't speak to -- I can't
19 speak to it without asking my -- asking my leadership, but I
20 would imagine so.

21 Q Moving onto your income-qualified
22 recommendations. To increase participation in the
23 company's income-qualified programs, you recommend that
24 the company provide or obtain funding for prerequisite
25 health and safety repairs.

1 A (Witness Seydel) Uh-huh.

2 Q Are these types of repairs directly tied to a
3 customer's energy usage?

4 A (Witness Seydel) Well, I think that's the -- I
5 think that's the issue. A lot of the times that they aren't
6 able to participate in energy efficiency programs because of
7 the health of the home and safety -- the health and safety
8 repairs that are needed. When you're talking about a roof
9 leak, you're talking about -- you're talking about health
10 issues, you're talking about homes that, you know, don't
11 have a lot of the precursors for -- to be an
12 energy-efficient house, or just a healthy house in general,
13 which can lead to different, you know, energy use behaviors
14 that might not be, you know -- that could be connected to
15 exactly what you're asking.

16 Q But if these repairs don't reduce energy
17 usage in a cost-effective manner, why should all
18 residential customers pay for such costs on their electric
19 bill?

20 A (Witness Seydel) So I think especially when
21 looking at -- when looking at a portfolio of different
22 energy efficiency possibilities, if you link it with health
23 and safety repairs, not only are you going to be able to get
24 a lot more potential federal grant dollars and support from
25 outside Georgia Power or outside any type of

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1 ratepayer-funded -- funded program -- and I believe you
2 asked why should people -- what was the question one more
3 time?

4 Q Sure. Why should residential customers pay
5 this on their -- on their electric bill for repairs or
6 efforts that don't actually reduce their energy savings?

7 A (Witness Seydel) Are you talking about people
8 that aren't -- that wouldn't -- are you talking about all
9 ratepayers for Georgia Power to help pay for health and
10 safety repairs?

11 Q My understanding was that you wanted to
12 include it as part of the income -- income-qualified
13 program. So the payments for that go through the DSM
14 rider, which is paid -- for residential --

15 A (Witness Seydel) Yeah.

16 Q -- programs is through the DSM rider for the
17 residential customers.

18 A (Witness Seydel) Cool. That's what I meant,
19 what I was getting at.

20 Q Yeah.

21 A (Witness Seydel) Well -- sorry, I didn't know
22 who was going.

23 So, I mean, I feel like health and safety
24 repairs are just, you know, the precursor for being able to
25 become energy efficient or have affordable high standard of

1 living. And so at the end of the day, especially when
2 you're talking about energy efficiency, especially in areas
3 where you're looking at what we were just talking about with
4 the solar rebate that are going to require a lot more
5 resources for transmission, I think you can offset the --
6 you know, you don't have to -- just like with the solar
7 rebate and the amount that can go back into the grid that
8 helps reduce overall prices by being able to avoid those
9 major investments in centralized units or, you know, massive
10 installations that help with interconnection. I think that
11 it's kind of the same type of general thinking is that
12 it's -- that that's all connected.

13 MS. PRYOR: Thank you. No further questions.

14 WITNESS SEYDEL: Thank you.

15 MADAM CHAIR PRIDEMORE: Redirect.

16 MS. BROWN: Yes, ma'am.

17 REDIRECT EXAMINATION

18 BY MS. BROWN:

19 Q Mr. Seydel, is energy efficiency a resource
20 like solar or gas is?

21 A (Witness Seydel) Yeah.

22 Q Do you need infrastructure like transmission
23 and distribution lines to deliver solar and natural
24 gas-produced energy?

25 A (Witness Seydel) Yes.

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1 Q Do you also, in some cases, need tools in
2 order to deliver energy efficiency?

3 A (Witness Seydel) Yes.

4 Q And do we not pay for transmission and
5 distribution through our rates?

6 A (Witness Seydel) Yes.

7 Q Dr. Axelrod, all of the numbers aside,
8 whether you're using NREL numbers or Georgia numbers, is
9 the gist of your testimony that it is unjust and
10 unreasonable to charge Community Solar participants for
11 nuclear and fuel for the portion they are dedicating to
12 receive from solar?

13 A (Witness Axelrod) Yes, it is unfair. But I
14 would like to add onto that a bit. I've given it some
15 thought, because we're -- the company's argument is, is that
16 it's making them whole and, therefore, there's no
17 cross-subsidization.

18 Well, my testimony points out that by adding
19 those on, as just said, it seems unfair. Somebody who's
20 participating and willing to go forward with what the
21 company calls a premium product, it's premium because not
22 only are they paying for that resource, but because of the
23 other components that we talked about like the nuclear cost,
24 as well as environmental restoration costs on other -- from
25 other types of generation.

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1 But more importantly is, to me, the hypocrisy
2 of being concerned about cross-subsidization when, in fact,
3 there is a higher likelihood that whatever the price is,
4 there could be cross-subsidization through a subscription
5 rate, and let me explain.

6 If you took a low -- a low-energy consumer, and
7 I looked at the first block of rates at 650 or 640
8 kilowatt-hours, it turns out that at that rate, you know, it
9 turn -- it ends up being around 19 cents a -- no, I'm sorry.
10 It's about 9 or 10 cents a kilowatt-hour.

11 On the other hand, if you look at the proposed
12 \$27.99, which I point out also in my testimony is kind of
13 like a used car salesman, that why don't we call it \$28 set
14 and not \$27.99, where people think naturally of the lower
15 number, it's only costing me \$27 a month, not 28. But
16 anyhow, that's a side point. That's a personal matter.

17 But on the other hand, if you look at that
18 customer at 640 kilowatt-hours and you look at one -- one of
19 the units of the solar production, if you take the \$27.99
20 and divide it by what the capacity factor of that one
21 kilowatt unit would be, it ends up being approximately,
22 like, 19 cents per kilowatt-hour. And so it's high but it's
23 premium. I understand that.

24 But what happens -- that number is based upon
25 predicated the average production of that solar facility,

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1 which I used the 12 -- or 20 percent for that computation.
2 Others might use a little lower and some a little higher,
3 but the point is, the number comes out to be what's that
4 base price on average.

5 If it's a -- if it's a less than sunny day or
6 long stretches of rainy cloudy days or the plant is out of
7 service for a period of time, that consumer is still paying
8 the 27.99 and receiving zero, which includes already all the
9 costs that the company for that amount of energy is charging
10 to cover all its costs, that's what it's saying, so you're
11 not cross-subsidizing, so I'm paying that, and then I turn
12 around and they charge me because I'm paying -- now I have
13 to use the normal tariff rate. I'm being charged all over
14 again for that nuclear cost and that environmental cost and
15 the DSM cost. So I'm being charged twice if the plant is
16 down.

17 Now, that's cross-subsidization where the
18 consumer -- especially a low-income consumer who might be
19 environmentally -- not a low income, but a low energy
20 consumer who might be interested in contributing to helping
21 the environment, you're really charging them twice.

22 And my last point is, what's the likelihood
23 they're going to have more sun on a given day than you have
24 all the opportunities to have less sun or no operation at
25 all? I would say the probability is much greater that I'm

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1 going to be overpaying or double paying than I would be in
2 receiving some benefit for those days where I get a little
3 more sun than -- than normal.

4 So I -- I want to point out that the pristine
5 aspects of let's call this rate, the 27.99, one that
6 produces revenue neutrality among classes really misses the
7 point.

8 Q Pivoting to CARES, Mr. Seydel, you were asked
9 if this would -- if the portions from that program were
10 awarded on a pro rata basis.

11 Would not being awarded any solar be the only
12 reason that the City of Atlanta might not move forward with
13 a program like this, or could there be other reasons that
14 you ultimately procure nonrenewable energy?

15 A (Witness Seydel) There could be other reasons.

16 Q Would you like to share those with us.

17 A (Witness Seydel) Well, first, I mean, we're
18 going for it with CRSP, so we're certainly trying and, you
19 know, to, you know, investigate. We're really just trying
20 to investigate, you know, what other things that are out
21 there that can prevent local governments from being able to
22 participate.

23 Q So would one barrier potentially be that you
24 find that this program is outside of your budget and you
25 simply can't make it work?

1 A (Witness Seydel) Yes, especially smaller
2 governments.

3 Q Do you feel like you always have the
4 information in-house to make that decision until Georgia
5 Power spells it out for you?

6 A (Witness Seydel) I know -- I know we struggle
7 sometimes, and I can only imagine for smaller governments
8 that, you know, either have one or two people working on
9 their sustainability programs much less, you know, people
10 who don't have sustainability even in their title, but
11 they're just doing this just to try and be a good steward
12 for their government and also helping meet their clean
13 energy goals, even if they don't have funding for that
14 specific title.

15 MS. BROWN: Thank you, gentlemen. You're
16 excused.

17 Madam Chair, may I move for our exhibits to be
18 entered into evidence as Georgia Coalition of Local
19 Governments 1 and 2?

20 MADAM CHAIR PRIDEMORE: So moved.

21 (Georgia Coalition of Local Governments
22 Exhibits 1 and 2 was admitted into evidence.)

23 MR. SEYDEL: And we're excused?

24 MS. BROWN: Gentlemen, you're excused.

25 MADAM CHAIR PRIDEMORE: You may excuse your
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1 witnesses, Ms. Brown.

2 You're excused.

3 Okay. Don't get too excited. I know. I
4 really appreciate your eagerness, Ms. Kysor, I really
5 do, but we're going to call it a day. All right?

6 So according -- some housekeeping matters
7 before we go. According to my calculations, GIPL,
8 you've got a panel?

9 MS. KYSOR: We have two witnesses.

10 MADAM CHAIR PRIDEMORE: You have two witnesses,
11 but you're doing them together; correct?

12 MS. KYSOR: We weren't planning on it, but if
13 the Commission prefers it that way, we could.
14 They'll have their own separate summaries, they filed
15 separately.

16 MADAM CHAIR PRIDEMORE: Yes. Let's do those
17 together.

18 All right. GLSSA, I've got -- I've got a
19 four-person panel. Are they together?

20 Okay. Vote Solar, I've a four-person panel,
21 are they together?

22 MR. THOMASSON: Yes, ma'am.

23 MADAM CHAIR PRIDEMORE: All right. Restore
24 Chattooga Gorge, I've got a two-person panel. Are
25 you together?

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1 MR. JONES: Yes, ma'am.

2 MADAM CHAIR PRIDEMORE: Okay. Sierra Club, I
3 have three witnesses, how are you going to arrange
4 those? Together?

5 MS. ARIZA: Not together?

6 MADAM CHAIR PRIDEMORE: You don't want them
7 together?

8 MS. ARIZA: If possible, no.

9 MADAM CHAIR PRIDEMORE: What if I asked really
10 nicely, would you do them together? With three
11 separate summaries?

12 MS. ARIZA: Definitely the last one, Mark
13 Quarles, should be separate. The first two could be
14 together with different --

15 MADAM CHAIR PRIDEMORE: Well, that's how it's
16 written out anyway, no favors there. Okay. All
17 right. So two for Sierra Club.

18 SACE, I have four -- I have three links, three
19 witnesses. Together or separate?

20 MR. BAKER: Their testimony is distinct and
21 submitted -- submitted individually, so, I mean, they
22 understand they're going to be hitting the ground
23 running.

24 MADAM CHAIR PRIDEMORE: Define that "hitting
25 the ground running." Are they hitting the ground

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1 running as a threesome or by themselves?

2 MR. BAKER: Individually. Individually.

3 MADAM CHAIR PRIDEMORE: Individually?

4 MR. BAKER: Individually.

5 MADAM CHAIR PRIDEMORE: And that's important to
6 you?

7 MR. BAKER: I mean, I don't know -- I mean, if
8 Georgia Power has cross-examination for each of those
9 witnesses, I would ask Georgia Power --

10 MADAM CHAIR PRIDEMORE: I'm just trying to
11 speed the time. It takes time to load witnesses. It
12 takes -- it just -- I'm just trying to help us along.

13 MR. BAKER: Well -- well, Mr. Wright is going
14 to be testifying remotely, so he'll be testifying
15 whenever he's called upon.

16 MADAM CHAIR PRIDEMORE: All right. Let's do
17 him on a panel, then, with Mr. Binz, and Ms. Brown
18 can go alone.

19 MR. BAKER: How about Forest and Dr. Brown
20 together?

21 MADAM CHAIR PRIDEMORE: Got it.

22 MR. BAKER: With separate summaries now.

23 MADAM CHAIR PRIDEMORE: Mr. Binz -- of course.

24 MR. BAKER: Okay.

25 MADAM CHAIR PRIDEMORE: Obviously. And

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Mr. Binz is on his own. Okay.

All right. And Southern Renewable Energy Association, you're one?.

All right. Got everybody. Very good. Thank y'all very much for your attention today. We'll see you back here tomorrow morning at 9:30.

(Hearing adjourned at 5:16 p.m.)

C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.



A handwritten signature of Kelley Marie Nadotti in cursive script, positioned to the left of a circular professional seal.

Kelley Marie Nadotti, RPR
CCR-6256-8388-8026-4192



A handwritten signature of Debbie A. Eickhoff in cursive script, positioned to the left of a circular professional seal.

Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664



A handwritten signature of Brenda P. Elwell in cursive script, positioned to the left of a circular professional seal.

Brenda P. Elwell, RPR, CRR, B-2023

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